IN THE MATTER OF the *Public Utilities Act*, (R.S.N. 1990, Chapter P-47 (the "Act"), and

IN THE MATTER OF a General Rate Application (the "Application") by Newfoundland and Labrador Hydro for approvals of, under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to Newfoundland Power, Rural Customers and Industrial Customers; and under Section 71 of the Act, changes in the Rules and Regulations applicable to the supply of electricity to Rural Customers.

Prefiled Evidence and Exhibits of Larry Brockman

NEWFOUNDLAND POWER
A FORTIS COMPANY

At the hearing into Newfoundland Power's 2003 General Rate Application, the Cost of Service Expert Evidence will be adopted by Larry Brockman, President of Brockman Consulting based in Atlanta, Georgia.

A witness profile for Larry Brockman follows.

Larry Brockman
President of Brockman Consulting
Atlanta, Georgia

Larry Brockman has over 29 years experience as a power system planning engineer, rate designer, regulatory staff member and consultant. He specializes in regulatory and generation planning assistance and analysis, as well as the analysis of competitive generation markets.

Mr. Brockman has testified before this Board as an expert witness on 7 previous occasions.

He has presented evidence on behalf of Newfoundland Power Inc. concerning cost of service, rate design and least cost planning in Newfoundland and Labrador Hydro's 1990 and 1992 general rate referrals. In addition, Mr. Brockman appeared as an expert witness on behalf of Newfoundland Power at Hydro's 1992 generic cost of service proceeding and the 1995 rural rate inquiry. Mr. Brockman also appeared as an expert witness on cost of service and rate design on behalf of Newfoundland Power in the 1996 Newfoundland Power General Rate Application, the 2001 Hydro General Rate Proceeding and the 2003 Newfoundland Power General Rate Application.

A more detailed description of Mr. Brockman's professional background is provided as Exhibit LBB-1 to this Evidence.

Contents

SUMMARY OF EVIDENCE

After reviewing the Energy-Only rate compared to the Sample Rate using generally accepted principles of good rate design, I make the following conclusions:

- The Energy-Only rate is superior to the Sample Rate in collecting revenue requirements for a fair return.
- The Energy-Only rate fairly recovers Hydro's cost-of-service revenue requirement from Newfoundland Power.
- A demand/energy rate fairly apportions cost between Hydro's Industrial customers, but is not needed for Newfoundland Power, since it is the only customer in its class.
- The current Energy-Only rate is superior to the Sample Rate in promoting energy efficiency. An inappropriate emphasis on demand charges in the Sample Rate design contributes to inefficiency in the Sample Rate energy charges.
- The Energy-Only rate allows Hydro and Newfoundland Power to optimize the use of their hydraulic and thermal generation resources. The proposed Sample Rate would send an inappropriate pricing signal that would encourage Newfoundland Power to modify its hydraulic storage patterns to reduce costs. Newfoundland Power indicates that the storage modification would increase the likelihood of spillage and result in a less than optimal use of generation resources.
- Newfoundland Power's current rate designs reasonably reflect the Island Interconnected System costs of demand and energy. The Sample Rate will not change Newfoundland Power's rate designs.

- There is no evidence to support additional cost-effective demand management on Newfoundland Power's system. The available evidence indicates that demand management would have little effect on Hydro's future generation plans.
- The Sample Rate will encourage Newfoundland Power to spend up to $84 per kW to reduce peak demand when Hydro has provided evidence that $28.20 per kW is too much to pay for peak demand reduction through interruptible rates.
- The Energy-Only rate creates a more stable revenue stream for both Hydro and Newfoundland Power than the Sample Rate. The Energy-Only rate, therefore, avoids the costs of dealing with additional revenue volatility. There are no benefits to customers of imposing additional revenue volatility on Newfoundland Power.
- Both the Sample Rate and the Energy-Only rate are understandable for a large customer such as Newfoundland Power. However, the Energy-Only rate is more practical to administer because it is less complicated.

Overall, the current Energy-Only rate out-performs the Sample Rate when evaluated using generally accepted principles of good rate design. The Sample Rate should not be implemented.

1. BACKGROUND

In its 2003 General Rate Application, Newfoundland & Labrador Hydro has proposed that both the Industrials and Newfoundland Power be served under a demand/energy rate. While Hydro has not yet proposed a final rate design, the illustrative rate (i.e. the "Sample Rate") created by Stone & Webster in its *Review of Rate Design for Newfoundland Power* report submitted April 9, 2003 (the "Report") appears to form the basis of Hydro's proposal. The Sample Rate would represent a major change from the Energy-Only rate under which Newfoundland Power is now served.

I was asked by Newfoundland Power to compare the current Energy-Only rate to the Sample Rate using generally accepted principles of good rate design.

2. APPROACH

I have previously reviewed Newfoundland Power's rate designs for conformance to generally accepted ratemaking principles. These principles have been used and accepted by this Board and other boards across North America for many decades[1]. The characteristics of a good rate design can be summarized as:

1. The rate is **effective in collecting revenue** requirements for a fair return;
2. The rate is **fair in the apportionment of costs** both between and within rate classes;
3. The rate **encourages efficient use** of society's resources and discourages inefficient use;
4. The rate design creates both **stable rates** and **stable revenues** for the utility and its customers;

[1] Commonly known as Bonbright's Principles.

5. The rate is **understandable** to the customers on the rate; and
6. The rate is **practical** to apply and administer.

The comparison of each of these criteria for the Sample Rate and the Energy-Only rate is presented in more detail in the following sections.

3. EFFECTIVENESS IN COLLECTING REVENUE REQUIREMENTS FOR A FAIR RETURN

A good rate design should be capable of collecting the revenue requirements from each customer and each customer class. In the case of Newfoundland Power's rate, both the Energy-Only rate and the Sample Rate flow directly from the cost of service study and both are designed to collect the same revenue from the customer, assuming the billing determinants[2] are the same as were used in the cost-of-service study.

For Hydro, the current rate stabilization plan (the "RSP") ensures proper revenue collection under a variance in energy consumption, but does not ensure it for demand costs. Therefore, if the actual billing determinants are different than those used in the cost of service study, there is a difference in revenue collection effectiveness between the Sample Rate and the Energy-Only rate.

Under the Energy-Only rate, variances from Hydro's forecast revenue to be collected from Newfoundland Power are solely related to variance from test year energy consumption. Any

[2] Billing determinants are the test year forecast amounts of kilowatts and kilowatt-hours to be used in billing each customer in the test year. The application of the proposed rates to the billing determinants calculates the requested test year revenue requirement.

earnings shortfall or earnings gain resulting from variance from test year forecast revenue from Newfoundland Power is either recovered or credited to the RSP through the load variations component.

Under the Sample Rate, if Newfoundland Power's billing demand differs from forecast, Hydro's costs to serve will not change. However, the revenue Hydro will collect from Newfoundland Power will change by the value of the demand charge (i.e. $84/kW/yr.) times the kilowatt variance from the test year billing demand forecast. This will result in Hydro recovering more than, or less than, their approved test year costs.

As a result, the current Energy-Only Newfoundland Power rate is superior to the Sample Rate at collecting the revenue requirement for a fair return.

4. FAIRNESS IN THE APPORTIONMENT OF COSTS BOTH BETWEEN AND WITHIN CLASSES

Fairness is generally judged by a cost of service standard. That is, if customers are charged what it costs to serve them, they are being treated fairly. As such, if customer classes are charged rates sufficient to collect a reasonable percentage[3] of the revenue requirement that comes from an embedded cost of service study (See Exhibit LBB-2 for the principle and practices of Cost of Service Studies), the rates are generally thought to be fair from an inter-class viewpoint.

[3] In the case of Newfoundland Power revenue requirements to each class are deemed to be fair if they collect plus or minus 10% of the revenue requirement derived from the cost of service study.

Within a class with many customers, it is often important to recognize that customers within the class do not have exactly the same load characteristics. Some use more energy relative to their demand than others. Demand and energy are treated differently in the cost of service study, so it is often fairer to put these customers on demand/energy rates. In that way, those who use more or less than the average demand or energy of the class will pay a more appropriate amount. This is one of the major reasons that Newfoundland Power has demand/energy rates for its larger general service customer classes. Because Hydro's Industrial Class has more than one customer, demand/energy rates are appropriate to ensure intra-class fairness.

In the case of a class where all customer usage patterns are relatively similar, it is not necessary to have complicated rate forms such as demand/energy rates. Consider the street light class, for example. The rate characteristics of streetlights are so well known that meters are not even necessary, and a proper rate design could be as simple as a set charge for each type of light.

Newfoundland Power is the only customer in its class. Its usage characteristics are quite well known by Hydro. Since total revenue requirements are apportioned to the Industrial customers and Newfoundland Power directly from the cost-of-service study, there is no issue of inter-class fairness in their rate design. On systems such as Ontario, there may be numerous small distribution customers served in a wholesale class. They may have different characteristics with respect to demand and energy. Usually, the fairest way to treat them is to put them on demand/energy rates, just as Newfoundland Power does in its classes with more than one large customer.

In conclusion, the current Hydro rate designs fairly allocate the cost-of-service revenue requirements to Newfoundland Power and the Industrial customers. The demand/energy rate fairly apportions cost within the industrial class, but is not needed for Newfoundland Power, since it is the only customer in its class.

5. ENCOURAGING EFFICIENT USE OF ELECTRICITY AND DISCOURAGING INEFFICIENT USE

5.1 General

The encouragement of efficiency through electricity rates involves the use of marginal costs. In fact as one of the early practioners of the art pointed out,

> *I propose to maintain that marginal cost must play a major and even a dominant role in the elaboration of any scheme of rates or prices that seriously pretends to have as a major motive the efficient utilization of available resources and facilities.*[4]

In practical terms, this involves setting the various demand, energy and customer charges so that they reflect the short-run marginal or long-run incremental costs to the supplier of supplying them[5]. Exhibit LBB-2 discusses the principles and practices associated with marginal cost of service studies.

5.2 Short-Run Marginal Costs

Short-Run marginal costs are relatively easy to determine with a general acceptance between experts as to what they are. Short-Run marginal costs are the variable costs of production,

[4] William Vickery 1955, taken from Princlples of Public Utility Rates, Bonbright, Danielsen, and Kamerschen, Public Utility Reports, 1988, p 410.

[5] In economic theory, when all goods and services in society are priced at marginal cost, a condition known as Paredo-Optimality is reached.

namely fuel and variable operating and maintenance cost. There is general agreement among economists that rates should not be set below short-run marginal costs. Selling a product below the short-run marginal cost of production is not considered an efficient practice.

The island of Newfoundland is blessed with an abundance of water resources, with approximately two thirds of total generated kilowatt-hours coming from water. Substantially all of the remainder comes from the thermal steam system at Holyrood. Due to the low cost of water, production from water resources is maximized. Any change in consumption affects the amount of production required from Holyrood. It also means that the short-run marginal cost of energy has the same cost whether it is required at peak or off-peak[6]. Therefore, shifting energy consumption to off-peak periods does not result in savings to the system. The Request for Information NP-130 NLH estimates the 2004 forecast variable production cost at Holyrood to be 4.68 cent / kWh for fuel plus 0.45 cents / kWh for variable O&M for a total of 5.13 cents/kWh. Therefore, the short-run marginal cost is expected to be 5.13 cents/kWh for 2004.

The relatively simple situation in Newfoundland contrasts significantly with most of North America where electrical energy is generated from a wide variety of generators with differing variable production costs[7].

---

[6] See NP-171 NLH.

[7] The US is now 71% thermal, 21% nuclear and 7% hydraulic and 1% other, according to 2002 generation statistics from the US Energy Information Administration, Monthly Energy Review July 2003.

On many North American systems, less efficient thermal units are running during peak hours. These are generally higher heat rate gas turbines or older less efficient steam units. Shifting consumption from peak to off-peak on such systems can save money by shifting generation to more efficient units.

Failure to recognize the essential differences in system operation between a predominantly thermal system and a predominantly hydraulic system can lead to the misapplication of good rate design principles.

5.3 Long-Run Incremental Costs

The determination of long-run incremental costs and their use in determining rates generally results in considerable debate. This debate arises because electrical system long-run costs do not respond in a smooth fashion to changes in demand. Predicting what those costs may be is often difficult, especially those costs associated with the addition of new generation.

Generation additions are quite "lumpy," because large units are added to the system at one time. It often takes many years of load growth to create a need for such additions. After large units are added, it usually takes several years before additional load requires new units. Until that time, the incremental cost of adding more load is simply the fuel and variable O&M cost of supplying the load. Therefore, there is considerable debate as to the extent future incremental generation cost should be recognized in rate design today.

Determining long-run incremental costs requires sophisticated computer studies that vary the future demand and energy on the system to determine the resultant costs. For the Island Interconnected System, only Hydro has the information and tools required to accurately perform this type of study. A long-run incremental cost study has not been completed by Hydro. What is known is the short-run marginal cost of increasing load on the system. When and if a long-run incremental cost study is completed, the results may still not be free from controversy since the calculation of the long-run incremental costs of demand on a system requires knowledge of the next set of alternatives, what they cost, and what would trigger their addition to the system. Often the cost of new generation alternatives is considered confidential as it may affect future competitive bidding. Technological innovation may also present future alternatives that are simply not available today.

5.4 Demand and Energy Growth on the Island Interconnected System

5.4.1 System Planning Criteria

We know certain characteristics about the Island Interconnected System. It is a predominantly hydraulic system. As such, the need for new generation plants is determined differently than thermal systems. On a thermal system, peak demands are the predominant indicator of the need to add new capacity. Hydraulic systems, such as Hydro's [8], are planned principally to satisfy the following two criteria:

1. Sufficient firm energy capability to serve the firm energy requirements of customers, even in dry years; and

[8] 2001 Hydro GRA evidence of H.G. Budgell, Page 8, line 4 to 16.

