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UTAH PUBLIC SERVICE COMMISSION

January 17, 1995

TO: DSR COST RECOVERY COLLABORATIVE
Active and Informational Members

RE: Final Subcommittee Reports
January 25, 1995 Meeting

Enclosed are copies of the final reports from the Rate Spread and Shared Savings Subcommittees. Please review these prior to the January 25, 1995 Collaborative Meeting.

Enclosed also is a copy of the Update Report, 1994 Joint Recommendation issued January 13, 1995, and an Agenda for the next meeting. If you have any questions, please let me know.

Sincerely,

Steve McDougal

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Enclosures

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DSR COST RECOVERY COLLABORATIVE

January 25, 1995 AGENDA

The next meeting of the Utah DSR Cost Recovery Collaborative is scheduled for 1:30 p.m. on Wednesday, January 25, 1995 in Conference Room 863, 8th floor of the One Utah Center. The final reports for each of the 5 subcommittees, as well as the final Collaborative report will be discussed. All members should review the Rate Spread, Shared Savings, and Statistical Recoupling subcommittees reports prior to the meeting and be prepared to give comments on them. The latest versions of the Rate Spread and Shared savings reports are included in this mailing. The Statistical Recoupling Report has not changed since the version included with the minutes of the November 21, 1994 meeting.

OLD BUSINESS

All previous items have been closed.

NEW BUSINESS

1.25.1 Evaluation and Net Lost Revenue ("NLR") Subcommittee Report

1.25.2 Rate Spread and Non-Participant Impacts Subcommittee Report

1.25.3 Shared Savings & Total Factor Productivity Subcommittee Report

1.25.4 DSR Performance Standards Subcommittee Report

1.25.5 Statistical Recoupling Subcommittee Report

1.25.6 Other Business

Public Service Commission

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INTERNAL CORRESPONDENCE

DATE: January 11, 1995

TO: Members of Demand Side Resource Cost Recovery Collaborative

FROM: Dave Taylor

SUBJECT: **Final Draft Report - Impact Subcommittee**

Attached please find the final draft of the Rate Spread and Non-Participant Impact Subcommittee report.

Demand Side Resource
Cost Recovery Collaborative

Rate Spread & Non-Participant Impact Subcommittee

Draft Report

December 20, 1994

INTRODUCTION

The Rate Spread and Non-Participant Impact Subcommittee (Impact Subcommittee) was formed as a part of the DSR Cost Recovery Collaborative. Its purpose was to explore ways to mitigate the adverse effects of the costs of many DSR programs on the customers who do not participate in those programs. The subcommittee was established with three members, but because of increased interest in the topic it grew to the following seven members.

Lowell Alt	Division of Public Utilities
Ron Burrup	Division of Public Utilities
Mark Flandro	Division of Public Utilities
Dan Gimble	Committee of Consumer Services
Craig Johnson	Pacificorp
Jim Logan	Utah Public Service Commission Staff
Dave Taylor	PacifiCorp

Mission of DSR Impact Subcommittee

Assess and make recommendations regarding the impact of DSR programs on non-participants.

Goals of DSR Impact Subcommittee

Review and apply different methods for evaluating the impact of DSR investments on non-participants

Look at Company programs and assess their impact on non-participants

Examine ways to minimize the impact of DSR programs on non-participants

Review and make recommendations on how DSR costs should be treated in class cost of service studies

Summarize findings and recommendations in a letter to the DSR Cost Recovery Collaborative and the Commission

RECOMMENDATIONS

DSR Program Strategies

The subcommittee concluded that the best way to mitigate impacts of DSR investments on non participants is to collect as much of the cost as possible from the direct participants. This can be accomplished through increased levels of Energy Service Charge (ESC) payments or some other means of customer participation charges. It can also be accomplished when customers follow effective price signals and pursue energy efficiency on their own. Only in cases where the benefits to the system are greater than the benefits to the participant should any utility financial incentive be required. This view was espoused by Mike Katz, a former Oregon Public Service Commissioner:

> "What portion of a utility's conservation investment in a customer's premises should be recovered directly from that customer? All of it up to the point where the cost of conservation is no more than the utility's embedded average system cost per kWh. If, however, cost-effective conservation exceeds the utility's average system cost it should still be acquired when needed to meet load. ... Such costs in excess of system average should be recovered from all customers based on each customer's consumption of energy services (including, of course, conservation kWh)."

Our analysis of Utah Power's prices in the State of Utah show that they are equal or greater than long run marginal cost in most cases. As such there are financial incentives for customers to make investments in energy efficiency. The utility should promote energy efficiency by providing information on the benefits and the availability of cost effective DSR measures. The utility can, and perhaps should, facilitate market based transactions between customers and reputable vendors.

Cost of Service Allocation Methods

The subcommittee determined that all reviewed procedures for allocating DSR costs in embedded cost of service studies had shortcomings. We felt that using demand and energy factors to allocate net DSR costs (DSR costs less participation charges) to all customer classes was the best overall approach. While this method may result in some adverse impact on all customers, it results in the most even distribution of the impacts on nonparticipants of the methods tested. Additionally, although it is far from ideal, it follows more closely the traditional principles of cost causation. It is based on the belief that DSR investments are made to meet the demand and energy requirements of all customers.

