D. DOUGLAS LARSON
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(801) 220-2190
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PACIFICORP
PACIFIC POWER • UTAH POWER

April 28, 1993

Rich Collins

TO: ALL ATTENDEES
AT DSR TECHNICAL CONFERENCE
HELD APRIL 20, 1993

Enclosed is a Draft copy of the April 20th DSR Technical Conference Minutes, together with attachments. Also enclosed is a copy of a memo from Eric Blank and Eric Hirst, together with attached articles, regarding the effects of utility DSM programs on electricity prices.

The next Technical Conference is scheduled for Tuesday, May 11, at 9:00 a.m., in the large conference room on the 20th Floor of the One Utah Center. If you have any questions, please feel free to call.

Sincerely,

D. Douglas Larson

D. Douglas Larson
Director, Economic Regulation

lfs

Enclosures

4:16

ATTACHMENT 1

DSR TECHNICAL CONFERENCE #4
ATTENDEES
April 20, 1993

NAME	ORGANIZATION	TELEPHONE	FAX
Kenneth Wilson	Deseret G&T	801-566-1238	801-562-6302
Gary Dodge	Geneva	801-532-7840	801-532-7750
Bill Evans	Kennecott, et al	801-532-1234	801-536-6111
Eric Hirst	Land and Water Fund	303-444-1188	303-786-8054
Eric Blank	Law Fund	303-444-1188	303-786-8054
Colleen Larkin Bell	Mountain Fuel	801-534-5556	801-534-5131
Brad Markus	Mountain Fuel	801-534-5631	801-534-5166
Arty Trost	Organizational Dynamics	503-668-7979	503-668-3420
Anne Eakin	PacifiCorp - Portland	503-464-5065	503-275-2636
Gordon McDonald	PacifiCorp - Portland	503-464-5986	503-275-2896
Doug Larson	PacifiCorp - Utah	801-220-2190	801-220-2422
Bob Lively	PacifiCorp - Utah	801-220-4052	801-220-2422
Barrie L. McKay	PacifiCorp - Utah	801-220-4160	801-220-2422
Dan Peterson	PacifiCorp - Utah	801-220-4014	801-220-2422
Mary Cleveland	Utah CCS	801-530-6957	801-530-7655
Dan Gimble *	Utah CCS	801-530-6798	801-530-7655
Margo Hovingh	Utah CCS	801-530-6646	801-530-7655
Rebecca Wilson	Utah Division of Energy	801-538-5428	801-521-0657
Ron Burrup	Utah DPU	801-530-6686	801-530-6512
George Compton	Utah DPU	801-530-6950	801-530-6512
Audrey J. Curtiss	Utah DPU	801-530-6672	801-530-6512
Mark V. Flandro	Utah DPU	801-530-6788	801-530-6512
Mike Ginsberg	Utah DPU	801-530-6651	801-530-6512
Judith Johnson	Utah DPU	801-530-6776	801-530-6512
Ken Powell *	Utah DPU	801-530-6664	801-530-6512
Jim Byrne	Utah PSC	801-530-6716	801-530-6796
Rich Collins *	Utah PSC	801-530-6770	801-530-6796
Stephen Hewlett	Utah PSC	801-530-6716	801-530-6796
Doug Kirk	Utah PSC	801-530-6716	801-530-6796
Jim Logan	Utah PSC	801-530-6716	801-530-6796
Ellen Eckels	Wasatch Clean Air Coalition	801-277-6664	4780 Idlewild Cr. SLC, UT 84124

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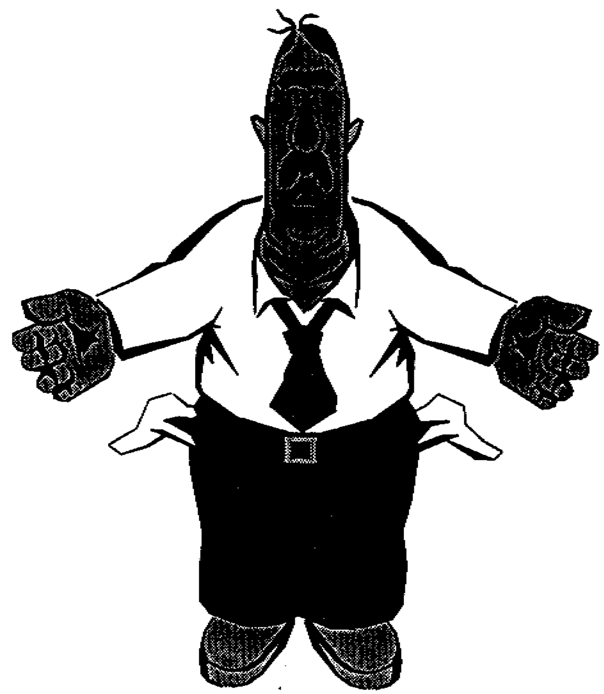
ATTACHMENT 2



Lost Revenues Presentation

Technical Conference

April 20, 1993

Problems

(As identified by this technical conference)

1. **Profitability**

2. **Equity**

3. **Competition Effects**

Goal of Technical Conference:

- Encourage the Company to implement a Least Cost Plan by developing a cost recovery mechanism which encourages the Company to look at a variety of alternatives for acquiring cost effective DSR, including rate design.

Solutions

1. Accounting Treatment
2. Participant Cost Sharing
3. Balancing Account Mechanisms
4. Incentive Mechanisms
   - Shared Savings
5. Decoupling

Accounting Treatment Solutions to the "Profitability" Problem

- Defer DSR program costs
- Delay amortization of the costs
- Accrue carrying charges on unamortized program costs - similar to AFUDC on SSR resources
- Recover Lost Revenues

Net Lost Revenue Adjustments

1. Definition & Purpose

2. Measurement

3. Calculation

Lost Revenue Definition & Purpose

- **Lost revenues result from the additional sales the Company would have made, absent its investment in DSR resources.**
- **Whether successful DSR programs impact current customers or new customers, they reduce revenues that would otherwise have been earned.**
- **A Lost Revenue adjustment is essentially a mechanism for recovering "fixed" costs of service, given a declining base of kwh sales.**

Lost Revenue Measurement Issues

- Measurement Techniques
  - Engineering studies
  - Industry standard
  - Comparison to prior usage
- Elimination of bias (Likely to understate as well as overstated)
- "Take-Back" Issues
- True-up For Actual (Balancing account?)

Lost Revenue Calculation

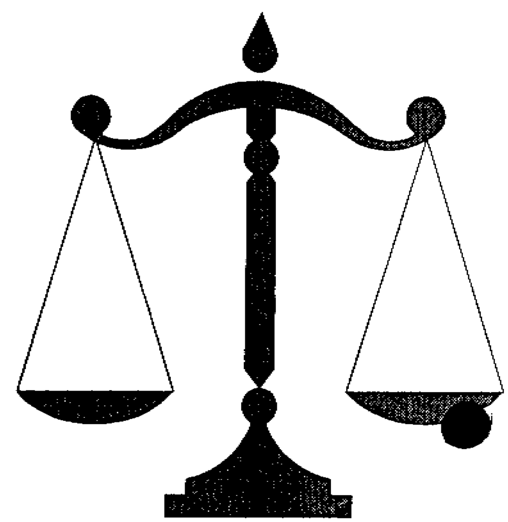
- Lost Rev = Savings x (Tail Block Rate - Avoided Cost)
  - Savings - As defined in the measurement discussion
  - Tail Block Rate - Cost to customer of last kwh used
  - Avoided Costs - Utah Short-Run Avoided Costs rate adjusted for sales for resale

Lost Revenue Calculation Example

- **Gross Savings - 29,000 kwh**
- **Tail Block Rate - 5.72 cents per kwh**
- **Avoided Energy Costs - 1.775 cents per kwh**
  - Lost Rev = 29,000 x (5.72 - 1.775)
  - Lost Rev = $1,144

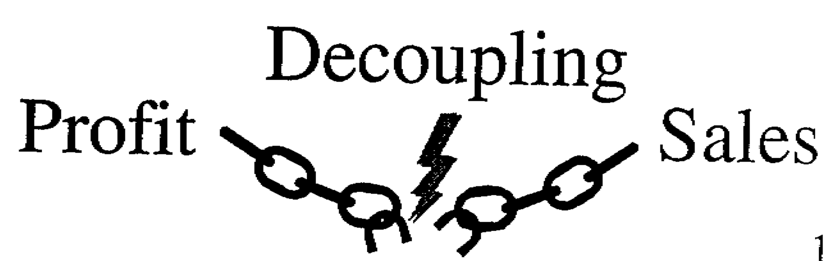
Criteria Met By Implementing Company Proposal

- **Consistency between DSR and SSR**
- **Financial impact on Company of regulation change or cost recovery**
- **Risk bearing and risk shifting**
- **DSR performance standards**



Company Concerns With Decoupling Mechanisms

- Shifts weather & business cycle risks to customers
- Isolates the utility from its customers
- Removes utility incentive to pursue socially desirable goals
- Dissatisfaction with decoupling in other jurisdictions (Washington & Maine)



Shifts Weather and Business Cycle Risks to Customers

- Increases risk of price volatility
- Contrary to long-established regulatory policy

Isolates the Utility From Its Customers

- Insulates the utility from market forces

- Tends to limit choices available to consumers

Removes Utility Incentive To Pursue Socially Desirable Goals

- No incentive to promote economic development
- No incentive to promote new, economically efficient uses for electricity

Dissatisfaction With Decoupling in Other Jurisdictions

- **Washington - Puget approach heavily criticized. $100M in increases.**

- **Maine - Central Maine Power experiment ended early. $42M balance left to collect from customers.**

ATTACHMENT 3

ELECTRIC-UTILITY REGULATION: DSM AND LOAD GROWTH

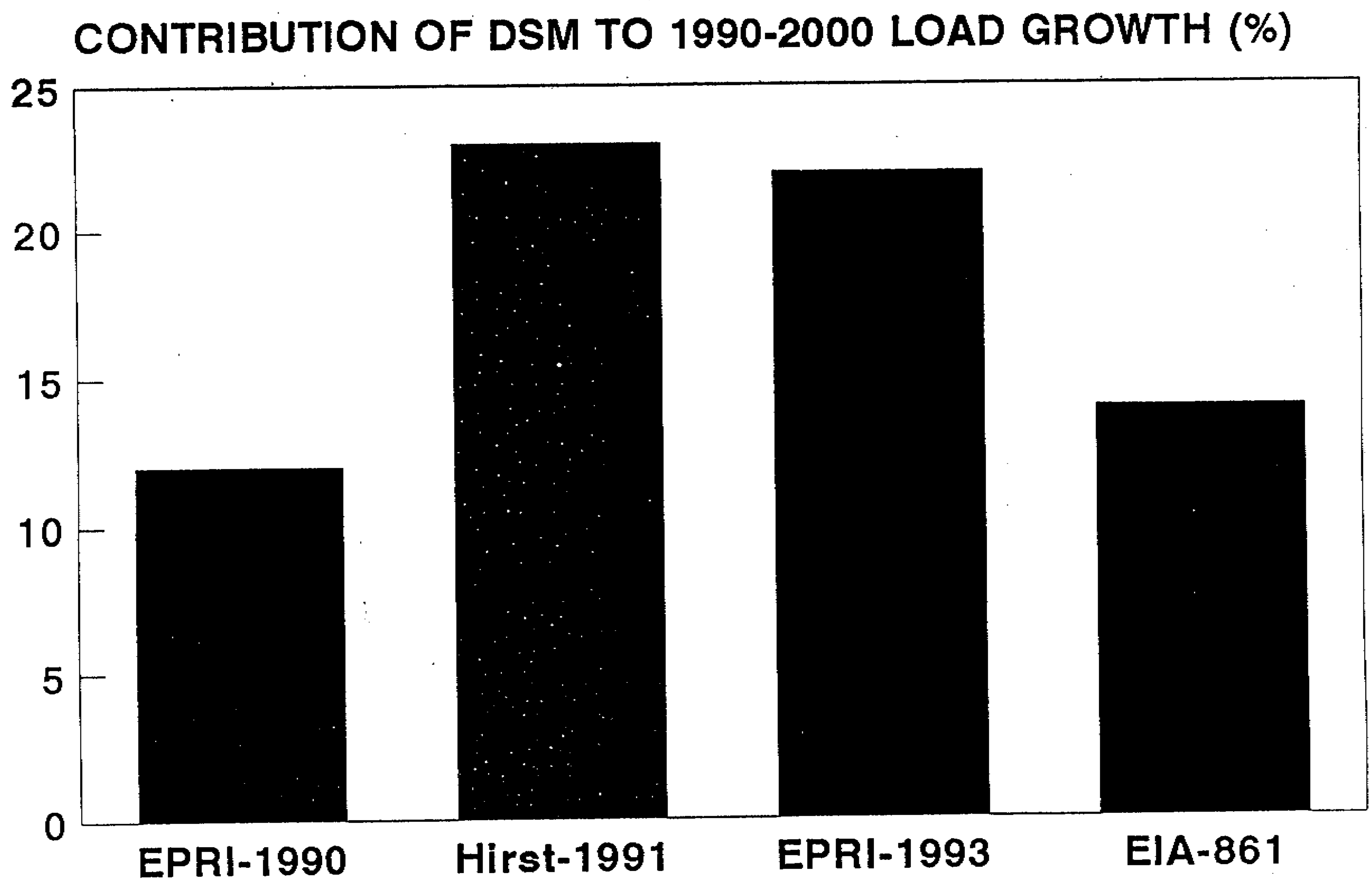
ERIC HIRST and ERIC BLANK
Land and Water Fund of the Rockies

w124

TWO ERICS WILL COVER FOUR TOPICS

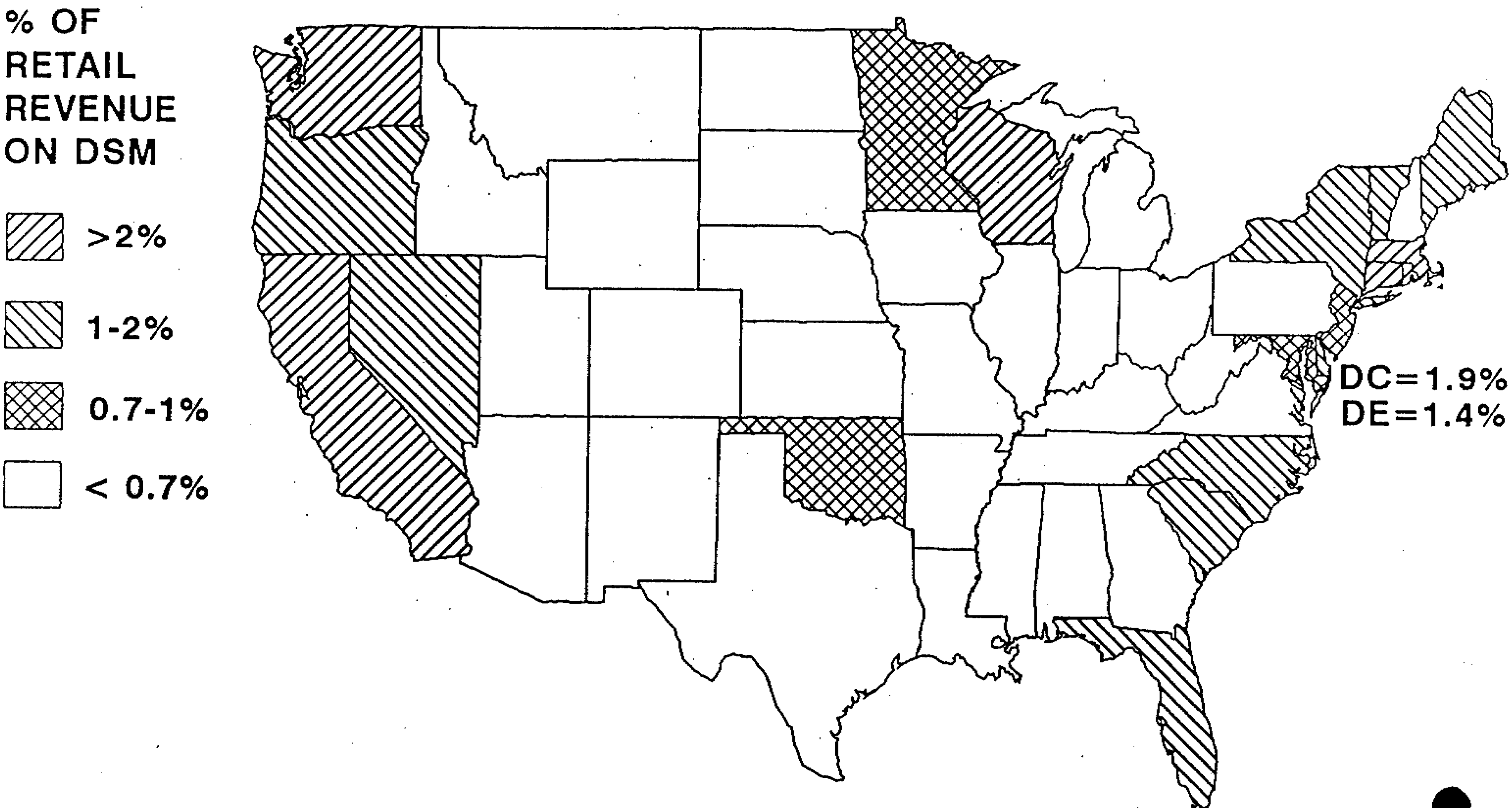
- Utility DSM programs
  - 1991 activities and potential
- Elements of DSM incentives issues
  - Cost recovery, lost revenues, incentives
- Lost revenues caused by DSM programs
- Ways to address lost revenues
  - Decoupling, lost revenue adjustment, or command and control

VARIOUS ESTIMATES OF DSM CONTRIBUTION TO LOAD GROWTH



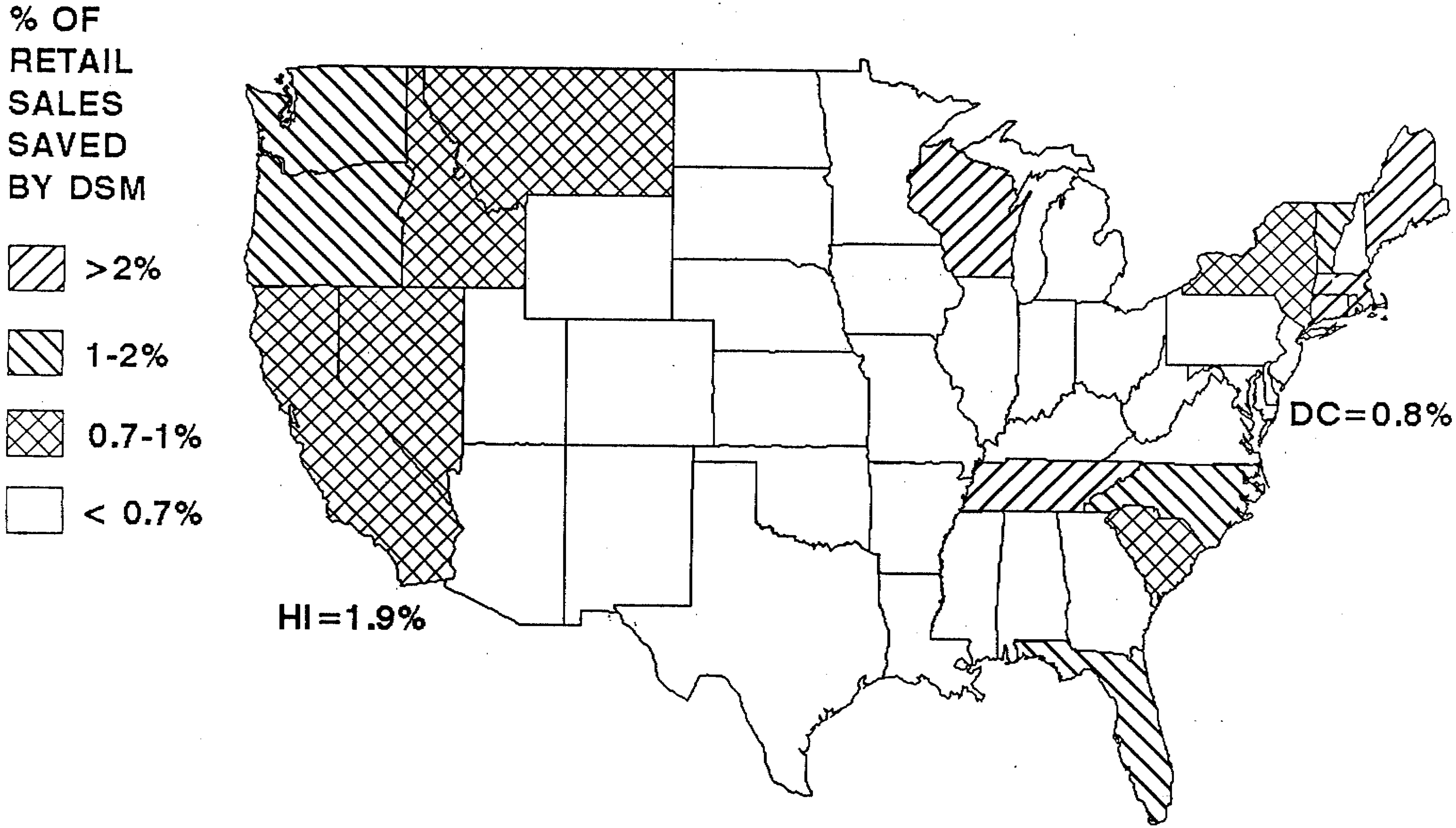
93038

16 STATES SPENT > 1% OF REVENUES ON DSM IN 1991



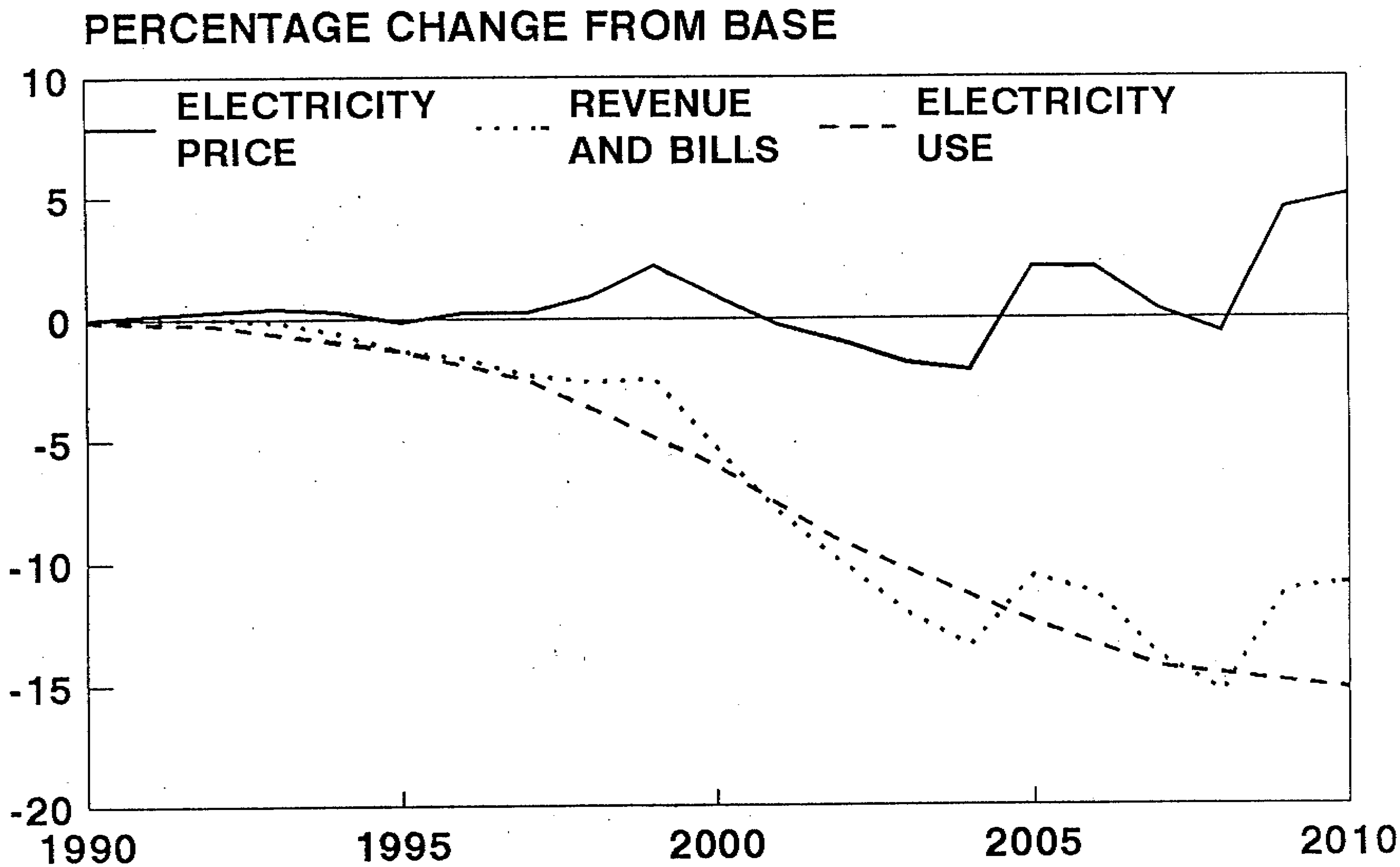
93014

12 STATES SAVED > 1% OF ENERGY FROM DSM IN 1991



93020

DSM AFFECTS ELECTRICITY PRICES, REVENUES, AND USE



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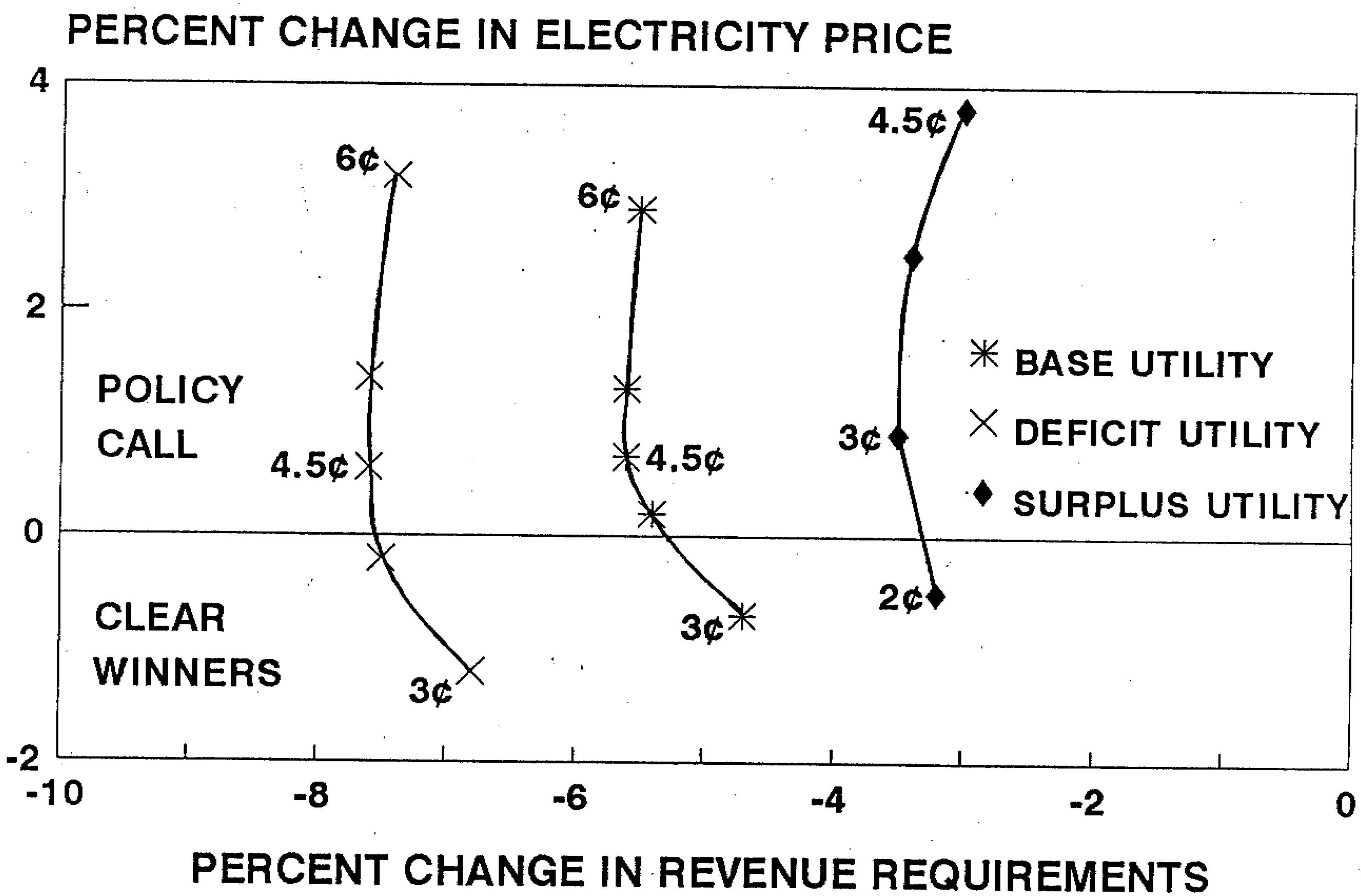
UTILITY DSM PROGRAMS AFFECT REVENUES MORE THAN PRICES



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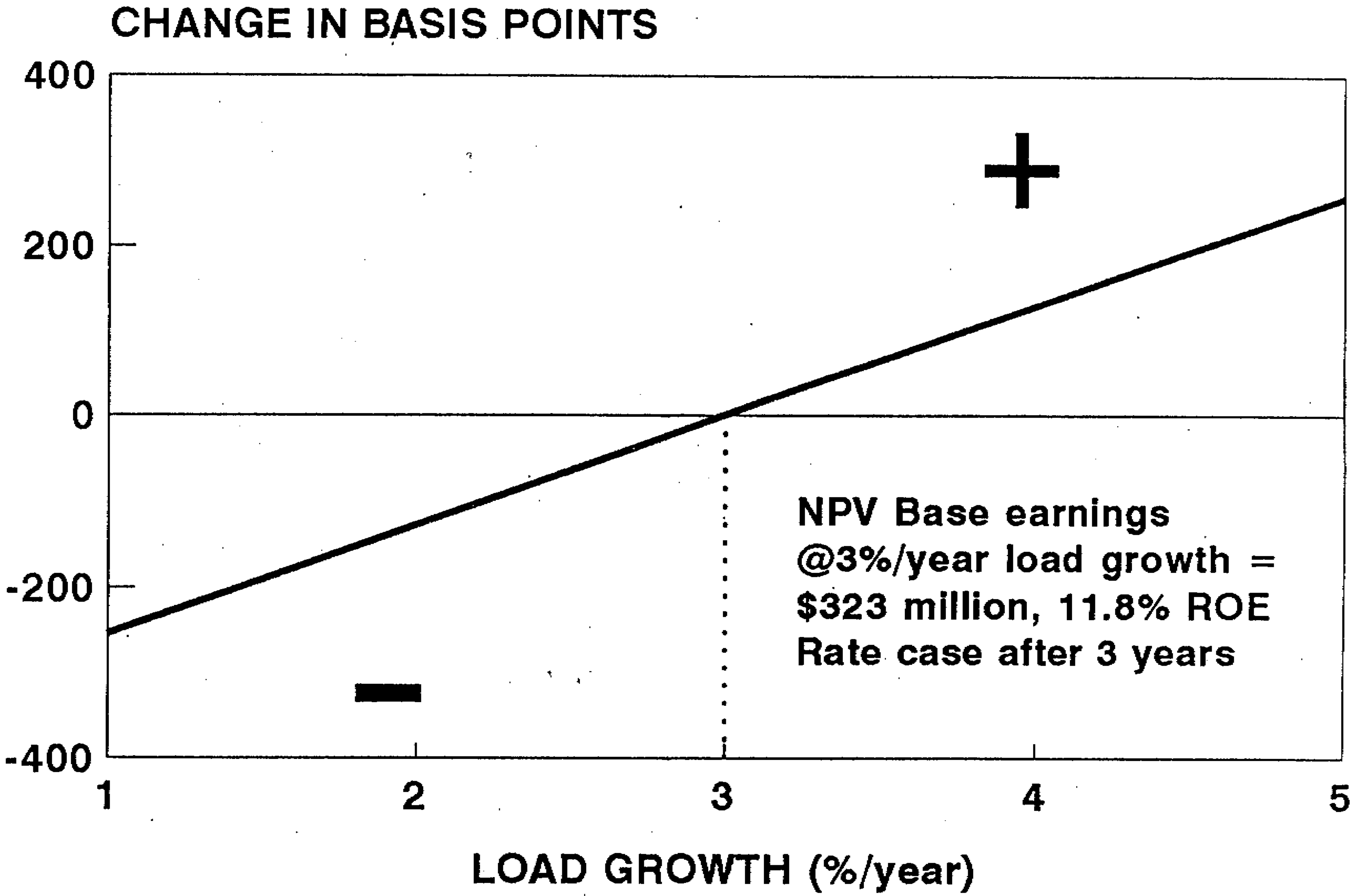
THREE ELEMENTS TO FINANCING UTILITY DSM PROGRAMS