2. Sufficient capacity to meet system demand such that loss of load hours ("LOLH") does not exceed 2.8 hours per year.

Hydraulic systems are planned so that during dry years there will be sufficient energy available to meet the year's energy requirements. Hydro will build a plant when there is not enough energy forecast to be available from plants during a year.

5.4.2 Energy Growth and the System Expansion Plan

Prefiled testimony of Hydro's witness, Mr. Haynes, at page 37, Table 8 shows the following:

Island Interconnected System
Near Term Capability Requirements

	Load Forecast		**Existing plus Committed System**			
Year	**Peak**	**Energy**	**Net Capacity**	**Firm Capability**	**LOLH**	**Energy Balance**
	(MW)	(GWh)	(MW)	(GWh)	Hrs/Yr	(GWh)
2003	1,578	8,441	1,919	8,706	0.6	265
2004	1,602	8,504	1,919	8,706	1.1	202
2005	1,607	8,512	1,919	8,706	1.2	194
2006	1,613	8,556	1,919	8,706	1.3	150
2007	1,624	8,606	1,919	8,706	1.6	100
2008	1,634	8,653	1,919	8,706	1.9	53
2009	1,643	**8,716**	1,919	**8,706**	2.3	**(10)**
2010	1,654	8,793	1,919	8,706	2.8	(87)
2011	1,666	8,865	1,919	8,706	**3.5**	(159)
2012	1,728	9,309	1,919	8,706	10.4	(603)

In 2009 the energy load forecast exceeds the firm energy capability on the Island Interconnected System (i.e., the firm energy criteria is violated). This signifies that a unit is needed to meet the system's forecast energy requirements. Hydro's witness, Mr. Haynes states that a generator will be needed in 2010 to meet firm energy criteria. Thus, the next unit of generation is driven by energy growth on the system and not demand growth. Consequently reducing or increasing energy will have direct impact on the timing of new generation, as well as having an immediate impact on the amount of fuel burned at Holyrood today. Also, reducing demand will not impact the timing of the next new generation (See Response to NP-154 NLH). Therefore, efficient energy pricing is more important at this time than peak demand management.

5.4.3 A Change from the Past

In 1990 Newfoundland Power proposed the implementation of a wholesale Hydro demand/energy rate[9] to Newfoundland Power because Newfoundland Power was concerned about the fact that demand was growing quickly and potentially causing new units to be added to the system. Newfoundland Power wanted to pursue the possibility of demand management to help reduce demand growth.

Since 1990 several things have changed:

- Overall load growth has decreased dramatically;
- Forecast of total island load indicate the Island Interconnected system load factor has improved since 1990;

[9] 1990 Hydro GRA, prefiled evidence of Larry Brockman. Page 13 – 17.

- New sources of generation now appear to be driven more by energy than demand, the opposite as was the case in 1990;
- Significant amounts of cost effective peak demand reduction programs have not been found since 1990; and
- Analysis indicates that the Sample Rate would increase uncertainty in Newfoundland Power's annual earnings.

Exhibit LBB-3 shows the load growth projections for Hydro in 1990 and 2003 and the underlying load factor in both forecasts. From LBB-3, we see that peak demand is now expected to reach 1,728 MW in 2012. In 1990, Hydro was forecasting this to occur in 1996.

Clearly, both the absolute magnitude and the relationship of demand and energy have changed since Newfoundland Power initially proposed a demand/energy rate be implemented. Demand growth is simply not the driving force in generation system additions that it once was. However, the short-run marginal cost of fuel burned at Holyrood continues to be a direct driver of costs.

5.5 Evidence of Efficiency Gains from Demand Management

There is no evidence to support cost effective demand management that could be implemented on the Newfoundland Power system. In the Report, Stone and Webster suggests that one of the principal reasons for proposing that Newfoundland Power be served under a demand/energy rate is to give Newfoundland Power an incentive to engage in more demand management. Stone and Webster have presented no evidence that such demand management potential exists, beyond a vague statement in the report about 150 MW of potential water heater controls.

NP-140 NLH asked Hydro to test what would happen to the generation system expansion plan if the recently discontinued 46 MW of interruptible Schedule B where added back to the system. Hydro found that there was no effect on the timing of the next generating unit from such an action. Thus, even 46 MW of demand management had virtually no effect on Hydro's future generation requirements before 2012.

Discontinuing a demand management rate such as the Interruptible B contract at $28.20 per kW per year implies that $28.20 per kW per year is too high a price to pay to reduce demand at time of peak. At the same time, the Sample Rate indicates to Newfoundland Power that it is worth $84 per kW per year to reduce demand at time of peak. The Sample Rate will effectively pay Newfoundland Power $84 per kW to reduce demand at peak hour using the curtailable/interruptible load provided by its customers. The inconsistency of these two propositions creates confusion on cost effective demand management.

In NP-188 NLH, Newfoundland Power requested a list of demand control programs that Hydro is planning to undertake on the Island Interconnected system and the response indicated that they are not planning any.

Proving that cost-effective programs exist is a complicated undertaking. Exhibit LBB-4 contains an overview of Demand Side Management and how it is evaluated. It seems premature to implement a demand/energy rate under the assumption that it will drive these programs before they have been identified and tested.

In conclusion, there is no evidence that additional material cost effective demand management exists with respect to Newfoundland Power's customers. Rather, the available evidence indicates that demand management opportunities are limited and would have little effect on Hydro's future generation plans.

5.6 Encouraging Energy Efficiency

If the Sample Rate to Newfoundland Power is not approved, the comparable Energy-Only Rate to Newfoundland Power would be about $0.0546[10]. This is slightly above the marginal costs of Holyrood (about $0.0513). The Energy-Only rate provides a good reflection of short-run marginal costs and therefore promotes energy efficiency. Hydro's proposal for imposing relatively high demand charges at the expense of proper signaling of the immediate and well known costs of increasing or decreasing energy on the system seems to place too much emphasis on the uncertain long-run costs of demand, while discounting the effects of the known short-run cost of energy.

The Energy-Only Rate maximizes the energy charge, as there is no demand charge. This correctly reflects the need to conserve energy consumption as opposed to reducing peak demand. If a demand component is introduced, the energy component would be lower, creating a rate that places greater emphasis on controlling demand at a time when there is a need to put greater emphasis on controlling energy.

[10] See Evidence of Mr. Banfield, page 3 lines 6-8.

5.7 Efficiency of the Sample Rate

Efficiency demands that energy not be sold for less than the cost of producing it. To do otherwise is to encourage customers to waste energy. This idea is not only well known to economists, but even to the ordinary businessman. You simply do not sell products below the short-run marginal cost to produce them (except perhaps as loss-leaders) because you will lose money on every incremental unit you produce.

Newfoundland Power attempts to price its energy tail block rate near the short-run marginal cost of Holyrood, with Board approval. This practice reflects pricing efficiency, a principle that should not be discarded in the quest for demand charges.

Hydro is now proposing a demand/energy rate with the following characteristics:
Energy Charge first 420,000,000 - $0.0344/kWh
Energy Charge all over 420,000,000 - $0.0470/kWh
Demand Charge - $7.00/ kW of billing demand

Newfoundland Power purchases do not exceed the first block for 8 months of the year. Therefore, the $0.0344/kWh is effectively the tail block energy charge for those months. This results in a charge for additional energy during those months that is well below the short-run cost of producing it. Therefore, the first block energy charge of $0.0344/kWh is priced improperly.

Lowering the energy price signal results from the strong demand signal in the Sample Rate. This results in demand-related costs being emphasized over energy costs at a time when energy consumption is driving generation additions on the Island Interconnected system more than increases in peak demand.

The emphasis on demand related costs is also inconsistent with the discontinuance of the Interruptible B contract. The inconsistency of these two propositions indicates that the emphasis Hydro is placing on demand costs in the Sample Rate is suspect.

The inappropriate emphasis on demand charges in the Sample Rate design contributes to the inefficiency of the proposed energy charges.

5.8 Newfoundland Power Retail Rate Designs

Stone and Webster offer two major arguments for the Sample Rate to Newfoundland Power. The first is the suggestion that Newfoundland Power may be able to do some additional demand management. There is no current evidence to support that suggestion. The second suggestion is that Newfoundland Power might change its own rate design to better reflect the Sample Rate. As indicated in the evidence of Mr. Henderson and Mr. Perry, Newfoundland Power's rate designs reflect Island Interconnected system costs and are not influenced by the form of the purchase power rate. Designing rates based on Island Interconnected system costs is more appropriate from a societal viewpoint, than designing them on the structure of the rate that passes Hydro's costs onto Newfoundland Power.

In conclusion, there is no evidence that Newfoundland Power would or should change its retail rate design in response to the Sample Rate from Hydro.

5.9 The Efficient Operation of Newfoundland Power's Generation

At the 2001 Hydro General Rate Proceeding Hydro's Cost of Service witness, Mr. Brickhill recommended the continued use of the Energy-Only rate. He explained that the use of the Energy-Only rate was consistent with the operation coordination between the two companies to ensure the hydraulic generation on the Island Interconnected system is optimized and to avoid spillage and minimize thermal production. Mr. Brickhill expressed the concern that a demand charge may encourage Newfoundland Power to operate its generation in such a way that prevents the most efficient operation by Hydro of the generation on the Island Interconnected System.

In the Report, Stone and Webster recommended the application of the generation credit to Newfoundland Power's native load to determine the billing demand (Option A). This recommendation is made to prevent Newfoundland Power from responding to the price signal and using its thermal generation to create an overall system inefficiency. Option A partly addresses the concern expressed by Mr. Brickhill. However, the energy price block structure in the Sample Rate (i.e., the higher tail block charge that only applies in winter months) provides a clear signal to Newfoundland Power to maximize hydraulic generation during winter months to minimize purchased power costs. Newfoundland Power indicates that modification of storage patterns to maximize hydraulic production in winter months would increase the likelihood of spilling, thereby not resulting in the optimal use of water resources on the Island Interconnected system on an annual basis.

5.10 Efficiency Summary

The current Energy-Only rate encourages efficiency by appropriately pricing Newfoundland Power's incremental consumption very near the marginal cost of production from Holyrood. The Energy-Only rate allows Hydro and Newfoundland Power to optimize the use of their hydraulic and thermal generation resources. The proposed Sample Rate puts too much emphasis on the value of demand and does not encourage efficiency as effectively as the Energy-Only rate.

No amount of cost signaling will create more efficiency on the Island Interconnected system (or any system for that matter) if there is nothing the customer can do about its demand and energy consumption. There is no evidence that there is anything Newfoundland Power can or should do in response to the proposed Sample Rate.

Newfoundland Power already offers its customers a demand/energy rate when the customer's demands reach 10 kW. Billing Domestic and small general service customers on energy-only rates is common practice among Canadian utilities. Therefore, it is difficult to see what new rate form Newfoundland Power would offer in response to the Sample Rate.

The simple fact of the matter is that unless changing the wholesale rate results in changes in Newfoundland Power's rate designs and their customers' behavior, there is no good reason for imposing a demand/energy rate.

6. STABILITY OF RATES AND REVENUES

The Sample Rate includes three elements to minimize the potential impact on Hydro's earnings. These are:

1) the inclusion of a ratcheted demand charge based on Newfoundland Power's single winter peak;
2) a floor on the minimum level of demand Hydro would use in billing Newfoundland Power (i.e., 98% of the test year billing demand for Newfoundland Power); and
3) the weather normalization of system peaks to minimize volatility in revenues resulting from weather conditions.

In the Report, at page 12, Stone and Webster recognizes that "basing billing demand on the single winter peak may be seen as punitive from the customer's perspective" but is the "preferred option from Hydro's perspective".

As stated in response to Request for Information NP-127 NLH, Stone and Webster did not perform analysis to evaluate the impact of the proposed rate on the volatility of earnings of Newfoundland Power.

The Sample Rate will introduce additional uncertainty into the revenue streams of Newfoundland Power and Hydro. The potential impacts on Newfoundland Power's earnings are discussed in detail in the Evidence of Mr. Perry and Mr. Henderson.

Based on the possible range of impacts of the implementation of the Sample Rate on Newfoundland Power's purchased power expense, one of the options to deal with the increased earnings volatility is to create a reserve to deal with financial impacts that would be viewed as extreme. Another option, would be for Newfoundland Power to request the regulator to approve a rate increase to pass through increased costs in years when actual billing demand is materially above the forecast billing demand. In Canada, there is a propensity to have rate adjustment mechanisms to deal with purchased power cost volatility among distribution investor-owned utilities. The costs of such measures to deal with revenue volatility are ultimately borne by ratepayers.

In summary, the Energy-Only rate provides more stable revenues to both Newfoundland Power and Hydro. The Sample Rate has an increased likelihood of having a negative impact on the earnings of Newfoundland Power than the earnings of Hydro. There are no benefits to customers of creating additional revenue volatility.

7. UNDERSTANDABILITY OF THE RATES BY THE CUSTOMERS

One of the generally accepted ratemaking principles is that rates ought to be understandable to the customers. If rates are not understood by the customers on them, controversy and ill-will is created and any efficiency signal is muted.

Both the Energy-Only rate and the Sample Rate would be well understood by Newfoundland Power. Understandability is simply not an issue.

8. PRACTICALITY IN THE APPLICATION OF THE RATES

The Sample Rate is a more complicated rate with greater volatility. As such it will be more complicated to administer.

Hydro is also proposing a statistical model to remove the effects of abnormal peak day weather in determining billing demand for the Sample Rate. The output of such a statistical procedure can be a point of contention in the application of a wholesale rate. For example, Newfoundland Power's peak demand may be less than the test year native peak demand. If the weather conditions on the peak day were not as cold as a normal peak day, the normalization process would result in an increase in billing demand to reflect normal peak day weather. The normalized billing demand may then exceed the test year billing demand thus imposing a financial penalty to Newfoundland Power for load that was not actually required. This approach adds to the complexity of the Sample Rate which makes it less practical than the Energy-Only rate.