The Direct Assignment and Split Rim methods were rejected because, although they reduced or eliminated adverse effects on customers in classes other than the participants class, the methods resulted in greater adverse impacts on non participating customers within the participants class. We felt that, just because they happen to purchase electricity on the same rate schedule as the participant, a customer should not bear a greater responsibility to pay for DSR programs than any other customer. This is particularly true when many of these customers are not eligible to participate in the utility's programs.

This procedure for allocating DSR costs to customer classes differs in some respects from the treatment of DSR costs in the interjurisdictional allocation process. Upon the agreement of the PITA members, DSR costs are assigned to the states in which they are incurred and in which the various programs are offered. We feel that procedure is appropriate. Each of the seven states PacifiCorp serves has a different philosophy toward Demand Side Resources. Those philosophies differ in the level of DSR that should be acquired, what types of programs a utility should offer, and to what level they are willing to let prices increase to recover DSR costs.

Once costs have been assigned to a specific state, however, those costs still must be recovered from customers. This is true for DSR costs, distribution costs, or any other costs that are assigned directly to states. DSR costs, at the level agreed upon in a state, should then be allocated to customer classes in that state in a way that minimized the impacts on all nonparticipating customers.

ANALYSIS

In the process of developing the above recommendations, the subcommittee conducted a review of much of the literature, filed testimony, and regulatory action relating to mitigating the impacts of DSR investments on non participating customers. These items were discussed by the subcommittee and augmented by each member's view of how demand side resources fit into the ratemaking process. The subcommittee focused its efforts in three areas: How the impacts of DSR investments are measured, how to design strategies and programs in such a way as to mitigate rate impacts, and how to treat the costs of DSR programs in class cost of service studies.

How the impacts of DSR investments are measured

In our review of the impacts of DSR investments on non participants we reviewed the four California Standard Practices Manual Tests. These test look at how DSR costs and benefits are measured in total. Each of the four tests measures the impact of DSR investments on a different parameter.

Participant Test	=	Impact on Direct Participants
Utility Cost Test	=	Impact on Utility Revenue Requirement
RIM Test	=	Impact on Price per kWh
TRC Test	=	Impact, in the aggregate, on All Parties

While these test may do an effective job of measuring the effects of DSR costs in total. Only the RIM test makes any attempt to address the impact on non participants. Even the RIM test measures the effect of DSR investments on the average price per kWh, not the effect on individual customers.

DSR Program Strategies designed to mitigate rate impacts

The subcommittee identified seven DSR program strategies designed to mitigate rate impacts on non participants. Several of these are discussed in an article published in *The Electricity Journal* written by John Chamberlain, Patricia Herman and Greg Winkler. These strategies, plus several pro and cons of each, are:

1. Only accept DSR programs that pass the Rate Impact Measure (RIM) test.

Advantages: By definition, programs that pass RIM do not increase the unit cost per kWh. As a result, prices for non-participating customers would not be increased. This strategy would be easy to understand and implement.

Disadvantages: Because rates are very often above avoided costs, very few DSR programs pass the RIM test. This has certainly been the case at Utah Power. If this is the case at Utah Power, where rates are below national average, it would be even more the case for most other utilities. It is doubtful that Utah Power, or most any other utility can meet the agreed upon DSR target energy savings by employing only programs that pass RIM.

2. Ensure that all customers have access to feasible DSR programs.

Advantages: This option plays upon fairness. Each customer has the chance to offset the rate increase caused by DSR programs, with the bill reducing benefits of that program. If all customers participate, all customers benefit. This strategy also provides for the greatest total amount of DSR to be implemented.

Disadvantages: This strategy would be difficult to execute in practice. The direct and administrative cost of having a DSR program menu that meets the needs or desires of every customer might be impractical and economically unacceptable. Additionally, it is unlikely that all customers would choose to participate. Many have already installed the most cost effective measures.

3. Charge for energy services, such as lighting or hot water, instead of kWh.

Advantages: This strategy changes the entire concept behind pricing utility services. This was the original Thomas Edison approach to utility billing. It focuses on charging for the benefits provided rather than the commodity delivered. Customers would pay the same for lighting or other services both before and after energy efficiency measures have been implemented. Since there would be no revenue loss, all programs would pass RIM.

Disadvantages: Such a program would be extremely difficult to administer. Kilowatt hours are much easier to measure than are energy services. A utility would have to develop methods to identify and measure each of the many types of energy services provided.

4. Recover all or a portion of the DSR program costs or revenue loss through an Energy Service Charge (ESC).

Advantages: This is a more workable refinement of the above strategy. In fact, the Utah Power Energy FinAnswer programs offer this approach. The ESC can be designed to recover the cost of the measures, the total program costs, or the total lost revenue. Rate increases to non participants are mitigated by the fact that the participating customer pays for much of the costs.

Disadvantages: The energy service charge approach is very labor intensive and comes with a high level of administrative overhead. Penetration levels may be lower than a program that doesn't require such a high level of customer financial participation. When participating customer pays only portion of the program costs, non-participants may still end up with price increases.