- Recovery of DSM-program costs
  - Prompt and assured
- Treatment of net lost revenues
  - Decoupling or DSM adjustment
- Incentive to utility for DSM
  - Innovative, ambitious, and cost-effective programs

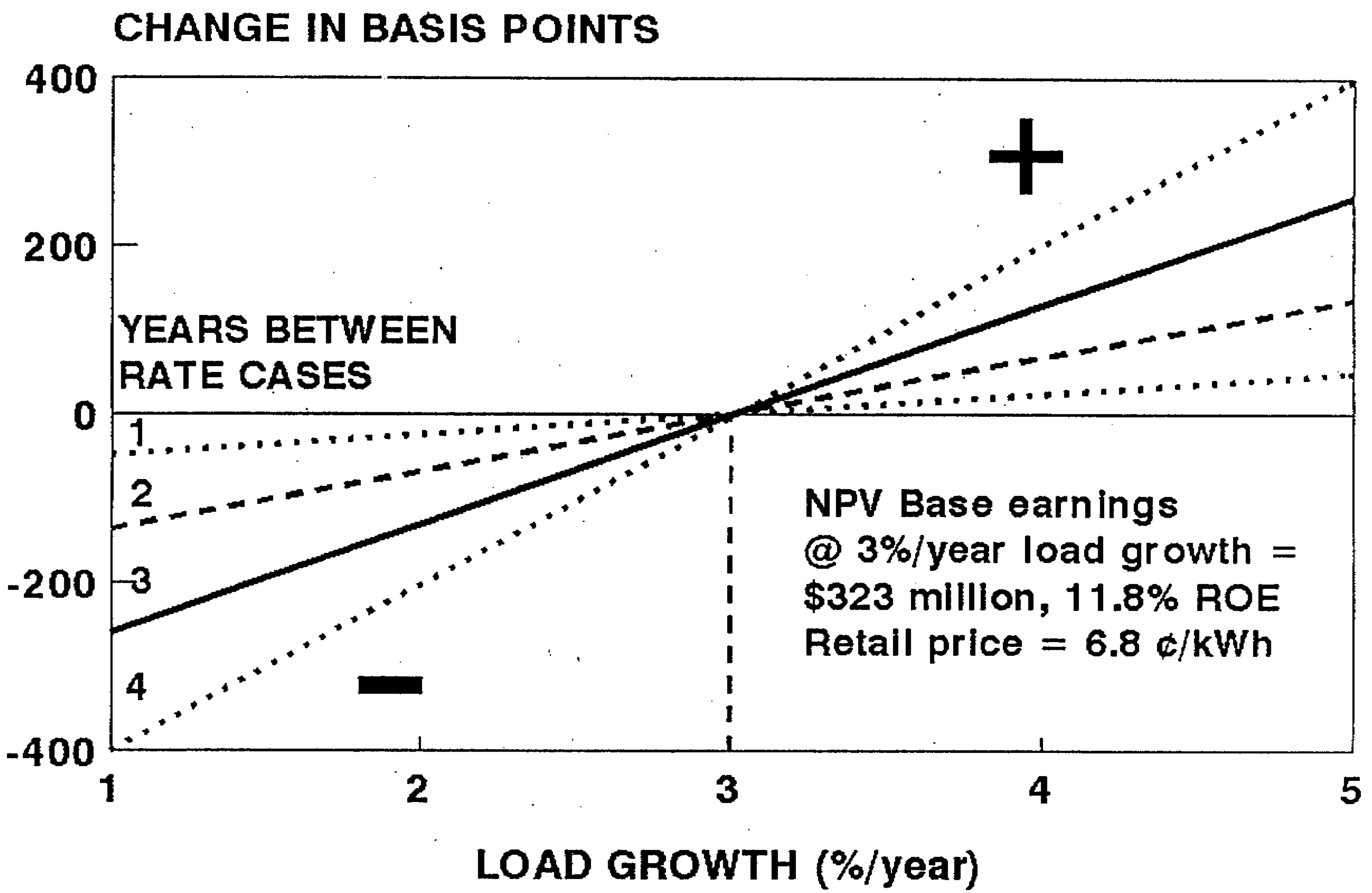
ECONOMIC REGULATION OF ELECTRIC UTILITIES AFFECTS DSM

- Retail prices cover fixed and variable costs
- If sales grow, utilities collect more money than needed to cover fixed costs
- If DSM cuts sales, shareholder earnings suffer
- Built simple model to quantify effects for PacifiCorp Utah area

PACIFICORP EARNINGS DEPEND ON LOAD GROWTH BETWEEN RATE CASES

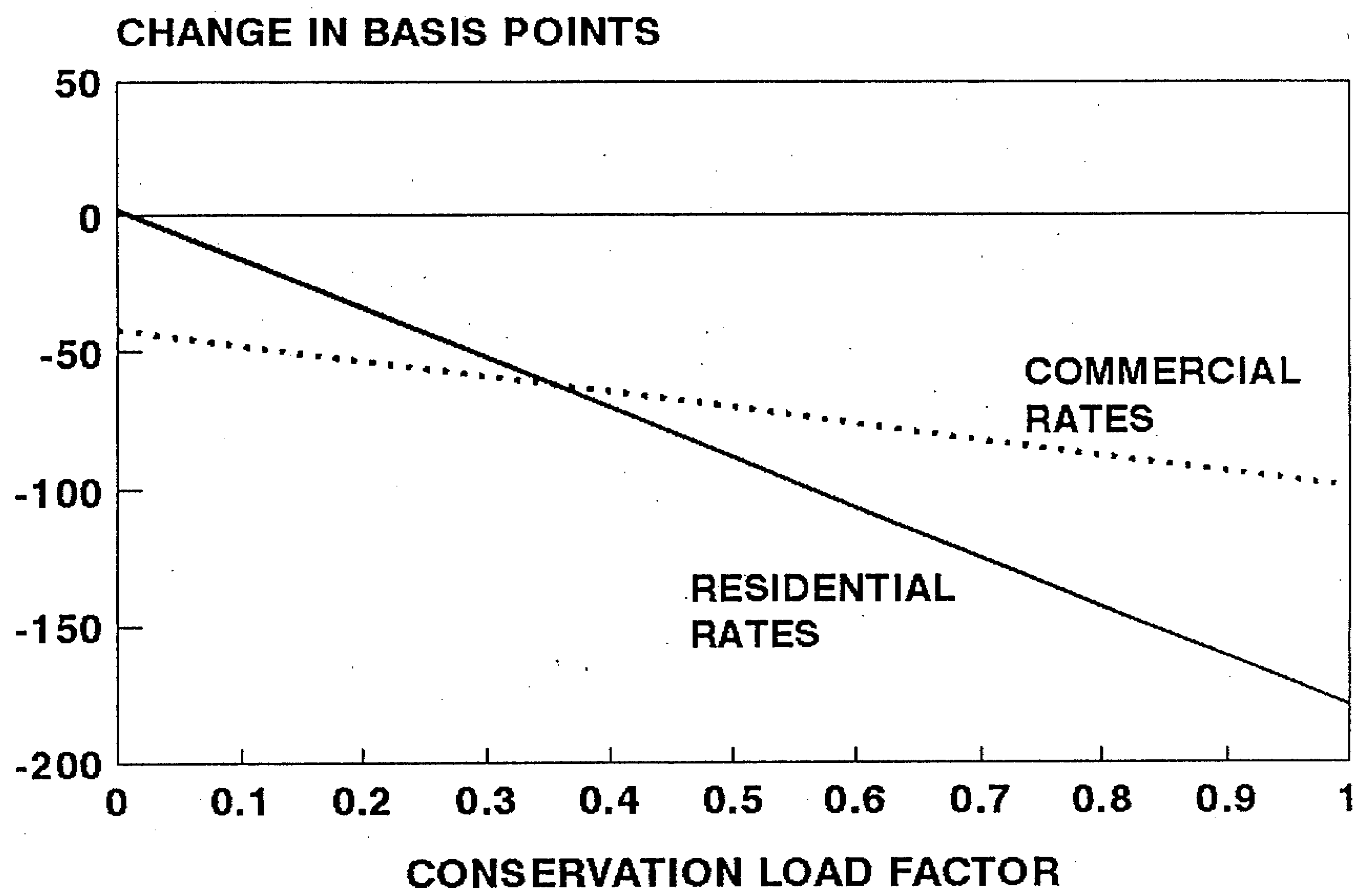


PACIFICORP EARNINGS DEPEND ON FREQUENCY OF RATE CASES



93039B

PACIFICORP EARNINGS DEPEND ON DSM LOAD FACTOR AND RATE STRUCTURE



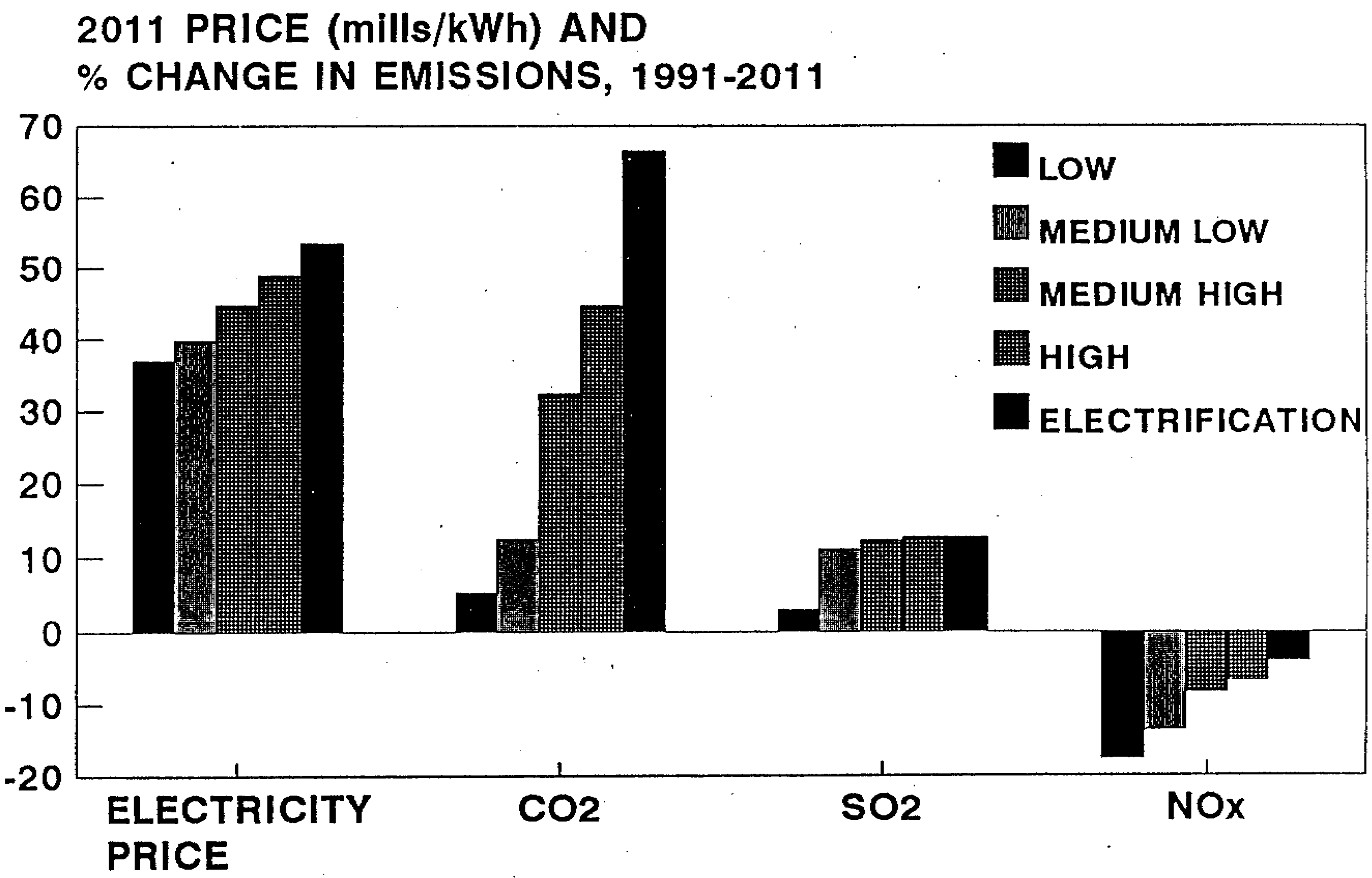
93039C

DSM CUSTOMER BENEFITS OPPOSITE SHAREHOLDER EFFECTS

Type of DSM program	Percent of load growth	Customer benefit (million $)	Shareholder effects (basis points)	Shareholder effects (million $)
Pilot	11	7	-6	-2
Ramp-up	22	41	-52	-14
Full-scale	36	80	-136	-37

W127A

PACIFICORP's RESULTS SHOW COSTS OF LOAD GROWTH



92082

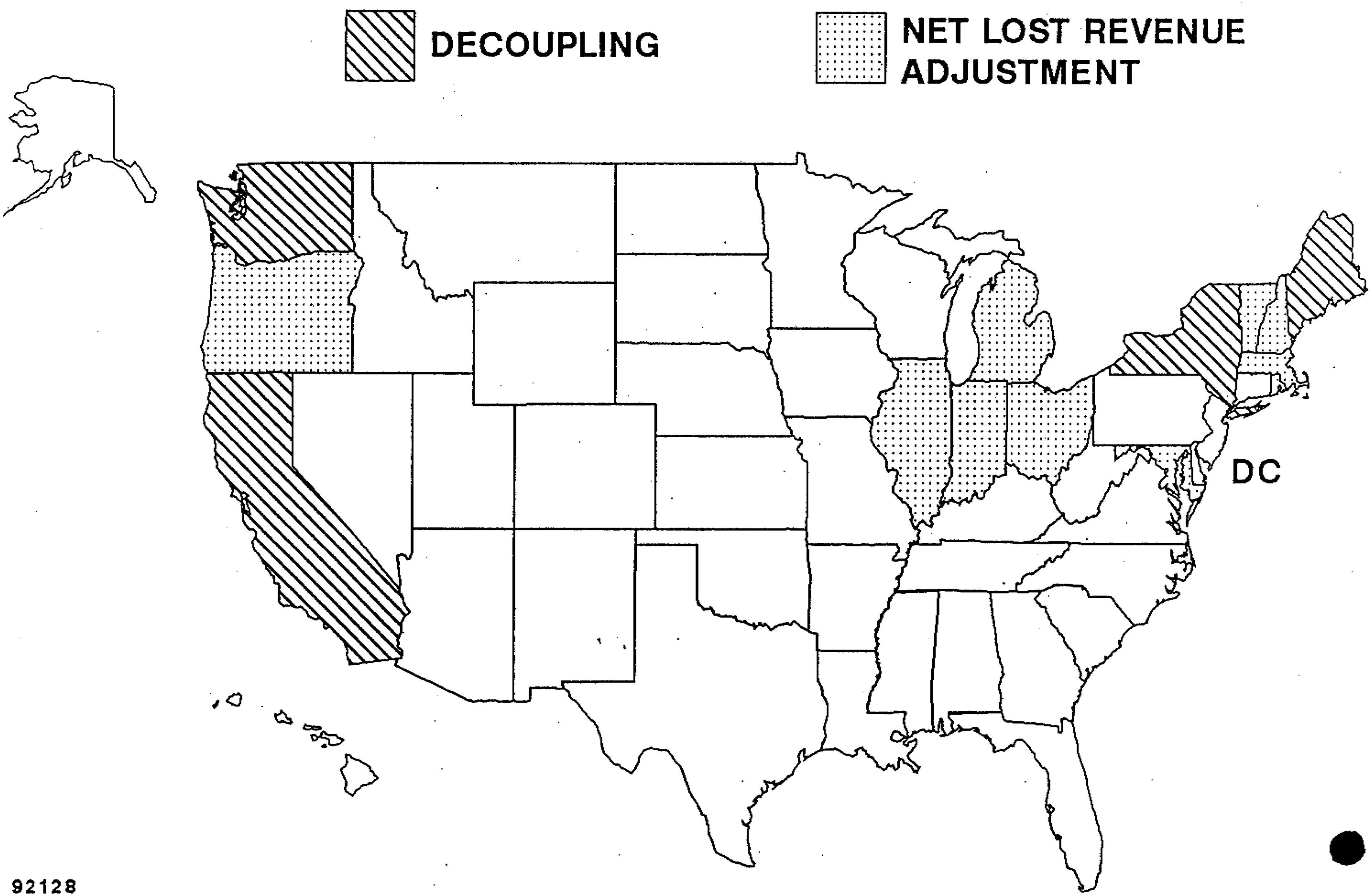
SEVERAL SOLUTIONS ARE POSSIBLE

After Lunch

- Command and control regulation
- Frequent rate cases
- Rate design
- Lost-revenue adjustments
- Decoupling
- Statistical recoupling

See LAW Fund report for assessments

FOUR STATES WITH DECOUPLING, TEN WITH NET LOST REVENUE ADJUSTMENT



92128

DECOUPLING BREAKS LINK BETWEEN SALES AND REVENUES

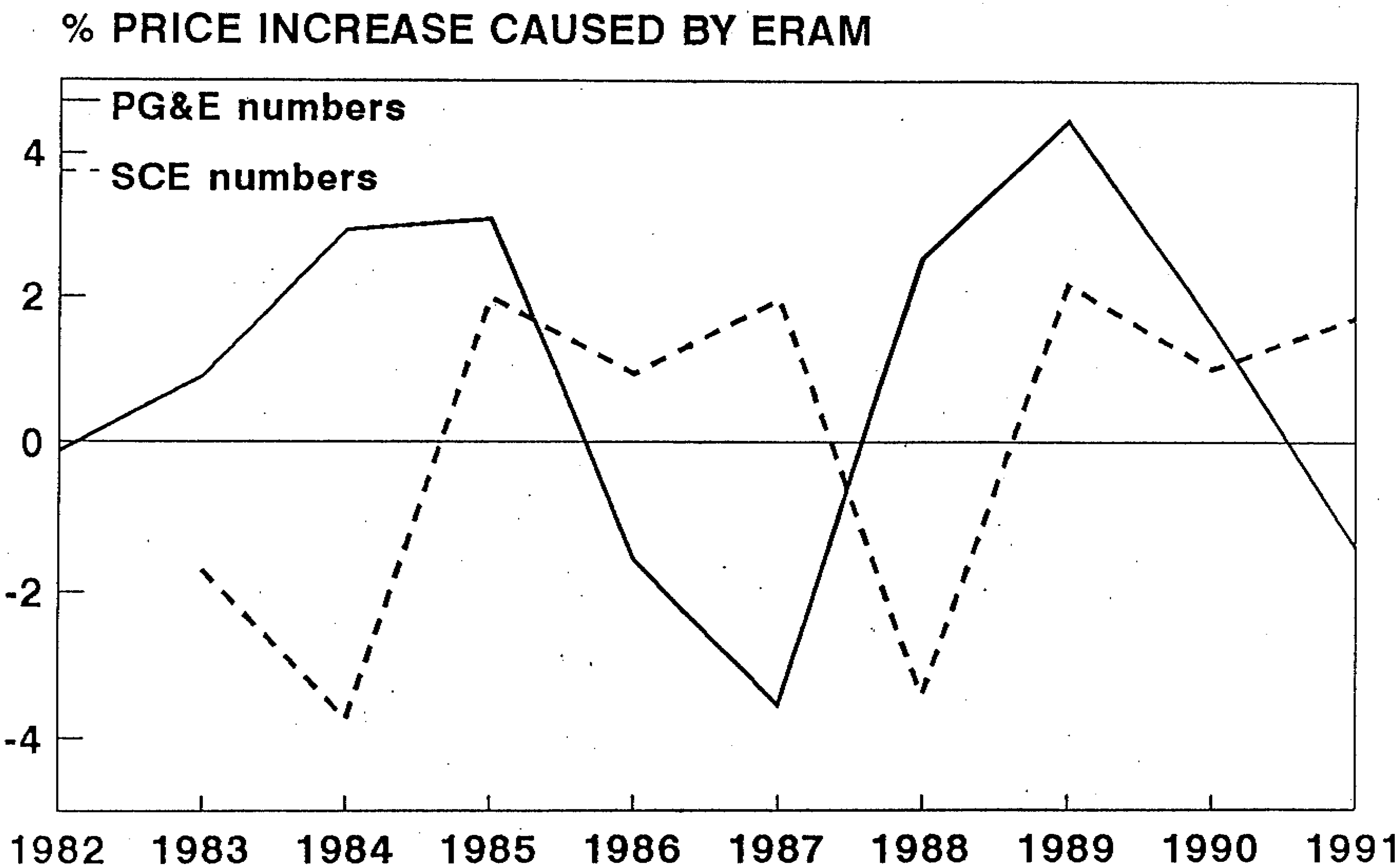
- California and New York use explicit attrition adjustments.
  Allowed revenues for fixed costs based on indices outside utility control.

- Washington and Maine use customer growth as proxy for attrition.
  Allowed revenues for fixed costs based on growth in number of customers.

CA ERAM AND ATTRITION HAVE THREE ELEMENTS

- Operational attrition - adjust labor and materials with price indices
- Financial attrition - adjust cost of capital with actual interest rates
- Rate base attrition - adjust rate base with forecasts from general rate case

PG&E AND SCE ERAM ALWAYS LESS THAN 5% CHANGE

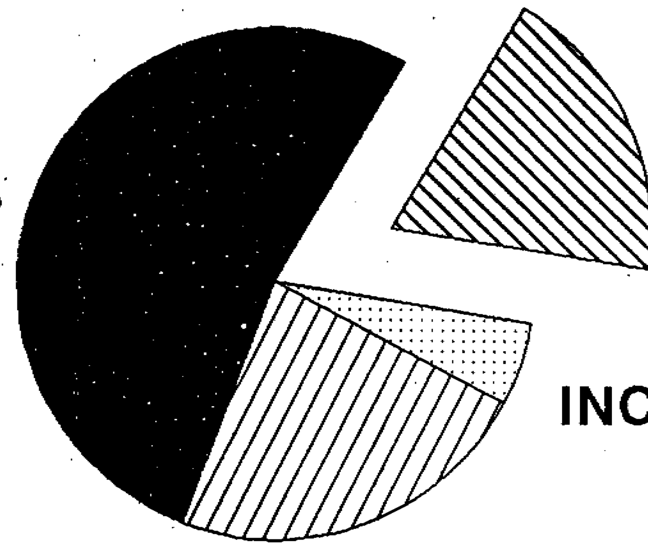


93013

PROBLEMS IN WA AND ME WITH REVENUE PER CUSTOMER DECOUPLING

- Shifting risks from utility to customers (weather and the economy)
- Adjusting for growth in kWh/customer
- Defining fixed and variable costs
- Service quality for large customers

POWER SUPPLY COSTS DOMINATED WA DECOUPLING



PUGET POWER COSTS

92146

STATISTICAL RECOUPLING ADDRESSES THESE PROBLEMS

- Estimate statistical model with historical data
  $E_i = a_i + b_i{*}DD_t + c_i{*}Y_t + d_i{*}P_{it} + \ldots$
  i = customer class, t = ~~year~~ monthly or quarter

- Use statistical model with actual values for independent variables for future year
  Allowed revenue = E'* N * P
  for each customer class
  E' is computed value of E

W123

PSCO TOTAL SALES MODEL: EXAMPLE OF STATISTICAL RECOUPLING

Total GWh = -3128

+ 0.694*Cooling degree days

+ 0.194*Heating degree days

+ 0.00869*No. Customers

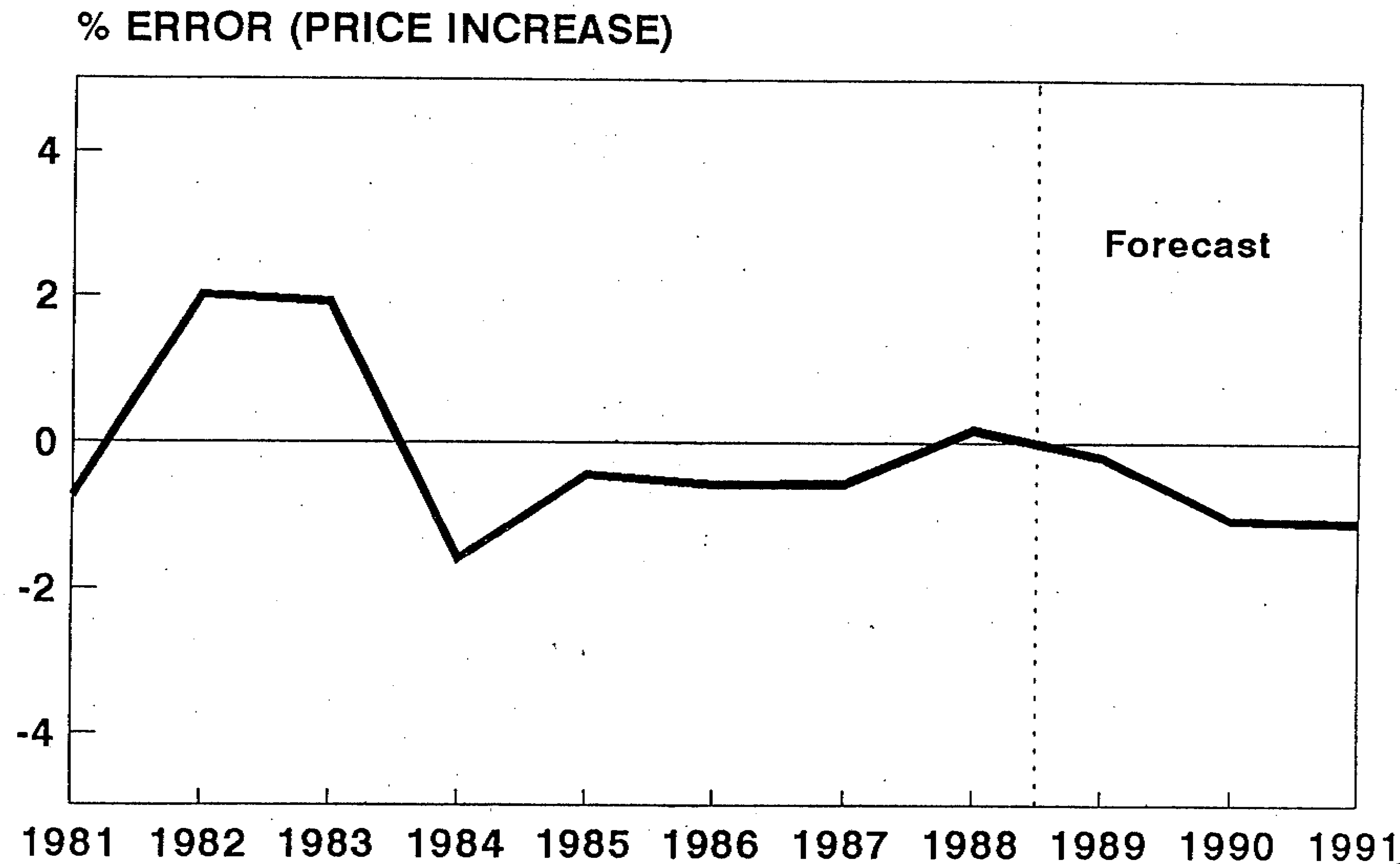
- 194*Electricity price$_{-1}$

n = 26 (quarterly data, 198~~2~~1-198~~9~~8)

R^2 = 0.97

W138

ANALYSIS OF PSCO TOTAL SALES PER CUSTOMER YIELDS GOOD RESULTS



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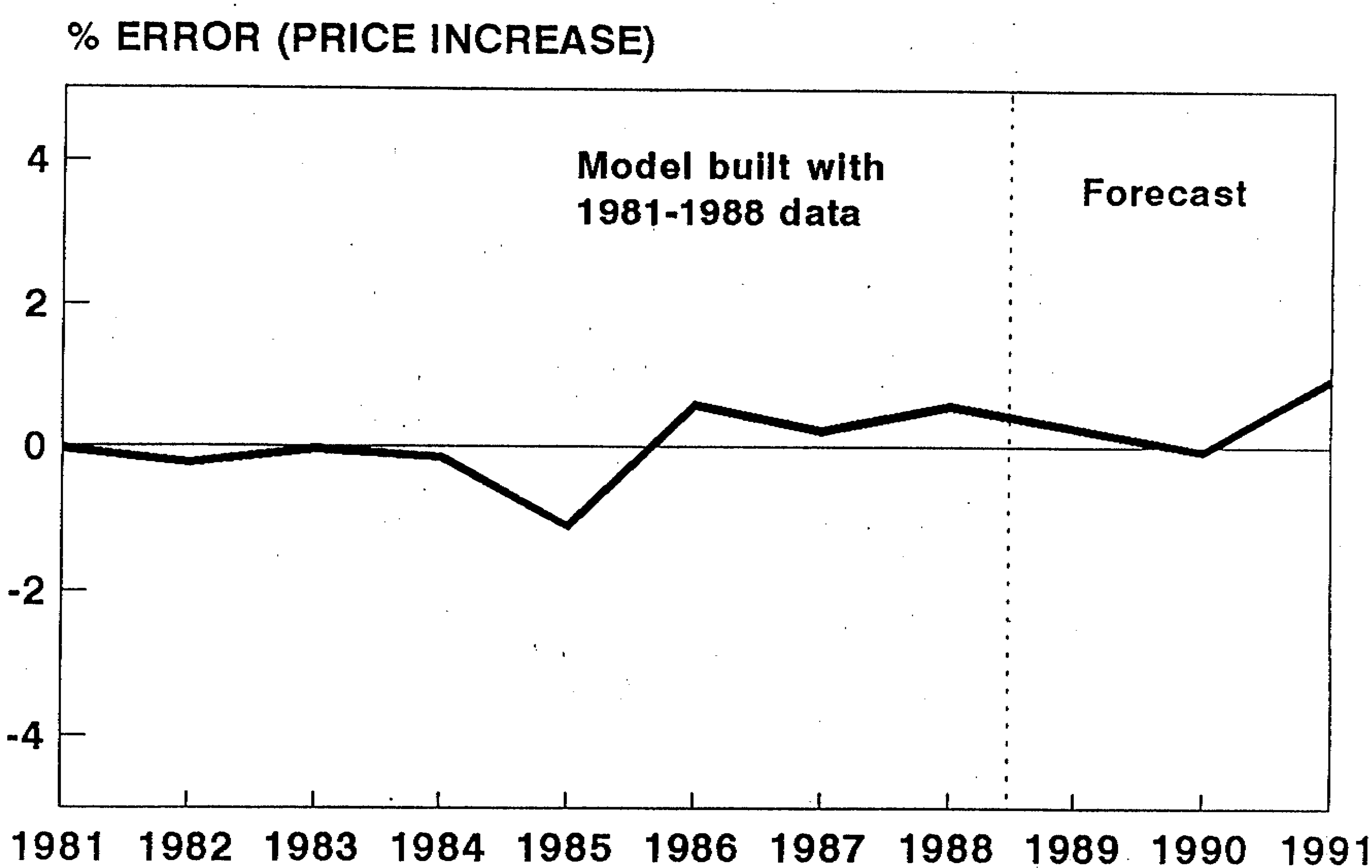
DECOUPLING ANALYSIS WITH SCE DATA SHOWS GOOD RESULTS