9. SUMMARY

Overall, the current Energy-Only rate out-performs the Sample Rate when evaluated using generally accepted principles of good rate design. The Sample Rate should not be implemented.

Personal Profile	
Name	Larry B. Brockman
Present Position	President, Brockman Consulting
Education	Mr. Brockman earned a bachelor's degree in engineering from the University of Florida in 1973. He subsequently completed 35 quarter-hours towards a master's degree in electrical engineering, with a minor in regulatory economics at the University of Florida.
Qualifications Summary	Mr. Brockman has over 28 years experience as a utility planner, consultant, regulator, educator, rate designer, and expert witness. He specializes in strategic planning, regulatory assistance, competitive market assessments, bid evaluation processes, merger and acquisition analysis, cost of service, and rate design, and computer simulation, to help utilities and IPPs meet their strategic goals and maintain competitive advantage.
Prior Experience	During his career, Mr. Brockman has helped perform, and manage numerous consulting projects, including: ***Cost of Service and Rate Design*** Numerous cost of service and rate design investigations for Canadian and US utilities, examining the utilities' marginal and embedded cost-of-service and rate design procedures for their ability to meet the utilities' strategic and regulatory goals. In many of these examinations, Mr. Brockman has appeared as an expert witness. Review of a restructured utility's shared services costs of service separation study to allocate the costs between regulated and unregulated subsidiaries, and procedures for tracking the costs in the future. ***Expert Litigation Assistance*** Project manager of an anti-trust case involving investigation of all phases of power supply planning covering a 40 year historical period and a successful defense against over $3 Billion damage suit over alleged actions by an investor owned utility. Managed a successful defense against a cogenerator seeking to convince regulators that a utility's ratepayers should pay over $1.5 Billion in unnecessary and uneconomic new generation avoided costs by the cogenerator. Project manager for a precedent setting FERC case defending a utility from an attempt to abrogate a long term bulk power contract

worth over $400 Million. Mr. Brockman's team was able to convince the FERC that contract abrogation was not in the public interest, that the plaintiff was not going bankrupt, and that the plaintiff's difficulties were the result of arbitrary and capricious state regulation.

Financial Analysis and Asset Valuation

Construction of detailed utility financial simulation models to forecast regional bulk-power prices and profits for use by Independent Power Producers (IPPs) and power marketers to judge market entry positions and create successful negotiating strategies for purchases and sales in unregulated generation markets.

A profitability study for an electric utility to assess effects on shareholder returns and economic value added (EVA), of various marketing activities of the utility. These studies resulted in re-engineering the marketing department to yield higher returns and be more consistent with corporate goals.

Several asset valuation studies for electric utilities to determine whether a market existed to sell existing generating assets, what they were worth, and whether they would be competitive with existing and new generation in the region. Results were presented to senior management and used to revise the strategic planning direction.

Competitive Market Assessments

Expert testimony to the Arkansas and Louisiana Public Service Commissions on the market clearing prices for generation in a competitive market, and the relative competitive positions of many of the generating companies in the SPP and ERCOT regions. To perform this work, Mr. Brockman used sophisticated computer models and a database containing over 120,000 MW of capacity in the region.

A study on the effects of retail competition on the states of North and South Carolina, presented to the South Carolina Legislature and performed for Carolina Power and Light Company. The study required research on the behavior of prices in other formerly regulated industries and detailed modeling of the market prices and financial effects on the utilities, as well as the effects on state and local taxes.

An independent review of the effectiveness and reliability of a large Mid-Western utility's Power Marketing and Purchases Department in deregulated generation markets, performed as a joint project with the utility and the state's attorney general.

Numerous market outlook and generator profitability studies of the ERCOT, Eastern Interconnect, and WSCC markets for merchant plant developers, using the GEMAPS transmission-constrained production cost simulation tool.

An analysis for a large Canadian utility of the profitability of increased transmission line investments to move power into various competitive markets in the US and Canada.

Strategic Planning

A strategic planning project for a large South-Eastern electric utility identifying strengths, weaknesses, opportunities, and threats, in competitive open-access power markets. For each utility in the region, the project identified which customers would be gained and lost, and assessed the impacts of alternative transmission, and contracting strategies. The entire South Eastern US generating and major transmission systems were simulated. Over $1.5 Billion of potential customer revenue migration was identified at the client utility. Strategies for maintaining the utility's profitability were recommended and accepted by senior management.

Development of several successful strategies and power supply bid evaluation procedures in use at investor owned and rural electric cooperatives, to ensure that winning bids are consistent with the utility's business goals and objectives.

Computer Simulation of Power Systems

Mr. Brockman is an expert in the use of utility simulation software for: planning; operations; and financial analysis including: PROMOD; PROVIEW; PROSCREEN II; PMDAM; EVALUATOR; GEMAPS, IREMM, and power flow programs.

Operational Studies

A salt dome natural gas storage study for a South Central electric utility. The study identified the hourly operational characteristics necessary for favorable economics of the required storage facility. Estimated savings in excess of $100 Million were identified. The facility was constructed and has been successfully benchmarked against the study results.

Merger and Acquisition Analysis

Mr. Brockman has participated in several merger and acquisition studies assessing the production cost and planning and operational synergies arising from the merger. He testified before the FERC on the accuracy and appropriateness of computer simulations a merger application. He also participated in a regulated/non-regulated cost separation study for a shared services group of a major utility.

Prior Positions Held

Managing Consultant PA Consulting, 2000-2002. Mr. Brockman managed a group of consultants engaged in the analysis of transmission-constrained competitive generation markets, as well as managing several litigation cases involving electric utilities.

President of Brockman Consulting 1997-2000. Mr. Brockman assisted clients with strategic planning and regulatory assistance.

Managing Director and Vice President 1994-1996, EDS Management Consulting Services. Responsible for annual revenues of $3.5 Million in the Atlanta office, engaged in providing technical consulting services in planning, regulatory assistance, marketing, competitive assessments, reliability, bid evaluation, financial simulation, and expert testimony.

Vice President Energy Management Associates (EMA) Consulting Department 1985-1994. Started as lead consultant and rose to position of Vice President. He marketed and provided strategic planning, regulatory assistance, and operational consulting to electric and gas utilities worldwide.

Assistant Director Electric and Gas Department, Florida Public Service Commission 1981-1985. Supervised 48 employees engaged in all phases of electric and gas regulation. Made recommendations to the Commission on rate cases and resource planning dockets for all electric and gas utilities in Florida. Responsible for financial and management audit scopes, prudence reviews of rate base, expenses, revenue requirements, and final rate design. Also advised Commission on economic effects of regulatory and energy policy actions.

Corporate Planning Engineer 1979-1981, Gainesville Regional Utilities. Developed, analyzed, and presented to senior management and the City Council, ideas, plans, and studies affecting the growth, financial well-being and efficient operation of the city owned electric system. Performed detailed simulations and studies of new generation, substations, transmission lines, voltage conversions, re-conductoring, and power factor correction. Mr. Brockman conducted public hearings and testified before the City Council on proposed transmission lines, substations, and rate designs.

Special Consultant 1979-1980, University of Florida Public Utilities Research Center. Under a grant from Florida Power Corporation and the Florida Public Service Commission, performed a detailed review of marginal cost study techniques for electric utilities and completed a marginal cost study for Florida Power Corporation.

Transmission Planning Engineer 1973-1976, Jacksonville Electric Authority. Responsible for bulk transmission planning, including extensive use of power-flow, fault current, and transient stability computer programs. Chairman of the Florida Electric Coordinating Group's Long Range Transmission Planning Task Force 1974.

Adjunct Faculty Member 1976, University of North Florida. Taught courses in industrial and commercial building wiring design and conformance with National Electrical Codes.

Expert Witness Appearances	City of Gainesville City Council, 1980, testified on behalf of Gainesville Regional Utilities concerning a joint utility and citizen's collaborative effort on rate design. City of Gainesville City Council, 1981, testified concerning a Long-Range Transmission and Distribution Plan and proposals to construct a new substation. Florida Public Service Commission, Florida Power and Light, 1981 Docket No. 810002, Rate Case, testified on cost-of-service. City of Tallahassee - Surcharge Outside the City Limits, 1983. Testified concerning marginal and embedded costs inside and outside the city limits. Florida Public Service Commission, 1988, West Florida Natural Gas Company. Testified on cost-of-service and rate design and why the utility needed flexibility to meet competition. Oklahoma Corporation Commission, 1988, Avoided Cost Proceeding. Testified on the appropriate use of computer models to determine avoided cost of generation. Nova Scotia Board of Commissioners of Public Utilities, 1989, Nova Scotia Power Rate Case. Testified on cost of service and rate design. Nova Scotia Board of Commissioners of Public Utilities, 1990, Nova Scotia Power Rate Case. Testified on integrated resource planning, cost of service and rate design Nova Scotia Board of Commissioners of Public Utilities, 1993, Nova Scotia Power Rate Case. Testified on cost of service and rate design. Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1990. Newfoundland and Labrador Hydro rate case. Testified on integrated resource planning and rate design. Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992, Newfoundland and Labrador Hydro rate case. Testified on Cost of Service and Rate Design. Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992, Generic Hearing on Cost of Service and Rate Design. Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1995, In the Matter of an Inquiry Into Issues Relating to Rural Rate Subsidies. Public Service Commission Colorado, 1994, testified on behalf of Public Service Company of Colorado on the proper use of dynamic programming models in the utility's integrated resource planning process.

	Federal Energy Regulatory Commission, 1994, Merger Case, Testified on behalf of Central and Southwest utility concerning production cost merger benefits. Nova Scotia Board of Commissioners of Public Utilities, 1995, Nova Scotia Power Rate Case. Testified on cost of service and rate design. Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1996, Newfoundland Power Rate Case, testified on cost of service and rate design. Arkansas Public Service Commission, 1997, Arkansas Power and Light Rate Case, testified concerning the market clearing prices for power in deregulated markets and the relative competitive positions of various generators in such markets. Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2001, Newfoundland and Labrador Hydro rate case. Testified on Cost of Service and Rate Design. Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2003, Newfoundland Power rate case. Testified on Cost of Service and Rate Design
Clients Served	Mr. Brockman's clients have included: Ahlstrom Pyro Power Alabama Electric Cooperative Alberta Power Company Balch and Bingham Black and Veatch California Energy Commission Carolina Power and Light Company Central and Southwest Company Central Vermont Power Company Chugach Electric Cooperative Cincinnati Gas and Electric Company Citibank Commonwealth Edison Company Duke Power Company Enron Entergy Florida Public Service Commission Georgia Power Company Gainesville Gas Company Hawaiian Electric Company

	Howery and Simon Hydro One McKinsey and Company Mission Energy Nevada Power Company New Brunswick Power Company New York State Electric and Gas Newfoundland Power Niagara Mohawk Nova Scotia Power Company Oklahoma Gas and Electric Company Ontario Power Generation Pacific Gas and Electric Company Public Service Company of Colorado Public Service Company of New Mexico Rochester Gas and Electric SCANA Southern California Edison Tampa Electric Company The City of Austin The Southern Company TransEnergie West Florida Natural Gas Company The World Bank

COST OF SERVICE PRINCIPLES AND PRACTICES

1.0 Principles

Cost of service studies are based upon a few basic principles which will be discussed in this section.

1.1 Purpose of Cost of Service Studies

Cost of service studies are performed for several reasons. The *1992 National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual* (the "NARUC Manual") on page 12 gives the following purposes for cost of service studies:

1. to attribute costs to different categories of customers based on how those customers cause costs to be incurred;

2. to determine how costs will be recovered from customers within each customer class;

3. to calculate costs of individual types of service based on the costs each service requires the utility to expend;

4. to determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets; and

5. to separate costs between different regulatory jurisdictions.

The use of cost of service studies to attribute cost responsibility follows logically from the generally accepted principles of good rate design. James Bonbright was one of the first to codify these principles in his classic book *Principles of Public Utility Rates*. The Bonbright principles which relate most to cost of service studies are:

1. effectiveness in yielding total revenue requirements;

2. fairness in the apportionment of total cost of service among the different ratepayers; and

3. static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

(a) in the control of the total amounts of service supplied by the Company;

(b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

1.2 Embedded and Marginal Cost of Service Studies

There are two basic types of cost of service studies. The first is called an embedded cost of service study, the other is called a marginal cost of service study. Embedded cost of service studies deal with the costs of existing utility plant and operating expenses. Marginal cost of service studies deal with the costs of meeting future customer, energy and demand requirements. Embedded cost of service studies look backward; marginal cost of service studies look forward.

1.3 How Cost of Service Studies Achieve Bonbright's Goals

Bonbright's first goal of effectiveness in yielding total revenue requirements applies only to embedded cost of service studies. This is done by first setting the total revenue requirements which are substantially recovered between the customer classes with the guidance of a cost of service study.

The goal of achieving fairness in the apportionment of total cost of service among the different ratepayers and preventing undue discrimination is the stated purpose of most embedded cost of service studies. Fairness in allocating revenues is accomplished by paying attention to one or both of two basic principles. The first principle is "causality"; the second principle is "extent of use."

1.4 The Causality Principle

The causality principle holds that the customer (or customer characteristic) that causes a cost to go up or down should bear that cost in a cost of service study. For example, if demand on the system causes new transmission lines to be built, then transmission lines are causally related to demand and customers should be allocated the costs of those lines based on their respective demands. Most people feel this to be fair. When the costs reflected are marginal costs, it is thought to help achieve economic efficiency[1].