5. Utility provides energy efficiency information and facilitates DSR projects only.

Advantages: In this strategy, the customer makes the investment with their own funds. Since there is no utility money involved in the project, there is less of an adverse effect on utility prices. This approach is similar to the Utah Power Path B projects, where customers take advantage of the Company's engineering studies and inspections, but use their own financing. The approach is even more similar to Path C projects, where the Company becomes the facilitator that brings customers and equipment vendors together.

Disadvantages: Since the utility provides none of the capital, less DSR may occur. Lack of available capital is one of the reasons customers do not install DSR measures on their own. The effects of reduced consumption may still result in increased utility prices in the near term when current prices are above short run marginal costs.

6. Redesign rates with higher fixed components and lower usage charges or with declining block structures.

Advantages: Lower usage charges make it easier for programs to pass the RIM test because the portion of the rates affected by DSR will be closer to variable costs. As such, lost revenues will be more in line with avoided costs.

Disadvantages: Lower usage charges will provide less of an incentive for customers to invest in energy efficiency measures on their own.

7. Redesign rates with higher usage charges such as inverted block rates.

Advantages: Higher usage charges provide a greater incentive to customers to make energy efficiency investments, or reduce their consumption on their own.

Disadvantages: Rates that are above long run marginal cost promote conservation for the sake of conservation itself. When rates are above the full, long run, cost of production, the benefits of many economically responsible uses of electricity are lost because of an artificially high price. Rates above long run marginal cost also make it very difficult to implement any utility programs without creating adverse impacts on non participating customers.

Mitigation of DSR costs through cost allocation procedures

Through use of a NARUC survey, the subcommittee prepared a summary of how DSR costs are allocated in other jurisdictions. We noted that allocation of DSR costs remains unresolved in many jurisdictions. There doesn't yet seem to be a consensus.

This is not surprising. None of the generally used methods is a clear cut winner from either a practical or theoretical basis. We reviewed the three major approaches to cost allocation being used in most jurisdictions as well as one non traditional approach..

1. DSR costs are recovered through a uniform energy charge.

Advantages: A uniform energy charge is easy to understand and to calculate. In some jurisdictions, DSR costs are allocated in cost studies using an energy factor. In other jurisdictions, DSR costs are accumulated in a balancing account, similar to the former Utah EBA, and billed to all customers as a surcharge. If the surcharge is shown on the bill as a separate rider, customers are aware of how much they are paying for DSR.

Disadvantages: A uniform energy charge does not follow cost causation principles. It assumes that all DSR costs are classified as energy related, which is not correct. An energy charge assigns a disproportionate share of the costs to high load factor customers. Fairness may be an issue since direct beneficiaries (participants) and indirect beneficiaries (non participants) pay the same uniform energy charge. In some states a DSR balancing account and rider may not be allowed by law.

2. Costs assigned to customer classes that are eligible to participate:

Advantages: Allocation of DSR costs to participating or beneficial customer classes is an effort to better match program costs and benefits. Customers in classes not eligible to participate in the program are not required to pay any of the costs. This method is relatively straightforward and easy to understand. Recovering the costs of DSR programs from the participants' class may also bring closer scrutiny of proposed programs that are targeted for specific classes of customers.

Disadvantages: Under this method cost causation principles are ignored. It disregards the concept that DSR investments are made to acquire resources to be used by all customers. Because of this, indirect beneficiaries outside of the participants class are allocated none of the costs. While program participants will see net bill reductions, non-participating customers that purchase electricity on the participants' rate schedule will experience bill increases even greater than if costs were allocated system wide.

3. Allocating DSR costs to all customer classes using demand and energy factors:

Advantages: While this method results in some adverse impact on all customers, of the methods tested, it results in the most even distribution of those impacts. All non participants are treated similarly, regardless of their rate schedule. This method also comes closer to following the traditional principles of cost causation. It assumes that DSR investments are made to meet the demand and energy requirements of all customers and that all customers benefit to some degree from these investments because new Supply Side Resources are avoided. As such, the costs of DSR investments are allocated using traditional cost of service demand and energy allocation factors.

Disadvantages: No attempt is made to collect a greater portion of the costs of DSR investments from participants. Direct beneficiaries (participants) and indirect beneficiaries are allocated the same level of costs. Classification of DSR investments between demand or energy related components is difficult and may seem arbitrary. Allocating the costs of DSR programs to all customer classes may encourage special interest groups to pursue targeted DSR programs that are not cost effective.

4. Split Rim Approach

The subcommittee used these concepts to develop what became known as the "Split Rim Approach". This Split RIM approach selectively allocates costs to minimize the impact on non-participating customers. The theory behind this approach is that costs up to the RIM level benefit all customers by meeting customer's energy & capacity needs in a way that does not increase prices to a customer class any more than a supply-side resource would affect prices. As such, these cost are allocated to all customers just as supply side resources. The costs above RIM do not directly benefit non-participating customers, so they are assigned to the participating customer class.