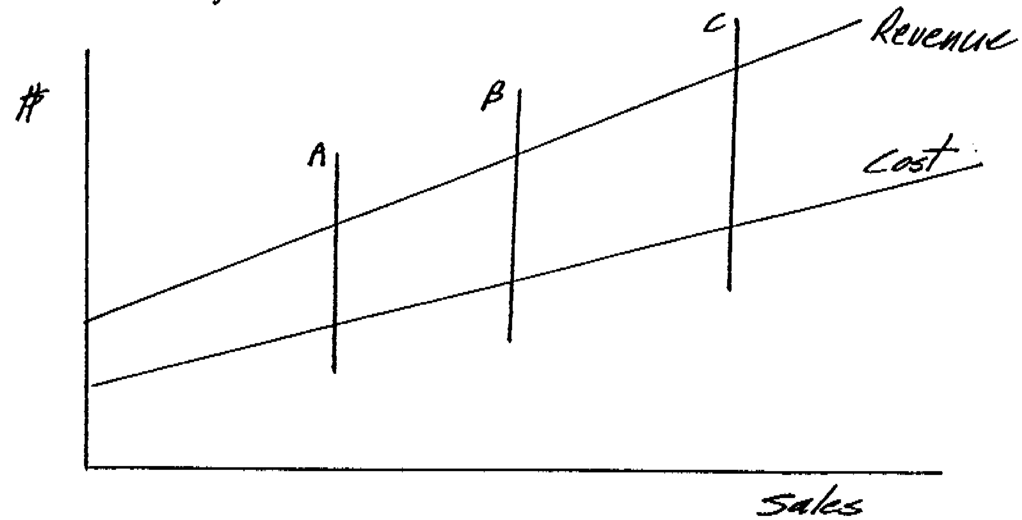
93010A

REGULATORY REFORM NEEDED TO ACHIEVE FULL DSM POTENTIAL

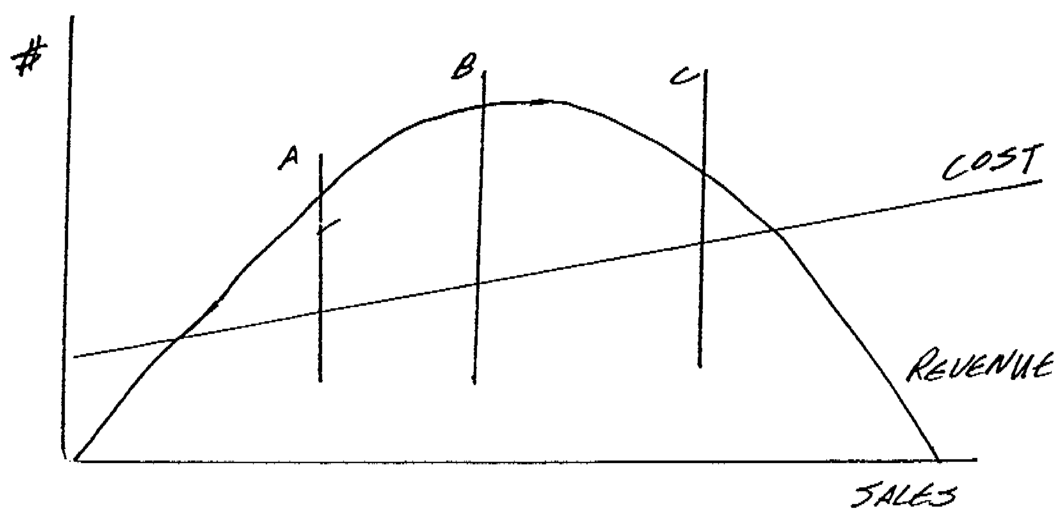
- Current regulation
  - Rewards load growth
  - Penalizes energy-efficiency
- Several solutions possible
- Decoupling or statistical recoupling preferred
  - address directly these problems
  - simple to understand and administer

UTAH DIVISION OF PUBLIC UTILITES
BASIC CONCERNS ABOUT LOST REVENUES

The figure below shows the traditional concept of the relationship between utility costs and revenues. Theoretically the utility's revenue requirement includes all its costs plus a percentage return on investment. If these were the actual relationships, then reducing sales would reduce both revenues and profits for the utility. This would occur no matter where on the sales curve the utility was.



That traditional concept is flawed, however. Any enterprise that has price elasticity will have a quadratic revenue curve, as shown below. Above a certain maximum point, additional sales can actually lower revenues.



In this kind of relationship, there are still some sales levels where decreasing sales decreases revenues and decreases profits. (See line A.) But, there are sales levels where reducing the sales increases the revenues and decreases the profits.(See line B.) There are also sales levels where reducing sales increases both revenues and profits. (See line C.) Although we assumed a linear cost curve here, the same situation will occur with other shapes of cost curves.

Are these really what utility operating curves look like? Utilities around the country found during the 80's that they surely did have price elasticity. As prices climbed rapidly, sales began to slow down. Actual circumstances matched theory.

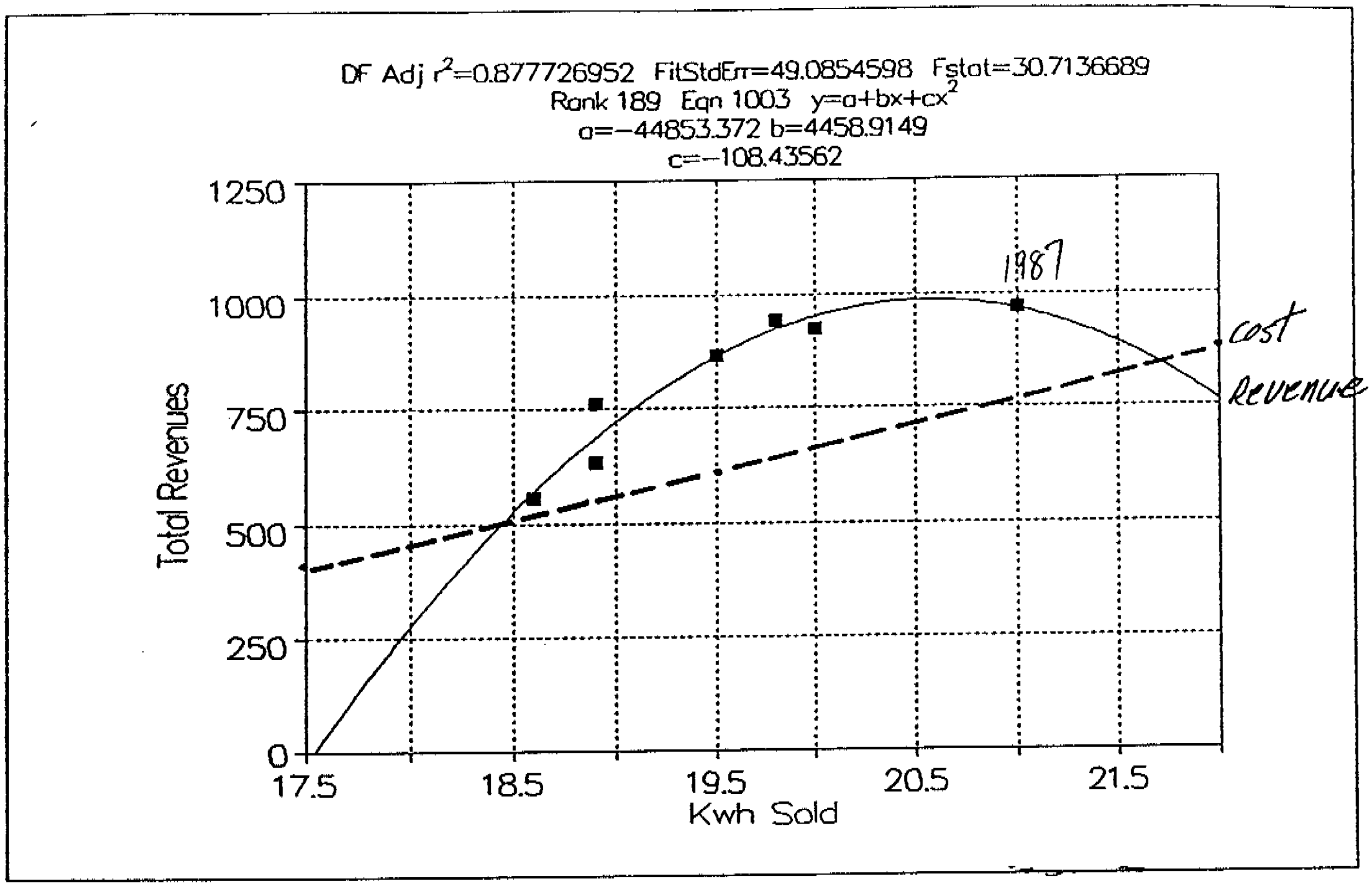
We can see this verfied closer to home. If we look at the total revenues and total costs of PP&L from 1981-1987 and apply curve fitting techniques to the curves, we find the patterns shown on the following pages. Page 3 shows the quadratic revenue curve expected with elasticity and a linear cost curve. The linear cost curve only has an r^2 of .71 so we might want to look at another relationship. Page 4 shows the same revenue curve with a quadratic cost curve. Both curves in this case have an r^2 above .85, a reasonable level, considering that we haven't normalized the data for weather or any other adjustments.

On these curves, we can again see how changes in sales have different impacts, depending on where the utility is currently operating. Lines A, B, and C have the same characteristics as in the theoretical chart. PP&L had sales of 21 billion kwh in 1987.
Reducing sales from that level could increase both revenues and profits. What about UP&L? We would expect similar patterns, but the data is not consistent because of the Simonelli adjustments and resulting coal cost changes. What about PC? We may not have enough years of history to accurately predict where PC is on their operating curves.

The point is: Not every utility will loose revenues or profits by reducing sales. "Lost Revenues" should not be a foregone conclusion. Moreover, if we don't know where a utility is on its operating curves, then we <u>cannot</u> predict with any accuracy what lost revenues will be, or even if there will be any at all.

The other pages of this handout are the supporting data for this analysis. The basic source of the data, is the FERC Form 1.

Kenneth B. Powell
April 20, 1993



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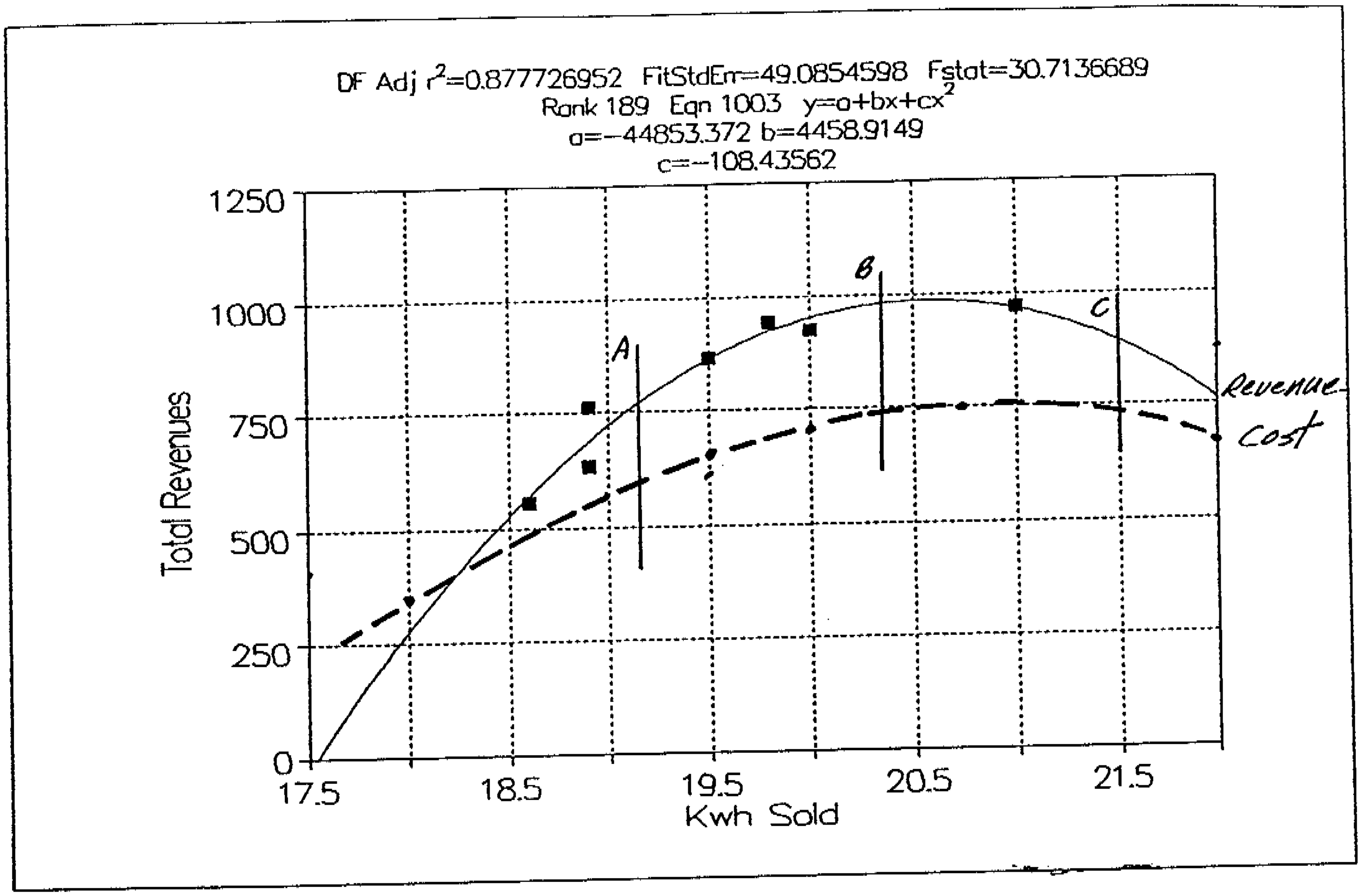
7 Active X-Y Points
X: Kwh Sold Mean: 19.528571429 SD: 0.8280786712
Y: Total Revenues Mean: 805.57142857 SD: 162.09023942
File Source: PPLSTAT2.PRN

Rank 189 Eqn 1003 y=a+bx+cx2

r2 Coef Det	DF Adj r2	Fit Std Err	F-value
0.9388634762	0.8777269524	49.085459842	30.713668943

Parm	Value	Std Error	t-value	95% Confidence Limits	
a	-44853.3717	12389.73032	-3.62020565	-79294.8782	-10411.8653
b	4458.914922	1254.580023	3.554109615	971.3792907	7946.450553
c	-108.435621	31.71830459	-3.41870799	-196.607532	-20.2637109



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c	-108.435621	31.71830459	-3.41870799	-196.607532	-20.2637109

PP&L MARGINAL PROFIT WITH QUADRATIC COST CURVE			
Kwh Sales (billions)	Marginal Rev $–millions	Marginal Cost $–millions	Marginal Profit $–millions
17.5	663.1	337.1	326.0
18.0	554.7	285.6	269.1
18.5	446.3	234.0	212.2
19.0	337.8	182.5	155.3
19.5	229.4	130.9	98.4
20.0	120.9	79.4	41.5
20.5	12.5	27.8	–15.4
21.0	–96.0	–23.7	–72.3
21.5	–204.5	–75.3	–129.2
22.0	–312.9	–126.8	–186.1
22.5	–421.4	–178.4	–243.0
23.0	–529.8	–229.9	–299.9
23.5	–638.3	–281.4	–356.8

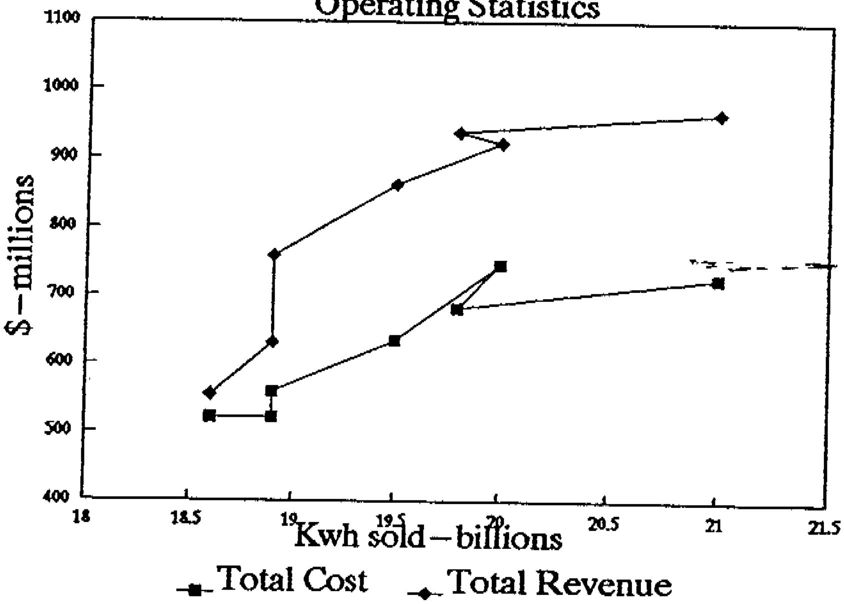
PP&L MARGINAL PROFIT WITH LINEAR COST CURVE			
Kwh Sales (billions)	Marginal Rev $–millions	Marginal Cost $–millions	Marginal Profit $–millions
17.5	663.1	103.3	559.8
18.0	554.7	103.3	451.4
18.5	446.3	103.3	343.0
19.0	337.8	103.3	234.5
19.5	229.4	103.3	126.1
20.0	120.9	103.3	17.6
20.5	12.5	103.3	–90.8
21.0	–96.0	103.3	–199.3
21.5	–204.5	103.3	–307.8
22.0	–312.9	103.3	–416.2
22.5	–421.4	103.3	–524.7
23.0	–529.8	103.3	–633.1
23.5	–638.3	103.3	–741.6

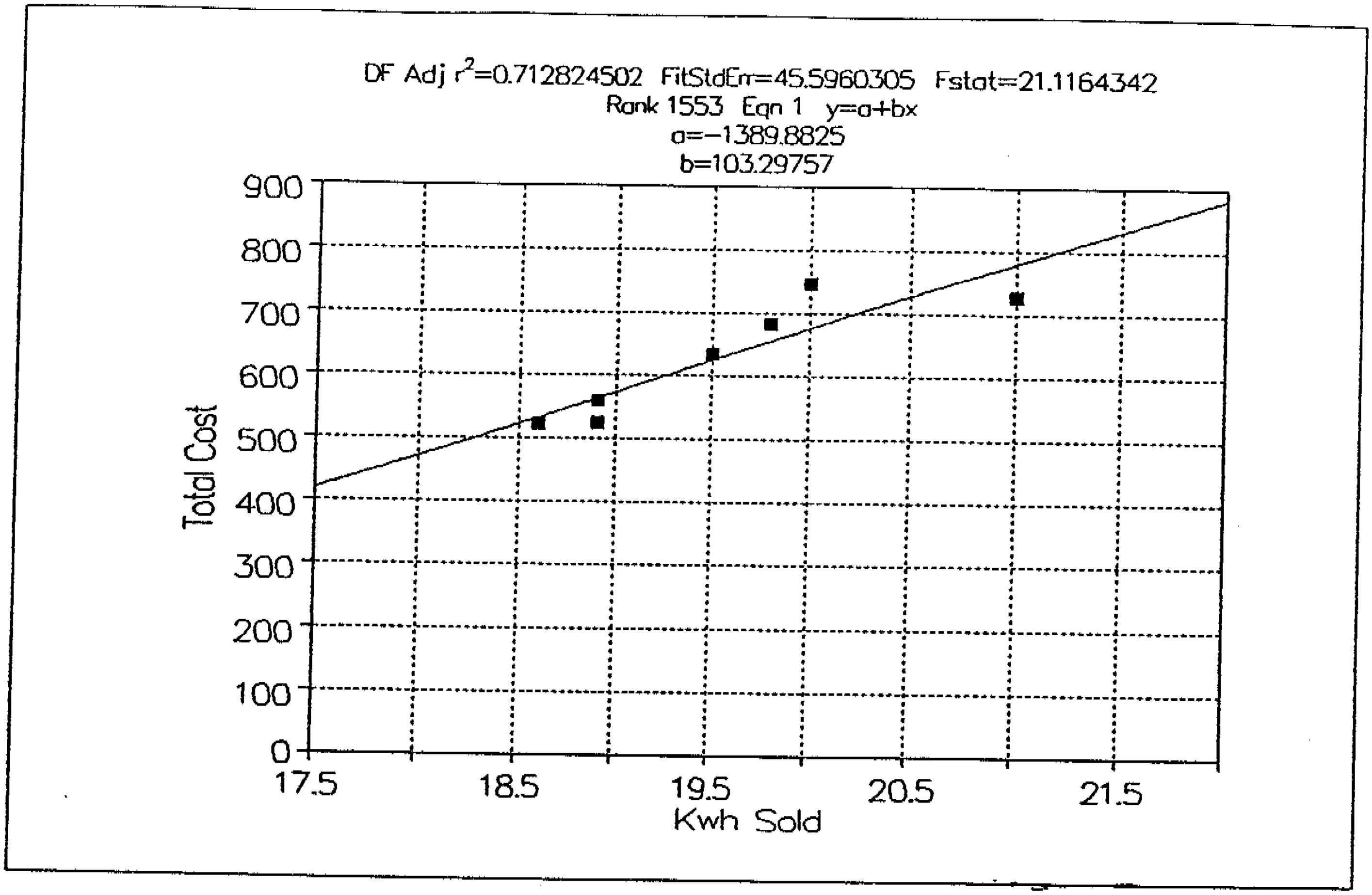
PACIFIC POWER AND LIGHT

YEAR	Total Oper Rev ($-millions)	Total Cost ($-millions)	Kwh Sold (Billions)
1981	554.1	521.0	18.6
1982	630.9	522.0	18.9
1983	759.1	558.7	18.9
1984	863.2	634.0	19.5
1985	923.8	746.7	20.0
1986	939.8	682.8	19.8
1987	968.1	726.4	21.0

Pacific Power & Light

Operating Statistics





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7 Active X-Y Points
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Y: Total Cost Mean: 627.37142857 SD: 95.12799648
File Source: PPLSTAT1.PRN

Rank 1553 Eqn 1 y=a+bx

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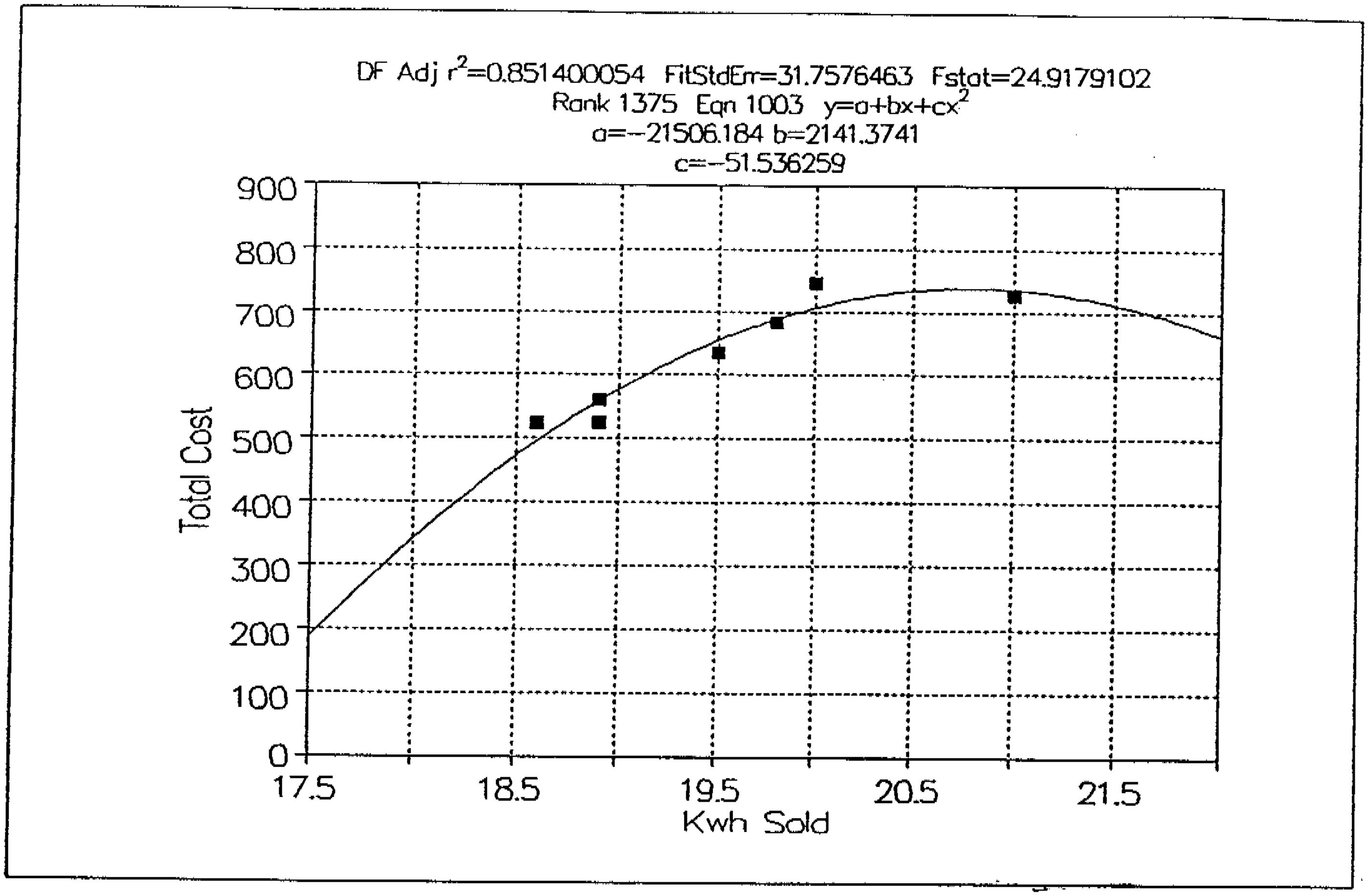
b	103.2975694	22.47914617	4.595262144	45.29921826	161.2959206



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7 Active X-Y Points

X: Kwh Sold	Mean: 19.528571429	SD: 0.8280786712
Y: Total Cost	Mean: 627.37142857	SD: 95.12799648

File Source: PPLSTAT1.PRN

Rank 1375 Eqn 1003 y=a+bx+cx2

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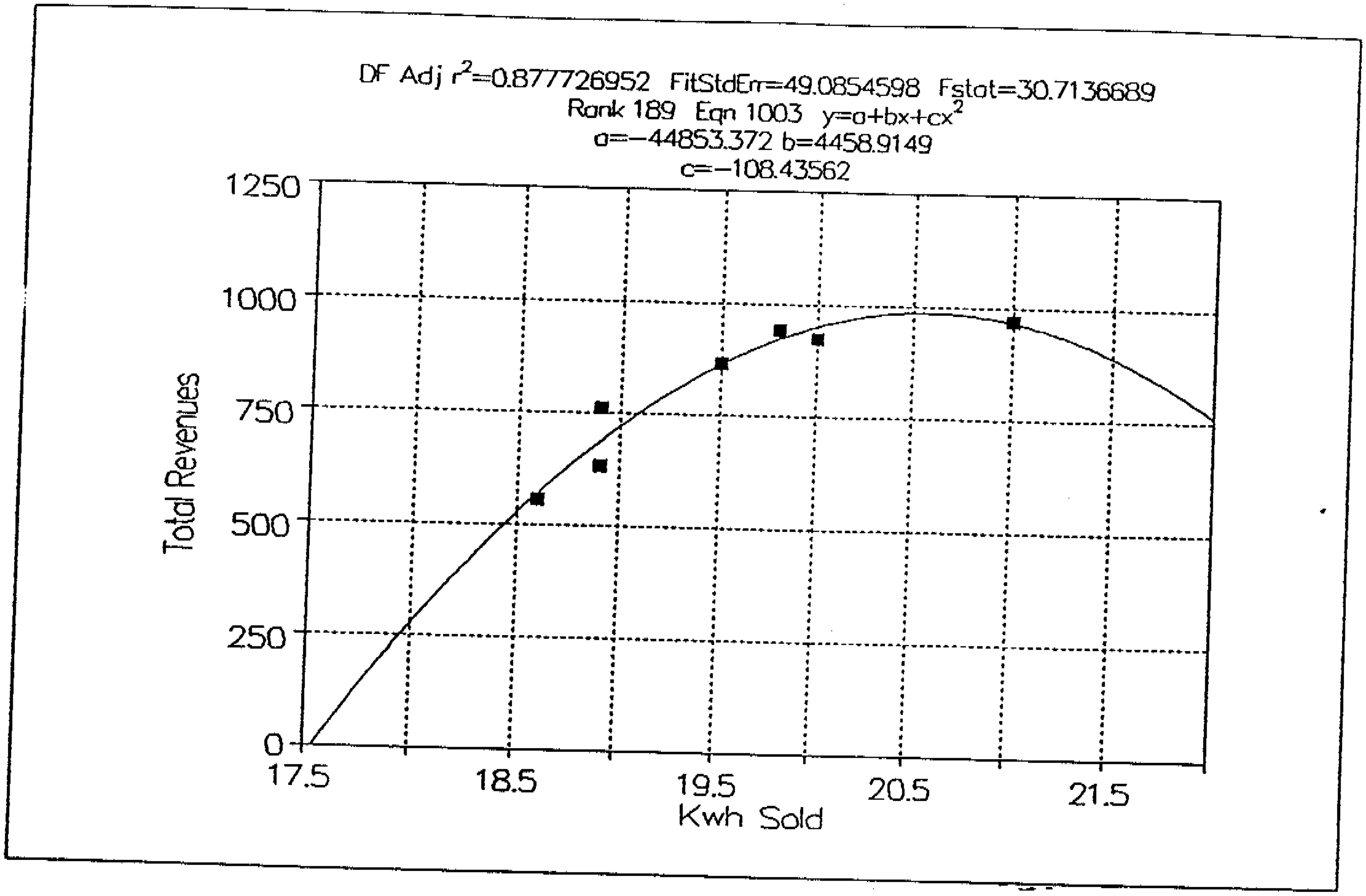
Parm	Value	Std Error	t-value	95% Confidence Limits	
a	-21506.184	8015.992405	-2.68290973	-43789.3852	777.0172534
b	2141.374083	811.6967582	2.638145418	-115.015556	4397.763723
c	-51.5362589	20.5213255	-2.51135137	-108.582324	5.509806396



7 Active X-Y Points — Apr 19,1993 2:40 PM

X: Kwh Sold — Mean: 19.528571429 SD: 0.8280786712

Y: Total Revenues — Mean: 805.57142857 SD: 162.09023942

File Source: PPLSTAT2.PRN

Rank 189 Eqn 1003 y=a+bx+cx2

r2 Coef Det	DF Adj r2	Fit Std Err	F-value
0.9388634762	0.8777269524	49.085459842	30.713668943

Parm	Value	Std Error	t-value	95% Confidence Limits	
a	-44853.3717	12389.73032	-3.62020565	-79294.8782	-10411.8653
b	4458.914922	1254.580023	3.554109615	971.3792907	7946.450553
c	-108.435621	31.71830459	-3.41870799	-196.607532	-20.2637109

LOST REVENUE COMPARISONS
PacifiCorp, dba Utah Power & Light

Utah DSM Technical Conference
April 20, 1993

	KWH	DOLLARS
Utah Power & Light 1991 operating revenues (Utah Only)		$779,718,302
Utah Power & Light 1991 tariff revenues (Utah only)		$688,896,480
UP&L Average number of total customers 1991	495,873	
UP&L Average number of total customers 1992	506,272	
Annual Increase	10,399	
RESIDENTIAL CUSTOMERS SCHDULE 1 UP&L Average number of customers 1991	356,756	
JP&L Average number of customers 1992	366,593	
Annual Increase	9,837	
1992 Average annual kwh, Schedule 1	7,061	
Additional KWH sales due to additional customers	69,459,057	
1991 WEATHER NORMALZATION ADJUSTMENT Dollar amount for residential only		$4,407,724
Kwh, residential only	64,448,889	
ECONS ANNUAL LOST REVENUE Estimated lost kwh sales (1072 kwh x 12,000 customers)	12,864,000	
Estimated GROSS lost revenue @ $.068391 per kwh		$879,782
Estimate NET lost revenue @ 40 mills/kwh		$514,560
ECONS lost kwh sales as a percent of new sales	18.52%	
ECONS lost kwh as a percent of the weather normalization	19.96%	

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Serving the Rocky Mountain West

TO: Members of the Utah DSR Task Force

FROM: Eric Blank (& Eric Hirst)

At the last two meetings of our task force, we discussed briefly the effects of utility DSM programs on electricity prices. This topic will almost surely come up again, probably at the May 11 meeting.