[1] The concept of economic efficiency is based on the notion by an Italian economist, Vilfredo Paredo, who reasoned that if people see what it costs society to produce all goods in society (marginal cost), they will consume exactly the right amount of each good to make everyone as well off as they can be. This principle is known as Paredo Optimality. If all competing goods in society are not priced at marginal cost, then the best that can be hoped for under marginal cost pricing is what is known as "Second Best".

We can see the principle of causality in other aspects of life as well. When you buy a house, you usually pay an amount based on the cost to build it plus a contractor's commission. Most people would not feel it was fair or efficient to price all houses the same no matter how much they cost to build.

1.5 The Extent of Use Principle

The extent of use principle is grounded in a belief that if you use something you ought to pay for it (whether you caused it to be built or not). For example, extent of use advocates would argue if you use a thermal system's generation on an interruptible basis, you ought to pay some of its fixed costs even though you may not be responsible for its construction. The use of the non-coincident peak in the "average and excess generation demand allocation technique" is based heavily on the extent of use philosophy. In many ways, the extent of use principle is more of a rate setting principle than a cost of service principle, but it is used so extensively to make decisions in cost of service studies that it is hard to separate the two.

The idea that pricing based on extent of use seems fair to most people can also be illustrated in everyday life. If one person buys a pizza but cannot eat it all, the marginal cost of giving it to someone else is zero. If someone else wants it, however, it would seem fair to most people to have them pay something for it - after all, they are eating it too. However, some economists do not acknowledge such notions of fairness.

1.6 Fairness vs. Efficiency

The principles of fairness (based on past causality and extent of use) and efficiency (based primarily on future causality) are often in conflict.

It is the job of the ratemaker to weigh these goals and decide what best balances people's notions of fairness and society's need for efficiency.

2.0 Practices

Implementing the principles over time has led to fairly widespread agreement on how cost of service studies ought to be conducted. A discussion of the relevant practices follows for both embedded and marginal cost of service studies.

2.1 Embedded Cost of Service Practices

2.1.1 Steps in Performing an Embedded Cost of Service Study

There are three main steps involved in performing a cost of service study. These steps are:

(1) functionalization;

(2) classification; and

(3) allocation.

Each of these steps is a process of sub-dividing the utility's overall costs into smaller portions, each associated with specific customer classes and customer load characteristics that cause the costs to occur (causality) or that a customer is thought to use (extent of use).

2.1.2 Functionalization in Embedded Cost of Service

Functionalization is the process of deciding what purpose or "function" a utility investment or expenditure services. Common examples of utility functions are production, transmission and distribution. As an example of functionalization, consider the cost of fuel burned at a power plant and the cost of carrying the investment in that plant. These costs would be functionalized as production.

Functionalization is performed because it helps identify the costs of providing service to various customer classes when the load characteristics of those customers change.

The costs assigned to the major utility functional categories are often broken down further into sub-categories associated with individual customers or groups of customers. For example, if a transmission line was built just to serve a specific group of customers, the cost of that line should be functionalized as transmission whose function is to service only that group of customers. This will promote fairness by ensuring that the cost of that line will eventually be assigned only to that group of customers.

2.1.3 Classification in Embedded Cost Service

Classification is the process of deciding what customer characteristics cause each functionalized cost to increase or decrease as customer load characteristics change. Costs are classified as increasing or decreasing because of changes in number of customers, demand on the system or energy consumed.

As an example, the following table shows the commonly accepted ways of classifying production plant costs.

CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
301-303	Intangible Plant	x	-
310-316	Steam Production	x	x
320-325	Nuclear Production	x	x
330-336	Hydraulic Production	x	x
340-346	Other Production	x	-

As the above table shows, production can be classified as demand and/or energy related. Production costs are not usually classified as customer related. The amount of production cost classified to demand (versus energy) is a matter of judgement. In order to decide how to properly classify each item, the analyst must go through each one and ask whether number of customers, demand or energy causes each cost item to increase. If extent of use is to be a criterion, then the analyst must decide whether the extent of use of demand or energy, or simply being a customer, constitutes a fair classification of the item.

Transmission costs are usually classified as demand but may have some energy component. Rarely are transmission costs considered to have a customer component beyond directly assigned costs.

Distribution costs are usually classified as being somewhat related to demand and customers, but not related to energy.

Even in simple tables such as those included in the NARUC Manual, classification can be controversial because no single universally accepted method for classifying production, transmission or distribution related costs exists.

2.1.4 Allocation in Embedded Cost of Service

In the allocation step, the previously functionalized and classified costs are allocated to the individual customer classes. Allocation to the classes is usually done in proportion to each class' share of the demand, energy or number of customers depending on how the cost was classified in the prior step. The following example might prove useful in understanding these concepts.

Suppose a utility has spent $50 in a year to provide a generating plant to serve two customer classes. After investigation of the utility's accounting books, it was found that $25 was spent at the power plant for fuel and $25 was associated with carrying the investment in the power plant. The first $25 cost would be functionalized as production fuel and the second $25 cost would be functionalized as production carrying costs.

Next, suppose that consultation with the planners and operators of the plant revealed that:
1) the cost of fuel increases only as more energy is used from the plant; and
2) one-half of the investment in the plant was spent due to the system energy requirements and the other one-half of the investment in the plant was due to system demand requirements.

Applying the principle of causality, the $25 production fuel costs would be classified as energy related, $12.50 of the carrying charges on the plant as demand related and the $12.50 of the carrying charges as energy related.

To perform the allocation step it must first be determined how much demand and energy requirement each of the two classes place on the system. Suppose in this example that Class 1 is responsible for two-thirds of the total demand at system peak but uses only one-third of the total energy on the overall system. Class 1 has a worse load factor than Class 2. Two-thirds of the $12.50 demand related carrying charges on the plant would be allocated to Class 1 because that would be its share of the total demand. (The principle of causality would suggest that they caused two-thirds of the demand costs.) Also, one-third of the $37.50 energy related costs would be allocated to Class 1 because that is its share of the total energy used from the plant.

2.1.5 Final Comments on Embedded Costs

In theory, the embedded cost of service study is relatively simple. However, there are hundreds of cost categories that must be properly functionalized, classified and allocated. Cost of service practitioners have differences of opinion which result in different treatments of different items. Other differences occur because utilities have different factors driving the costs up or down.

In addition, there have been technological changes in production plant equipment and load research capabilities in the last 30 years. If capturing cost causation is the goal, both have changed what can and should be done with respect to cost allocation. Prior to the late 1960s, large inexpensive gas turbines were not available to the electric utility industry for meeting peaking type loads. This meant that in many cases, fossil fuel steam plants were constructed as both base load and peaking plants. Since the same type of plant was constructed to serve both high and low load factor loads, the maximum demand on the plants was all that really drove the cost of installing them. Under such circumstances, classifying all thermal production plants as demand related made causal sense. However, it still offended the ratemakers' sense of fairness that classes using power off-peak under such a classification scheme might not be allocated any of the fixed costs of the generating plants that served them. This led to the use of methods such as the average and excess demand method which allocates a portion of production plant costs on energy and a portion on each classes' non-coincident demand (which is an extent of use idea).

The fact that good load research data was uncommon prior to the 1960s meant that cost of service methods which required coincident peak data by class could not be used effectively. Since the average and excess demand method required only class energy consumption and non-coincident demands, it could be applied with very little load research. It thus became a popular method with analysts who wanted to recognize the fact that power plant planning involved balancing investment and operating costs that varied with both demand and energy.

2.2 Marginal Cost of Service Practices

2.2.1 Purpose of Marginal Cost of Service Studies

Marginal cost of service studies attempt to calculate how the future costs of a utility change with a change in demand, the number of customers or the amount of energy used. This basic concept can be written as the change in cost, divided by the change in quantity demanded or:

$$\mathbf{MC = \Delta Costs / \Delta Quantity}$$

Since the changes in costs in the above equation are changes in future costs, they cannot be determined by examining the books and records of a company. Instead, they must be determined from engineering studies or estimated from past trends.

2.2.2 Differences Between Marginal and Embedded Costs

Marginal cost of service study practice is different from embedded cost of service study practice in several ways. One difference already alluded to is that marginal cost of service studies look forward to how costs change in the future rather than backward as in embedded cost of service studies. Marginal cost of service studies are mostly concerned with what causes the costs to change rather than extent of use notions of fairness. Marginal cost of service studies do not usually go through the steps of functionalization, classification and allocation in the same way as embedded cost of service studies. Instead, they rely more on engineering calculations and hypothetical studies which ask "if the utility experiences an increase in the number of customers, demand or energy how will future costs increase?" Marginal cost of service studies usually recognize that time of use can be important in how the costs change and are usually performed for on-peak and off-peak time periods. There is not as much of a focus on customer classes except for the differences in losses, metering and billing. Marginal cost of service studies are usually time differentiated. That is, they calculate marginal costs on-peak and off-peak. Marginal cost of service studies generally are performed to determine the marginal customer, demand and energy costs.

2.2.3 Difficulties in Determining Marginal Costs

Marginal costs can be difficult to determine for several reasons. First, since they are determined by doing engineering calculations or simulations of the future, the results are heavily dependent on the assumptions about how costs will change in the future. The last 20 years of electric utility history is replete with examples of how poorly these future costs were estimated, either because of inaccurate input data, or simulation models which did not capture the changes in costs accurately.

There is also a basic timing dilemma that must be addressed when dealing with marginal cost studies. For example, if more energy is demanded from most power systems in the next hour, there is no time and usually no need to build additional plant to supply the energy. The change in costs to serve the additional requirements is therefore just the change in fuel and variable operating costs of certain power plants. When the time period or the quantity is small enough so that additional plant is not needed, the resulting change in costs is known as short run marginal cost. A simple small spike in demand would have no effect on the costs of the system in the short run. The short run marginal costs on such a system would therefore be said to be the variable fuel and operating costs for energy and zero for demand. To relate these costs to the individual classes losses would be factored in at various voltage levels at which the customers are served.

When the time period for which the marginal cost study is performed is longer, change in demand and energy requirements will generally be larger and additional generating, transmission and distribution plant may need to be built to serve the increase. When this becomes the case, the resulting marginal costs are known as long run marginal costs. Because the changes we are dealing with over longer periods are larger, they are often called incremental costs rather than marginal costs and are often simulated by adding a fixed amount of demand and energy to the utility load curve and studying what happens to the costs in the planning process. The amount of incremental load to be added in these studies can effect the outcome because it affects the type of plant that may be added.

In the end, it is the use to which the marginal costs are to be put that determines whether we should use long run or short run marginal costs and for how long into the future we want to calculate them. Some regulators believe that when marginal costs will be low for a long time into the future they should reflect those low costs in the tail blocks of the rates and let the customers enjoy the advantages of low cost power for that time. Others believe that because customers are making long run equipment purchasing decisions the long run marginal costs should be brought back to the present and reflected in the rates.

2.2.4 Marginal Customer Related Costs

The basic question to be answered by a marginal customer related cost study is "how do the costs change in the future if we add another customer?" This question is usually answered by asking the planning engineers what they would add if a new customer was connected to the system. A new meter and service drop would obviously be required and additional billing costs would be incurred. Instead of assigning the average embedded costs of such devices as we did in embedded cost studies we would assign the costs of all new equipment. As new customers are added, system standards would require additions and upgrades to the distribution system to meet the increased demands. This is the same argument used in the minimum size distribution system in the embedded cost of service studies. One way of capturing how the fixed costs of the distribution system change when a customer is added is the *Natural Economic Research Associates* ("NERA") facilities charge method, this method was used by Newfoundland Power in their 1997 Marginal Cost Study.

2.2.5 Marginal Energy Related Costs

There is relatively little controversy over the short run marginal energy costs of a power system. They are usually taken to be the fuel and variable operating costs of the generating unit which will supply the next kilowatt hour in any given hour. For time of use pricing purposes they are often averaged over the off-peak and on-peak times. In the long run, some systems will have marginal energy costs that include some fixed costs because the increases in energy may cause the utility to invest in new plant simply because more energy is required. An example is pollution equipment that would need to be added to power plants to keep the utility below emissions caps. For isolated systems relying on water power, firm energy criteria may mean that increases in energy will require system expansion whether peak demands increase or not.

To determine the short run marginal energy costs on complicated systems, production cost computer simulations are performed. To determine the long run marginal costs on systems where firm energy criteria may be controlling, system generation expansion studies should be performed. The long run marginal energy costs can then be calculated by taking the changes in costs divided by the energy that caused them. The time value of money must be appropriately treated in such analyses.

2.2.6 Marginal Demand Related Costs

The marginal demand related costs are the change in costs for a change in demand. In the short run, these costs are zero as we discussed above. However, in the long run increases in demand cause additional distribution, transmission and generation plant to be built. Determining the marginal cost of demand is usually done by examining all parts of the system separately.

The marginal demand related costs of the distribution system can be determined in several ways. The first is to simply do a regression analysis of the expenditures on the distribution system over some past period of time with demand as an independent variable. The second way is to do engineering "what if?" studies where the planning engineers are asked to calculate the difference in costs of a hypothetical system with different levels of demand. The two methods yield similar results if inflation is accounted for and distribution technology does not change much.

The marginal demand related costs of transmission are calculated in much the same way as distribution the difference being that "number of customers" would not be an independent variable in any historical regressions. It is important to make sure that any costs of transmission lines directly associated with new power plants be treated in the same way as the plants. That is, if the plants were built primarily to satisfy firm energy criteria they should not be included in the marginal demand related costs.

Several methods have been devised to calculate the marginal demand related costs of the generation system. They can be lumped into three major categories: system planning methods, proxy unit methods or regression models. The regression methods are not often used on generation systems and I shall not discuss them further.