Advantages: In theory, Split Rim is a good balance or compromise that embraces the positive aspects of the various cost recovery approaches. It separates the costs of DSR programs into two categories, those that benefit all customers (non-participants), and those that benefit direct participants.

Disadvantages: In practice, several challenges were discovered in the application of the method. For programs that don't pass RIM, non-participating customers in the eligible class pick up extra costs and are worse off than if costs allocated system wide. In practice it was found that even when all utility costs are removed, many Utah Power programs still didn't pass RIM.

Effect of different approaches on Utah Cost of Service

The committee specifically examined the impact of actual 1993 PacifiCorp DSR expenditure on cost of service results using the four allocation approaches discussed above. The results are shown in Exhibits 1, 2, & 3.

Exhibit 1 shows the actual dollars of class revenue requirement directly identified with 1993 DSR expenditures. The class revenue requirements were calculated using the 1993 embedded cost of service study filed in conjunction with the 1993 results of operations. The study was run four different times with DSR rate base investment and associated expenses allocated to customer classes using one of the discussed allocation approaches each time.

Exhibit 2 shows the effect of the revenue requirements in Exhibit 1 in costs per kWh. The class revenue requirement directly associated with DSR expenditures was divided by the annual kWh sales for that class.

Exhibit 3 shows the change in the percent increase or decrease required to reach full class cost of service (class revenue requirement at jurisdictional average rate of return) between the identified allocation methodology and the 50% demand/50% energy allocator. It assumes that DSR cost, net of ECS revenues, are included in revenue requirement. The 50% demand/50% energy allocator was used in the embedded class cost of service study filed in conjunction with the 1993 results of operations.

As the 1993 DSR expenditures were relatively small compared to the total state revenue requirement, so the 1993 expenditures were multiplied by factors of 10 and 100 to amplify impact of each scenario.

Demand/Energy Factor Allocation

While this method resulted in some impact on all non participating customers, it does result in the most evenly distributed impacts among all customers. Because of the relationship of DSR investments to the total cost of service, the impact on all customers, both participants and non participants, is relative minor.

Energy Factor Allocation

The examination showed that the energy factor allocation produced very similar results to the demand/energy factor.

Direct Assignment to Participating Class

Direct assignment of costs to participating customer classes pushes up revenue requirement in the participating classes as expected. While the impact upon customers not in the participants classes is essentially eliminated, the impact upon non-participants within the same class as the participant is greatly increased.

Split Rim

The Split RIM approach produced results even more skewed toward the direct participants class that did the direct assignment approach. This is because in our study only the large industrial programs passed the RIM test. All other programs had lost revenue above avoided costs so that even with all utility cost removed the programs still didn't pass RIM. The cost of these programs were directly assigned to the participating class. These two circumstances resulted in participating class, other than the large industrial class, being allocated a portion of the cost of the large industrial programs plus 100% of the cost of their own programs.

Summary

Of the options reviewed, all cost allocation methodologies allocate some costs to non-participating customers. However, because current investments in DSR are relatively small in comparison to total cost of service, the impact on relative prices is minimal. Only the studies where DSR investments were increased by 100 times showed a measurable difference between the methods.

Exhibit 1

Revenue Requirement at 1993 DSR Level in Dollars

	Residential Schedule 1	General Service Schedule 6	General Service High Voltage Schedule 9	General Service Small Customer Schedule 23
50% Demand / 50% Energy	$93,179	$126,832	$58,759	$23,563
Energy	95,164	120,042	60,568	20,723
Direct	56,057	244,576	43,211	4,139
Split/RIM	67,627	260,325	7,296	7,065

Revenue Requirement at 10X 1993 DSR Level in Dollars

	Schedule 1	Schedule 6	Schedule 9	Schedule 23
50% Demand / 50% Energy	931,790	1,268,320	587,590	235,630
Energy	951,640	1,200,420	605,680	207,230
Direct	560,570	2,445,760	432,110	41,390
Split/RIM	676,270	2,603,250	72,960	70,650

Revenue Requirement at 100X 1993 DSR Level in Dollars

	Schedule 1	Schedule 6	Schedule 9	Schedule 23
50% Demand / 50% Energy	9,317,900	12,683,200	5,875,900	2,356,300
Energy	9,516,400	12,004,200	6,056,800	2,072,300
Direct	5,605,700	24,457,600	4,321,100	413,900
Split/RIM	6,762,700	26,032,500	729,600	706,500

Note: Exhibit 1 shows the change in the percent increase or decrease required to reach full class cost of service (class revenue requirement at jurisdictional average rate of return) between the identified allocation methodology and the 50% demand/50% energy allocator. It assumes that DSR cost, net of ESc revenues, are included in revenue requirement. The 50% demand/50% energy allocator was used in the embedded class cost of service study filed in conjunction with the 1993 results of operations.