Therefore, I thought you would be interested in the two enclosed papers on this subject. The first, by Hirst, creates three hypothetical electric utilities and then examines the tradeoff between the total resource cost test and the rate impact measure. The second paper, by Faruqui and Chamberlin of Barakat & Chamberlin, is empirical. This paper examines the same tradeoff based on the plans of 14 utilities throughout the U.S.

Both papers, from different perspectives, reach the same conclusion. The TRC benefits of DSM programs are likely to be much larger than the RIM penalty.

Ultimately what matters to the Utah DSR Task Force is how this plays out for PacifiCorp. Until the company conducts this type of analysis using the RAMPP-3 results and assumptions, however, we won't know the specifics for Utah.

Please call me or (the other) Eric if you have any comments or questions on these papers.

Thanks.

2260 Baseline Road • Suite 200 • Boulder, Colorado 80302 • (303) 444-1188 • FAX (303) 786-8054

Quantifying Tradeoffs between Costs and Prices in Utility DSM Programs

Debates about the appropriate economic tests to use in assessing utility DSM programs miss the point in failing to address the magnitude of the impacts. This analysis shows that DSM programs generally reduce electricity costs (significantly) while raising electricity prices (usually only slightly).

Eric Hirst

Eric Hirst *is a corporate fellow at Oak Ridge National Laboratory, where his work focuses on improved planning methods and their application to electric utilities. He has published over 300 reports, journal articles and book chapters on engineering and policy issues related to energy use and efficiency. Dr. Hirst holds a Ph.D. in mechanical engineering from Stanford University.* *Work reported here was sponsored by the Office of Conservation and Renewable Energy, U.S. Dept. of Energy, under contract with Martin Marietta Energy Systems, Inc.*

During the past several years, more and more electric utilities and their regulators have recognized the benefits of improving efficiency of electricity use. However, considerable controversy remains over the appropriate economic test(s) to use in assessing utility programs that increase customer energy efficiency and, therefore, reduce electricity use and utility revenues. People concerned about minimizing the total cost of electric-energy services favor the total-resource-cost test (TRC), while those concerned about minimizing electricity prices favor the rate-impact measure (RIM). See **Table 1**.

Most of the debates and discussions about the appropriate economic tests are philosophical and fail to address the magnitude of the impacts. As a consequence, questions remain about the relationships among utility DSM programs and acquisition of supply resources and the effects of these choices on electricity prices and costs. If aggressive DSM programs are implemented, by how much will electricity prices rise, and over what time? If the RIM test is used, how much of a resource that would be cost effective under the TRC will be foregone? Most of the quantitative estimates that have been made of the tradeoffs between the RIM and TRC tests are based on the static equations developed by the California Public Utilities Commission and California Energy Commission[1] or are for a particular utility under its baseline assumptions.

During the past few years, several state public utility commissions have issued orders on the cost-effectiveness tests for DSM programs.[2] These PUCs have rejected use of the RIM test to screen DSM programs, relegated the RIM test to a secondary role, or mandated use of the TRC as the primary determinant of the cost effectiveness of utility DSM programs.[3] Others argue that utilities should aim to minimize electricity prices. Any other strategy, they say, would needlessly raise prices, encouraging electricity consumers to shift their energy needs to other fuels.[4]

Some proponents of the RIM test argue that it is economically inefficient for the utility to pay customers "twice" for energy-efficiency improvements.[5] Utilities pay once through the direct cost of their programs (marketing and financial incentives to install energy-efficient devices); they pay a second time through the customer's reduction in his/her electricity bill. These analysts note that electricity prices send important signals to consumers and are the basis of a properly functioning market system.[6] Providing additional incentives (beyond that allowed by the RIM test) to consumers to improve energy efficiency is equivalent to substituting the judgment of central planners in utilities and PUCs for the normal workings of the marketplace.

Others argue that consumers in all sectors of the economy face many market barriers to improving energy efficiency. Thus, energy markets do not operate properly and require utility involvement. Utilities can help overcome these barriers and do so at low cost, they argue.[7]

The reduction in customer electricity bills stimulated by utility DSM programs, often called lost revenues, is at the heart of the debate over the appropriate role of utilities in promoting energy efficiency. Some believe that the RIM test ensures that (1) markets are not tampered with needlessly and (2) nonparticipating ratepayers do not suffer because of utility DSM programs. Others believe that strict adherence to the RIM test ensures "no losers, but few winners" and will increase the overall cost of electric-energy services.[8]

I. Analyzing DSM Impacts in Utility Expansion Plans

We used a dynamic model of an electric utility — Decision Impact Assessment Model, or DIAMOND[9] — to assess the effects of utility DSM programs on utility revenues, total resource costs, electricity prices, and electricity consumption.[10] Results obtained with a dynamic model are likely to be more realistic than results obtained with a static model, because a dynamic model captures the effects of different types of resources on future load growth, electricity prices, dispatch of power plants, and the financial status of the utility.[11]

DIAMOND was used to assess DSM programs under alternative scenarios that vary fossil-fuel prices, load growth, the amount of excess capacity the utility has in the initial year of the simulation, planned retirements of existing power plants, the financial treatment of DSM programs, and the costs of energy-efficiency pro-

Table 1: Elements of the key economics tests used to assess the benefits and costs of utility demand-side management (DSM) programs

Perspective	Benefits	Costs
Rate-Impact Measure	Avoided supply costs (production, transmission, and distribution) based on energy and load reductions	Utility program costs, including incentives to participants, plus net lost revenue caused by reduced sales
Total-Resource Cost	Avoided supply costs (same as above)	Total program costs to the utility and participants (i.e., measure costs plus utility administrative costs)

grams. These analyses are conducted for the 1990—2010 period for three utilities (Table 2):

— a "typical" U.S. utility, based on data and estimates from the Energy Information Administration[12]

— a "surplus" utility that has excess capacity, few planned retirements, and slow growth in fossil-fuel prices and incomes; and

— a "deficit" utility that has little excess capacity, many planned retirements, and rapid growth in fossil-fuel prices and incomes.

Information on these utilities was then fed into DIAMOND to assess the effects of DSM programs on electricity costs and prices when a utility faces *different* avoided costs.

For simplicity, in the present analysis utility-built power plants are limited to only a few choices: 500 MW coal, 200 MW coal, 100 MW combustion turbine, and 100 MW combined-cycle combustion turbine.

The utility can also run DSM programs. Because the utility has only one customer class, only two types of DSM are practical, one aimed at new customers and one at existing customers. Conservation-program performance depends on participation in the program and the net energy savings of the program. DSM-program cost-effectiveness depends on the energy savings and the utility's cost to run the program.

The utility's cost has three components:

(1) a fixed charge ($/year) that reflects the overall planning, design, and administration of the program;

(2) a marketing charge ($/participant) that reflects the utility's cost to get customers to participate in the program

(3) an acquisition charge (¢/kWh) that reflects the financial incentive paid by the utility for the materials and installation needed to acquire the conservation resource.

To simplify comparisons across cases, the utility pays 100% of the DSM-measure costs in all programs. This represents a worst-case scenario in terms of the RIM test. To the extent that customers share the cost of purchasing and installing DSM measures, the adverse rate impacts of DSM programs are reduced.

All the utility's capital costs, both supply and demand, are included in the rate base. The costs of DSM programs are depreciated over 15 years, investments in transmission and distribution are depreciated over 20 years, other investments (e.g., computers and office buildings) over seven years, and power plants over the lifetime of the plant (ranging from 30 years for combustion turbines to 40 years for coal plants).

For these analyses, the utility maintains a balancing account to ensure that any variations between actual and forecast sales do not affect the utility's rate of return. This system is similar to the Electric Revenue Adjustment Mechanism used in California[13] plus a fuel-adjustment clause. This mechanism ensures that utility shareholders are not penalized because DSM programs reduce electricity use.

A. The Base-Case Utility

I begin the analysis of the base utility by developing a supply-only plan. This plan is then used as the reference against which to compare plans that include DSM programs. Growth between 1990 and 2010 in income; retail gas price; and prices to the utility for gas, coal, and nuclear fuels are the same for all the cases discussed in

Table 2: Comparison of situations facing the three utilities

	Base	Surplus	Deficit
Installed capacity in 1990 (MW)	2275	2475	2275
1990 reserve margin (%)	14	27	14
Planned retirements of power plants (MW)	600	200	1100
Total resources added from 1990 to 2010 (MW)	1400	400	1900
First year of deficit	1995	2004	1995
Load growth (%/year)	2.0	1.5	2.4
Prices, 1990 values[a] (%/yr growth, 1990-2010)			
Natural gas	3.12 (3.4%)	2.50 (1.3%)	4.26 (3.8%)
Coal	1.61 (2.0%)	1.24 (1.1%)	1.96 (2.0%)
Retail electricity	6.46 (0.6%)	6.11 (−0.8%)	6.90 (0.9%)

[a] The 1990 prices paid by the utility for natural gas and coal are in $/MBtu, while the price of electricity is in ¢/kWh, in 1990 dollars. The growth rates are also in constant dollars.

This supply-only plan is the one, among many alternatives tested, that yields the lowest net present value (NPV) of revenue requirements for the 1990—2010 period.[14] The alternatives tested include construction of different types and numbers of power plants, started at various dates between 1990 and 2000. This plan includes a combination of coal- and gas-fired power plants, with additions that total 1400 MW between 1994 and 2008 (**Table 3**).

Electricity consumption increases at an average rate of 2.0%/year in this case, driven partly by the growth in the number of new customers (0.8% per year). Real electricity prices increase slowly at 0.6% per year. Utility assets increase slightly faster than growth in electricity use, at 0.9%/year. Construction expenditures peak at $170 million in 1996 and again at $160 million in 2003 (**Fig. 1**). Over the 20-year period, the utility spends $1,880 million on new construction, of which 67% is for new power plants. The remainder is for transmission and distribution and other investments.

Starting with this supply plan, several cases were developed that incorporated DSM programs of different intensities. Intensity refers to the utility's incentive payment for energy-efficiency investments (expressed as the maximum cost of conserved electricity, "CCE") and its marketing budget per participant. In all cases, DSM programs were started in 1990 for both existing and new customers and were run unchanged for the full 20 years of the simulation. In addition, the utility always paid 100% of the costs associated with DSM measures.

Programs were tested with maximum costs of 6, 5, 4.5, 4, and 3 ¢/kWh. No effort was made to optimize the DSM programs by testing different combinations of marketing budgets and financial incentives for DSM measures. For example, requiring participants to pay part of the cost of DSM measures would lower utility costs, reducing the adverse effect on electricity prices (the RIM test). However, this strategy would also reduce the amount of energy savings obtained from the DSM programs.

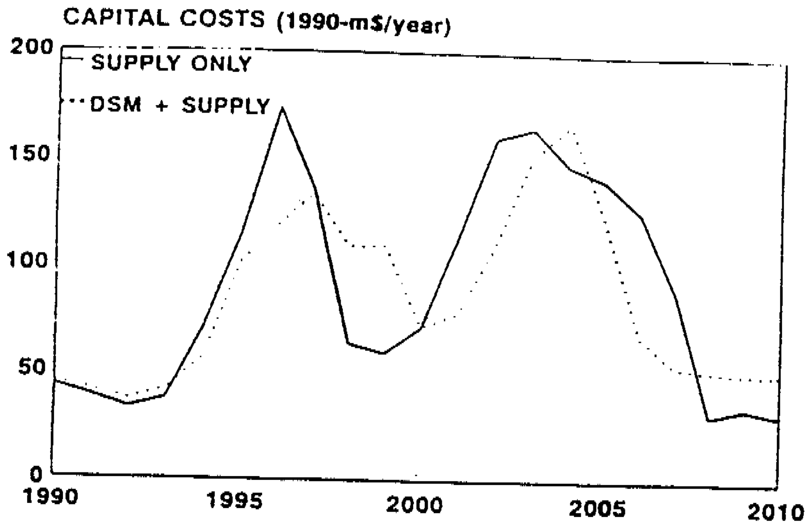
In all these DSM cases, some of the power plants that were constructed in the supply-only case are deferred or displaced by the energy and capacity resources provided by the DSM programs. The analysis proceeded as follows. The DSM program, begun in 1990, was added to the full set of power plants constructed in the supply-only case. Then, several additional cases were run in which some of these power plants were deferred or eliminated. These iterations stopped when revenue requirements could be reduced no further, subject to the constraint that the reserve margin was roughly what it was in the supply-only case.

Results for the case with a maximum CCE of 4.5¢/kWh are shown in Table 3 and in Fig. 2. Over the 20-year period, construction costs total $1,770 million, *6% less than in the supply-only case* (**Figure 1**). Also, construction of new power plants accounts for a smaller share of the total in the DSM case (35%) than in the base case (67%). Whereas 1400 MW of new power plants were constructed in the supply-only case, only 800 MW of new power plants were constructed in the DSM case. Thus, these DSM programs displace almost half the power plants that would otherwise have been built.

Table 3: Summary of results for a combined supply/demand plan with DSM resources purchased up to 4.5¢/kWh for the base utility

	Average growth rate, 1990-2010 (%/year)	
	DSM	Supply-only
Total electricity use (GWh/year)	1.2	2.0
Electricity price (¢/kWh)	0.9	0.6
Average electric bill ($/customer)	1.3	1.9
Utility revenues ($ millions)	2.1	2.7
Utility assets ($ millions)	0.04	0.9
Summary statistics, 1990-2010		
Net present value ($ millions):		
Revenue requirements	9,450	10,000
Environmental costs	3,080	3,150
Average electricity price (¢/kWh)	6.94	6.89
Average electric bill ($/customer)	1,100	1,190

Figure 1. *Capital costs (for power plants, DSM programs, and transmission and distribution facilities) for the supply-only base case and the 4.5¢/kWh DSM-program case discussed later in this section.*



Electricity use in this case grows more slowly than in the supply-only case (1.2 vs 2.0%/year) and in the year 2010 is 15% lower (Figure 2). Correspondingly, utility revenues, assets, and customer bills are lower with the DSM programs. According to the TRC test, these DSM programs have a benefit/cost ratio of 2.7. The average CCE for these DSM programs (including the cost of the measures plus the utility's cost of program administration and marketing) is about 3.5¢/kWh at the customer meter, roughly two-thirds the cost of a small coal plant. Accounting for transmission and distribution losses (5% for energy and 10% for peak) plus transmission and distribution construction makes the DSM programs even more cost effective.

Electricity prices are slightly higher with DSM programs. As shown in Fig. 2, electricity prices are initially almost unchanged because of the DSM programs and then increase from 2005 to 2010. At the end of the analysis period, electricity prices are higher with DSM programs than without because no new power plants are started at the end of the period. In the supply-only case, construction costs for new power plants are zero in 2009 and 2010. However, in the DSM case, the DSM programs continue unchanged through the year 2010, leading to higher construction costs from 2008 to 2010 (Fig. 1).

Overall, electricity *prices* are 0.7% higher, but electric *bills* are 8% lower, and utility revenue requirements are almost 6% lower. Bills and utility revenues are consistently lower throughout the 20-year period with DSM programs (Fig. 2).

Other cases with different DSM programs were run, and the comparisons between each of these cases and the supply-only case are shown in Fig. 3. At values of maximum CCE above 5¢/kWh, conservation programs increase both electricity bills and prices relative to cases with moderate conservation programs. These results also show that it is possible to reduce both revenue requirements and electricity prices with modest DSM programs. For example, the case with maximum CCE of 3¢/kWh yields an average reduc-

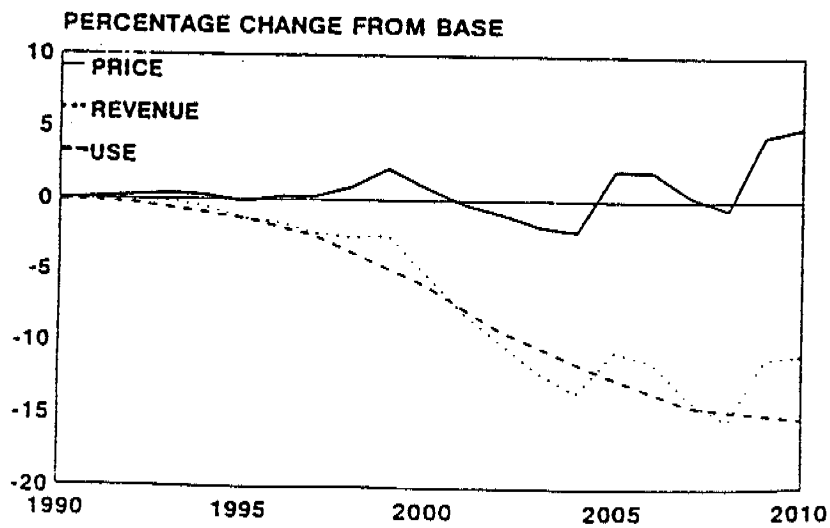
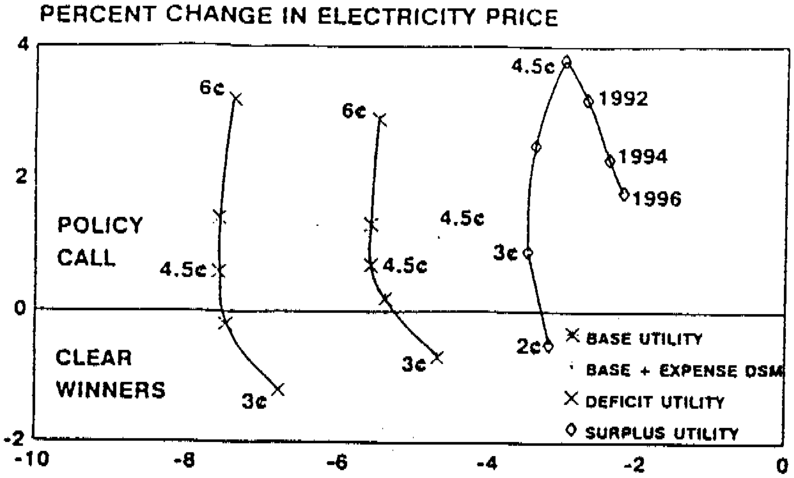


Figure 2. *Effects of a utility DSM program (CCE = 4.5¢/kWh) on electricity use, revenues (and average electric bill), and electricity price. Model results for the last few years of the simulation are confounded by the fact that no new power plants are under construction to meet post-2010 electricity needs.*

Figure 3. *The effects of utility DSM programs on NPV of utility revenues and average electricity price (1990 through 2010) for the base, surplus, and deficit utilities. Programs all began in 1990, except for the three noted. The prices shown refer to the maximum CCE (in ¢/kWh) paid by the utility in its DSM programs.*



tion in electricity price of 0.7% relative to the supply-only case. Even this "modest" program cuts electricity use in the year 2010 by 11% and cuts revenue requirements by 4.7% (compared with the 15% cut in 2010 electricity use and the 5.6% cut in revenue requirements achieved with the 4.5¢/kWh program).

In the cases discussed above, the utility's costs of its DSM programs were capitalized and depreciated over 15 years. This financial treatment of DSM is consistent with the treatment of other investments (e.g., in power plants and transmission and distribution systems) and ensures that the costs and benefits of DSM are roughly contemporaneous.

However, utilities often treat DSM-program costs as an expense, which means that they recover these costs the year they occur; these costs appear immediately in electricity prices. I tested the effects of different financial treatments of DSM programs on the tradeoff between total costs and electricity prices: expensing, rate-basing with a 10-year depreciation, and rate-basing with a 15-year depreciation (**Figure 3**).

These results show that expensing DSM-program costs, rather than rate-basing these costs, reduces the benefits of these programs. This finding is true for both the TRC and the RIM [illegible]s, affecting both utility costs and electricity prices. Expensing increases utility costs relative to the supply-only case each year from 1990 through 1997; it is only in the later years that revenues are lower with expensing. Contrast this situation with the one when DSM-program costs are rate-based (shown in Fig. 3); there, revenue requirements are lower every year with DSM programs than without.

This difference in the timing of DSM-program costs shows up in electricity prices also (**Figure 4**). Prices are higher with DSM programs than without until 2003 if DSM-program costs are expensed. As discussed above, if these costs are depreciated over 15 years, DSM programs have little effect on electricity prices until the early 2000s, after which prices are usually higher with DSM programs than without.

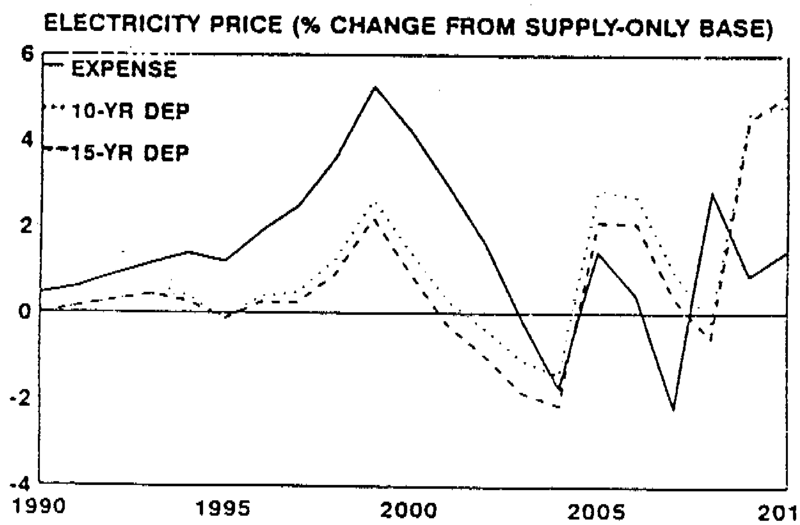


Figure 4. *The effects of different financial treatments of DSM-program costs on electricity price. The three treatments shown here are expensing, depreciation over ten years, and depreciation over 15 years.*

As expected, the effects of depreciating DSM-program costs over [illegible] years fall between the effects of expensing and depreciating over 15 years.

B. The Surplus Utility

These cases are similar to those developed above but with different assumptions concerning installed capacity in 1990, 1990 reserve margin, load growth, and fossil-fuel prices (Table 2). These assumptions simulate the situation in which a utility has substantial excess capacity (a 27% reserve margin in this case) and slow load growth, leading to only a modest need for additional capacity between 1990 and 2010 (only 400 MW here, compared with 1400 MW in the case discussed above). The purpose of these cases is to show whether DSM programs offer benefits to a utility with excess capacity.

The supply-only plan includes the addition of 200 MW of coal plants and 200 MW of combustion turbines. Again, several cases with DSM programs were simulated. As before, these DSM cases differed in the maximum CCE offered by the utility. The case with a CCE of 4.5¢/kWh increased electricity price almost 4% and decreased revenue requirements 3% (compared with an increase in electricity price of 0.7% and a decrease in revenue requirements of almost 6% for the base utility; see Fig. 3). Thus, for the surplus utility, the benefits of DSM programs are much less than for the base utility from a TRC perspective and even worse from a RIM perspective.

At first glance, these reductions in revenue requirements seem startling: How can DSM programs reduce costs for a utility that has substantial excess capacity and needs no additional capacity until 2004? Because the DSM-program costs are depreciated over 15 years, revenue requirements with the DSM program are lower in all years except 1990 and 1991. In other words, the cost of the DSM programs is less than the reduction in operating costs plus the reduction in transmission and distribution construction costs. If the DSM-program costs were expensed instead of rate-based, revenue requirements with DSM would be greater each year from 1990 through 2002 than in the supply-only case because DSM costs appear immediately in rates. Again, these results show the substantial effect of financial treatment on DSM-program economics.

> *If the DSM-program costs were expensed instead of rate-based, revenue requirements with DSM would be greater each year.*

The case with a CCE of 3¢/kWh led to the greatest reduction in the NPV of revenue requirements. The DSM programs displaced the need for 75% of the power plants that were constructed in the supply-only case (i.e. 200 MW of coal plants and 100 MW of combustion turbines). With such reductions, the NPV of revenue requirements is cut by 3.5%, and electricity price is higher by 0.9% (compared with 3.0% and 3.8%, respectively, for the 4.5¢/kWh DSM-program case).

Delaying the DSM program by two, four, or six years (Fig. 3) cuts both the reductions in utility revenue requirements and the increases in electricity prices.

C. The Deficit Utility

In this section, I discuss cases for a utility that faces rapid load growth, has a small reserve margin in 1990, plans to retire much of its existing generating units by 2010, and faces higher fossil-fuel prices (Table 2). In essence, these cases are the opposite of those discussed in Section B, above.

The supply-only plan for this deficit utility involves construction of 1600 MW of coal plants plus 300 MW of combustion turbines. As shown in Fig. 3, the reductions in revenue requirements caused by DSM programs are much greater for the deficit utility than for either the base or surplus utility. However, even for the deficit utility, most of the DSM programs increase average electricity prices. Only when the maximum CCE is at or below 4¢/kWh do both revenues and prices decline compared to the supply-only case.

The case with a CCE of 4.5¢/kWh, which led to the largest reduction in revenue requirements (almost 8%), increased the average electricity price by 0.6%. This set of DSM programs cut load growth from 2.4 to 1.5%/year and displaced the construction of 500 MW of power plants.

The cases with a maximum CCE of 4 to 6¢/kWh led to almost the same reduction in revenue requirements. However, the effects of these programs on electricity prices and consumption are large. While the 6¢/kWh case reduced electricity use in the year 2005 by 17%, it increased the average price of electricity by more than 3%. On the other hand, the 4¢/kWh case reduced electricity use by 11% and led to a 0.2% decrease in electricity price. These results show that the decision on DSM-program intensity involves more than a tradeoff between costs and prices; it also involves electricity consumption and the displacement of supply sources.

II. Conclusions

Is the increasing use of demand-side management programs good for the customers of electric utilities? The answer, of course, depends on the criteria used to judge "goodness." Those who argue over the appropriate economic test(s) to use in selecting DSM programs see customer benefits in different ways. Some focus on the *price* of electricity, while others focus on the *cost* of electric-energy *services* (where services refer to the benefits provided by the combination of electricity and electricity-using devices, such as cold food in a refrigerator, an elevator that takes you to the tenth floor of an office building, and motors that operate a factory assembly line).

This study does not suggest how best to define benefits. Rather, it focuses on the tradeoffs between price and cost and identifies how much of a price increase might be associated with how much of a cost reduction when a utility provides DSM programs for its customers.

This tradeoff was explored with a new planning model developed at ORNL (DIAMOND). The model was used to examine the effects of DSM programs on revenue requirements, electricity prices, electricity consumption, and the need for additional power supplies under a variety of circumstances. These simulations include a base utility that corresponds roughly to the EIA projections of electricity demand, prices, construction, and so on for the United States as whole during the next two decades. In addition, the effects of DSM programs on a surplus utility and a deficit utility were simulated. In all these cases, the utility was assumed to pay 100% of the cost of purchasing and installing the DSM measures; that is, customers paid nothing for these improvements. These cases, therefore, represent the extreme in terms of both the TRC and RIM tests.

Is a 1% average increase in electricity price justified by a 5% decrease in electricity costs over the next 20 years?

The base-case results show that the percentage reductions in customer costs (reflected by utility revenue requirements) are much greater than the percentage increases in electricity prices. This finding holds regardless of whether the utility costs of running DSM programs are expensed or capitalized. Thus, the appropriate question to ask in regulatory proceedings and utility boardrooms is: Is a 1% average increase in electricity price justified by a 5% decrease in electricity costs over the next 20 years?

The primary findings from the analyses conducted here are:

- In general, DSM programs reduce electricity costs and raise electricity prices. Utilities and PUCs must make tradeoffs between the TRC and the RIM tests.
- Typically, the percentage reduction in electricity cost far exceeds the percentage increase in electricity price caused by DSM programs. Roughly speaking, the ratio of percentage changes is 2:1 for the surplus utility, 5:1 for the base utility, and 8:1 for the deficit utility.
- The financial treatment of DSM programs is important. Expensing the costs of DSM programs raises electricity prices in the short term, whereas capitaliz-

ing these costs over 15 years defers the price increase for several years. Overall, expensing reduces the cost and price benefits of DSM programs.

- Even if the utility faces very high avoided costs, the tradeoff (conflict) between costs and prices remains. However, the percentage reduction in costs will be far greater than the percentage increase in prices. In special cases where the cost per kWh of DSM programs is very low, both prices and costs can be reduced.

- From the perspective of the TRC test, DSM programs are cost effective even if the utility has excess capacity and slow load growth. This situation occurs because DSM programs offset not just the operating costs of existing power plants, but also reduce the other costs of operating the utility system, defer construction of new transmission and distribution facilities, and in the long term defer the construction and operation of new power plants.

- The tradeoff between the TRC and RIM tests can be reduced by having customers share in the costs of the DSM measures installed by the program, by reducing the maximum CCE paid by the utility, or by delaying implementation of the program. However, each of these approaches also reduces the amount of electricity savings achieved by the programs, increasing the need for additional power supplies.

Based on these simulations, I recommend that utilities and PUCs adopt a flexible approach to the assessment of DSM programs. Rather than adhering strictly to any single measure of cost effectiveness, the parties should modify program design and timing so that DSM programs provide major reductions in electric energy service costs (the TRC test) with only minor increases in electricity prices (the RIM test). In particular, I urge that the large reductions in total costs not be foregone because of small increases in electricity prices. ■

Endnotes:

1. Cal. Pub. Util. Comm'n and Cal. Energy Comm'n, Standard Practice Manual, Economic Analysis of Demand-Side Management Programs (1987).