The system planning methods use some sort of generation expansion planning tools to examine the effect an increase in demand has on the future generation expansion plans of the utility. A base case is often created, then demand is increased by 50 to100 MW and a new plan is produced. The difference in the costs of these two plans is taken to be the marginal demand related cost of the system.

The proxy unit method does not use a full planning simulation. It simply assumes that the cost of deferring the lowest cost way of meeting future demand is the marginal demand related cost. This is often the cost of deferring a simple cycle combustion turbine divided by its capacity.

The situation is complicated to a large degree by the complex interaction between increases in demand and increases in energy. Increases in demand usually cause the addition of combustion turbines; however, on systems with high energy costs this may not be the case. Increasing demand on these systems may accelerate the construction of base load plants because the fuel savings from such actions more than justifies building them instead of the combustion turbine. In that case, the marginal demand related cost is often taken to be the cost of the base load plant minus the fuel savings.

Systems with firm energy criteria can also make it difficult to calculate the marginal generation demand related costs. With these systems, the generation expansion plan sometimes appears not to change when demand is increased or reduced. This is because the firm energy criteria is controlling the expansion plan. In such cases, the marginal cost of demand on the generation system may be close to zero.

The best method for calculating the marginal demand related cost of generation depends on the system. For simple systems that are close to having the optimal generation mix, the proxy unit method yields good results. For more complicated systems, or those with firm energy criteria, it is best to perform planning studies to determine the effects of changing demand.

2.2.7 Final Comments on Marginal Costs

There are additional costs not captured in the marginal customer, demand and energy techniques described. These are administrative and general ("A&G") costs. In the long run, some of these costs will also increase if more customers, demand or energy occurs. They are usually accounted for by calculating a historical percentage, known as A&G loading, and adding them to the costs for demand and customer related marginal costs.

Peak & Energy Forecast
From Hydro's 1990 Hearing
Table 1, Page 23 of T. D. Collett Evidence

Year	Peak (MW)	Energy (GWh)	Load Factor
1990	1,422	7,384	59%
1991	1,473	7,693	60%
1992	1,544	7,883	58%
1993	1,602	8,054	57%
1994	1,650	8,232	57%
1995	1,693	8,331	56%
1996	1,745	8,549	56%
1997	1,760	8,692	56%
1998	1,761	8,824	57%
1999	1,796	8,992	57%
Annual Growth Rates	2.63%	2.21%	

Peak & Energy Forecast
From Hydro's 2003 Hearing
Table 8, Page 37 of Production Evidence

Year	Peak (MW)	Energy (GWh)	Load Factor
2003	1,578	8,441	61%
2004	1,602	8,504	61%
2005	1,607	8,512	60%
2006	1,613	8,556	61%
2007	1,624	8,606	60%
2008	1,634	8,653	60%
2009	1,643	8,716	61%
2010	1,654	8,793	61%
2011	1,666	8,865	61%
2012	1,728	9,309	61%
Annual Growth Rates	1.01%	1.09%	

An Overview of Demand Side Management

Demand Side Management (DSM) is an attempt to influence load through direct means (such as water heater controls), or indirect means (such as rate design). DSM is generally targeted at one of the following categories[1]:

1. Conservation
2. Load Management
3. Fuel Substitution
4. Load Building
5. Self-Generation

Conservation is an improvement in energy efficiency that results in reduced energy and demand usage. Examples of conservation programs include putting additional insulation in a home attic, and encouraging more efficient appliances. Conservation is encouraged mostly through appropriate energy rates, or by direct programs by the utility. The savings from conservation include both fuel not burned at power plants and the resources saved from not building power plants and other load serving facilities.

[1] See the California Standard Practice Manual (2001) Appendix 1, which has become a handbook for many states using DSM because it was one of the first to document the common DSM tests in a standardized manner.

Load Management (i.e., sometimes referred to as demand management) either eliminates peak load, or shifts it from peak to off-peak times. Examples of load management include water heater controllers, which shift the demand to off-peak times, and interruptible load programs. The savings from load management programs are primarily the savings in resources from not having to build additional power plants and transmission and distribution lines to serve the peak load.

Fuel substitution shifts load from one fuel (such as electricity) to another (such as natural gas). Examples of a fuel substitution program include encouraging gas-fired water heaters, which convert energy to heat more efficiently than first converting gas to electricity and then converting the electricity back to heat. The savings from fuel substitution include deferred power plants and lines, plus any net fuel savings.

Load building is an attempt to increase load in some time period, such as an attempt to more efficiently utilize available off-peak capacity to spread fixed costs over more kWh and thus reduce rates. Self-generation may also be encouraged where customers can generate more efficiently than the utility.

DSM objectives are usually determined by cost-effectiveness tests and the major drivers of the utility’s generation expansion plans. A utility that is particularly concerned about peak demand driving the need for new plant additions would probably target load management programs heavily, whereas a utility that is concerned more about not burning precious fossil fuels might target conservation programs more heavily.

DSM should be cost-effective. There are several types of cost-effectiveness tests[2]. They are:

1. Participant Test
2. Rates Impact Measure (RIM)
3. Program Administrator Cost (PAC)
4. Total Resource Test (TRC)

The Participant Test measures the cost effectiveness to the person participating in the DSM program. If a customer has to pay for some or all of the insulation in an attic insulation program, the present value of their costs should be less than the present value of the savings in electric bills over time. It is very difficult to get participants to engage in DSM programs that are not cost-effective to them.

The Rate Impact Measure (RIM) measures whether a program will reduce the electric bills of the total body of ratepayers over time. In order to pass this test, programs must cost less on a per kWh basis than they save in fuel and other resources. The idea behind the RIM test is that ratepayers as a whole should not be made to encourage programs that will drive their rates up.

The Program Administrator Cost (PAC) test measures the cost-effectiveness of the program to the administrator of the program (including any rebates they have to pay and revenues they receive for administering the program).

[2] Ibid.

The Total Resource Test (TRC) measures the present value of total resources that are used to implement the program against the total resources saved. The TRC is sometimes extended to include all externalities (such as air pollution) and is then called a Societal Test.

In summary, DSM programs are usually chosen to manage demand and energy in such a way as to save more than they cost. The choice of one program type (conservation, load management, etc.) is driven by what is driving the addition of plants on the system. The programs should be attractive to the participants and non-participants.

CALIFORNIA STANDARD PRACTICE MANUAL: ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

OCTOBER 2001

TABLE OF CONTENTS

Chapter I

INTRODUCTION: BASIC METHODOLOGY

Background

Since the 1970s, conservation and load management programs have been promoted by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) as alternatives to power plant construction and gas supply options. Conservation and load management (C&LM) programs have been implemented in California by the major utilities through the use of ratepayer money and by the CEC pursuant to the CEC legislative mandate to establish energy efficiency standards for new buildings and appliances.

While cost-effectiveness procedures for the CEC standards are outlined in the Public Resources Code, no such official guidelines existed for utility-sponsored programs. With the publication of the *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* in February, 1983, this void was substantially filled. With the informal "adoption" one year later of an appendix that identified cost-effectiveness procedures for an "All Ratepayers" test, C&LM program cost effectiveness consisted of the application of a series of tests representing a variety of perspectives--participants, non-participants, all ratepayers, society, and the utility.

The Standard Practice Manual was revised again in 1987-88. The primary changes (relative to the 1983 version), were: (1) the renaming of the “Non-Participant Test” to the “Ratepayer Impact Test“; (2) renaming the All-Ratepayer Test” to the “Total Resource Cost Test.”; (3) treating the “Societal Test” as a variant of the “Total Resource Cost Test;” and, (4) an expanded explanation of “demand-side” activities that should be subjected to standard procedures of benefit-cost analysis.

Further changes to the manual captured in this (2001) version were prompted by the cumulative effects of changes in the electric and natural gas industries and a variety of changes in California statute related to these changes. As part of the major electric industry restructuring legislation of 1996 (AB1890), for example, a public goods charge was established that ensured minimum funding levels for “cost effective conservation and energy efficiency” for the 1998-2002 period, and then (in 2000) extended through the year 2011. Additional legislation in 2000 (AB1002) established a natural gas surcharge for similar purposes. Later in that year, the Energy Security and Reliability Act of 2000 (AB970) directed the California Public Utilities Commission to establish, by the Spring of 2001, a distribution charge to provide revenues for a self generation program and a directive to consider changes to cost-effectiveness methods to better account for reliability concerns.

In the Spring of 2001, a new state agency—the Consumer Power and Conservation Financing Authority was created. This agency is expected to provide additional revenues—in the form of state revenue bonds---that could supplement the amount and type of public financial resources to finance energy efficiency and self generation activities.

The modifications to the Standard Practice Manual reflect these more recent developments in several ways. First, the “Utility Cost Test” is renamed the “Program Administrator Test” to include the assessment of programs managed by other agencies. Second, a definition of self generation as a type of “demand-side” activity is included. Third, the description of the various potential elements of “externalities” in the Societal version of the TRC test is expanded. Finally the limitations section outlines the scope of this manual and elaborates upon the processes traditionally instituted by implementing agencies to adopt values for these externalities and to adopt the the policy rules that accompany this manual.

Demand Side Management Categories and Program Definitions

One important aspect of establishing standardized procedures for cost-effectiveness evaluations is the development and use of consistent definitions of categories, programs, and program elements.

This manual employs the use of general program categories that distinguish between different types of demand-side management programs--conservation, load management, fuel substitution, load building and self-generation. Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. ‘Conservation’ in this context includes all ‘energy efficiency improvements’. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on-peak to non-peak periods.

Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self generation refers to distributed generation (DG) installed on the customer’s side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid.

In some cases, self generation products are applied in a combined heat and power manner, in which case the heat produced by the self generation product is used on site to provide some or all of the customer’s thermal needs. Self generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines.

Fuel substitution and load building programs were relatively new to demand-side management in California in the late 1980s, born out of the convergence of several factors that translated into average rates that substantially exceeded marginal costs. Proposals by utilities to implement programs that increase sales had prompted the need for additional procedures for estimating program cost effectiveness. These procedures maybe applicable in a new context. AB 970 amended the Public Utilities Code and provided the motivation to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation. Hence self-generation was also added to the list of demand side management programs for cost-effectiveness evaluation. In some cases Self-generation programs installed with incremental load are also included since the definition of self-generation is not necessarily confined to projects that reduce electric load on the grid. For example, suppose an industrial customer installs a new facility with a peak consumption of 1.5 MW, with an integrated on-site 1.0 MW gas fired DG unit. The combined impact of the new facility is *load building* since the new facility can draw up to 0.5 MW from the grid, even when the DG unit is running. The proper characterization of each type of demand-side management program is essential to ensure the proper treatment of inputs and the appropriate interpretation of cost-effectiveness results.

Categorizing programs is important because in many cases the same specific device can be and should be evaluated in more than one category. For example, the promotion of an electric heat pump can and should be treated as part of a conservation program if the device is installed in lieu of a less efficient electric resistance heater. If the incentive induces the installation of an electric heat pump instead of gas space heating, however, the program needs to be considered and evaluated as a fuel substitution program. Similarly, natural gas-fired self-generation, as well as self-generation units using other non-renewable fossil fuels, must be treated as fuel-substitution. In common with other types of fuel-substitution, any costs of gas transmission and distribution, and environmental externalities, must be accounted for. In addition, cost-effectiveness analyses of self-generation should account for utility interconnection costs. Similarly, a thermal energy storage device should be treated as a load management program when the predominant effect is to shift load. If the acceptance of a utility incentive by the customer to, install the energy storage device is a decisive aspect of the customer's decision to remain an electric utility customer (i.e. to reject or defer the option of installing a gas-fired cogeneration system), then the predominant effect of the thermal energy storage device has been to substitute electricity service for the natural gas service that would have occurred in the absence of the program.

In addition to Fuel Substitution and Load Building Programs, recent utility program proposals have included reference to "load retention," "sales retention," "market retention," or "customer retention" programs. In most cases, the effect of such programs is identical to either a Fuel Substitution or a Load Building program--sales of one fuel are increased relative to sales without the program. A case may be made, however, for defining a separate category of program called "load retention." One unambiguous example of a load retention program is the situation where a program keeps a customer from relocating to another utility service area. However, computationally the equations and guidelines included in this manual to accommodate Fuel Substitution and Load Building programs can also handle this special situation as well.

Basic Methods

This manual identifies the cost and benefit components and cost-effectiveness calculation procedures from four major perspectives: Participant, Ratepayer Impact Measure (RIM), Program Administrator Cost (PAC), and Total Resource Cost (TRC). A fifth perspective, the Societal, is treated as a variation on the Total Resource Cost test. The results of each perspective can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts.

Table I summarizes the cost-effectiveness tests addressed in this manual. For each of the perspectives, the table shows the appropriate means of expressing test results. The primary unit of measurement refers to the way of expressing test results that are considered by the staffs of the two Commissions as the most useful for summarizing and comparing demand-side management (DSM) program cost-effectiveness. Secondary indicators of cost-effectiveness represent supplemental means of expressing test results that are likely to be of particular value for certain types of proceedings, reports, or programs.

This manual does not specify how the cost-effectiveness test results are to be displayed or the level at which cost-effectiveness is to be calculated (e.g. groups of programs, individual programs, and program elements for all or some programs). It is reasonable to expect different levels and types of results for different regulatory proceedings or for different phases of the process used to establish proposed program funding levels. For example, for summary tables in general rate case proceedings at the CPUC, the most appropriate tests may be the RIM lifecycle revenue impact, Total Resource Cost, and Program Administrator Cost test results for programs or groups of programs. The analysis and review of program proposals for the same proceeding may include Participant test results and various additional indicators of cost-effectiveness from all tests for each individual program element. In the case of cost effectiveness evaluations conducted in the context of integrated long-term resource planning activities, such detailed examination of multiple indications of costs and benefits may be impractical.