Exhibit 2

Cost per kWh at 1993 DSR Level

	Residential Schedule 1	General Service Schedule 6	General Service High Voltage Schedule 9	General Service Small Customer Schedule 23
50% Demand / 50% Energy	$0.000035	$0.000033	$0.000044	$0.000034
Energy	$0.000035	$0.000031	$0.000046	$0.000030
Direct	$0.000021	$0.000064	$0.000033	$0.000006
Split/RIM	$0.000025	$0.000068	$0.000005	$0.000010

Cost per kWh at 10x 1993 DSR Level

	Schedule 1	Schedule 6	Schedule 9	Schedule 23
50% Demand / 50% Energy	$0.000346	$0.000331	$0.000442	$0.000335
Energy	$0.000353	$0.000313	$0.000456	$0.000295
Direct	$0.000208	$0.000638	$0.000325	$0.000059
Split/RIM	$0.000251	$0.000679	$0.000055	$0.000101

Cost per kWh at 100x 1993 DSR Level

	Schedule 1	Schedule 6	Schedule 9	Schedule 23
50% Demand / 50% Energy	$0.003455	$0.003307	$0.004421	$0.003354
Energy	$0.003529	$0.003130	$0.004557	$0.002950
Direct	$0.002079	$0.006377	$0.003251	$0.000589
Split/RIM	$0.002508	$0.006788	$0.000549	$0.001006

Note: Exhibit 2 shows the effect of the revenue requirements in Exhibit 1 in cost per kWh. The class revenue requirement directly associated with DSR expenditures was divided by the annual kWh sales for that class.

Change in Revenue Requirement at 1993 DSR Level

	Residential Schedule 1	General Service Schedule 6	General Service High Voltage Schedule 9	General Service Small Customer Schedule 23
50% Demand / 50% Energy	-0.04%	0.05%	0.01%	-0.03%
Energy	-0.04%	0.04%	0.02%	-0.04%
Direct	-0.05%	0.08%	0.00%	-0.07%
Split/RIM	-0.04%	0.09%	-0.04%	-0.06%

Change in Revenue Requirement at 10X 1993 DSR Level

	Schedule 1	Schedule 6	Schedule 9	Schedule 23
50% Demand / 50% Energy	-0.15%	0.08%	0.18%	-0.07%
Energy	-0.12%	0.04%	0.19%	-0.11%
Direct	-0.22%	0.44%	0.04%	-0.45%
Split/RIM	-0.17%	0.50%	-0.40%	-0.39%

Change in Revenue Requirement at 100X 1993 DSR Level

	Schedule 1	Schedule 6	Schedule 9	Schedule 23
50% Demand / 50% Energy	-1.13%	0.41%	1.78%	-0.40%
Energy	-0.89%	0.01%	1.94%	-0.84%
Direct	-1.77%	3.85%	0.51%	-4.06%
Split/RIM	-1.27%	4.47%	-3.84%	-3.54%

Note: Exhibit 3 shows the actual dollars of class revenue requirement directly identified with 1993 DSR expenditures. The class revenue requirements were calculated using the 1993 embedded cost of service study filed in conjunction with the 1993 results of operations. The study was run four different times with DSR rate base investment and associated expenses allocated to customer classes using one of the discussed allocation approaches each time.

SHARED SAVINGS AND TOTAL FACTOR PRODUCTIVITY
SUB-COMMITTEE REPORT
January 12, 1995

THE SUBCOMMITTEE

The Joint Recommendation listed Shared Savings and Total Factor Productive (TFP) mechanisms as important issues for the new Cost Recovery Collaborative to study and report on. The Cost Recovery Collaborative created a subcommittee called the Shared Savings and Total Factor Productivity Subcommittee to study and provide recommendations on these issues. The Subcommittee is comprised of representatives from the DPU, CCS and the PacifiCorp. This is the report to the Cost Recovery Collaborative of the subcommittee.

The report is divided into four parts;

I. SUBCOMMITTEE CONCLUSIONS AND RECOMMENDATIONS

The subcommittee members concluded that, given PacifiCorp receives the opportunity to earn a "fair return" on its DSR investments no other incentive mechanism is needed. A "fair return" may be defined differently by different parties. The subcommittee members believe that PacifiCorp's desire to be the low cost provider of energy services is a powerful incentive to choose the lowest cost portfolio of resources, either supply side or demand side. Incentive payments add to the cost of DSR programs and put additional upward pressure on rates thus reducing the utilities ability to be competitive. Incentive payments increase administration costs and influence program evaluation methods. Also, there are potential unintended consequences of targeting incentives toward only one segment of PacifiCorp's operations.

Based on the foregoing discussion, the subcommittee members determined that their primary recommendations to the Cost Recovery Collaborative should be;

1. If PacifiCorp is provided with adequate opportunity to receive a fair return on their DSR investments, a DSR incentive mechanism is unnecessary. A fair return on DSR investments is defined as DSR program cost recovery without a carrying charge between rate cases, and may include a net lost revenue adjustment or statistical decoupling mechanism. It may also include an AFUDC type carrying charge.

2. A Shared Savings incentive program will not likely fit within the guidelines of the recent Utah Supreme Court order in the U S West case. That order required incentive plans to be linked to cost of service. Shared saving incentives are not linked to cost of service. Accordingly this subcommittee recommends that no Shared Savings program be adopted.