2. These include regulators in Connecticut, Idaho, Illinois, Montana, Nevada, Washington, D.C. and Wisconsin.

3. Personal communication with P. Centolella, Ohio Office of the Consumers' Counsel, Sept. 1991.

4. Electricity Consumers Resource Council, Profiles in Electricity Issues: Demand Side Management, No. 14, Wash. D.C., Dec. 1990.

5. L. E. Ruff., Utility Least-Cost Planning: Five Common Fallacies and One Simple Truth, Putnam, Hayes & Bartlett, Inc., Wash. D.C., Jan. 1988.

6. *Id. See also* A. E. Kahn, *An Economically Rational Approach to Least-Cost Planning*, Elec. J., June 1991 at 11-20; A. E. Kahn, *An Exchange of Views*, Elec. J., July 1991 at 55.

7. E. Hirst, *The Great Demand-Side Bidding Debate Rages On*, Elec. J., Mar. 1989 at 41-43; E. Hirst, *An Exchange of Views*, Elec J., July 1991 at 54; A. Lovins 1989, *The Great Demand-Side Bidding Debate Rages On*, Elec. J., Mar. 1989 at 34-40.

8. R. C. Cavanagh, *Least-Cost Planning Imperatives for Electric Utilities and Their Regulators*, 10 Harv. Envt'l L. Rev. 299-344 (1986).

9. M. Gettings, E. Hirst, and E. Yourstone, Diamond: A Model of Incremental Decision Making for Resource Acquisition by Electric Utilities (ORNL/CON-315, Oak Ridge Natl. Lab., Feb. 1991).

10. E. Hirst, The Effects of Utility DSM Programs on Electricity Costs and Prices (ORNL/CON-340, Oak Ridge Nat'l Lab., Nov. 1991).

11. A static model requires as inputs assumptions about future avoided energy and capacity costs, while dynamic models internalize these calculations.

12. Energy Info. Admin., Electric Power Annual 1988 (DOE/EIA-0348(88), U.S. Dept. of Energy, Dec. 1989); Energy Info. Admin., Annual Outlook for U.S. Electric Power 1991, Projections through 2010, (DOE/EIA-0474(91), U.S. Dept. of Energy, July 1991).

13. C. Marnay and G. A. Comnes, Ratemaking for Conservation: The California ERAM Experience (LBL-28019, Lawrence Berkeley Laboratory, Mar. 1990).

14. All costs and prices are in 1990 dollars. Calculations of net present value use the utility cost of money, roughly 10.5% in nominal terms and 6% in real terms.

Session 2D

THE RIM TEST: A NEW MARKETING TOOL

Dr. Steven R. Sim, Florida Power & Light

This presentation looks at the Rate Impact Measure (RIM) test from two perspectives. The first perspective takes a utility system planning point of view, looking at how supply and DSM options are evaluated. The Total Resource Cost (TRC) test and RIM test are examined to determine which test allows a more consistent and thorough means of evaluating all resources for all customers. The presentation concludes that the RIM test is clearly the better DSM test and demonstrates that the TRC test can lead to the worst possible resource decision for the majority of customers.

The presentation then takes the perspective of how one can use the RIM test as a "tool" and discusses two somewhat unconventional uses for the RIM test. These uses equate to using the RIM test as a tool for marketing programs/services beyond traditional DSM conservation programs and for identifying the best "markets" or groups of customers for any DSM product.

Note: The full paper was not available from the author at the time of printing.

THE TRADE-OFF BETWEEN ALL-RATEPAYER BENEFITS AND RATE IMPACTS: AN EXPLORATORY STUDY

Ahmad Faruqui and John H. Chamberlin
Barakat & Chamberlin, Inc.

ABSTRACT

This paper estimates the trade-off between positive all-ratepayer benefits and adverse rate impacts of DSM programs. In contrast to others who have studied this trade-off in theoretical terms, or through computer simulation, we estimate the trade-off empirically, through a review of 191 programs at 14 utilities. We quantify the trade-off using results from two commonly used cost-effectiveness tests, the TRC and RIM tests. The trade-off ratio is the amount of negative RIM net benefits that utilities absorb in return for a dollar of RIM net benefits. We measure the trade-off at three levels: (1) for the entire portfolio of programs across utilities, (2) on a program-by-program basis across utilities, and (3) on a program-basis within a utility. At the level of DSM portfolios, TRC net benefits are positive and RIM net benefits are negative for all 14 utilities in our sample. There is a trade-off between the TRC and RIM impacts, with some utilities taking a conservative approach towards DSM, displaying a trade-off ratio of -0.1, and others taking an aggressive approach, displaying a trade-off ratio of -2.00. At the level of individual programs, the trade-off exists in 139 of the 191 DSM programs, and ranges from a conservative value of -0.14 for some programs to an aggressive value of -1.00 for other programs. Within individual utilities, some portfolios reflect a unique trade-off ratio that applies to all programs; others reflect different trade-off ratios by program. The impact of DSM programs on rates is about one mill per kWh, for a sub-sample of nine utilities for whom such data is available. The rate impact appears to be invariant with respect to program size, as measured by the program's TRC net benefits. These conclusions are tentative, based on a small sample and the application of simple statistical methods. We will report on results from an expanded sample, using multivariate analysis, in a subsequent paper.

INTRODUCTION

Utilities whose rates exceed their marginal costs are faced with a dilemma: DSM programs directed at improving energy efficiency generally result in adverse rate impacts. At the same time, these programs can create substantial benefits for all ratepayers, through better use of existing generation facilities, and deferral or cancellation of new capacity. What is the magnitude of the trade-off between the positive all-ratepayer benefits and the negative rate impacts? This is the central question addressed in this paper.

This question is important to utilities, their customers, and regulatory commissions because it lies at the heart of the current controversy between groups that represent the interests of large power customers who claim they have adopted all the measures to improve energy efficiency on their own without any utility incentives, and groups that are interested in improving the quality of the environment and making the best use of our limited energy resources.

A closely-related question that we also address is: what cost-effectiveness test should utilities use in assessing DSM programs? Should it be the all-ratepayer test, also called the Total Resources Cost (TRC) test, or the Rate Impact test (RIM)? The RIM test is also called the Nonparticipant test or No-losers test. The TRC test generally results in more amounts of DSM being conducted than the RIM test.[1]

The issue of which test to use has been debated extensively in the literature on DSM planning. Much of this debate has been theoretical in nature.[2] A notable exception is Hirst, 1991.[3] He addresses this question through simulations with a computer model of three hypothetical utilities. He reports that the ratio of the percentage savings in utility revenue requirements to the percentage rate increase for DSM programs is 2:1 for utilities with excess capacity, 5:1 for "typical" U.S. utilities, and 8:1 for utilities with little excess capacity. These results indicate that the size of the gains generally outweigh the size of the losses experienced by the "losers" for DSM programs that fail the RIM test. Thus, these results offer support for placing emphasis on the results of the TRC test rather than those of the RIM test.

In this paper, we take an *empirical* approach to assessing the trade-off between all rate-payer benefits and rate impacts, using a database of 191 DSM programs and 14 utilities. The information presented in this paper is of an explanatory character, intended to promote dialogue and debate, and given its preliminary nature, is not intended to be definitive.

CONCEPTS AND DEFINITIONS

In this section, we describe the two main tests considered in this paper, TRC and RIM, and discuss their interrelationships.[4]

TRC Test

The TRC test compares the benefits and costs of a DSM program over its lifetime by considering the total cost of all resources, whether paid by the utility or the participating customers. The benefits of an energy-efficiency-type DSM program from this perspective include cost reductions in generation, transmission, and distribution. The costs of such a program from this perspective include both the program costs incurred by the utility and the costs incurred by participating customers. The utility's program costs exclude the incentives it pays to the customer but include all administrative, marketing, equipment installation and operation and maintenance costs, and monitoring and evaluation costs. The participants' costs include the incremental cost of the efficient equipment, including installation and operation and maintenance costs.

RIM Test

The RIM test compares the benefits and costs of a DSM program over its lifetime from the point of view of rate levels. The benefits of an energy-efficiency-type DSM program from this perspective include cost reductions for generation, transmission, and distribution. The cost of such a program includes the utility's program costs, as in the TRC test, but also includes two additional components: any incentives that the utility pays to the customer, and the utility's revenue reductions.

The net benefits under the TRC and RIM can be summarized by the following equations:

(1) $TRC_{NB} = AC - UPC - PC$

(2) $RIM_{NB} = AC - UPC - RL - I$

where:*

NB	=	Net benefits
I	=	Incentives
PC	=	Participant costs
AC	=	Avoided costs
UPC	=	Utility program costs
RL	=	Revenue loss

*Note: All variables defined above present values of a stream of values spread out over the life of the applicable DSM program.

Much of the empirical analysis that we present in this paper relates the TRC_{NB} to RIM_{NB} (or to LRI − RIM, a closely related concept, defined later in this section). To see this relationship in conceptual terms, equation (2) can be re-written as follows:

(3) $RIM_{NB} = (-RL + PC - I) + TRC_{NB}$

If the term in parenthesis, $(-RL + PC - I)$, is a constant, then the relationship between RIM net benefits and TRC net benefits is a simple linear relationship, with a slope of one. This is unlikely to be the case. To get some additional insights, we examine three special cases of equation (3).

(3a) The worst case, in which the utility pays 100% of the participant costs as incentives.

$$I = PC, \text{ then, } RIM_{NB} = TRC_{NB} - RL$$

If the revenue loss is large enough to outweigh the positive TRC net benefits of a TRC-passing program, the program will have negative RIM net benefits.

(3b) The case in which the utility pays part of the participant costs ($I < PC$), the RIM net benefits can be positive or negative.

$$I < PC, \text{ then, } RIM_{NB} = TRC_{NB} - [RL - (PC - I)]$$

(3c) The "best" case in which the utility pays none of the participant costs.

$$I = 0, \text{ then, } RIM_{NB} = TRC_{NB} - RL + PC$$

If the revenue loss is smaller than the participant cost, the program will have a positive TRC net benefit and a higher, and positive RIM net benefit.

In addition to looking at the net benefits of the RIM test, we also look at a closely-related concept called the Lifecyle Rate Impact (LRI-RIM). The Lifecycle Revenue Impact is a measure of the one-time change in rates caused by DSM. As discussed earlier, the RIM test compares the present worth of the savings in avoided costs (benefits) against the utility expenses associated with the implementation of the programs, including incentives and revenue decreases. If a program fails the RIM test, the utility will suffer a revenue deficiency – future revenues will not cover revenue requirements – and rates will have to increase to rematch revenues to revenue requirements. The LRI-RIM estimates the size of that rate increase. If rate levels are increased by the amount of the LRI-RIM, revenues would again match revenue requirements over the life of the program impacts.

The formula for calculating the LRI-RIM is shown as follows:

(4) $$LRI - RIM = -\frac{RIM_{NB}}{E}$$

where:

E = The discounted stream of system or class energy sales

REGULATORY STATUS

As of this writing, 32 states are either practicing integrated resource planning (IRP) or are in the process of implementation.[5] In general, the 32 states with IRP have not given utilities explicit direction on determining the cost-effectiveness of a DSM program in legislation or rules. However, in some of these states, cost-effectiveness policy has been determined through regulatory commission decisions in specific dockets.

Of the 24 states with IRP in practice, 15 provide some direction regarding the use of cost-effectiveness tests and 9 give no explicit direction. Of those providing explicit direction, 8 require the consideration of both the TRC and RIM tests, 3 require the TRC test and reject the RIM test, 2 require the TRC test but provide no direction on the TRC test. South Carolina requires the RIM test but explicitly rejects the TRC test. South Carolina's rejection of the TRC test is of interest because no state with IRP in practice has rejected this test.

SAMPLE UTILITIES

Our sample consists of 14 utilities that are geographically spread out over the United States and Canada. It includes utilities of different sizes. The sample utilities offer a total of 191 DSM programs. Most of these programs passed the TRC test, and were proposed by these utilities to their regulatory bodies for implementation, as part of their long-range integrated resource plan filing.

Five of these utilities are located in the Northeastern United States, two in the Southeastern United States, seven in the Midwestern United States, and one in Canada. While the sample includes some very big and some very small utilities, most of the utilities are midsized utilities.

RESULTS: RIM NET BENEFITS

We report comparisons between the TRC and RIM net benefits at three levels: the entire portfolio of DSM programs across the 14 utilities, individual DSM programs across those utilities, and individual programs by utility.

Portfolios Across Utilities

The TRC net benefits for DSM portfolios across our sample utilities range from \$8.7 million to \$787.7 million, with a mean value of \$267.9 million, and a median value of \$146.3 million.

The RIM net benefits are negative, indicating that the modified revenue loss [PC – RL – I] experienced by these utilities is greater than the TRC net benefits. The RIM net benefits are smaller in absolute value than the TRC net benefits, and range from negative \$6.9 million to negative \$328.5 million, with a mean value of negative \$94.7 million, and a median value of negative \$56.6 million.

Figure A presents a portfolio comparison by utility of RIM net benefits to TRC net benefits. The figure indicates that there are two very different rates of trade-off that utilities make between RIM net benefits and TRC net benefits. Some utilities (group one) are unwilling to give up much RIM net benefits as a trade for TRC net benefits. On the basis of visual inspection, we can say that group one utilities make the following trade-off: to get \$100 million in TRC net benefits, they are willing to absorb a loss of \$10 million in RIM net benefits, (slope of –0.10). On the other hand, utilities in group two are willing to absorb bigger RIM losses for comparatively little TRC gain: to get $100 million in TRC benefits, they are willing to absorb $200 million in RIM losses (slope of -2.00).

FIGURE A
PORTFOLIO COMPARISON
RIM_{NB} AGAINST TRC_{NB}

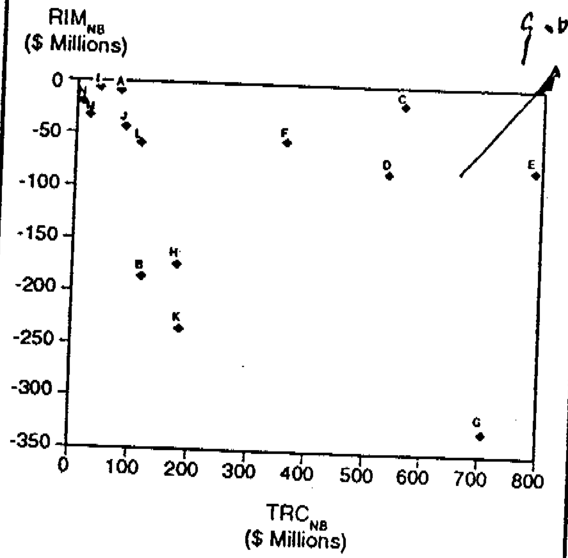
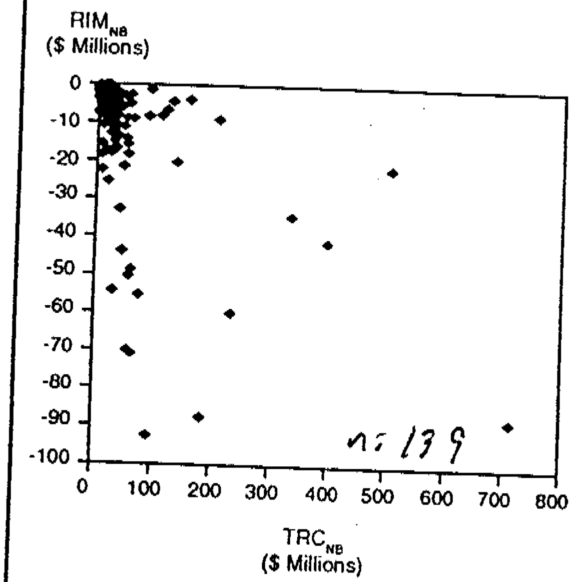


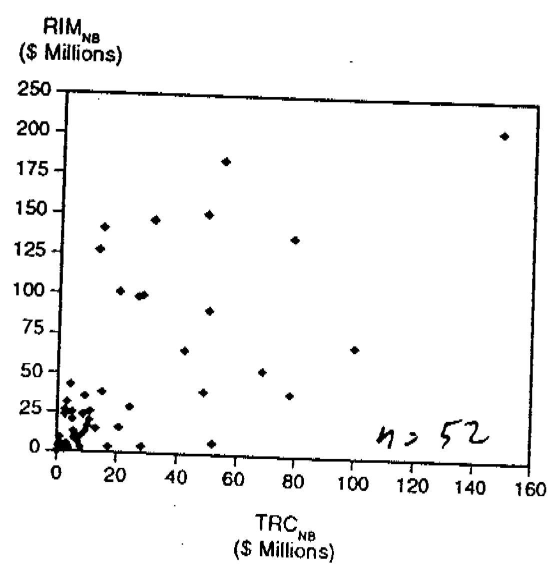
FIGURE B
PROGRAM-BY-PROGRAM COMPARISON
RIM_{NB} (NEGATIVE) AGAINST TRC_{NB}



Program-by-Program Across Utilities

Additional insights are obtained when we review the results on a program-by-program basis. Of the 191 programs in our sample, 139 have negative RIM net benefits and 52 have positive RIM net benefits. For graphical purposes, we display the results of the 139 programs in Figure B and of the 52 programs in Figure C. Figure B shows trends that are generally similar to those in Figure A. To get $100 million in TRC net benefits, programs in group one are willing to absorb a loss of $14 million in RIM net benefits, suggesting a trade-off ratio of -0.14. Programs in group 2 are willing to absorb a loss of $110 million in RIM net benefits, to get $100 million in TRC net benefits, suggesting a trade-off ratio of -1.10.

FIGURE C
PROGRAM-BY-PROGRAM COMPARISON
RIM_{NB} (POSITIVE) AGAINST TRC_{NB}

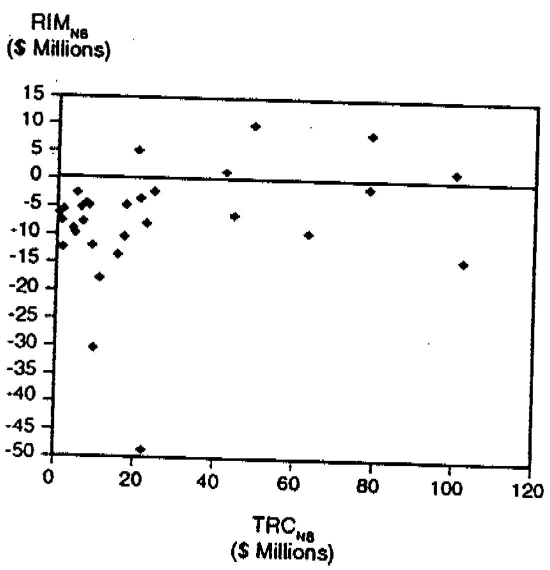


Of course, some programs do not have a negative trade-off between TRC net benefits and RIM net benefits. These programs, shown in Figure C, represent a win-win situation.

Program-by-Program By Utility

Within individual utilities, we see the same kind of relationships. Figure D is similar to Figures B and C, the comparison of DSM programs for all utilities in the sample. Below the zero line, it displays two different slopes, as did the portfolios for group 1 and 2 utilities in Figure B. Above the zero line, it displays a win-win situation.

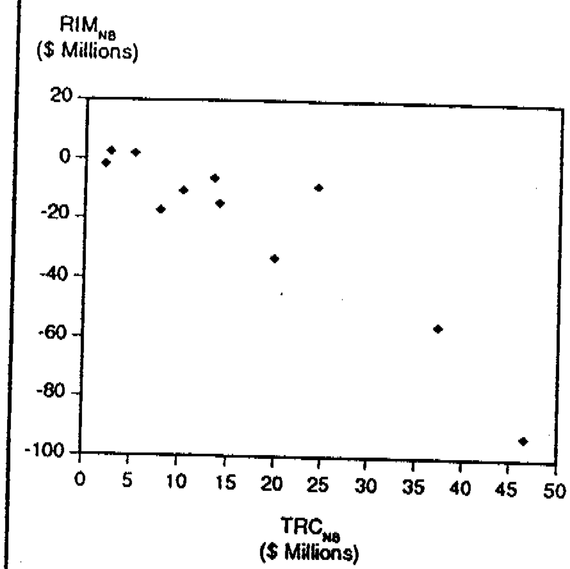
FIGURE D
UTILITY E
RIM_{NB} AGAINST TRC_{NB}



92M074.FigD fh

Figure E illustrates that some utilities may have programs that all fall on a single line, indicating that they apply a unique trade-off ratio to all DSM programs. Utility K's DSM programs resemble the group two utilities in Figure A and the group two programs in Figure B. To gain $20 million in TRC net benefits, Utility K is willing to lose $53 million in RIM net benefits, a trade-off ratio of -2.7.

FIGURE E
UTILITY K
RIM_{NB} AGAINST TRC_{NB}



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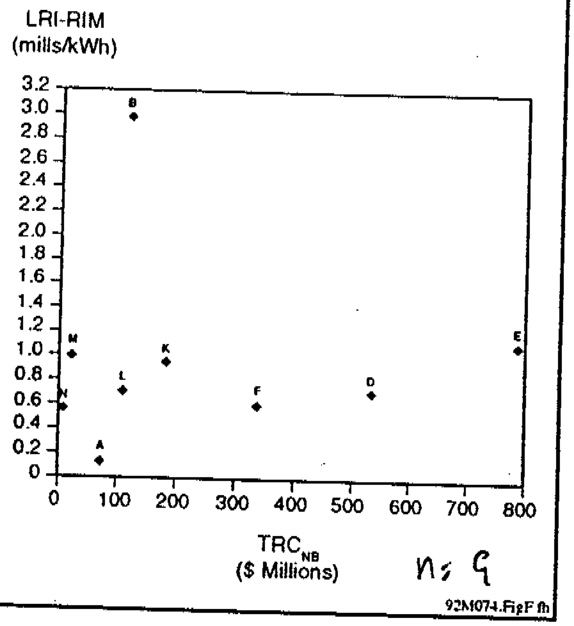
RESULTS: RATE IMPACTS

The LRI-RIM rate impacts across the nine utilities for which such impacts are available range from 0.13 mills/kWh to 2.95 mills/kWh, with a mean value of 1.03 mills/kWh, and a median value of 0.72 mills/kWh.

Portfolios Across Utilities

Figure F shows that with any amount of TRC net benefits, the LRI-RIM impact will stay about the same. If we exclude the one outlier observation of 2.9 mills/kWh, we get an average LRI-RIM rate impact of about 0.6 mills/kWh. This adverse rate impact is constant across a wide range of TRC benefits, a very encouraging result.

FIGURE F
PORTFOLIO COMPARISON
LRI-RIM AGAINST TRC_{NB}



Program-by-Program Across Utilities

Figure G shows the program-by-program comparison of the LRI-RIM net benefits to the TRC net benefits. Individual program LRI-RIM impacts are smaller than the portfolio LRI-RIM impacts. There is a small, positive slope in the relationship, indicating that increases in TRC net benefits are often accompanied by a small increase in LRI-RIM impacts.[6]

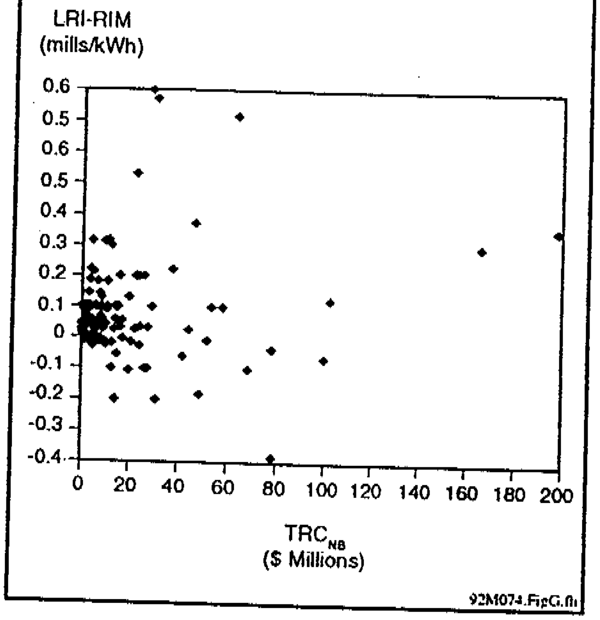
CONCLUSIONS

This paper has presented estimates of the trade-off between positive all-ratepayer benefits and adverse rate impacts that utilities often encounter with DSM programs. In contrast to other studies that have studied this trade-off in theoretical terms, or through computer simulation, we estimate the trade-off empirically, through a review of 191 programs analyzed by 14 utilities.

We measure this trade-off at three levels: (1) for the entire portfolio of programs across utilities, (2) on a program-by-program basis across utilities, and (3) on a program-basis within a utility.

- At the level of DSM portfolios, TRC net benefits are positive and RIM net benefits are negative for all 14 utilities in our sample. There is a trade-off between the TRC and RIM impacts, with some utilities taking a conservative approach towards DSM, displaying a trade-off ratio of −0.1, and others taking an aggressive approach, displaying a trade-off ratio of −2.00.

FIGURE G
PROGRAM-BY-PROGRAM COMPARISON
LRI-RIM AGAINST TRC_{NB}



- At the level of individual programs, the trade-off exists in 139 of the 191 DSM programs, and ranges from a conservative value of −0.14 for some programs to an aggressive value of −1.00 for other programs. Within individual utilities, some utilities have a unique trade-off ratio that they apply to all programs; others appear to apply different trade-off ratios by program.
- The impact of DSM programs on rates is about one mill per kWh for a subsample of nine utilities for whom such data is available. The rate impact appears to be invariant with respect to program size, as measured by the program's TRC net benefits.

These conclusions should be tempered with a realization that they are tentative, based on a small sample and the application of simple statistical methods. We will report on results from an expanded sample, using multivariate analysis, in a subsequent paper. We hope to be able to analyze why the trade-off ratio varies across programs and utilities, and seek to relate its variation to variables such as geographic region, type of utility ownership, type of DSM program (load management or energy efficiency), and customer class to which the program is targeted.

ENDNOTES

1. For further information, see the *Standard Practice Manual for Economic Analysis of Demand-Side Management Programs*, published in 1987 by the California Public Utilities Commission and the California Energy Commission, and EPRI's *TAG End-Use Technical Assessment Guide*, Vol. 4, *Fundamentals and Methods*, EPRI CU-7222, 1991.

2. C.J. Cicchetti and W. Hogan 1989, "Including Unbundled Demand-Side Options in Electric Utility Bidding Programs," *Public Utilities Fortnightly* 123 (12), June 8; A. E. Kahn 1991, "An Economically Rational Approach to Least-Cost Planning," *The Electricity Journal* 4(5), 11–20, June; and L. E. Ruff 1988, *Utility Least-Cost Planning: Five Common Fallacies and One Simple Truth*, Putnam, Hayes, & Bartlett, Inc., Washington, D.C., January.

3. Eric Hirst, *The Effects of Utility DSM Programs on Electricity Costs and Prices*, Oak Ridge National Laboratory, November 1991.

4. For a discussion of a new cost-effectiveness test that incorporates customer value considerations, see Chamberlin and Herman (1992), "Why All 'Good' Economists Reject the RIM Test," in these proceedings.

5. Barakat & Chamberlin, Inc. *Least-Cost Planning in the United States: 1990* (Palo Alto, Calif.: Electric Power Research Institute, September 1990), and recent telephone interviews.

6. For a discussion of strategies to mitigate rate impacts, see Chamberlin, Herman and Wikler (1992), "Mitigating Rate Impacts of DSM Programs," prepared for Pacific Gas & Electric Company, December; and for a discussion of issues in DSM cost allocation, see Toulson and Fry (1992), "DSM Cost Allocation: Who Gets Their Just Desserts?", Fourth National Conference on Integrated Resource Planning, Washington, D.C.: NARUC, September.

DSM: WHO SHOULD PAY THE BILL?

John Locher, Detroit Edison Co.
Dana Toulson, Barakat and Chamberlin, Inc.

ABSTRACT

The Detroit Edison Co. will be completing a 5 year rate moratorium in December 1993, a period when Demand-Side Management (DSM) expenditures were limited by agreement to 0.1 mills/kWh. The Company is addressing the entire DSM issue as part of a general rate case for which an order should be received prior to January 1994. In considering an expansion of its DSM activities, a key concern for the Company is the trade-off between customer bill savings from DSM and resulting rate impacts in competitive markets.

We will review customer bill impacts vs rate impacts and how both are affected by the interactions of DSM option mixes, spending levels, cost recovery methods. Using the Load Management Strategy Testing Model (LMSTM), Detroit Edison analyzed the impacts that DSM mixes and cost recovery methods have on class rates and average bills for various spending levels.

The results of our analyses show that appropriate cost allocation methods can be implemented to minimize rate impacts, thus limiting the anti-competitive effects of DSM programs. Changes in allocations of the cost of service caused by DSM factors can cause unexpected changes to occur in the rates and average bills of different classes. Utilities should be aware of the causes of these changes when designing and implementing DSM programs to avoid undesirable equity impacts.

BACKGROUND

Detroit Edison is Michigan's largest electric utility with annual sales of 40,000 GWh, a summer peak demand of 9,000 MW, and 1.9 million customers. It also has a concentration of large manufacturing customers with connected loads ranging from 50 kW to more than 100 MW. Currently large manufacturing customers account for approximately 30% of annual sales and 20% of peak demand.

Detroit Edison does not need new baseload capacity in the foreseeable future because it recently completed a 20-year building program. Near-term avoided capacity costs are determined by existing plants that have been taken out of service over the last several years and can be brought back into service quickly at minimal cost.

Although rates have remained stable during the 5-year moratorium, they are still higher than rates of neighboring utilities. This includes the large manufacturing class, where many customers are feeling their own competitive pressures. Part of the moratorium includes an agreement to limit DSM costs to 0.1 mills per kWh, recoverable from all customers through an energy rate surcharge. The Company is addressing the entire DSM issue for the post moratorium period as part of its current rate case filing. The strategy to support this filing was developed in 1992.