Table I

COST-EFFECTIVENESS TESTS

PARTICIPANT

Primary	Secondary
Net present value (all participants)	Discounted payback (years)
	Benefit-cost ratio
	Net present value (average participant)

RATEPAYER IMPACT MEASURE

Primary	Secondary
Lifecycle revenue impact per Unit of energy (kWh or therm) or demand customer (kW)	Lifecycle revenue impact per unit
Net present value	Annual revenue impact (by year, per kWh, kW, therm, or customer)
	First-year revenue impact (per kWh, kW, therm, or customer)
	Benefit-cost ratio

TOTAL RESOURCE COST

Primary	Secondary
Net present value (NPV)	Benefit-cost ratio (BCR)
	Levelized cost (cents or dollars per unit of energy or demand)
	Societal (NPV, BCR)

PROGRAM ADMINISTRATOR COST

Primary	Secondary
Net present value	Benefit-cost ratio
	Levelized cost (cents or dollars per unit of energy or demand)

Rather than identify the precise requirements for reporting cost-effectiveness results for all types of proceedings or reports, the approach taken in this manual is to (a) specify the components of benefits and costs for each of the major tests, (b) identify the equations to be used to express the results in acceptable ways; and (c) indicate the relative value of the different units of measurement by designating primary and secondary test results for each test.

It should be noted that for some types of demand-side management programs, meaningful cost-effectiveness analyses cannot be performed using the tests in this manual. The following guidelines are offered to clarify the appropriated "match" of different types of programs and tests:

1. For generalized information programs (e.g. when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts.
2. For any program where more than one fuel is affected, the preferred unit of measurement for the RIM test is the lifecycle revenue impacts per customer, with gas and electric components reported separately for each fuel type and for combined fuels.
3. For load building programs, only the RIM tests are expected to be applied. The Total Resource Cost and Program Administrator Cost tests are intended to identify cost-effectiveness relative to other resource options. It is inappropriate to consider increased load as an alternative to other supply options.
4. Levelized costs may be appropriate as a supplementary indicator of cost per unit for electric conservation and load management programs relative to generation options and gas conservation programs relative to gas supply options, but the levelized cost test is not applicable to fuel substitution programs (since they combine gas and electric effects) or load building programs (which increase sales).

The delineation of the various means of expressing test results in Table 1 is not meant to discourage the continued development of additional variations for expressing cost-effectiveness. Of particular interest is the development of indicators of program cost effectiveness that can be used to assess the appropriateness of program scope (i.e. level of funding) for General Rate Case proceedings. Additional tests, if constructed from the net present worth in conformance with the equations designated in this manual, could prove useful as a means of developing methodologies that will address issues such as the optimal timing and scope of demand-side management programs in the context of overall resource planning.

Balancing the Tests

The tests set forth in this manual are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the Total Resource Cost Test, the Societal Test, and the Program Administrator Cost Test, must be compared not only to each other but also to the Ratepayer Impact Measure Test. This multi-perspective approach will require program administrators and state agencies to consider tradeoffs between the various tests. Issues related to the precise weighting of each test relative to other tests and to developing formulas for the definitive balancing of perspectives are outside the scope of this manual. The manual, however, does provide a brief description of the strengths and weaknesses of each test (Chapters 2, 3, 4, and 5) to assist users in qualitatively weighing test results.

Limitations: Externality Values and Policy Rules

The list of externalities identified in Chapter 4, page 27, in the discussion on the Societal version of the Total Resource Cost test is broad, illustrative and by no means exhaustive. Traditionally, implementing agencies have independently determined the details such as the components of the externalities, the externality values and the policy rules which specify the contexts in which the externalities and the tests are used

Externality values

The values for the externalities have not been provided in the manual. There are separate studies and methodologies to arrive at these values. There are also separate processes instituted by implementing agencies before such values can be adopted formally.

Policy Rules

The appropriate choice of inputs and input components vary by program area and project. For instance, low income programs are evaluated using a broader set of non-energy benefits that have not been provided in detail in this manual. Implementing agencies traditionally have had the discretion to use or to not use these inputs and/or benefits on a project- or program-specific basis. The policy rules that specify the contexts in which it is appropriate to use the externalities, their components, and tests mentioned in this manual are an integral part of any cost-effectiveness evaluation. These policy rules are not a part of this manual.

To summarize, the manual provides the methodology and the cost-benefit calculations only. The implementing agencies (such as the California Public Utilities Commission and the California Energy Commission) have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation.

Chapter 2

PARTICIPANT TEST

Definition

The Participants Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

Benefits and Costs

The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The reductions to the utility bill(s) should be calculated using the actual retail rates that would have been charged for the energy service provided (electric demand or energy or gas). Savings estimates should be based on gross savings, as opposed to net energy savings[1].

In the case of fuel substitution programs, benefits to the participant also include the avoided capital and operating costs of the equipment/appliance not chosen. For load building programs, participant benefits include an increase in productivity and/or service, which is presumably equal to or greater than the productivity/ service without participating. The inclusion of these benefits is not required for this test, but if they are included then the Societal test should also be performed.

The costs to a customer of program participation are all out of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s). The out-of-pocket expenses include the cost of any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs; any removal costs (less salvage value);

[1] Gross energy savings are considered to be the savings in energy and demand seen by the participant at the meter. These are the appropriate program impacts to calculate bill reductions for the Participant Test. Net savings are assumed to be the savings that are attributable to the program. That is, net savings are gross savings minus those changes in energy use and demand that would have happened even in the absence of the program. For fuel substitution and load building programs, gross-to-net considerations account for the impacts that would have occurred in the absence of the program.

and the value of the customer's time in arranging for the installation of the measure, if significant.

How the Results Can be Expressed

The results of this test can be expressed in four ways: through a net present value per average participant, a net present value for the total program, a benefit-cost ratio or discounted payback. The primary means of expressing test results is net present value for the total program; discounted payback, benefit-cost ratio, and per participant net present value are secondary tests.

The discounted payback is the number of years it takes until the cumulative discounted benefits equal or exceed the cumulative discounted costs. The shorter the discounted payback, the more attractive or beneficial the program is to the participants. Although "payback period" is often defined as undiscounted in the textbooks, a discounted payback period is used here to approximate more closely the consumer's perception of future benefits and costs.[2]

Net present value (NPVp) gives the net dollar benefit of the program to an average participant or to all participants discounted over some specified time period. A net present value above zero indicates that the program is beneficial to the participants under this test.

The benefit-cost ratio (BCRp) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. The benefit-cost ratio gives a measure of a rough rate of return for the program to the participants and is also an indication of risk. A benefit-cost ratio above one indicates a beneficial program.

[2] It should be noted that if a demand-side program is beneficial to its participants (NPVp $\geq$ 0 and BCRp $\geq$ 1.0) using a particular discount rate, the program has an internal rate of return (IRR) of at least the value of the discount rate.

Strengths of the Participant Test

The Participants Test gives a good "first cut" of the benefit or desirability of the program to customers. This information is especially useful for voluntary programs as an indication of potential participation rates.

For programs that involve a utility incentive, the Participant Test can be used for program design considerations such as the minimum incentive level, whether incentives are really needed to induce participation, and whether changes in incentive levels will induce the desired amount of participation.

These test results can be useful for program penetration analyses and developing program participation goals, which will minimize adverse ratepayer impacts and maximize benefits.

For fuel substitution programs, the Participant Test can be used to determine whether program participation (i.e. choosing one fuel over another) will be in the long-run best interest of the customer. The primary means of establishing such assurances is the net present value, which looks at the costs and benefits of the fuel choice over the life of the equipment.

Weaknesses of the Participant Test

None of the Participant Test results (discounted payback, net present value, or benefit-cost ratio) accurately capture the complexities and diversity of customer decision-making processes for demand-side management investments. Until or unless more is known about customer attitudes and behavior, interpretations of Participant Test results continue to require considerable judgment. Participant Test results play only a supportive role in any assessment of conservation and load management programs as alternatives to supply projects.

Formulae

The following are the formulas for discounted payback, the net present value (NPVp) and the benefit-cost ratio (BCRp) for the Participant Test.

$$NPV_P = Bp - Cp$$

$$NPV_{avp} = (Bp - Cp) / P$$

$$BCRp = Bp / Cp$$

$$DPp = \text{Min } j \text{ such that } Bj \geq Cj$$

Where:

NPV_p = Net present value to all participants

NPV_{avp} = Net present value to the average participant

BCR_p = Benefit-cost ratio to participants

DP_p = Discounted payback in years

Bp = NPV of benefit to participants

Cp = NPV of costs to participants

Bj = Cumulative benefits to participants in year j

Cj = Cumulative costs to participants in year j

P = Number of program participants

J = First year in which cumulative benefits are cumulative costs.

d = interest rate (discount)

The Benefit (Bp) and Cost (Cp) terms are further defined as follows:

$$Bp = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1 + d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1 + d)^{t-1}}$$

Where:

BR_t = Bill reductions in year t

BI_t = Bill increases in year t

TC_t = Tax credits in year t

INC_t = Incentives paid to the participant by the sponsoring utility in year t[3]

PC_t = Participant costs in year t to include:

o Initial capital costs, including sales tax[4]

[3] Some difference of opinion exists as to what should be called an incentive. The term can be interpreted broadly to include almost anything. Direct rebates, interest payment subsidies, and even energy audits can be called incentives. Operationally, it is necessary to restrict the term to include only dollar benefits such as rebates or rate incentives (monthly bill credits). Information and services such as audits are not considered incentives for the purposes of these tests. If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate must be included in the PC_t term

[4] 1f money is borrowed by the customer to cover this cost, it may not be necessary to calculate the annual mortgage and discount this amount if the present worth of the mortgage payments equals the initial cost. This occurs when the discount rate used is equal to the interest rate of the mortgage. If the two rates differ (e.g. a loan offered by the utility), then the stream of mortgage payments should be discounted by the discount rate chosen.

- o Ongoing operation and maintenance costs include fuel cost
- o Removal costs, less salvage value
- o Value of the customer's time in arranging for installation, if significant

PAC_{at} = Participant avoided costs in year t for alternate fuel devices (costs of devices not chosen)

Ab_{at} = Avoided bill from alternate fuel in year t

The first summation in the Bp equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used for Bp.

Note that in most cases, the customer bill impact terms (BRt, BIt, and AB_{at}) are further determined by costing period to reflect load impacts and/or rate schedules, which vary substantially by time of day and season. The formulas for these variables are as follows:

$$BR_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC{:}E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC{:}D_{it} \times K_{it}) + OBR_t$$

AB_{at} = (Use BRt formula, but with rates and costing periods appropriate for the alternate fuel utility)

$$BI_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC{:}E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC{:}D_{it} \times (K_{it} - 1)) + OBI_t$$

where

ΔEG_{it} Reduction in gross energy use in costing period i in year t

ΔDG_{it} Reduction in gross billing demand in costing period i in year t

$AC{:}E_{it}$ = Rate charged for energy in costing period i in year t

$AC{:}D_{it}$ = Rate charged for demand in costing period i in year t

K_{it} 1 when ΔEG_{it} or ΔDG_{it} is positive (a reduction) in costing period i in year t, and zero otherwise

OBR_t Other bill reductions or avoided bill payments (e.g.

customer charges, standby rates).

OBI_t Other bill increases (i.e. customer charges, standby rates).

I = Number of periods of participant’s participation

In load management programs such as TOU rates and air-conditioning cycling, there are often no direct customer hardware costs. However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs.

If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period.

THE RATEPAYER IMPACT MEASURE TEST[5]

Definition

The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

Benefits and Costs

The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased. The avoided supply costs are a reduction in total costs or revenue requirements and are included for both fuels for a fuel substitution program. The increase in revenues are also included for both fuels for fuel substitution programs. Both the reductions in supply costs and the revenue increases should be calculated using net energy savings.

The costs for this test are the program costs incurred by the utility, *and/or other entities incurring costs and creating or administering the program,* the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). The decreases in revenues and the increases in the supply costs should be calculated for both fuels for fuel substitution programs using net savings.

[5] The Ratepayer Impact Measure Test has previously been described under what was called the "Non-Participant Test." The Non-Participant Test has also been called the "Impact on Rate Levels Test."

How the Results Can be Expressed

The results of this test can be presented in several forms: the lifecycle revenue impact (cents or dollars) per kWh, kW, therm, or customer; annual or first-year revenue impacts (cents or dollars per kWh, kW, therms, or customer); benefit-cost ratio; and net present value. The primary units of measurement are the lifecycle revenue impact, expressed as the change in rates (cents per kWh for electric energy, dollars per kW for electric capacity, cents per therm for natural gas) and the net present value. Secondary test results are the lifecycle revenue impact per customer, first-year and annual revenue impacts, and the benefit-cost ratio. LRI_{RIM} values for programs affecting electricity and gas should be calculated for each fuel individually (cents per kWh or dollars per kW and cents per therm) and on a combined gas and electric basis (cents per customer).

The lifecycle revenue impact (LRI) is the one-time change in rates or the bill change over the life of the program needed to bring total revenues in line with revenue requirements over the life of the program. The rate increase or decrease is expected to be put into effect in the first year of the program. Any successive rate changes such as for cost escalation are made from there. The first-year revenue impact (FRI) is the change in rates in the first year of the program or the bill change needed to get total revenues to match revenue requirements only for that year. The annual revenue impact (ARI) is the series of differences between revenues and revenue requirements in each year of the program. This series shows the cumulative rate change or bill change in a year needed to match revenues to revenue requirements. Thus, the ARIRIM for year six per kWh is the estimate of the difference between present rates and the rate that would be in effect in year six due to the program. For results expressed as lifecycle, annual, or first-year revenue impacts, negative results indicate favorable effects on the bills of ratepayers or reductions in rates. Positive test result values indicate adverse bill impacts or rate increases.