3. While this subcommittee is not recommending any incentive mechanism, if the Commission determines that an incentive mechanism is needed in addition to a fair return on DSR investment, the mechanism could be an environmental impact incentive related to potential NOX and CO2 taxes savings and thus more related to cost of service. The incentive could be in the range of 15 mills per kWh of DSR, or about $600,000 for 40,000 MWH of savings.

4. If a fair return on DSR investment is not afforded PacifiCorp, an environmental impact incentive mechanism should be adopted that is large enough to equalize the treatment of DSR and SSR programs.

5. A Total Factor Productivity mechanism that rewards the utility for increases in efficiency is not an appropriate candidate to equalize the treatment of DSR and SSR measures because Utah's DSR measures are too small to measure in comparison to total company costs.

A. History of Financial Incentives for DSR

An October 1993 NARUC survey on state-specific approaches to DSR incentive mechanisms indicated that approximately 30 state commissions have experimented with various types of incentive mechanisms. These incentive mechanisms have tended to be utility-specific rather than generically developed and applied within a given state. In the past, it appears that some state commissions played loose and fast with financial incentives for DSR as they attempted to levelize the playing field between DSR and SSR. However, many of the incentive experiments that were launched over the past few years are coming up for evaluation and state commissions are either rethinking the need for DSR incentives or are reinventing incentive mechanisms with different objectives in mind (e.g., incentives should be linked to performance standards rather than DSR expenditures).

The predominant incentive scheme implemented by commissions is the shared savings method (approximately 17 states). At this juncture there has been minimal assessment of this method, or of alternative DSR incentive mechanisms, as to whether any method has been effective in stimulating utilities to acquire economically feasible amounts of DSR. Finally, some states have adopted financial incentives along with lost revenue mechanisms, while other states view that financial incentives obviate the need for recovery of lost revenues.

During the year that this subcommittee has met it has become abundantly clear that the electric utility industry is about to undergo radical transformation. The Energy Policy Act, California's PUC's order on open access and technical changes are opening the industry to new market forces. The emerge of competition in the industry influenced the subcommittees decisions regarding incentive programs that tend to increase utility prices. The current trend has utilities such as Florida Power and Niagara Mohawk moving away from decoupling plans and

Also during the past year the Utah Supreme Court issued an order reversing prior Utah PSC decisions adopting incentive regulation for U S West. This order also influenced the subcommittee opinions and decisions on incentives for PacifiCorp's DSR programs.

B. Alternative Available

The principal purpose of an incentive mechanism is to create a regulatory environment in which the utility is neutral in its selection of either demand-side resources or supply-side resources, except on the basis of total resource cost. The incentive mechanism can be used alone (i.e., in place of) or in combination with other mechanisms such as lost revenues or recoupling.

The subcommittee members decided to make three alternative recommendations to the Cost Recovery Collaborative and to the Utah Public Service Commission. Each addresses a different alternative available to the Commission. These alternative recommendations are:

1. An incentive mechanism used in conjunction with other cost recovery mechanisms; such as Net Lost Revenues (NLR), recovery of program costs, or statistical recoupling.

2. An incentive mechanism that could be used alone without any other cost recovery mechanisms; this would be a substitute for NLR and reasonable recovery of program costs;

3. A total factor productivity mechanism that could be used in lieu of specific DSR incentives; but would still require recovery of program costs.

There is a potential for unintended consequences in targeting an incentive toward a particular aspect of PacifiCorp's operations, namely DSR. Unintended consequences refers to the tendency of a mechanism to achieve its intended outcome while producing an outcome that is contrary to ratemaking goals. Therefore the subcommittee studied a total factor productivity mechanism that would reward efficient performance in all aspects of utility operations.

II. INCENTIVE MECHANISMS

A. Types of incentive mechanism

As previously reported to the Commission in the August 1993 DSR Collaborative/Technical Conference Report (Report), there are six solutions based on incentives mechanisms used by other state commissions. They are:

1. no incentive mechanism;
2. shared savings;
3. bounty per unit savings;
4. markup on expenditures;
5. adjustment on overall return on equity; and
6. bonus return on equity on capitalized DSR.

1. No Incentive

This solution has two options. If PacifiCorp is given an opportunity to earn a fair return on its DSR investments, including NLR, there may be no need for additional incentives. If this opportunity does not exist, then incentives could play an important role in equalizing the treatment of DSR and SSR.

The disadvantage to this solution is that if PacifiCorp perceives that either it does not have an opportunity for full recovery of DSR costs, or that the solution does not adequately reduce the disincentives associated with NLR, PacifiCorp may not have the incentive necessary to follow its IRP.

However, PacifiCorp's desire to be the low-cost provider is a powerful incentive to choose the lowest cost portfolio of resources. PacifiCorp's position is that with fair rate treatment of DSR investment no additional incentives are necessary. Incentive payments add to the cost of DSR programs and put additional upward pressure on rates. PacifiCorp appropriately states in its RAMPP-3 Report at page 239:

> "The company's largest concern is the impact on price levels. The company takes very seriously the changes which are making the business environment more competitive. This has led to a strong commitment to be a low-cost producer and to keep retail prices competitive. **The market may preclude higher prices even if the regulatory commissions were willing to allow prices high enough to provide for full cost recovery.**" (emphasis added)

Additional disadvantages of incentive payments include increased administration and influence on program evaluation methods. Also, there are potential unintended consequences of targeting incentives toward one segment of PacifiCorp's operations.