Proceedings: 6th National Demand-Side Management Conference

Making a Difference

TR-102021

Proceedings, March 1993

March 24–26, 1993
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Demand-Side Management Program
Customer Systems Division

Ron Burrup 4/20/93

LOST REVENUE COMPARISONS
PacifiCorp, dba Utah Power & Light

Utah DSM Technical Conference
April 20, 1993

	KWH	DOLLARS
Utah Power & Light 1991 operating revenues (Utah Only)		$779,718,302
Utah Power & Light 1991 tariff revenues (Utah only)		$688,896,480
UP&L Average number of total customers 1991	495,873	
UP&L Average number of total customers 1992	506,272	
Annual Increase	10,399	
RESIDENTIAL CUSTOMERS SCHDULE 1 UP&L Average number of customers 1991	356,756	
JP&L Average number of customers 1992	366,593	
Annual Increase	9,837	
1992 Average annual kwh, Schedule 1	7,061	
Additional KWH sales due to additional customers	69,459,057	
1991 WEATHER NORMALZATION ADJUSTMENT Dollar amount for residential only		$4,407,724
Kwh, residential only	64,448,889	
ECONS ANNUAL LOST REVENUE Estimated lost kwh sales (1072 kwh x 12,000 customers)	12,864,000	
Estimated GROSS lost revenue @ $.068391 per kwh		$879,782
Estimate NET lost revenue @ 40 mills/kwh		$514,560
ECONS lost kwh sales as a percent of new sales	18.52%	
ECONS lost kwh as a percent of the weather normalization	19.96%	

Rich Collins
4/20/93

ELECTRIC-UTILITY REGULATION: DSM AND LOAD GROWTH

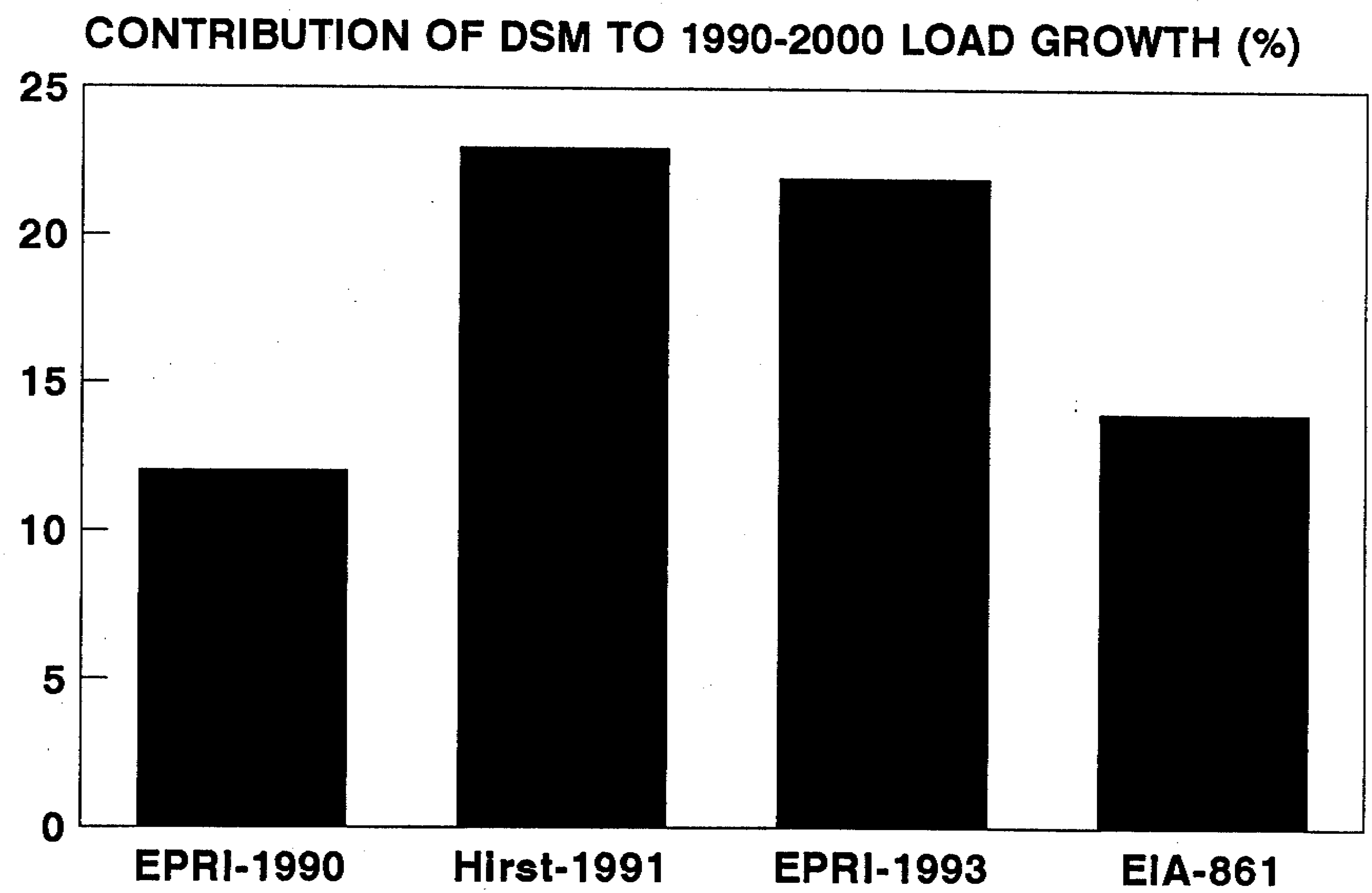
ERIC HIRST and ERIC BLANK
Land and Water Fund of the Rockies

w124

TWO ERICS WILL COVER FOUR TOPICS

- Utility DSM programs
  - 1991 activities and potential
- Elements of DSM incentives issues
  - Cost recovery, lost revenues, incentives
- Lost revenues caused by DSM programs
- Ways to address lost revenues
  - Decoupling, lost revenue adjustment, or command and control

VARIOUS ESTIMATES OF DSM CONTRIBUTION TO LOAD GROWTH



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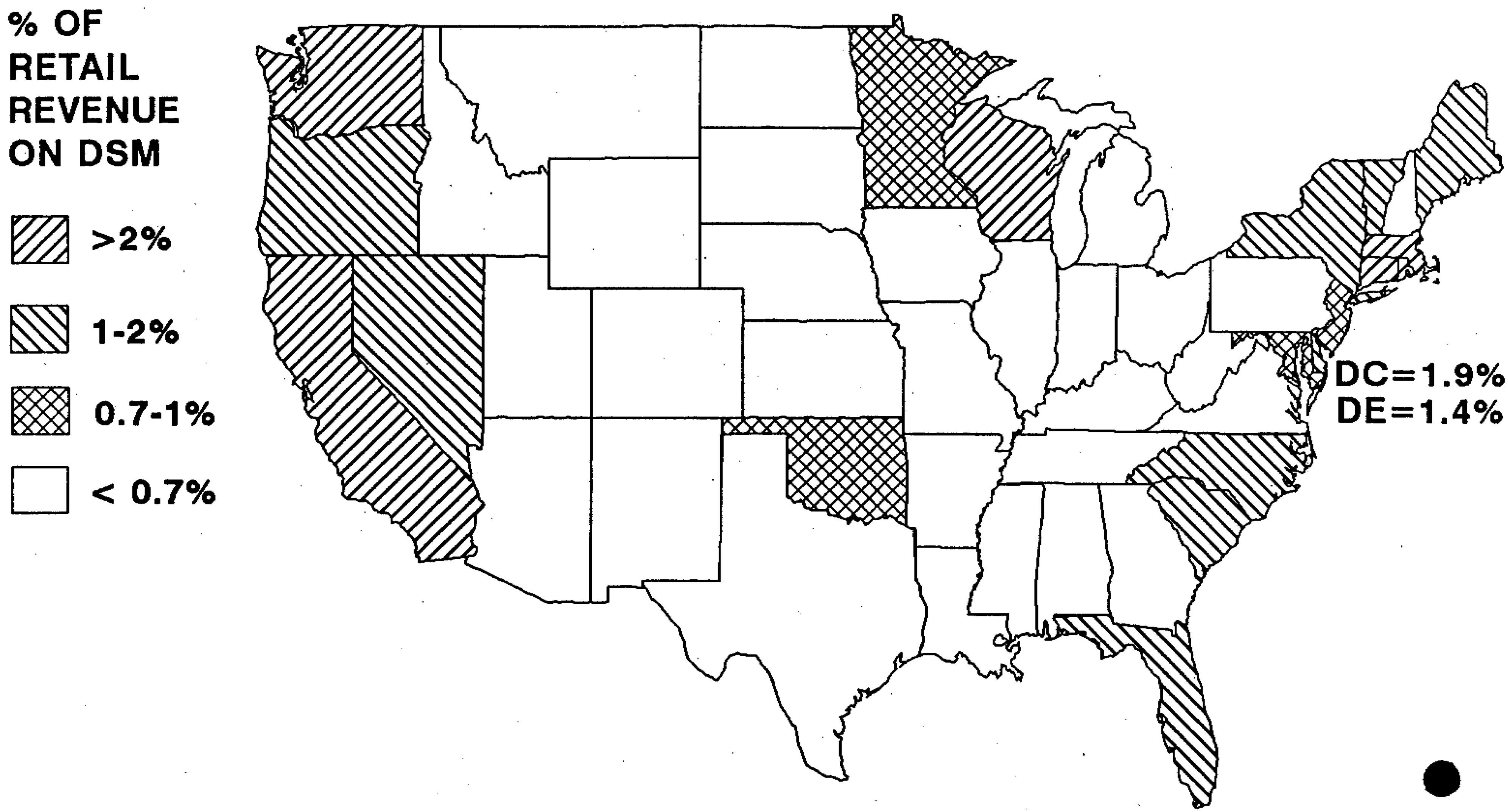
16 STATES SPENT > 1% OF REVENUES ON DSM IN 1991



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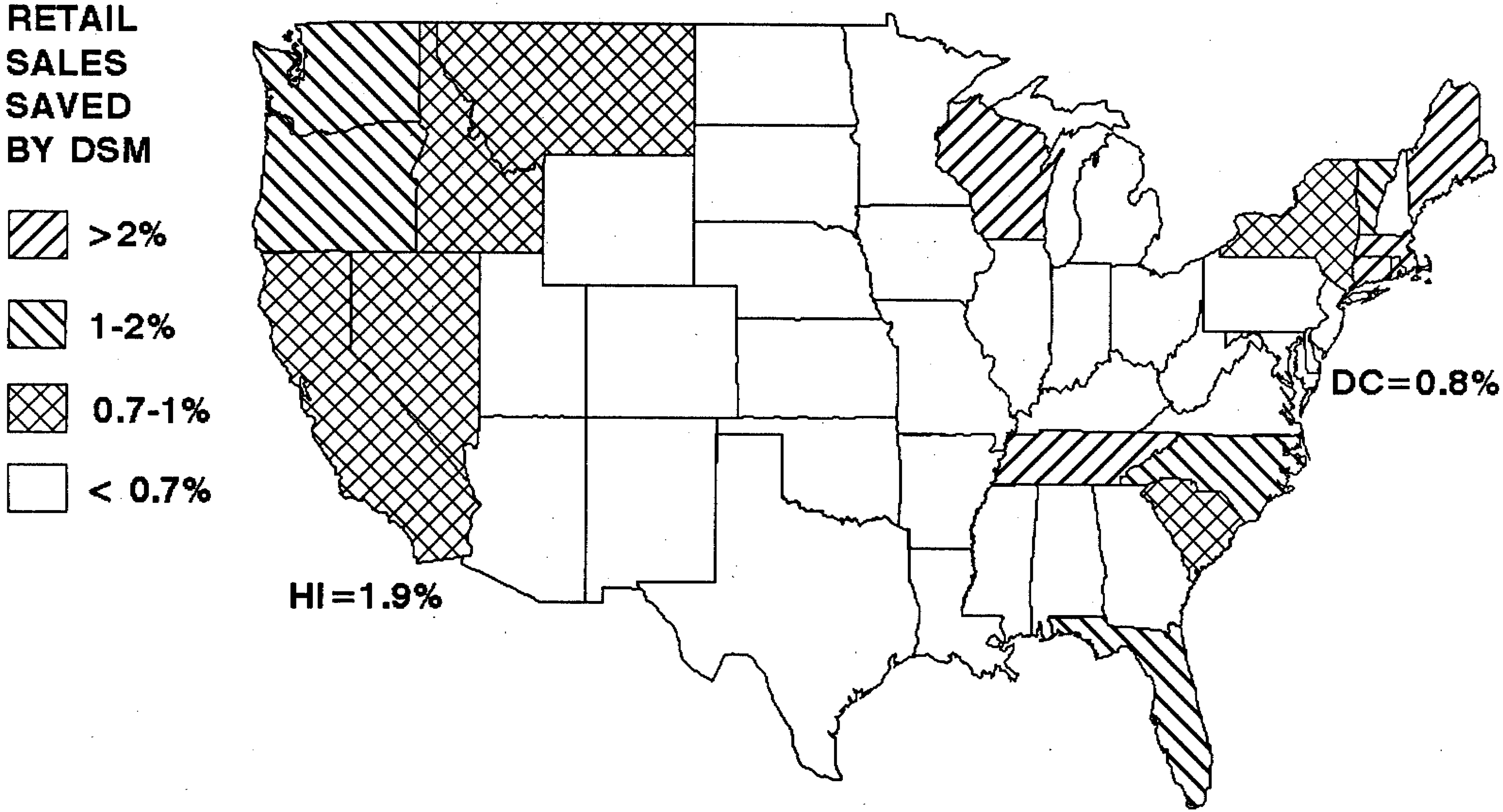
12 STATES SAVED > 1% OF ENERGY FROM DSM IN 1991



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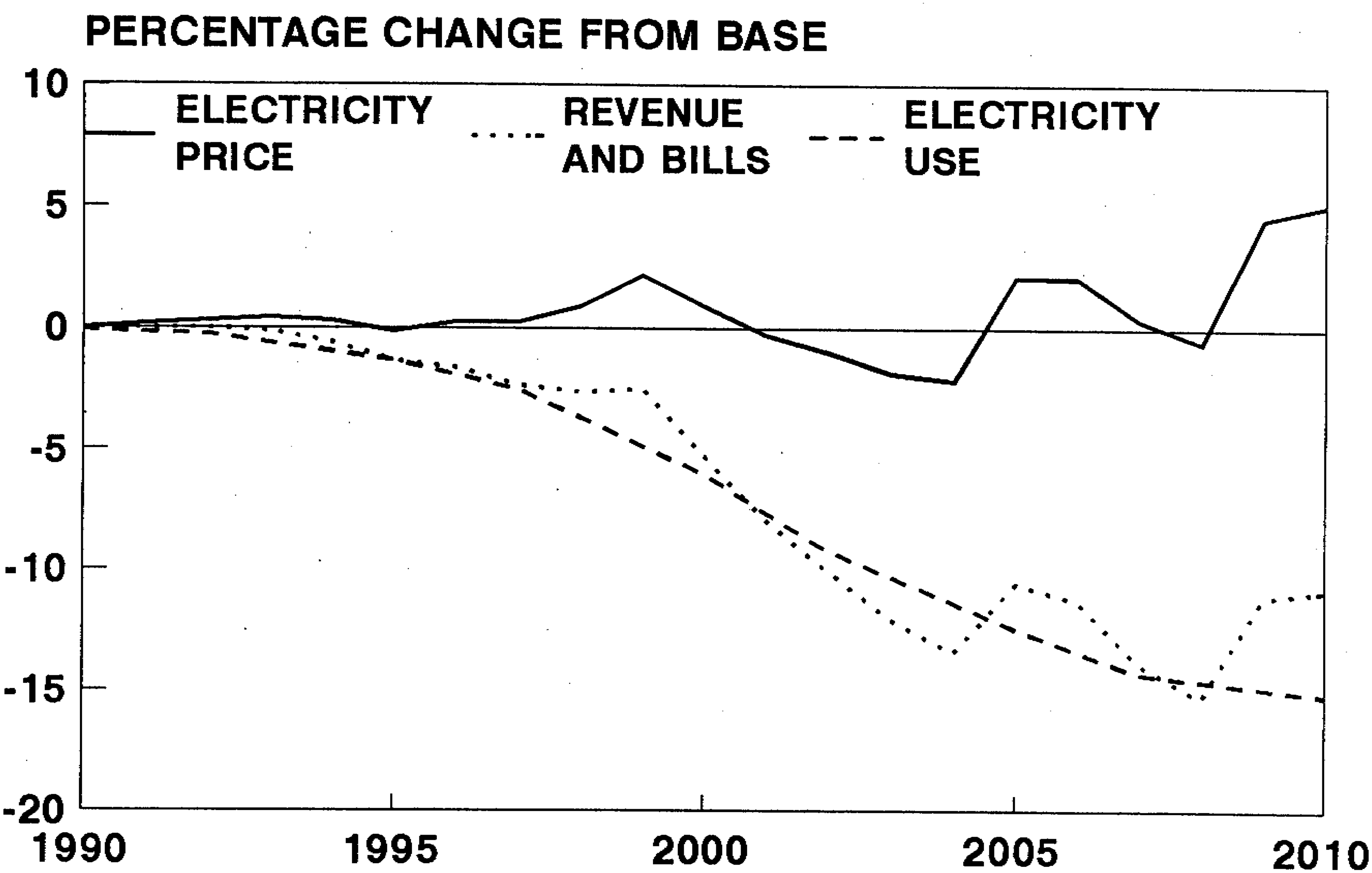
DSM AFFECTS ELECTRICITY PRICES, REVENUES, AND USE



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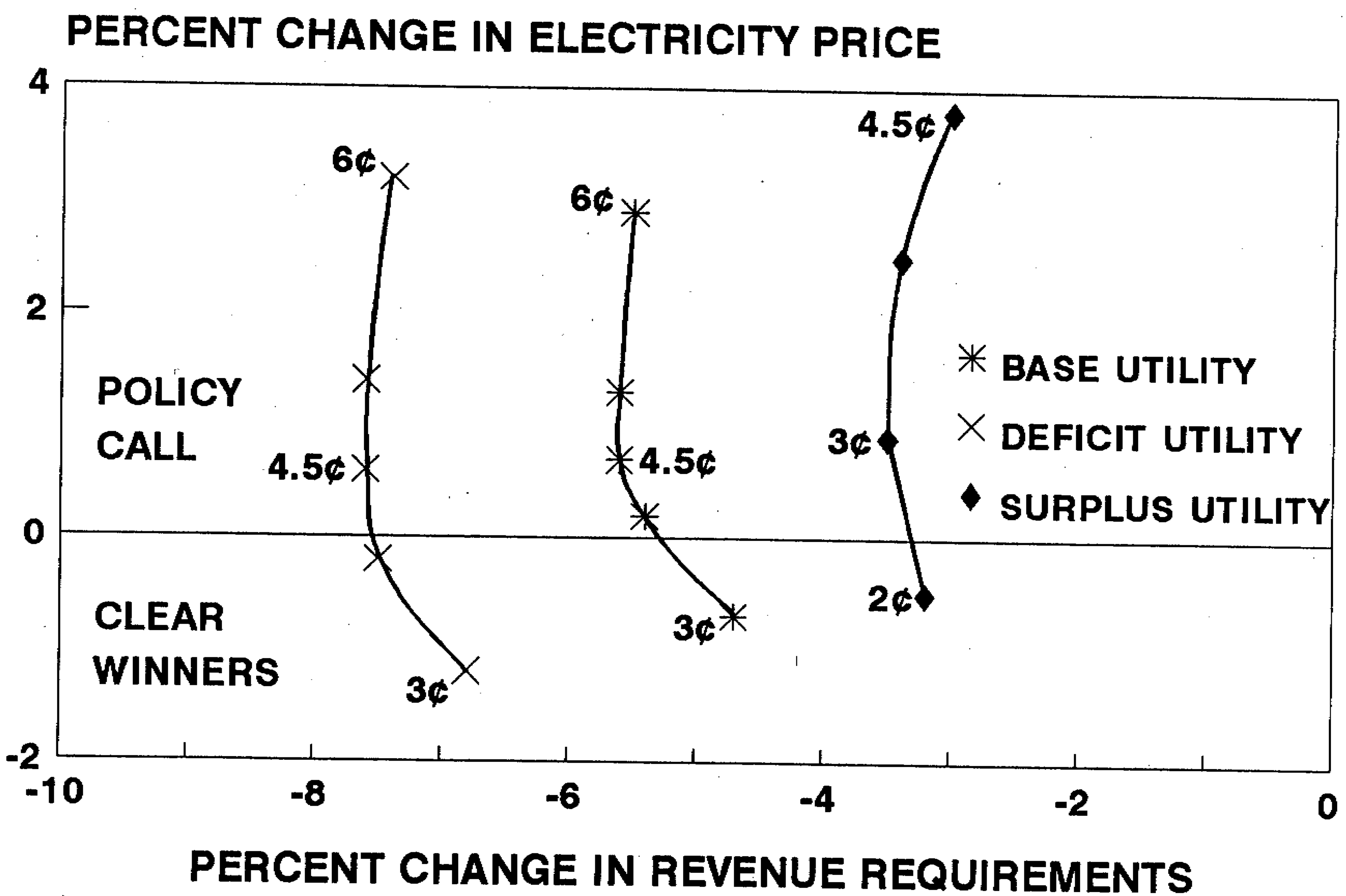
UTILITY DSM PROGRAMS AFFECT REVENUES MORE THAN PRICES



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THREE ELEMENTS TO FINANCING UTILITY DSM PROGRAMS

- Recovery of DSM-program costs
  - Prompt and assured

BIGGEST $

- Treatment of net lost revenues
  - Decoupling or DSM adjustment

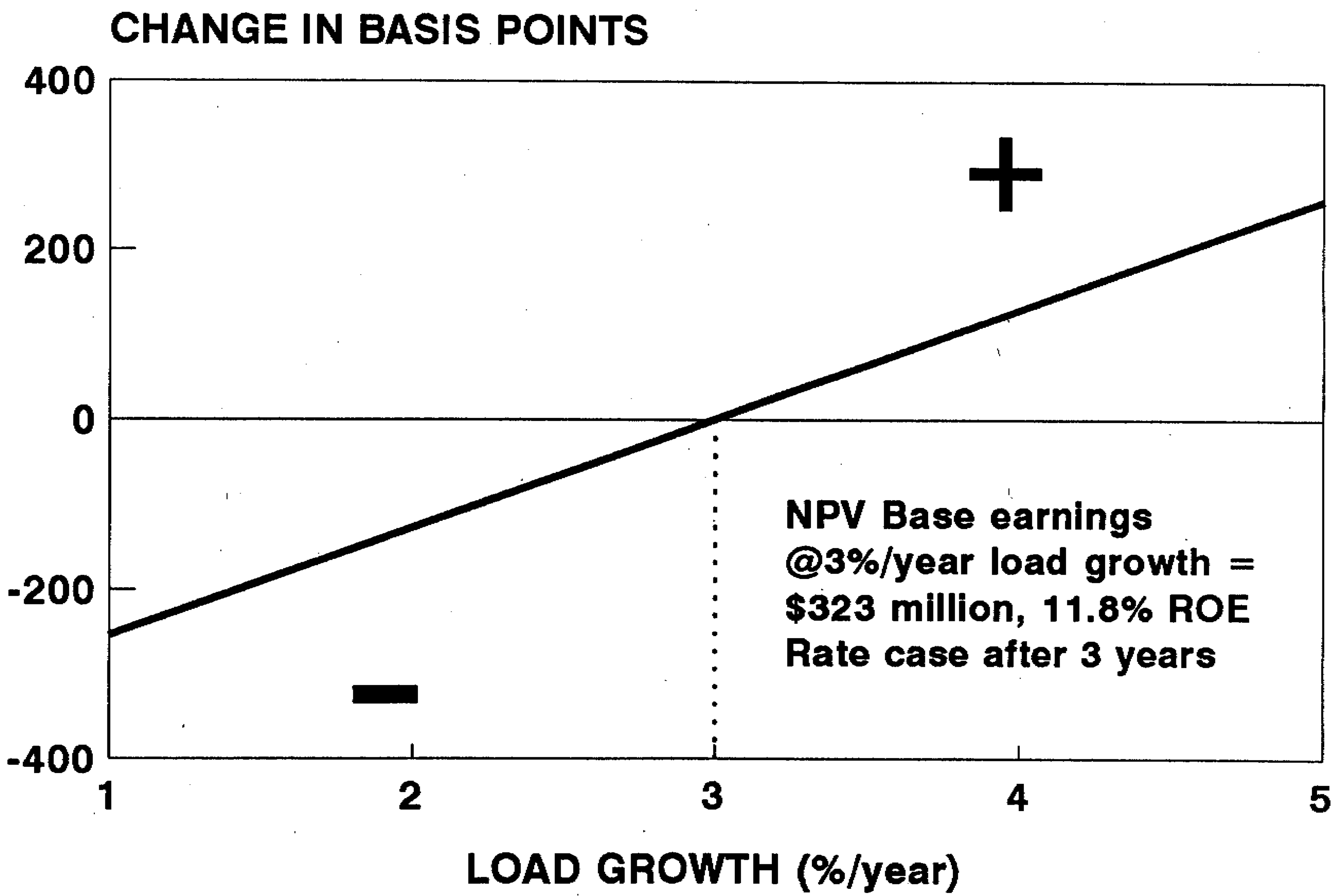
- Incentive to utility for DSM
  - Innovative, ambitious, and cost-effective programs

ECONOMIC REGULATION OF ELECTRIC UTILITIES AFFECTS DSM

- Retail prices cover fixed and variable costs
- If sales grow, utilities collect more money than needed to cover fixed costs
- If DSM cuts sales, shareholder earnings suffer

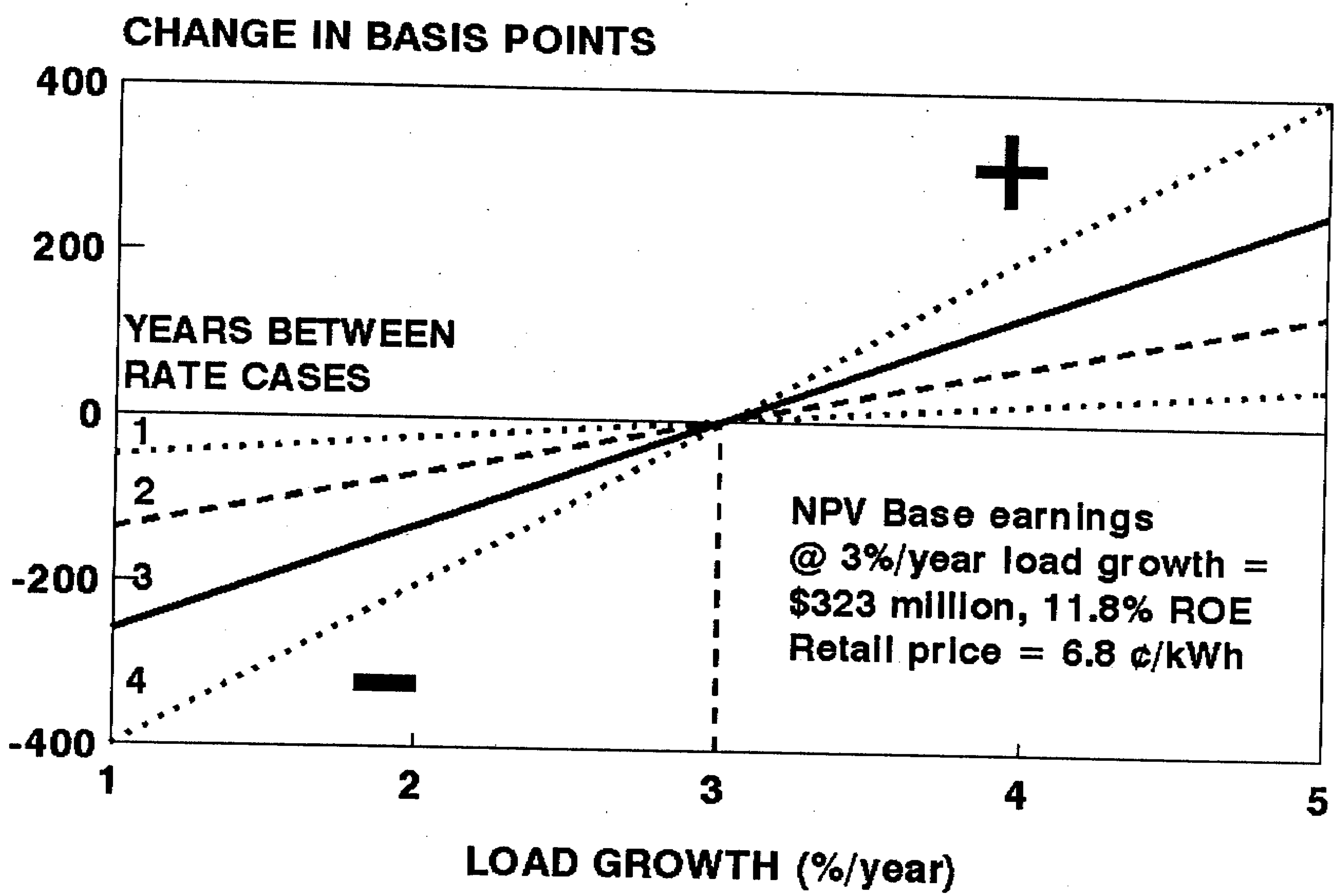
- Built simple model to quantify effects for PacifiCorp Utah area