Net present value (NPV_{RIM}) gives the discounted dollar net benefit of the program from the perspective of rate levels or bills over some specified time period. A net present value above zero indicates that the program will benefit (lower) rates and bills.

The benefit-cost ratio (BCR RIM) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. A benefit-cost ratio above one indicates that the program will lower rates and bills.

Strengths of the Ratepayer Impact Measure (RIM) Test

In contrast to most supply options, demand-side management programs cause a direct shift in revenues. Under many conditions, revenues lost from DSM programs have to be made up by ratepayers. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits associated with the program.

An additional strength of the RIM test is that the test can be used for all demand-side management programs (conservation, load management, fuel substitution, and load building). This makes the RIM test particularly useful for comparing impacts among demand-side management options.

Some of the units of measurement for the RIM test are of greater value than others, depending upon the purpose or type of evaluation. The lifecycle revenue impact per customer is the most useful unit of measurement when comparing the merits of programs with highly variable scopes (e.g. funding levels) and when analyzing a wide range of programs that include both electric and natural gas impacts. Benefit-cost ratios can also be very useful for program design evaluations to identify the most attractive programs or program elements

If comparisons are being made between a program or group of conservation/load management programs and a specific resource project, lifecycle cost per unit of energy and annual and first-year net costs per unit of energy are the most useful way to express test results. Of course, this requires developing lifecycle, annual, and first-year revenue impact estimates for the supply-side project.

Weaknesses of the Ratepayer Impact Measure (RIM) Test

Results of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.

RIM test results are also sensitive to assumptions regarding the financing of program costs. Sensitivity analyses and interactive analyses that capture feedback effects between system changes, rate design options, and alternative means of financing generation and non-generation options can help overcome these limitations. However, these types of analyses may be difficult to implement.

An additional caution must be exercised in using the RIM test to evaluate a fuel substitution program with multiple end use efficiency options. For example, under conditions where marginal costs are less than average costs, a program that promotes an inefficient appliance may give a more favorable test result than a program that promotes an efficient appliance. Though the results of the RIM test accurately reflect rate impacts, the implications for long-term conservation efforts need to be considered.

Formulae: The formulae for the lifecycle revenue impact (LRI RIM)' net present value (NPV RIM) , benefit-cost ratio (BCR RIM)' the first-year revenue impacts and annual revenue impacts are presented below:

$LRI_{RIM} = (C_{RIM} - B_{RIM}) / E$

$FRI_{RIM} = (C_{RIM} - B_{RIM}) / E$ for t = I

$ARI_{RIMt} = FRI_{RIM}$ for t = I

$= (C_{RIMt} - B_{RIMt})/E_t$ for t=2, ... ,N

$NPV_{RIM} = B_{RIM} - C_{RIM}$

$BCR_{RIM} = B_{RIM}/C_{RIM}$ where:

LRI_{RIM} = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW) (the one-time change in rates) or per customer (the change in customer bills over the life of the program). (Note: An appropriate choice of kWh, therm, kW, and customer should be made)

FRI_{RIM} = First-year revenue impact of the program per unit of energy, demand, or per customer.

ARI_{RIM} = Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. (Note: The terms in the ARI formula are not discounted; thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts <u>does not</u> equal the LRI RIM')

NPV_{RIM} = Net present value levels

BCR_{RIM} = Benefit-cost ratio for rate levels

B_{RIM} = Benefits to rate levels or customer bills
C_{RIM} = Costs to rate levels or customer bills
E = Discounted stream of system energy sales (kWh or therms) or demand sales (kW) or first-year customers. (See Appendix D for a description of the derivation and use of this term in the LRI_{RIM} test.)

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Where

UAC_t = Utility avoided supply costs in year t
UIC_t = Utility increased supply costs in year t
RG_t = Revenue gain from increased sales in year t
RL_t = Revenue loss from reduced sales in year t
PRC_t = Program Administrator program costs in year t
E_t = System sales in kWh, kW or therms in year t or first year customers
UAC_{at} = Utility avoided supply costs for the alternate fuel in year t
RL_{at} = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

For fuel substitution programs, the first term in the B RIM and C RIM equations represents the sponsoring utility (electric or gas), and the second term represents the alternate utility. The RIM test should be calculated separately for electric and gas and combined electric and gas.

The utility avoided cost terms (UAC_t, UIC_t, and UAC_{at}) are further determined by costing period to reflect time-variant costs of supply:

$$UAC_t \quad \sum_{i=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times (K_{it})) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times K_{it})$$

UAC_{at} = (Use UACt formula, but with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UIC_t = \sum_{i=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times (K_{it} - 1))$$

Where:

[Only terms not previously defined are included here.]
ΔEN_{it} = Reduction in net energy use in costing period i in year t
ΔDN_{it} = Reduction in net demand in costing period i in year t
$MC{:}E_{it}$ = Marginal cost of energy in costing period i in year t
$MC{:}D_{it}$ = Marginal cost of demand in costing period i in year t

The revenue impact terms (RG_t, RL_t, and RL_{at}) are parallel to the bill impact terms in the Participant Test. The terms are calculated exactly the same way with the exception that the net impacts are used rather than gross impacts. If a net-to-gross ratio is used to differentiate gross savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

$RG_t = BI_t$ * (net-to-gross ratio)

$RL_t = BR_t$ * (net-to-gross ratio)

$RL_{at} = AB_{at}$ * (net-to-gross ratio)

Chapter 4

TOTAL RESOURCE COST TEST[6]

Definition

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The test is applicable to conservation, load management, and fuel substitution programs. For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric).

A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g. environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

Benefits and Costs: This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost Test are the avoided supply costs--the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost--for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy-using equipment not chosen by the program participant.

[6] This test was previously called the All Ratepayers Test

The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test. For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program.

How the Results Can be Expressed

The results of the Total Resource Cost Test can be expressed in several forms: as a net present value, a benefit-cost ratio, or as a levelized cost. The net present value is the primary unit of measurement for this test. Secondary means of expressing TRC test results are a benefit-cost ratio and levelized costs. The Societal Test--expressed in terms of net present value, a benefit-cost ratio, or levelized costs--is also considered a secondary means of expressing results. Levelized costs as a unit of measurement are inapplicable for fuel substitution programs, since these programs represent the net change of alternative fuels which are measured in different physical units (e.g. kWh or therms). Levelized costs are also not applicable for load building programs.

Net present value (NPV_{TRC}) is the discounted value of the net benefits to this test over a specified period of time. NPV_{TRC} is a measure of the change in the total resource costs due to the program. A net present value above zero indicates that the program is a less expensive resource than the supply option upon which the marginal costs are based.

The benefit-cost ratio (BCR_{TRC}) is the ratio of the discounted total benefits of the program to the discounted total costs over some specified time period. It gives an indication of the rate of return of this program to the utility and its ratepayers. A benefit cost ratio above one indicates that the program is beneficial to the utility and its ratepayers on a total resource cost basis.

The levelized cost is a measure of the total costs of the program in a form that is sometimes used to estimate costs of utility owned supply additions. It presents the total costs of the program to the utility and its ratepayers on a per kilowatt, per kilowatt-hour, or per therm basis levelized over the life of the program.

The Societal Test is structurally similar to the Total Resource Cost Test. It goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Test utilizes essentially the same input variables as the TRC Test, but they are defined with a broader societal point of view. More specifically, the Societal Test differs from the TRC Test in at least one of five ways. First, the Societal Test may use higher marginal costs than the TRC test if a utility faces marginal costs that are lower than other utilities in the state or than its out-of-state suppliers. Marginal costs used in the Societal Test would reflect the cost to society of the more expensive alternative resources. Second, tax credits are treated as a transfer payment in the Societal Test, and thus are left out. Third, in the case of capital expenditures, interest payments are considered a transfer payment since society actually expends the resources in the first year. Therefore, capital costs enter the calculations in the year in which they occur. Fourth, a societal discount rate should be used[7]. Finally, Marginal costs used in the Societal Test would also contain externality costs of power generation not captured by the market system. An illustrative and by no means exhaustive list of 'externalities and their components' is given below (Refer to the Limitations section for elaboration.) These values are also referred to as 'adders' designed to capture or internalize such externalities. The list of potential adders would include for example:

1. The benefit of avoided environmental damage: The CPUC policy specifies two 'adders' to internalize environmental externalities, one for electricity use and one for natural gas use. Both are statewide average values. These adders are intended to help distinguish between cost-effective and non cost-effective energy-efficiency programs. They apply to an average supply mix and would not be useful in distinguishing among competing supply options. The CPUC electricity environmental adder is intended to account for the environmental damage from air pollutant emissions from power plants. The CPUC-adopted adder is intended to cover the human and material damage from sulfur oxides (SOX), nitrogen oxides (NOX), volatile organic compounds (VOC, sometimes called reactive organic gases or ROG), particulate matter at or below 10 micron diameter (PM10), and carbon. The adder for natural gas is intended to account for air pollutant emissions from the direct combustion of the gas. In the CPUC policy guidance, the adders are included in the tabulation of the benefits of energy efficiency programs. They represent reduced environmental damage from displaced electricity generation and avoided gas combustion. The environmental damage is the result of the net change in pollutant

[7] Many economists have pointed out that use of a market discount rate in social cost-benefit analysis undervalues the interests of future generations. Yet if a market discount rate is not used, comparisons with alternative investments are difficult to make.

emissions in the air basins, or regions, in which there is an impact. This change is the result of direct changes in powerplant or natural gas combustion emission resulting from the efficiency measures, and changes in emissions from other sources, that result from those direct changes in emissions.

2. The benefit of avoided transmission and distribution costs – energy efficiency measures that reduce the growth in peak demand would decrease the required rate of expansion to the transmission and distribution network, eliminating costs of constructing and maintaining new or upgraded lines.
3. The benefit of avoided generation costs – energy efficiency measures reduce consumption and hence avoid the need for generation. This would include avoided energy costs, capacity costs and T&D line
4. The benefit of increased system reliability: The reductions in demand and peak loads from customers opting for self generation, provide reliability benefits to the distribution system in the forms of:
   a. Avoided costs of supply disruptions
   b. benefits to the economy of damage and control costs avoided by customers and industries in the digital economy that need greater than 99.9 level of reliable electricity service from the central grid
   c. marginally decreased System Operator’s costs to maintain a percentage reserve of electricity supply above the instantaneous demand
   d. benefits to customers and the public of avoiding blackouts.
5. Non-energy benefits: Non-energy benefits might include a range of program-specific benefits such as saved water in energy-efficient washing machines or self generation units, reduced waste streams from an energy-efficient industrial process, etc.
6. Non-energy benefits for low income programs: The low income programs are social programs which have a separate list of benefits included in what is known as the ‘low income public purpose test’. This test and the sepcific benefits associated with this test are outside the scope of this manual.
7. Benefits of fuel diversity include considerations of the risks of supply disruption, the effects of price volatility, and the avoided costs of risk exposure and risk management

Strengths of the Total Resource Cost Test

The primary strength of the Total Resource Cost (TRC) test is its scope. The test includes total costs (participant plus program administrator) and also has the potential for capturing total benefits (avoided supply costs plus, in the case of the societal test variation, externalities). To the extent supply-side project evaluations also include total costs of generation and/or transmission, the TRC test provides a useful basis for comparing demand- and supply-side options.

Since this test treats incentives paid to participants and revenue shifts as transfer payments (from all ratepayers to participants through increased revenue requirements), the test results are unaffected by the uncertainties of projected average rates, thus reducing the uncertainty of the test results. Average rates and assumptions associated with how other options are financed (analogous to the issue of incentives for DSM programs) are also excluded from most supply-side cost determinations, again making the TRC test useful for comparing demand-side and supply-side options.

Weakness of the Total Resource Cost Test

The treatment of revenue shifts and incentive payments as transfer payments--identified previously as a strength--can also be considered a weakness of the TRC test. While it is true that most supply-side cost analyses do not include such financial issues, it can be argued that DSM programs should include these effects since, in contrast to most supply options, DSM programs do result in lost revenues.

In addition, the costs of the DSM "resource" in the TRC test are based on the total costs of the program, including costs incurred by the participant. Supply-side resource options are typically based only on the costs incurred by the power suppliers.

Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options.

Formulas

The formulas for the net present value (NPV_{TRC})' the benefit-cost ratio (BCR_{TRC} and levelized costs are presented below:

$NPV_{TRC} = B_{TRC} - C_{TRC}$

$BCR_{TRC} = B_{TRC} / C_{TRC}$

$LC_{TRC} = LCRC / IMP$

Where

NPV_{TRC} = Net present value of total costs of the resource

BCR_{TRC} = Benefit-cost ratio of total costs of the resource

LC_{TRC} = Levelized cost per unit of the total cost of the resource (cents per kWh for conservation programs; dollars per kW for load management programs)

B_{TRC} = Benefits of the program

C_{TRC} = Costs of the program

LCRC = Total resource costs used for levelizing

IMP = Total discounted load impacts of the program

PCN = Net Participant Costs

The B_{TRC} C_{TRC} LCRC, and IMP terms are further defined as follows:

$$BTRC = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$CTRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-l}}$$

$$LCRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-l}}$$

$$IMP = \sum_{t=1}^{N} \frac{[(\sum_{i=1}^{I} \Delta EN_{it}) \text{ or } (\Delta DN_{it} \text{ where i= peak period})]}{(1+d)^{t-l}}$$

[All terms have been defined in previous chapters.]

The first summation in the B TRC equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Chapter 5

PROGRAM ADMINISTRATOR COST TEST

Definition

The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

Benefits and Costs

The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand--the reduction in transmission, distribution, generation, and capacity valued at marginal costs--for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided supply costs for the energy-using equipment not chosen by the program participant only in the case of a combination utility where the utility provides both fuels.