2. Shared Savings

This mechanism allows the utility to keep a share of DSR program savings as retained earnings. The incentive payment is a portion of the difference between the cost of the DSR program and the value of its benefits. This is typically defined as the measured or estimated load reduction in kW or kWh multiplied by the value of avoided supply cost minus DSR program costs. Program costs can be defined as either utility costs or total resource costs.

Shared savings is the most common form of regulatory incentive. The incentive is typically structured as a reward-penalty mechanism or it can be structured to address recovery of program costs and net lost revenue. A threshold kW or kWh target can be established that must be met for a utility to receive the incentive. The incentive can be front end loaded or earned annually by the utility or delayed and recovered in the context of a rate case.

Since the incentive is based on net resource value, shared savings is performance based and rewards cost-effective DSR. The flexibility in structuring shared savings allows the procedure to address risk sharing between ratepayers and shareholders. Once established, a shared savings mechanism should be predictable and transparent.

The main disadvantage of shared savings stems from administration difficulties. Highly subjective or imprecise measurement and evaluation techniques may invariably foster contentious issues affecting the magnitude of the incentive reward or penalty. A second disadvantage relates to its potential for unintended consequences because only one aspect of the utility operations is being considered for incentive rewards.

3. Bounty Per Unit Savings

Bounty per unit savings is an incentive payment that is based on a fixed dollar amount for each kW or kWh saved from DSR programs. Since the incentive is not dependent upon the costs of the DSR program, this method does not provide any incentive to secure the appropriate amounts of cost-effective DSR.

4. Markup on Expenditures

This solution provides the utility with an incentive payment based on DSR program expenditures. The incentive is a percentage adder on DSR program costs which is readily measurable. The advantage of this approach is that it requires no measurement or evaluation of program-specific kW and kWh savings (i.e., program cost-effectiveness). The chief disadvantage with this method is that the incentive is activity based and not performance based. Stated differently, such a scheme provides a perverse incentive to the utility to increase DSR spending because the more dollars spent the greater the incentive payment. Consequently, most commissions have rejected this method because it may paradoxically reward a utility for investing in DSR that fails to meet cost-effectiveness criteria.

5. Adjustment to Overall Return on Equity

To compensate a utility for loss profit due to DSR investments, or as an incentive for meeting DSR targets, commissions could increase a utility's overall rate of return during rate cases to a higher level.

This solution could be structured to be performance based, and could include program costs and net lost revenue. Due to the infrequency of PacifiCorp rate cases, once started this method is difficult to adjust or stop. Timing differences between DSR expenditures and subsequent recovery through a higher rate of return leads to uncertainty of recovery, and may require write-off under FAS 71.

6. Bonus Return on Equity on Capitalized DSR

This approach assumes that DSR costs are capitalized and an increased rate of return is applied to only the investment in DSR in rate base. This incentive tends to be very small because the investment in DSR is not large compared to total rate base. If used to include recovery of program costs this solution, may not provide sufficient incentive to encourage the utility to implement DSR measures even where cost-effective.

B. Impact of the Utah Supreme Court Decision

On July 29, 1994, the Utah Supreme Court issued an opinion in Docket 910405, entitled petitioners v. Utah Public Service Commission and US West Communications. The order addressed the Commission's order allowing USWest an incentive program. The order stated:

> The Commission's order is defective for a number of reasons. First, it was entered without notice to any party or a hearing on the merits of the plan. Second, the plan essentially forsakes cost-of-service principles as required by Title 54 of the Public Utilities Code. The sharing of revenues begins at 12.2%, but all earnings over and above that percentage that USWC can retain are necessarily excessive because they are not justified by any cost-of-service principle. Nor can they be justified that they provide an "incentive" for USWC to invest in Utah....For all the above reasons, the Commission's incentive plan is arbitrary, capricious, and unlawful.

It is evident that for any future incentive plans to pass muster they must be tied to cost-of-service principles. The subcommittee necessarily found that a Shared Savings plan in which the difference between avoided cost and resource acquisition cost are shared between customers and investors is not tied to cost of service. Indeed is it difficult to craft any incentive plan that is based on cost-of-service principles.

C. Environmental Impact Incentive Option

One incentive plan that it may be argued is tied to cost-of-service is an environmental impact incentive. It is anticipated that in the future taxes may be based on the tons of NOX and CO2 that plants emit into the atmosphere. Some experts estimate that a tax of $2,000 per ton for NOX and $25 per ton for CO2 are reasonable figures. These estimates may also represent an estimate of the damage done to the environment by these substances.

If DSR programs reduce kWh consumption and therefore emissions, then there may be some future tax savings or some measure of reduced environmental impact. Using the estimates stated above, the impact of 40,000 MWh of DSR can be measured at approximately 33 mills per kWh or $1,320,000. An environmental incentive that was split between customers and shareholders may pass cost-of-service standards. This would put an incentive in the 15 mills per kWh range or about $600,000 for shareholders and customers. A disadvantage to adopting an environmental incentive is that it could take lengthy hearings to arrive at the appropriate environmental damage estimates.