PACIFICORP EARNINGS DEPEND ON LOAD GROWTH BETWEEN RATE CASES



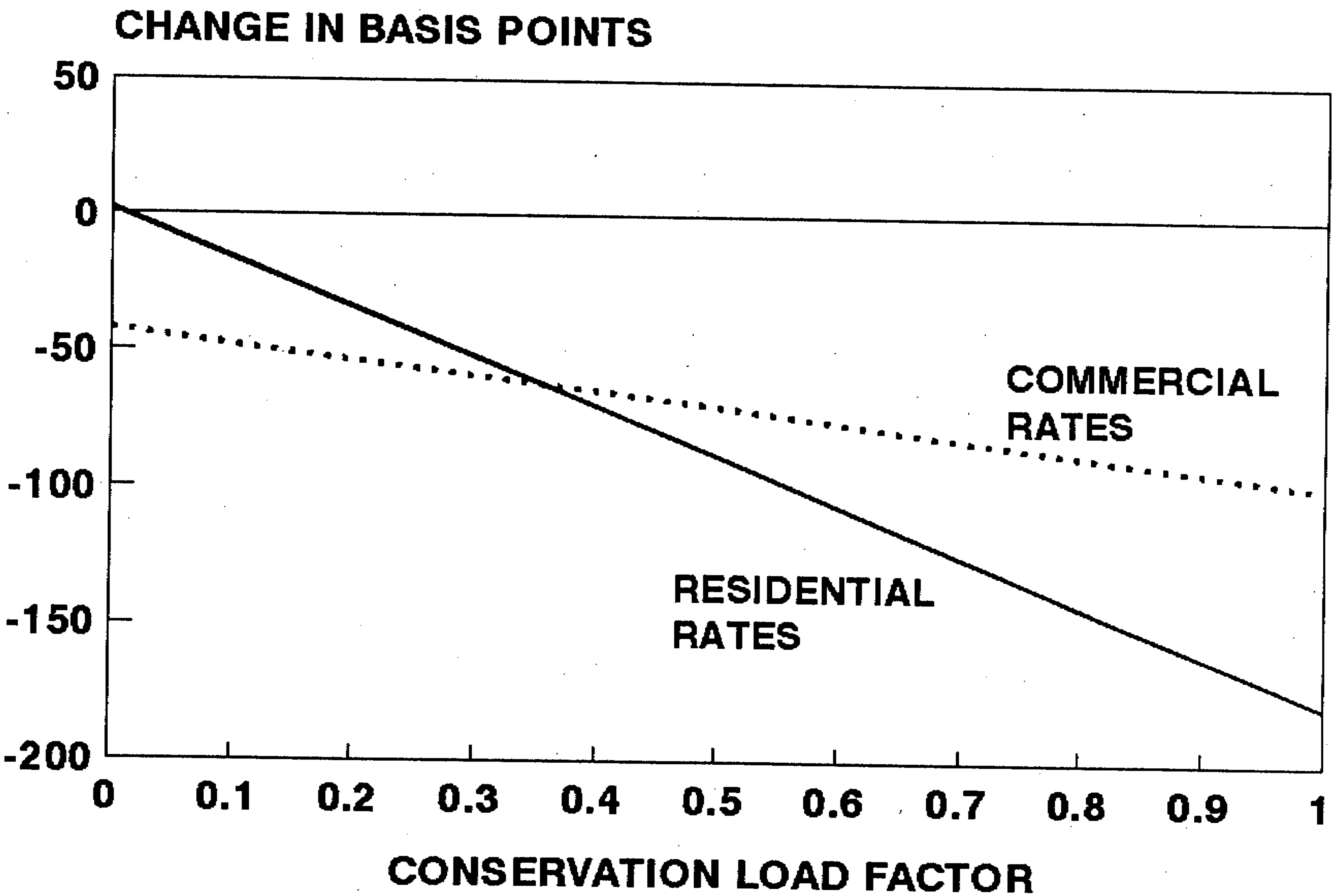
93039

PACIFICORP EARNINGS DEPEND ON FREQUENCY OF RATE CASES



93039B

PACIFICORP EARNINGS DEPEND ON DSM LOAD FACTOR AND RATE STRUCTURE



93039C

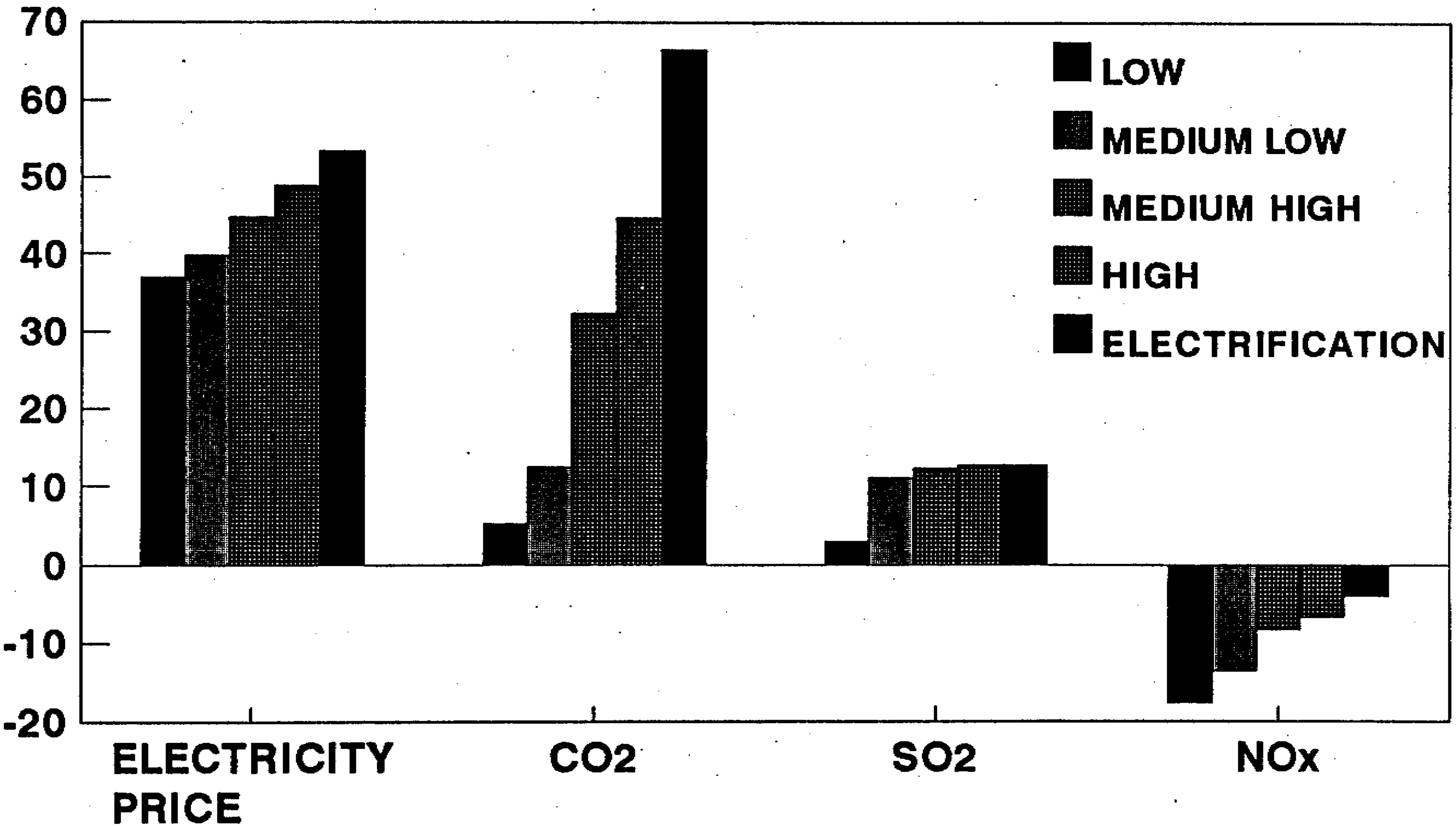
DSM CUSTOMER BENEFITS OPPOSITE SHAREHOLDER EFFECTS

Type of DSM program	Percent of load growth	Customer benefit (million $)	Shareholder effects (basis points)	Shareholder effects (million $)
Pilot	11	7	-6	-2
Ramp-up	22	41	-52	-14
Full-scale	36	80	-136	-37

W127A

PACIFICORP's RESULTS SHOW COSTS OF LOAD GROWTH

2011 PRICE (mills/kWh) AND
% CHANGE IN EMISSIONS, 1991-2011



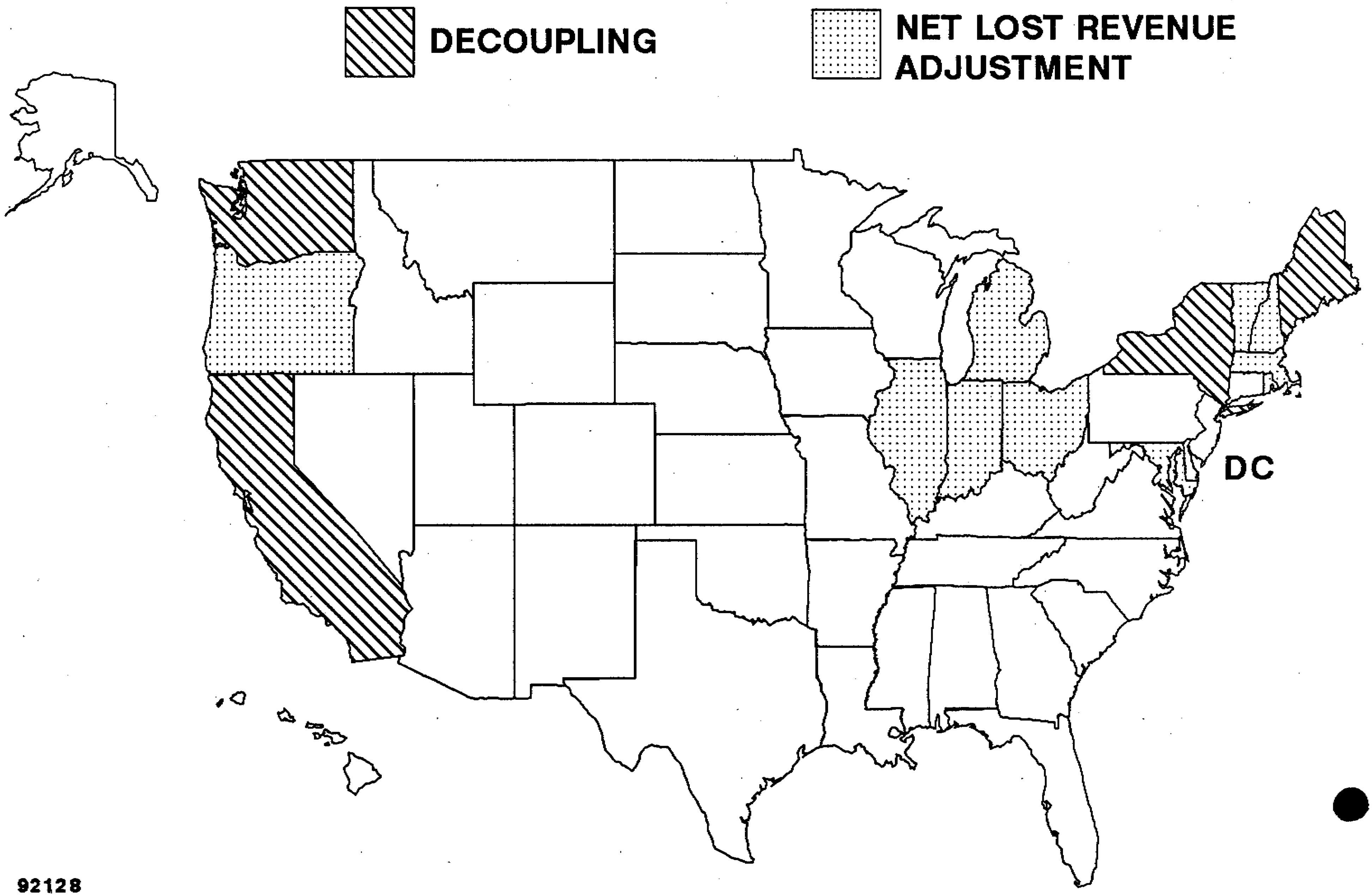
92082

SEVERAL SOLUTIONS ARE POSSIBLE

- Command and control regulation
- Frequent rate cases
- Rate design
- Lost-revenue adjustments
- Decoupling
- Statistical recoupling

See LAW Fund report for assessments

FOUR STATES WITH DECOUPLING, TEN WITH NET LOST REVENUE ADJUSTMENT



92128

DECOUPLING BREAKS LINK BETWEEN SALES AND REVENUES

- California and New York use explicit attrition adjustments.
  Allowed revenues for fixed costs based on indices outside utility control.

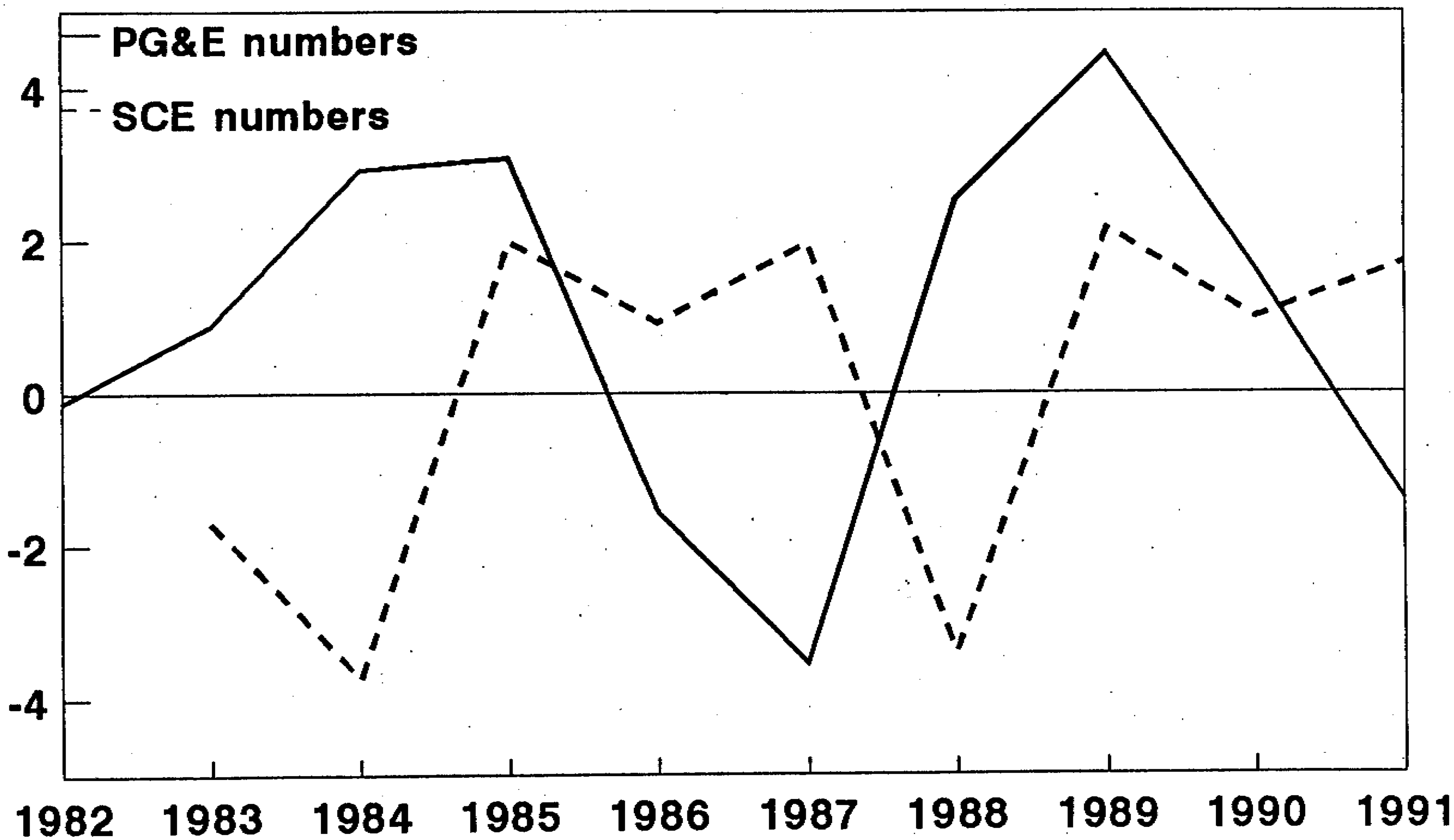
- Washington and Maine use customer growth as proxy for attrition.
  Allowed revenues for fixed costs based on growth in number of customers.

CA ERAM AND ATTRITION HAVE THREE ELEMENTS

- Operational attrition - adjust labor and materials with price indices
- Financial attrition - adjust cost of capital with actual interest rates
- Rate base attrition - adjust rate base with forecasts from general rate case

PG&E AND SCE ERAM ALWAYS LESS THAN 5% CHANGE

% PRICE INCREASE CAUSED BY ERAM

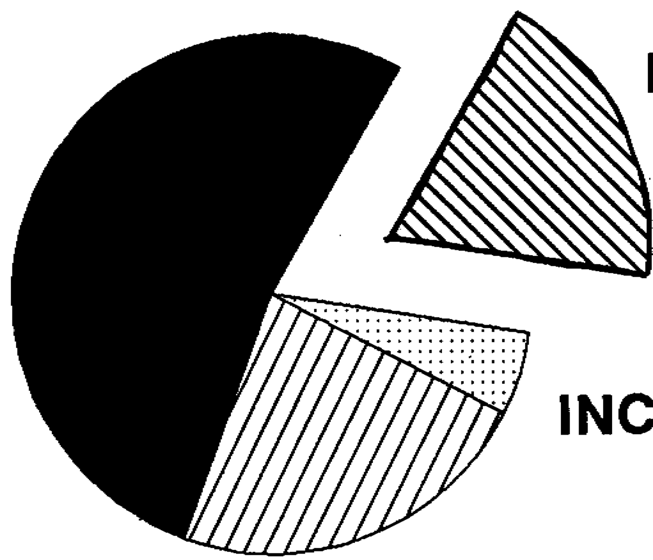


93013

PROBLEMS IN WA AND ME WITH REVENUE PER CUSTOMER DECOUPLING

- Shifting risks from utility to customers (weather and the economy)
- Adjusting for growth in kWh/customer
- Defining fixed and variable costs
- Service quality for large customers

POWER SUPPLY COSTS DOMINATED WA DECOUPLING



PUGET POWER COSTS

92146

STATISTICAL RECOUPLING ADDRESSES THESE PROBLEMS

- Estimate statistical model with historical data degree days income or other econ var. price electricity
  $E_i = a_i + b_i{*}DD_t + c_i{*}Y_t + d_i{*}P_{it} + \ldots$
  i = customer class, t = ~~year~~ monthly or quarter

- Use statistical model with actual values for independent variables for future year
  Allowed revenue = E'* N * P price of electricity # of customers
  for each customer class
  E' is computed value of E

W123

PSCO TOTAL SALES MODEL: EXAMPLE OF STATISTICAL RECOUPLING

Total GWh = -3128

+ 0.694*Cooling degree days

+ 0.194*Heating degree days   T-statistics?

+ 0.00869*No. Customers

- 194*Electricity price$_{-1}$

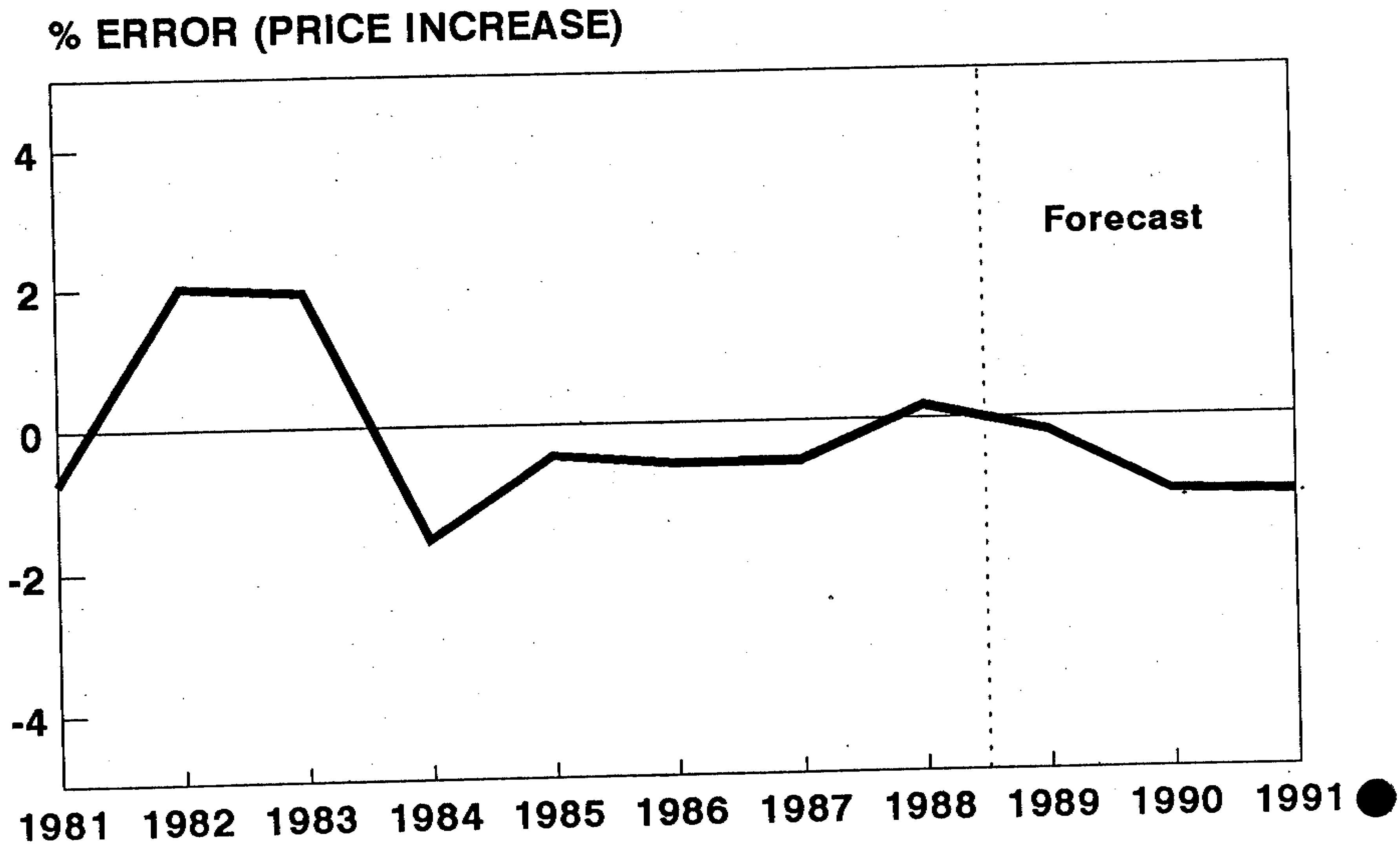
81 - 88

n = 26 (quarterly data, 1982-1989)

R^2 = 0.97

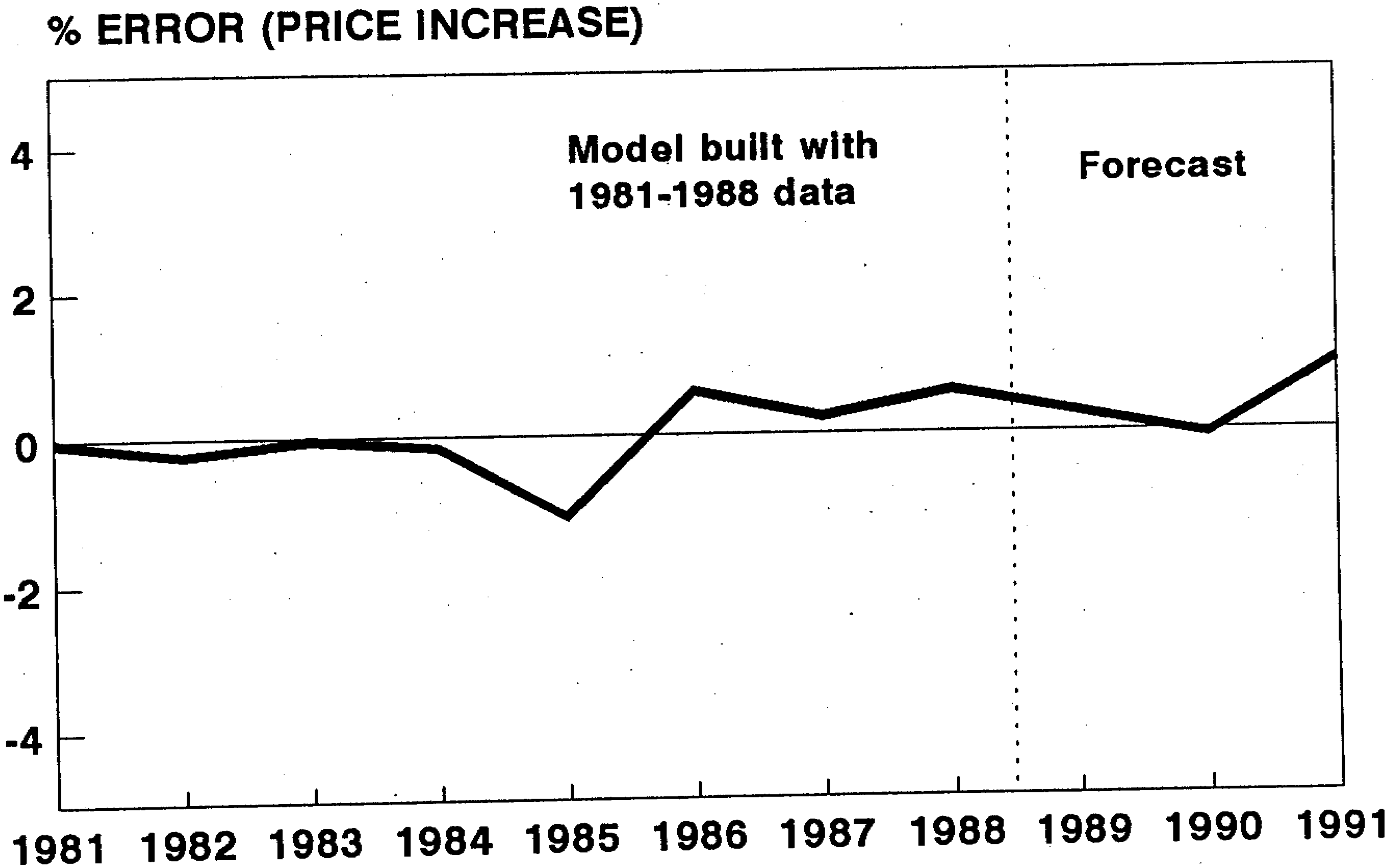
W138

ANALYSIS OF PSCO TOTAL SALES PER CUSTOMER YIELDS GOOD RESULTS



930334

DECOUPLING ANALYSIS WITH SCE DATA SHOWS GOOD RESULTS

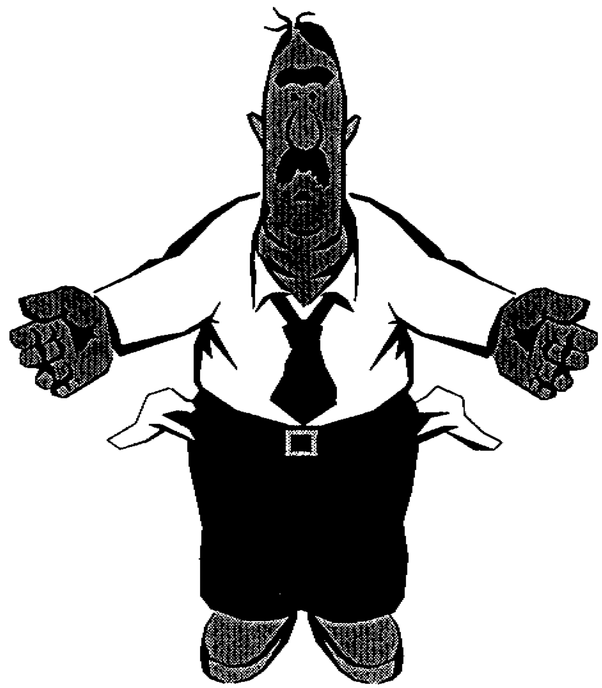


93010A

REGULATORY REFORM NEEDED TO ACHIEVE FULL DSM POTENTIAL

- Current regulation
  - Rewards load growth
  - Penalizes energy-efficiency
- Several solutions possible
- Decoupling or statistical recoupling preferred
  - address directly these problems
  - simple to understand and administer

Rich Collins
4/20/93



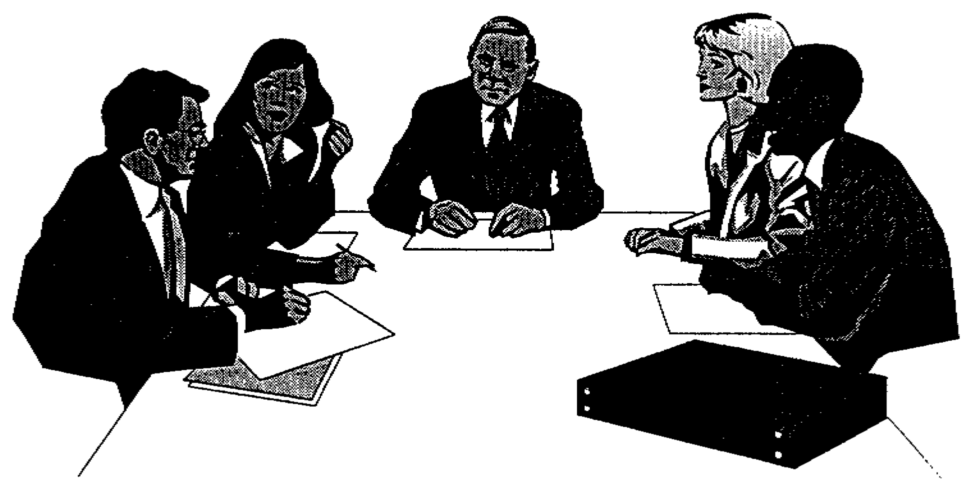
Lost Revenues Presentation

Technical Conference

April 20, 1993

Goal of Technical Conference:

- Encourage the Company to implement a Least Cost Plan by developing a cost recovery mechanism which encourages the Company to look at a variety of alternatives for acquiring cost effective DSR, including rate design.



Problems

(As identified by this technical conference)

1. **Profitability** make SSR and DSR equally profitable

2. **Equity** - between classes and w/in class

3. **Competition Effects** - Municipal - Gas - Esco

Solutions

1. **Accounting Treatment** LOST REVENUES / COST RECOVERY
2. **Participant Cost Sharing** addresses equity concerns.
3. **Balancing Account Mechanisms**
4. **Incentive Mechanisms**
   - **Shared Savings**
5. **Decoupling**

Factors That Reduce Profitability of DSR

- No mechanism for recovering investment
- No mechanism for return on investment APUDC or
  Timing of Rate Case
- No recovery of lost revenues

Need to compare DSR
w/SSR

Accounting Treatment Solutions to the "Profitability" Problem

- Defer DSR program costs
- Delay amortization of the costs
- Accrue carrying charges on unamortized program costs - similar to AFUDC on SSR resources
- Recover Lost Revenues
  - how to define + measure

Net Lost Revenue Adjustments

1. Definition & Purpose

2. Measurement

3. Calculation

Lost Revenue Definition & Purpose

- Lost revenues result from the additional sales the Company would have made, absent its investment in DSR resources.

- Whether successful DSR programs impact current customers or new customers, they reduce revenues that would otherwise have been earned.

- A Lost Revenue adjustment is essentially a mechanism for recovering "fixed" costs of service, given a declining base of kwh sales.

Lost Revenue Measurement Issues

- Measurement Techniques
  - Engineering studies
  - Industry standard
  - Comparison to prior usage
- Elimination of bias (Likely to understate as well as overstated)
- "Take-Back" Issues
- True-up For Actual (Balancing account?)

Lost Revenue Calculation

- Lost Rev = Savings x (Tail Block Rate - Avoided ? Cost) SRAC

  - Savings - As defined in the measurement discussion
  - Tail Block Rate - Cost to customer of ~~lost~~ last kwh used.
  - Avoided Costs - Utah Avoided Costs rate adjusted for sales for resale

Lost Revenue Calculation Example

Need to do the calculation for capacity

- **Gross Savings - 29,000 kwh**

Ave

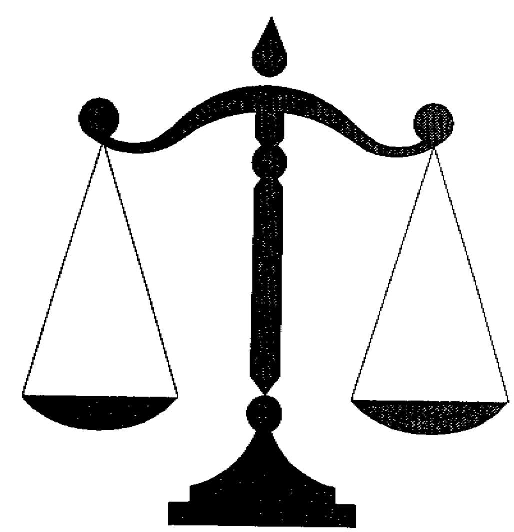
- **Tail Block Rate - 5.72 cents per kwh**

- **Avoided Energy Costs - 1.775 cents per kwh**
  - **Lost Rev = 29,000 x (5.72 - 1.775)**
  - **Lost Rev = \$1,144**

different avoided costs for different load factors

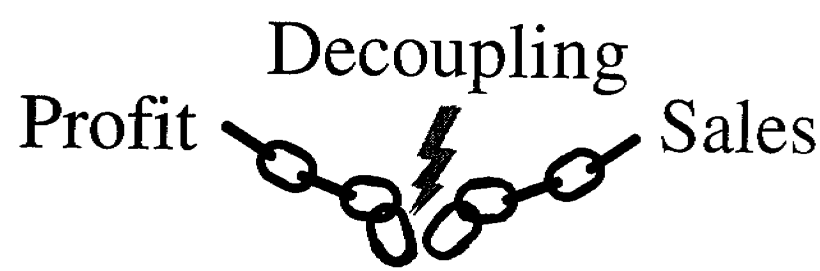
Criteria Met By Implementing Company Proposal

- Consistency between DSR and SSR
- Financial impact on Company of regulation change or cost recovery
- Risk bearing and risk shifting
- DSR performance standards



Company Concerns With Decoupling Mechanisms

- Shifts weather & business cycle risks to customers
- Isolates the utility from its customers
- Removes utility incentive to pursue socially desirable goals
- Dissatisfaction with decoupling in other jurisdictions (Washington & Maine)



Shifts Weather and Business Cycle Risks to Customers

- Increases risk of price volatility

- Contrary to long-established regulatory policy

Isolates the Utility From Its Customers

- Insulates the utility from market forces
- Tends to limit choices available to consumers

Removes Utility Incentive To Pursue Socially Desirable Goals

- No incentive to promote economic development
- No incentive to promote new, economically efficient uses for electricity

Dissatisfaction With Decoupling in Other Jurisdictions

- Washington - Puget approach heavily criticized. $100M in increases.

- Maine - Central Maine Power experiment ended early. $42M balance left to collect from customers.