The costs for the Program Administrator Cost Test are the program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). For fuel substitution programs, costs include the increased supply costs for the energy-using equipment chosen by the program participant only in the case of a combination utility, as above.

In this test, revenue shifts are viewed as a transfer payment between participants and all ratepayers. Though a shift in revenue affects rates, it does not affect revenue requirements, which are defined as the difference between the net marginal energy and capacity costs avoided and program costs. Thus, if $NPV_{pa} > 0$ and $NPV_{RIM} < 0$, the administrator’s overall total costs will decrease, although rates may increase because the sales base over which revenue requirements are spread has decreased.

How the Results Can be Expressed

The results of this test can be expressed either as a net present value, benefit-cost ratio, or levelized costs. The net present value is the primary test, and the benefit-cost ratio and levelized cost are the secondary tests.

Net present value (NPV_{pa}) is the benefit of the program minus the administrator's costs, discounted over some specified period of time. A net present value above zero indicates that this demand-side program would decrease costs to the administrator and the utility.

The benefit-cost ratio (BCR_{pa}) is the ratio of the total discounted benefits of a program to the total discounted costs for a specified time period. A benefit-cost ratio above one indicates that the program would benefit the combined administrator and utility's total cost situation.

The levelized cost is a measure of the costs of the program to the administrator in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the costs of the program to the administrator and the utility on a per kilowatt, per kilowatt-hour, or per therm basis levelized over the life of the program.

Strengths of the Program Administrator Cost Test

As with the Total Resource Cost test, the Program Administrator Cost test treats revenue shifts as transfer payments, meaning that test results are not complicated by the uncertainties associated with long-term rate projections and associated rate design assumptions. In contrast to the Total Resource Cost test, the Program Administrator Test includes only the portion of the participant's equipment costs that is paid for by the administrator in the form of an incentive. Therefore, for purposes of comparison, costs in the Program Administrator Cost Test are defined similarly to those supply-side projects which also do not include direct customer costs.

Weaknesses of the Program Administrator Cost Test

By defining device costs exclusively in terms of costs incurred by the administrator, the Program Administrator Cost test results reflect only a portion of the full costs of the resource.

The Program Administrator Cost Test shares two limitations noted previously for the Total Resource Cost test: (1) by treating revenue shifts as transfer payments, the rate impacts are not captured, and (2) the test cannot be used to evaluate load building programs.

Formulas

The formulas for the net present value, the benefit-cost ratio and levelized cost are presented below:

$NPV_{pa} = B_{pa} - C_{pa}$

$BCR_{pa} = B_{pa}/C_{pa}$

$LC_{pa} = LCpa/ IMP$

Where

NPV_{pa}	Net present value of Program Administrator costs
BCR_{pa}	Benefit-cost ratio of Program Administrator costs
LC_{pa}	Levelized cost per unit of Program Administrator cost of the resource
B_{pa}	Benefits of the program
C_{pa}	Costs of the program
LCpc	Total Program Administrator costs used for levelizing

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(l+d)^{t-1}} + \sum_{t+1}^{N} \frac{UAC_{at}}{(l+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(l+d)^{t-1}}$$

$$LCpc = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(l+d)^{t-1}}$$

[All variables are defined in previous chapters.]

The first summation in the B_{pa} equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Appendix A.
INPUTS TO EQUATIONS AND DOCUMENTATION

A comprehensive review of procedures and sources for developing inputs is beyond the scope of this manual. It would also be inappropriate to attempt a complete standardization of techniques and procedures for developing inputs for such parameters as load impacts, marginal costs, or average rates. Nevertheless, a series of guidelines can help to establish acceptable procedures and improve the chances of obtaining reasonable levels of consistent and meaningful cost-effectiveness results. The following "rules" should be viewed as appropriate guidelines for developing the primary inputs for the cost-effectiveness equations contained in this manual:

1. In the past, Marginal costs for electricity were based on production cost model simulations that clearly identify key assumptions and characteristics of the existing generation system as well as the timing and nature of any generation additions and/or power purchase agreements in the future. With a deregulated market for wholesale electricity, marginal costs for electric generation energy should be based on forecast market prices, which are derived from recent transactions in California energy markets. Such transactions could include spot market purchases as well as longer term bilateral contracts and the marginal costs should be estimated based on components for energy as well as demand and/or capacity costs as is typical for these contracts.
2. In the case of submittals in conjunction with a utility rate proceeding, average rates used in DSM program cost-effectiveness evaluations should be based on proposed rates. Otherwise, average rates should be based on current rate schedules. Evaluations based on alternative rate designs are encouraged.
3. Time-differentiated inputs for electric marginal energy and capacity costs, average energy rates, and demand charges, and electric load impacts should be used for (a) load management programs, (b) any conservation program that involves a financial incentive to the customer, and (c) any Fuel Substitution or Load Building program. Costing periods used should include, at a minimum, summer and winter, on-, and off-peak; further disaggregation is encouraged.
4. When program participation includes customers with different rate schedules, the average rate inputs should represent an average weighted

by the estimated mix of participation or impacts. For General Rate Case proceedings it is likely that each major rate class within each program will be considered as program elements requiring separate cost-effectiveness analyses for each measure and each rate class within each program.

5. Program administration cost estimates used in program cost-effectiveness analyses should exclude costs associated with the measurement and evaluation of program impacts unless the costs are a necessary component to administer the program.
6. For DSM programs or program elements that reduce electricity and natural gas consumption, costs and benefits from both fuels should be included.
7. The development and treatment of load impact estimates should distinguish between gross (i.e. impacts expected from the installation of a particular device, measure, appliance) and net (impacts adjusted to account for what would have happened anyway, and therefore not attributable to the program). Load impacts for the Participants test should be based on gross, whereas for all other tests the use of net is appropriate. Gross and net program impact considerations should be applied to all types of demand-side management programs, although in some instances there may be no difference between gross and net.
8. The use of sensitivity analysis, i.e. the calculation of cost-effectiveness test results using alternative input assumptions, is encouraged, particularly for the following programs: new programs, programs for which authorization to substantially change direction is being sought (e.g. termination, significant expansion), major programs which show marginal cost-effectiveness and/or particular sensitivity to highly uncertain input(s).

The use of many of these guidelines is illustrated with examples of program cost effectiveness contained in Appendix B.

Appendix B.
SUMMARY OF EQUATIONS AND GLOSSARY OF SYMBOLS

I. Basic Equations

Participant Test

$NPV_P = B_P - C_P$

$NPV_{avp} = (B_P - C_P) / P$

$BCR_P = B_P / C_P$

$DP_P = \min_j$ such that $B_j > C_j$

Ratepayer Impact Measure Test

$LRI_{RIM} = (C_{RIM} - B_{RIM}) / E$

$FRI_{RIM} = (C_{RIM} - B_{RIM}) / E$ for $t = 1$

$ARI_{RIMt} = FRI_{RIM}$ for $t = 1$

$= (C_{RIMt} - B_{RIMt}) / E_t$ for $t=2,...,N$

$NPV_{RIM} = B_{RIM} - C_{RIM}$

$BCR_{RIM} = B_{RIM} / C_{RIM}$

Total Resource Cost Test

$NPV_{TRC} = B_{TRC} - C_{TRC}$

$BCR_{TRC} = B_{TRC} / C_{TRC}$

$LC_{TRC} = LCRC / IMP$

Program Administrator Cost Test

$NPV_{pa} = B_{pa} - C_{pa}$

$BCR_{pa} = B_{pa} / C_{pa}$

$LC_{pa} = LC_{pa} / IMP$

II. Benefits and Costs

Participant Test

$$Bp = \sum_{t=l}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=l}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$Cp = \sum_{t=l}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Rategayer Impact Measure Test

$$B_{RIM} = \sum_{t=l}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=l}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=l}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=l}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=l}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Total Resource Cost Test

$$B_{TRC} = \sum_{t=l}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=l}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=l}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$L_{TRC} = \sum_{t=l}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=l}^{n} \left[\left(\sum_{i=l}^{n} \Delta EN_{it} \right) \text{ or } \left(\Delta DN_{it} \text{ where I = peak period} \right) \right]}{(1+d)^{t-1}}$$

Program Administrator Cost Test

$$B_{pa} = \sum_{t=l}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=l}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=l}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCPA = \sum_{t=l}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

III. **Glossary of Symbols**

AB_{at} = Avoided bill reductions on bill from alternate fuel in year t

$AC{:}D_{it}$ = Rate charged for demand in costing period i in year t

$AC{:}E_{it}$ = Rate charged for energy in costing period i in year t

ARI_{RIM} = Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. Note that the terms in the ARI formula are not discounted, thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRI_{RIM}*

BCR_p = Benefit-cost ratio to participants

BCR_{RIM} = Benefit-cost ratio for rate levels

BCR_{TRC} = Benefit-cost ratio of total costs of the resource

BCR_{pa} = Benefit-cost ratio of program administrator and utility costs

BI_t = Bill increases in year t

B_j = Cumulative benefits to participants in year j

B_p = Benefit to participants

B_{RIM} = Benefits to rate levels or customer bills

BR_t = Bill reductions in year t

B_{TRC} = Benefits of the program

B_{pa} = Benefits of the program

C_j = Cumulative costs to participants in year i

C_p = Costs to participants

C_{RIM} = Costs to rate levels or customer bills

C_{TRC} = Costs of the program

C_{pa} = Costs of the program

d = discount rate

ΔDG_{it} = Reduction in gross billing demand in costing period i in year t

ΔDN_{it} = Reduction in net demand in costing period i in year t

DP_p = Discounted payback in years

E = Discounted stream of system energy sales-(kWh or therms) or demand sales (kW) or first-year customers

ΔEG_{it} = Reduction in gross energy use in costing period i in year t

ΔEN_{it} = Reduction in net energy use in costing period i in year t

E_t = System sales in kWh, kW or therms in year t or first year customers

FRI_{RIM} = First-year revenue impact of the program per unit of energy, demand, or per customer.

IMP = Total discounted load impacts of the program

INC_t = Incentives paid to the participant by the sponsoring utility in year t

First year in which cumulative benefits are $\geq$ cumulative costs.

K_{it} = 1 when ΔEG_{it} or ΔDG_{it} is positive (a reduction) in costing period i in year t, and zero otherwise

LCRC = Total resource costs used for levelizing

LC_{TRC} = Levelized cost per unit of the total cost of the resource

LCPA = Total Program Administrator costs used for levelizing

LC_{pa} = Levelized cost per unit of program administrator cost of the resource

LRI_{RIM} = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW)--the one-time change in rates--or per customer--the change in customer bills over the life of the program.

$MC:D_{it}$ = Marginal cost of demand in costing period i in year t

$MC:E_{it}$ = Marginal cost of energy in costing period i in year t

NPV_{avp} = Net present value to the average participant

NPV_P = Net present value to all participants

NPV_{RIM} = Net present value levels

NPV_{TRC} = Net present value of total costs of the resource

NPV_{pa} = Net present value of program administrator costs

OBI_t = Other bill increases (i.e. customer charges, standby rates).

OBR_t = Other bill reductions or avoided bill payments (e.g. customer charges, standby rates).

P = Number of program participants

PAC_{at} = Participant avoided costs in year t for alternate fuel devices

PC_t = Participant costs in year t to include:

- o Initial capital costs, including sales tax
- o Ongoing operation and maintenance costs
- o Removal costs, less salvage value
- o Value of the customer's time in arranging for installation, if significant

PRC_t = Program Administrator program costs in year t

PCN = Net Participant Costs

RG_t = Revenue gain from increased sales in year t

RL_{at} = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

RL_t = Revenue loss from reduced sales in year t

TC_t = Tax credits in year t

UAC_{at} = Utility avoided supply costs for the alternate fuel in year t

UAC_t = Utility avoided supply costs in year t

PA_t = Program Administrator costs in year t

UIC_t = Utility increased supply costs in year t

Appendix C.

DERIVATION OF RIM LIFECYCLE REVENUE IMPACT FORMULA

Most of the formulas in the manual are either self explanatory or are explained in the text. This appendix provides additional explanation for a few specific areas where the algebra was considered to be too cumbersome to include in the text.

Rate Impact Measure

The Ratepayer Impact Measure lifecycle revenue impact test (LRI_{RIM}) is assumed to be the one-time increase or decrease in rates that will re-equate the present valued stream of revenues and stream of revenue requirements over the life of the program.

Rates are designed to equate long-term revenues with long-term costs or revenue requirements. The implementation of a demand-side program can disrupt this equality by changing one of the assumptions upon which it is based: the sales forecast. Demand-side programs by definition change sales. This expected difference between the long-term revenues and revenue requirements is calculated in the NPV_{RIM} The amount which present valued revenues are below present valued revenue requirements equals $-NPV_{RIM}$

The LRI_{RIM} is the change in rates that creates a change in the revenue stream that, when present valued, equals the $-NPV_{RIM}$* If the utility raises (or lowers) its rates in the base year by the amount of the LRI_{RIM}' revenues over the term of the program will again equal revenue requirements. (The other assumed changes in rates, implied in the escalation of the rate values, are considered to remain in effect.)

Thus, the formula for the LRI_{RIM} is derived from the following equality where the present value change in revenues due to the rate increase or decrease is set equal to the $-NPV_{RIM}$ or the revenue change caused by the program.

$$-NPV_{RIM} = \sum_{t=1}^{N} \frac{LRI_{RIM} \times Et}{(1+d)^{t-1}}$$

Since the LRI_{RIM} term does not have a time subscript, it can be removed from the summation, and the formula is then:

$$-NPV_{RIM} = LRI_{RIM} \times \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Rearranging terms, we then get:

$$LRI_{RIM} = -NPV_{RIM} \Big/ \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Thus,

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$