III. TOTAL FACTOR PRODUCTIVITY

The subcommittee built a model following the outline of the previously proposed TFP model. The original model was constructed in the 1980 when costs were rising and Energy Balancing Account existed. The subcommittee measured the actual results from 1989 through 1992, and attempted to determine if an incentive award would have been made based on 1993 actual results. By using this time period, only post merger results were measured. The subcommittee also created a sub-model to measure production costs since the EBA no longer exists. The model consists of 5 sub-models that measure different components of the utility. These results are combined to determine if the current years operating results falls with in a 5% deadband around the statistically projected results. Four of the sub model results had a downward trends, this required increased efficiency measures to obtain operating results below the 5% deadband.

Four of the five submodels were based on total company operating results, only the distribution submodel was based on Utah costs. When the impact of DSR programs is added back to the kWh figure, total company DSR programs was the appropriate figure to use, not Utah only kWh savings. In addition it was found that DSR savings were immaterial when compared to the total company kWh generation.

The subcommittee determined that the TFP model was inappropriate to use in equalizing DSR and SSR treatment. The model requires the use of total company expenses and rate base and to be comparable total company DSR savings estimates must be used. If Utah only DSR savings are used they are immaterial in comparison to the total company figures. Also the model was designed to measure reductions in areas where costs are normally increasing. The current period, 1990 to 1994, reflects declining costs. In order to achieve any incentive award during a declining costs period, costs must decrease greater than they have in the past. That is an unlikely outcome, and it is unlikely PacifiCorp would ever earn an incentive award under the TFP model, even if DSR activity in Utah had been exceptional.

IV. POSITIONS OF THE PARTIES

The subcommittee reviewed the positions of the parties contained in the Report and found their positions to be very similar to our recommendations. Therefore we have restated these positions below.

PacifiCorp stated, "PacifiCorp believes that if the Company is provided with adequate opportunity to receive a fair return on their DSR investments, an additional incentive program may be unnecessary. However, if an incentive program is desired, the Company feels a shared savings approach may be beneficial. A shared savings approach could provide a useful tool for encouraging development of cost-effective DSR while balancing risks between the Company and its customers. If the Cost Recovery and Lost Revenue proposals that are adopted give the Company an adequate opportunity to receive a fair return on their DSR investments, then this should provide the Company with sufficient incentive to invest in DSR programs.

The **Division of Public Utilities** stated, "It is not clear to the Division that incentives are necessary. Out of the possible incentive mechanisms examined during this technical conference / collaborative process, the Division considers shared savings to be the most effective mechanism for encouraging the Company to invest in cost-effective DSR. One shared savings mechanism under consideration entails the following:

1) a two-year sunset provision...
2) symmetry between rewards...and penalties...
3) ex ante estimates of savings adjusted on a forward-going basis consistent with verified achieved savings."

The **Committee of Consumer Services** stated, "The Committee firmly believes that financial incentives are not required to spur the Company to acquire demand-side resources. In adhering to its IRP, Company management has the responsibility to acquire the cost minimizing combination of resources, whether they be supply-side or demand-side resources."

The **Environmental Intervenors** stated, "EI recommends that a small financial incentive, perhaps a shared savings incentive mechanism be adopted. EI suggests linking these incentives to PacifiCorp's ability to meet its DSR and rate impact targets. Such linking would encourage adoption of PacifiCorp's least cost plan given DSR target based on RAMPP."

"Although important in encouraging desired utility behavior, financial incentives mechanisms tend to result in relatively small dollar transfers when compared to net lost revenue and cost-recovery adjustments. Thus, any final determination about financial incentives should probably await greater clarity on these other issues. As a general matter, however, we support shared savings approaches, They provide a strong incentive for the utility to obtain large electricity savings, but leave the majority of the benefits with utility customers. Moreover, these approaches appear to have worked fairly well in other states that have used them."

Deseret Generation and Transmission stated, "DG&T does not advocate incentive for DSR."

The **Office of Energy and Resource Planning** stated, "We are not convinced that an incentive mechanism is the best way to address providing regulatory incentives for DSR at this time.... We are especially interested exploring the development of a performance based shared savings mechanism. Such a mechanism could assist regulators in reviewing the achievements of the Company efforts in relation to the goals set forth in the Company's IRP. It could also promote cost minimization by encouraging the Company to implement its IRP, could identify and address inequities between ratepayers and shareholders and could reduce the disincentives associated with lost sales absent statistical recoupling or net lost revenue adjustment."

The **Utah Industrial Energy Consumers** stated, "UIEC is strongly opposed to attempts to provide incentives or rewards to utility management that are targeted specifically to DSR. It is inappropriate to focus the appraisal of management performance on a single item. This approach substantially tilts the playing field and could easily lead to the implementation of DSR that is not cost-effective and not in the best interest of customers.... No other party is seriously advancing the concept of shareholder incentives....While UIEC is opposed to the provision of incentive specifically targeted to one area, it does believe that a shared savings approach is the most logical, if incentives for DSR are adopted."

increp/rlb