Ken Powell

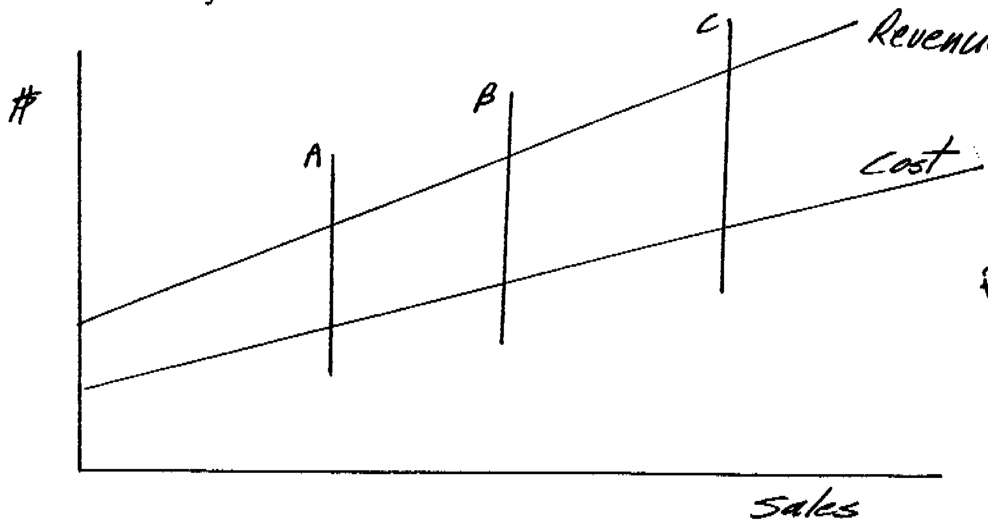
Rich Collins
4/20/93

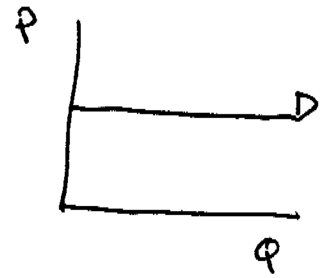
Good Try
But he confuses
Short term w/
Long term

UTAH DIVISION OF PUBLIC UTILITES
BASIC CONCERNS ABOUT LOST REVENUES

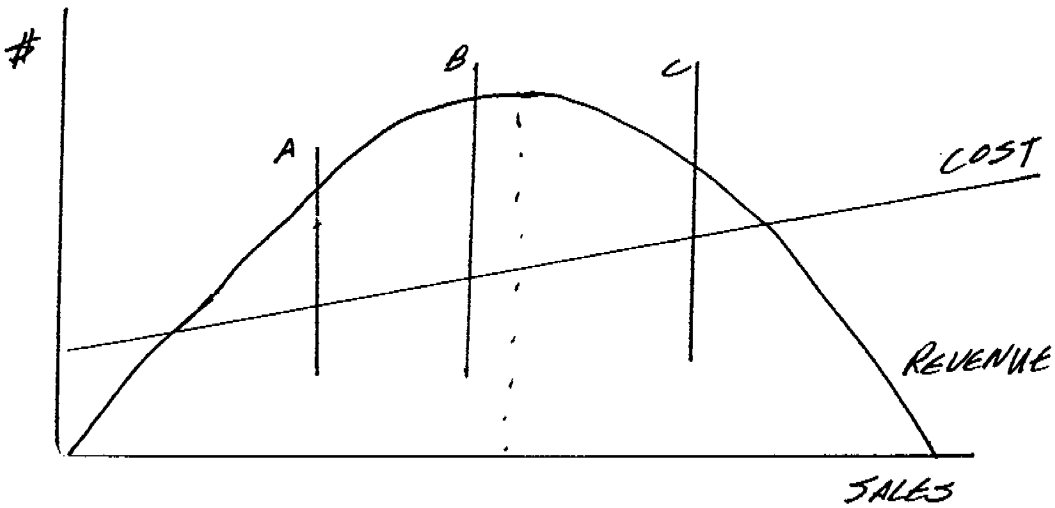
The figure below shows the traditional concept of the relationship between utility costs and revenues. Theoretically the utility's revenue requirement includes all its costs plus a percentage return on investment. If these were the actual relationships, then reducing sales would reduce both revenues and profits for the utility. This would occur no matter where on the sales curve the utility was.

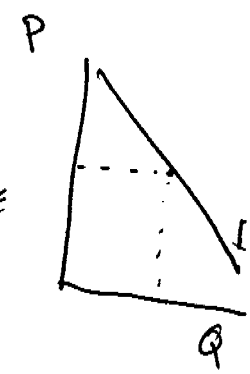
He forgot
ceteris
paribus





That traditional concept is flawed, however. Any enterprise that has price elasticity will have a quadratic revenue curve, as shown below. Above a certain maximum point, additional sales can actually lower revenues.





In this kind of relationship, there are still some sales levels where decreasing sales decreases revenues and decreases profits. (See line A.) But, there are sales levels where reducing the sales increases the revenues and decreases the profits.(See line B.) There are also sales levels where reducing sales increases both revenues and profits. (See line C.) Although we assumed a linear cost curve here, the same situation will occur with other shapes of cost curves.

Are these really what utility operating curves look like? Utilities around the country found during the 80's that they surely did have price elasticity. As prices climbed rapidly, sales began to slow down. Actual circumstances matched theory.

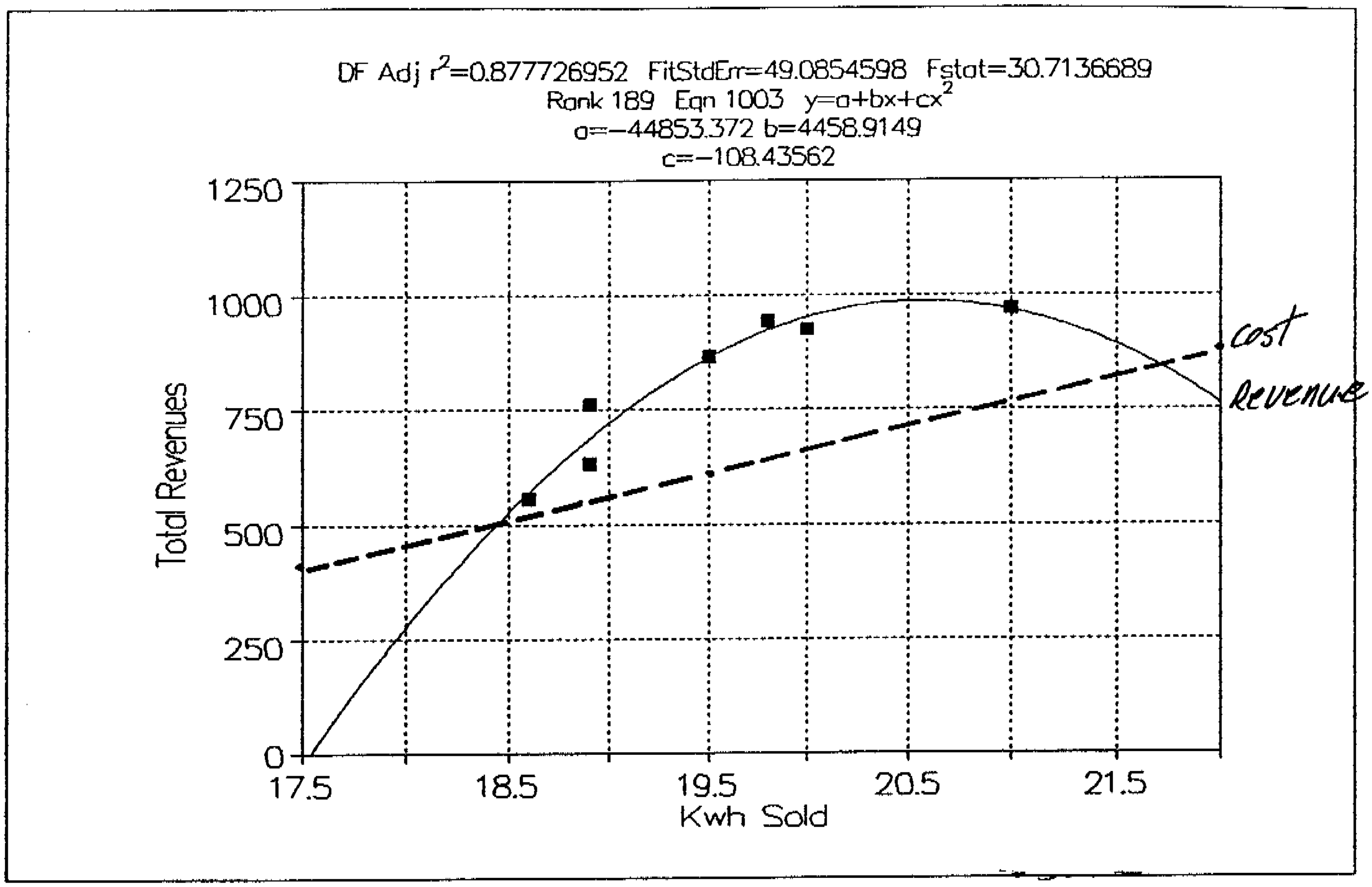
We can see this verfied closer to home. If we look at the total revenues and total costs of PP&L from 1981-1987 and apply curve fitting techniques to the curves, we find the patterns shown on the following pages. Page 3 shows the quadratic revenue curve expected with elasticity and a linear cost curve. The linear cost curve only has an r^2 of .71 so we might want to look at another relationship. Page 4 shows the same revenue curve with a quadratic cost curve. Both curves in this case have an r^2 above .85, a reasonable level, considering that we haven't normalized the data for weather or any other adjustments.

On these curves, we can again see how changes in sales have different impacts, depending on where the utility is currently operating. Lines A, B, and C have the same characteristics as in the theoretical chart. PP&L had sales of 21 billion kwh in 1987. Reducing sales from that level could increase both revenues and profits. What about UP&L? We would expect similar patterns, but the data is not consistent because of the Simonelli adjustments and resulting coal cost changes. What about PC? We may not have enough years of history to accurately predict where PC is on their operating curves.

The point is: Not every utility will loose revenues or profits by reducing sales. "Lost Revenues" should not be a foregone conclusion. Moreover, if we don't know where a utility is on its operating curves, then we cannot predict with any accuracy what lost revenues will be, or even if there will be any at all.

The other pages of this handout are the supporting data for this analysis. The basic source of the data, is the FERC Form 1.

Kenneth B. Powell
April 20, 1993



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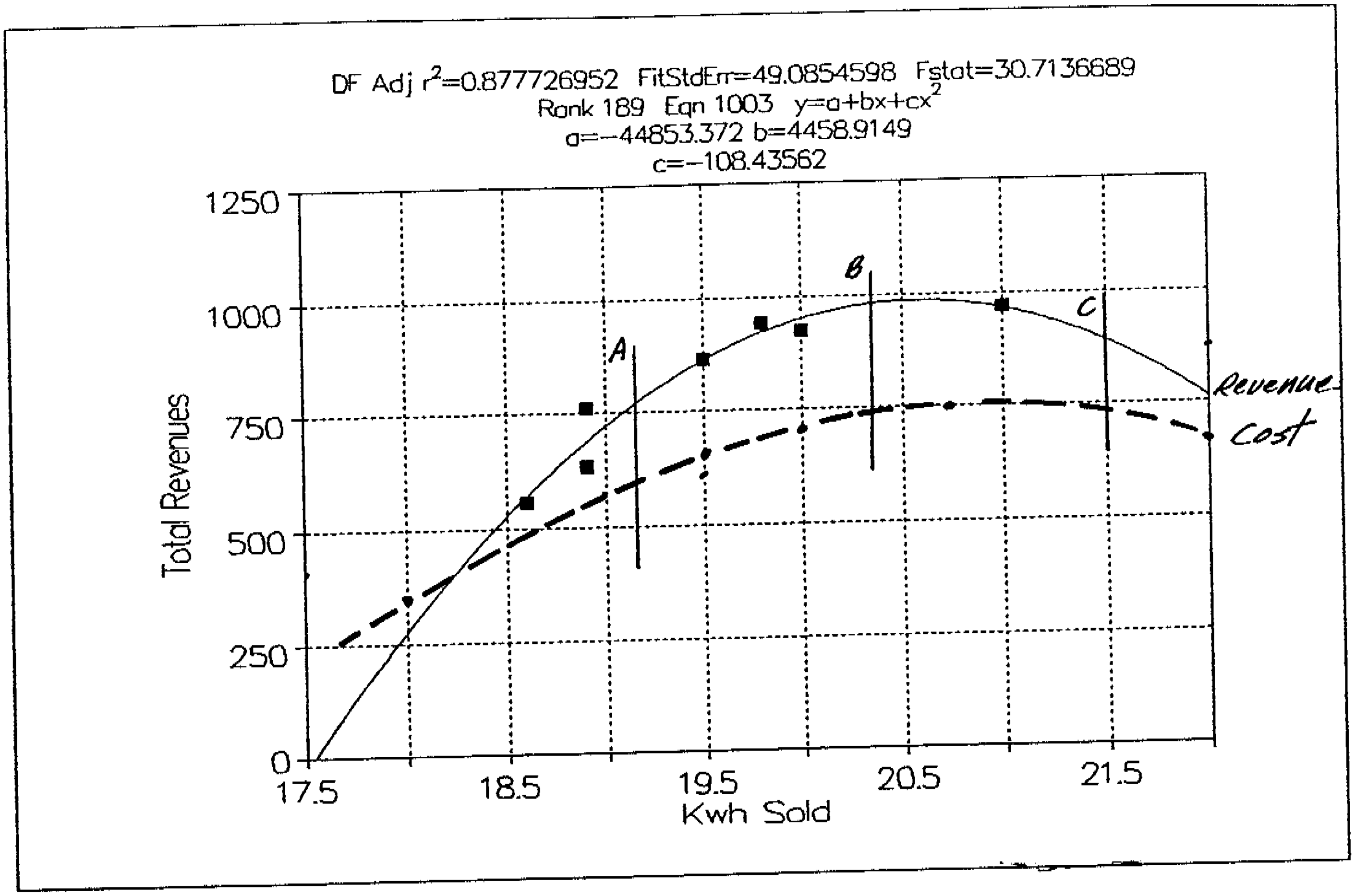
7 Active X-Y Points
X: Kwh Sold Mean: 19.528571429 SD: 0.8280786712
Y: Total Revenues Mean: 805.57142857 SD: 162.09023942
File Source: PPLSTAT2.PRN

Rank 189 Eqn 1003 y=a+bx+cx2

r2 Coef Det	DF Adj r2	Fit Std Err	F-value
0.9388634762	0.8777269524	49.085459842	30.713668943

Parm	Value	Std Error	t-value	95% Confidence Limits	
a	-44853.3717	12389.73032	-3.62020565	-79294.8782	-10411.8653
b	4458.914922	1254.580023	3.554109615	971.3792907	7946.450553
c	-108.435621	31.71830459	-3.41870799	-196.607532	-20.2637109



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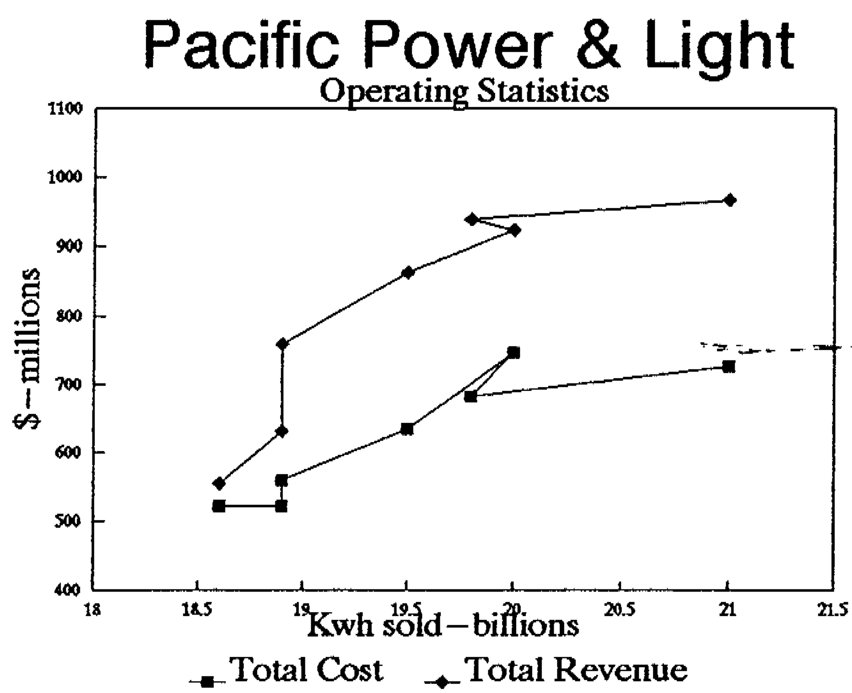
c	-108.435621	31.71830459	-3.41870799	-196.607532	-20.2637109

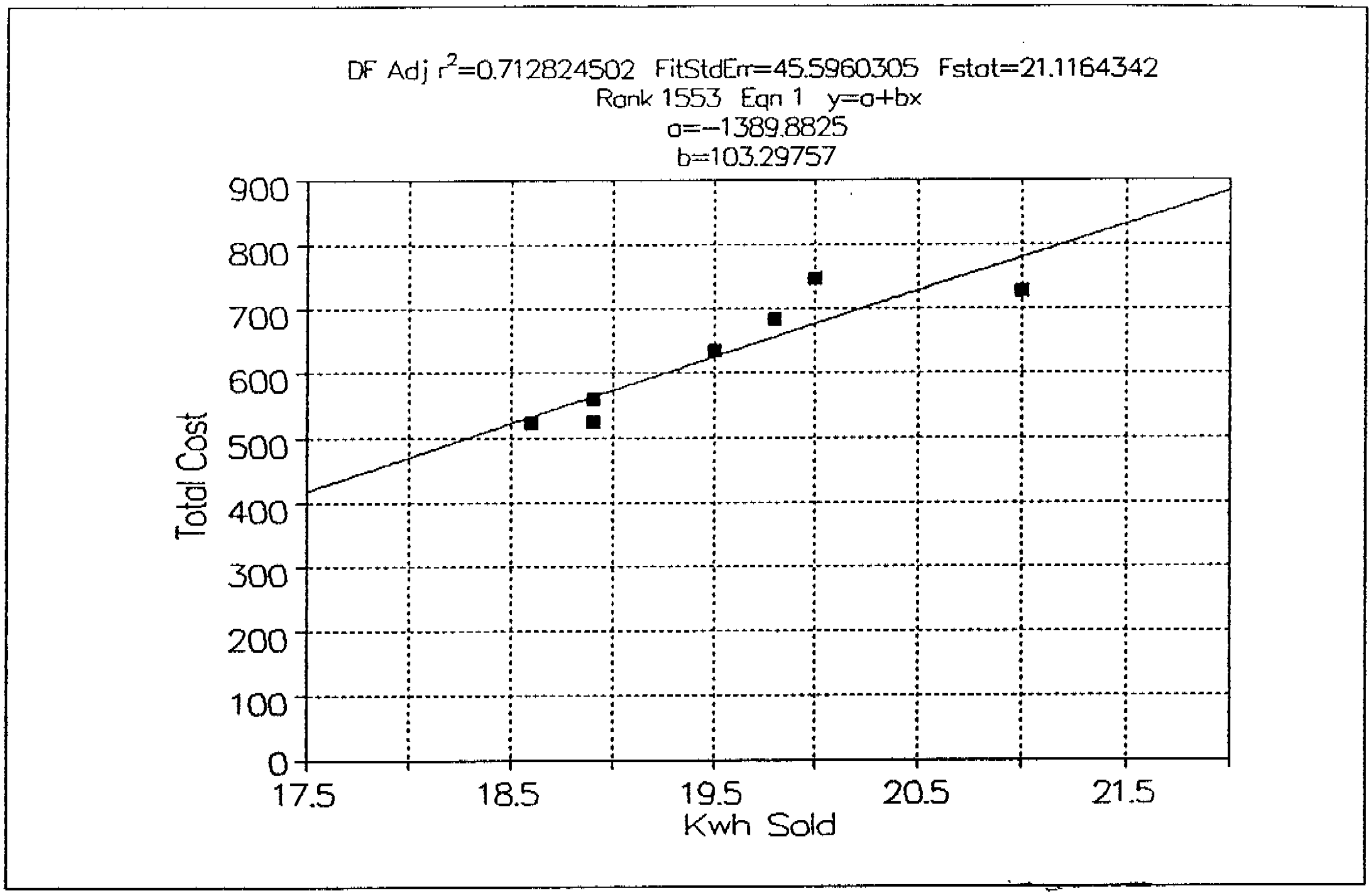
PP&L MARGINAL PROFIT WITH QUADRATIC COST CURVE			
Kwh Sales (billions)	Marginal Rev $−millions	Marginal Cost $−millions	Marginal Profit $−millions
17.5	663.1	337.1	326.0
18.0	554.7	285.6	269.1
18.5	446.3	234.0	212.2
19.0	337.8	182.5	155.3
19.5	229.4	130.9	98.4
20.0	120.9	79.4	41.5
20.5	12.5	27.8	−15.4
21.0	−96.0	−23.7	−72.3
21.5	−204.5	−75.3	−129.2
22.0	−312.9	−126.8	−186.1
22.5	−421.4	−178.4	−243.0
23.0	−529.8	−229.9	−299.9
23.5	−638.3	−281.4	−356.8

PP&L MARGINAL PROFIT WITH LINEAR COST CURVE			
Kwh Sales (billions)	Marginal Rev $−millions	Marginal Cost $−millions	Marginal Profit $−millions
17.5	663.1	103.3	559.8
18.0	554.7	103.3	451.4
18.5	446.3	103.3	343.0
19.0	337.8	103.3	234.5
19.5	229.4	103.3	126.1
20.0	120.9	103.3	17.6
20.5	12.5	103.3	−90.8
21.0	−96.0	103.3	−199.3
21.5	−204.5	103.3	−307.8
22.0	−312.9	103.3	−416.2
22.5	−421.4	103.3	−524.7
23.0	−529.8	103.3	−633.1
23.5	−638.3	103.3	−741.6

PACIFIC POWER AND LIGHT

YEAR	Total Oper Rev ($-millions)	Total Cost ($-millions)	Kwh Sold (Billions)
1981	554.1	521.0	18.6
1982	630.9	522.0	18.9
1983	759.1	558.7	18.9
1984	863.2	634.0	19.5
1985	923.8	746.7	20.0
1986	939.8	682.8	19.8
1987	968.1	726.4	21.0





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7 Active X-Y Points
X: Kwh Sold Mean: 19.528571429 SD: 0.8280786712
Y: Total Cost Mean: 627.37142857 SD: 95.12799648
File Source: PPLSTAT1.PRN

Rank 1553 Eqn 1 y=a+bx

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Parm	Value	Std Error	t-value	95% Confidence Limits	
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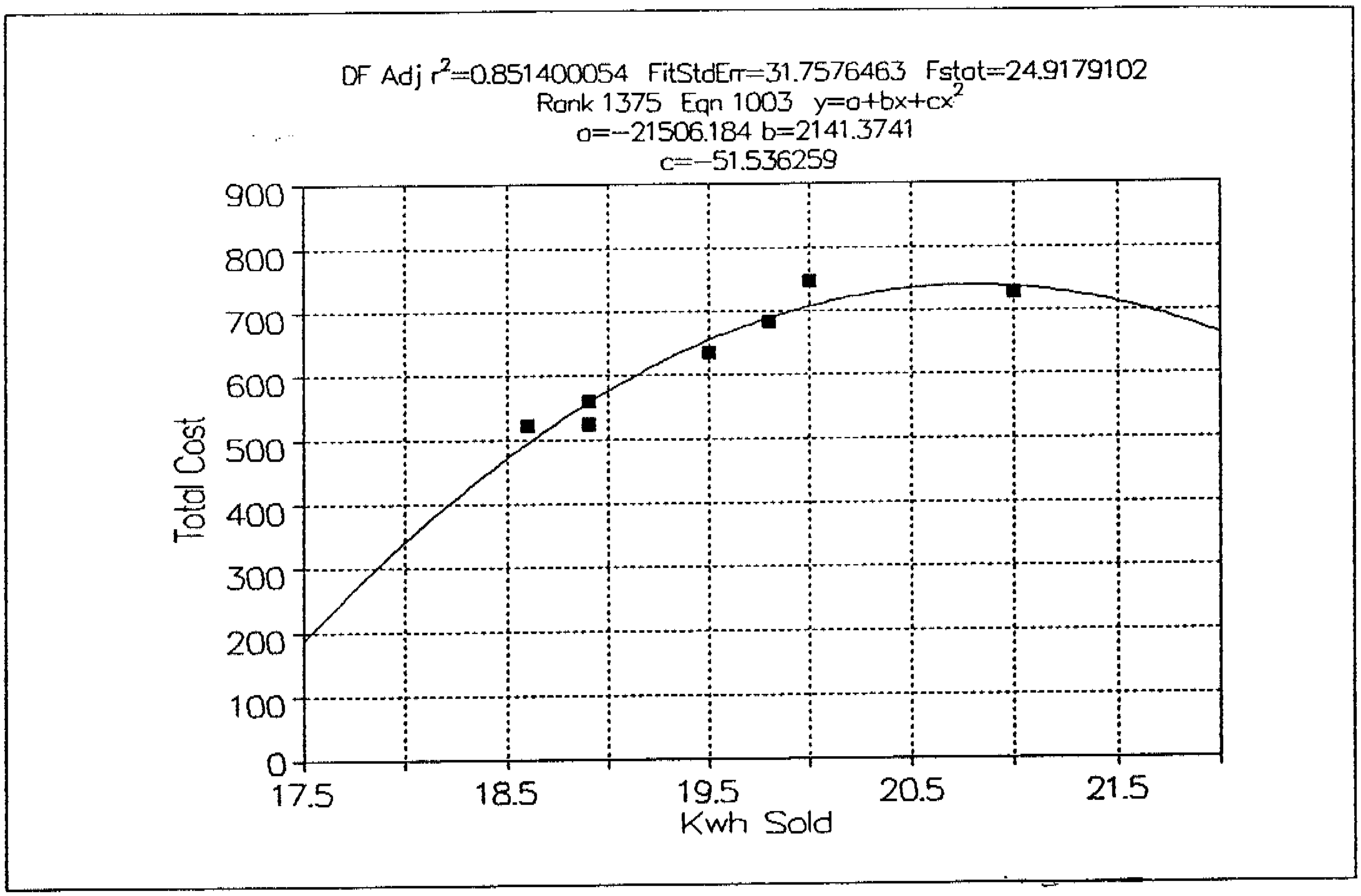
b	103.2975694	22.47914617	4.595262144	45.29921826	161.2959206



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7 Active X-Y Points

X: Kwh Sold	Mean: 19.528571429	SD: 0.8280786712
Y: Total Cost	Mean: 627.37142857	SD: 95.12799648

File Source: PPLSTAT1.PRN

Rank 1375 Eqn 1003 y=a+bx+cx2

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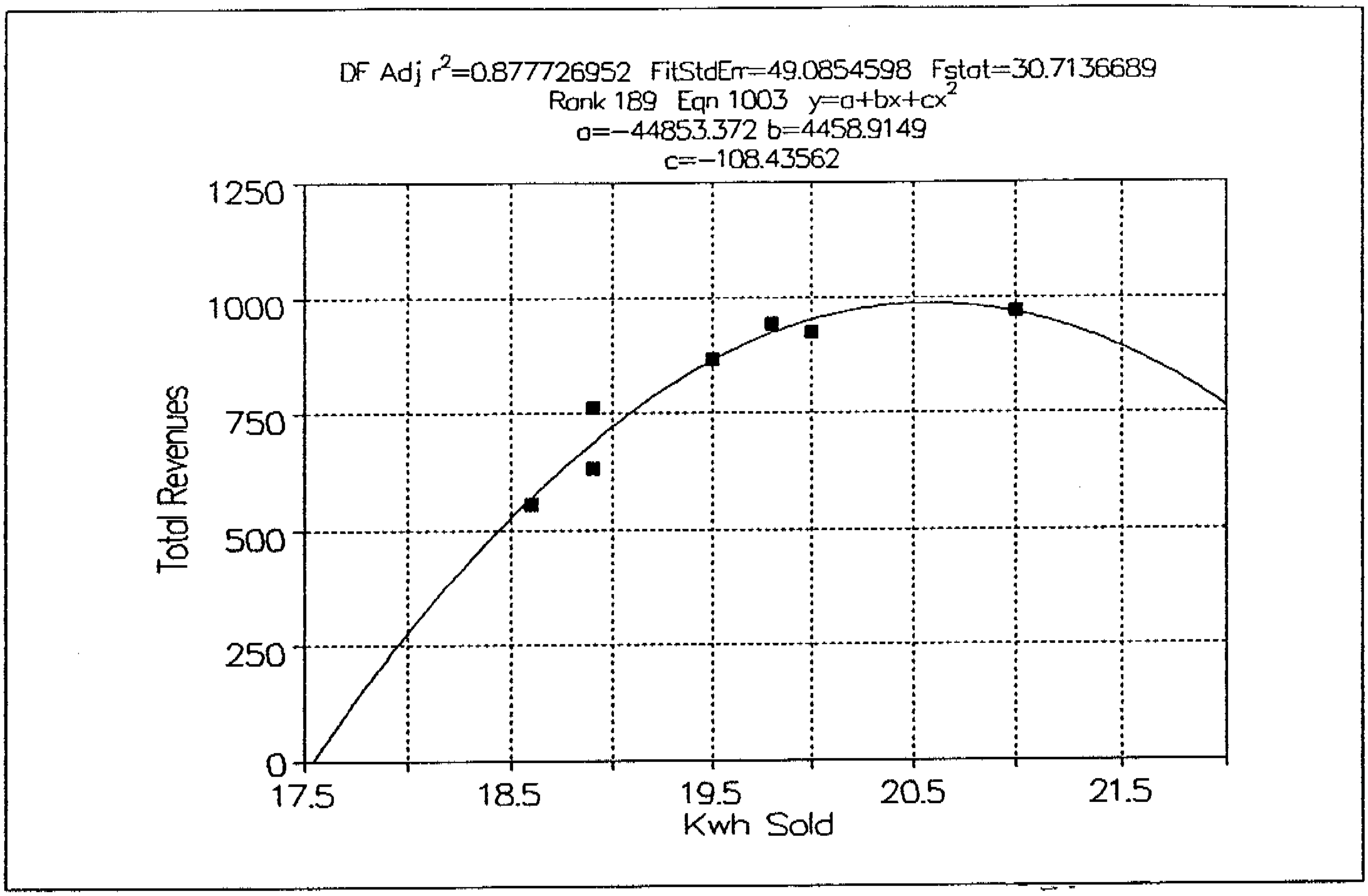
0.925700027	0.851400054	31.757646306	24.917910185

Parm	Value	Std Error	t-value	95% Confidence Limits	
a	-21506.184	8015.992405	-2.68290973	-43789.3852	777.0172534
b	2141.374083	811.6967582	2.638145418	-115.015556	4397.763723
c	-51.5362589	20.5213255	-2.51135137	-108.582324	5.509806396



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7 Active X-Y Points

X: Kwh Sold	Mean: 19.528571429	SD: 0.8280786712
Y: Total Revenues	Mean: 805.57142857	SD: 162.09023942

File Source: PPLSTAT2.PRN

Rank 189 Eqn 1003 y=a+bx+cx2

r2 Coef Det	DF Adj r2	Fit Std Err	F-value
0.9388634762	0.8777269524	49.085459842	30.713668943

Parm	Value	Std Error	t-value	95% Confidence Limits	
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