

Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act, R.S.N.S., 1989, c. 380, as amended*

- and -

IN THE MATTER OF an Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

Responses to Information Requests:

Sempra Atlantic Gas Inc. - Questions 1 to 14

DATED: December 31, 1999

1999

NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-1: Application by Nova Scotia Power Inc. ("NSPI") for a Load Retention
Rate.

NSPI proposes a Load Retention Rate to retain existing customers it
fears may otherwise be attracted to switch to natural gas.

- (1) Is NSPI currently planning any future expansion of its power
generation capability or does it otherwise foresee a need to
expand to meet future demand?
- (2) If the answer to (1) is "yes", provide details of what expansion
NSPI foresees.
- (3) If the answer to (1) is "yes", did NSPI, in determining there
would be a future need to expand power generation capability,
take into consideration the coming availability of natural gas
throughout Nova Scotia?
- (4) If the answer to (1) is "yes", how does NSPI purport to justify
planning for expanded power generation capacity with this
Application to reduce rates to retain present customers?

Response IR-1: (1) No. See response to UARB-IR-7 and UARB-IR-21.

 (2) See above.

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FROM: NSPI

Responses IR-1: (3) The forecast upon which the response to UARB-7 is predicated does
take into consideration the coming availability of natural gas.
Residential and commercial gas impacts have been included, but no
loss of large industrial load due to customer cogen projects has been
included.

(4) N/A.

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FROM: NSPI

Question IR-2: Proposed Load Retention Rate, Application by Nova Scotia Power Inc.

The proposed rate sets out certain circumstances that must exist before the rate would be granted. It includes a requirement that the "rate shall be available only to customers who are considering an alternative supply of at least 2000 KVA or 1800 KW"

- (1) How many customers does NSPI estimate have loads that could make them eligible for the proposed load retention rate?
- (2) Who are those customers?
- (3) What is the combined load of these customers?
- (4) What is the annual revenue generated for NSPI by that load?
- (5) What is the annual contribution by these customers toward NSPI's fixed costs?

- Responses IR-2:**
- (1) There are currently 61 customers with loads greater than 2MVA. (See response to UARB-IR-17) It is our expectation that not many of these customers will have alternate supply options.
 - (2) Information relating to specific customer loads is confidential.
 - (3) These customers currently consume approximately 3500 Gwh annually, as shown in response UARB-IR-17.
 - (4) The revenue received from these customers is approximately \$169 million as shown in response UARB-IR-17.

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FROM: NSPI

Responses IR-2: (5) These customers contribute an estimated \$68 million in fixed cost
contribution, as stated on page 8 of Mr. Whalen's evidence.

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TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-3: Evidence of Christopher Huskilson, Application of Nova Scotia Power Inc., Page 2.

Mr. Huskilson states "For some of our customers, preliminary studies indicate . . . " that some customers may leave NSPI's system for an alternate energy supply.

- (1) Were these "preliminary studies" done by NSPI or by individual customers?
- (2) To the extent such "studies" are in the possession of NSPI, produce them.
- (3) For any such "study" not in NSPI's possession, provide such details of that study as are known to NSPI.

- Responses IR-3:**
- (1) See response to UARB-IR-12.
 - (2) NSPI is not in possession of these studies.
 - (3) See response to UARB-IR-12.

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TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-4: Evidence of Christopher Huskilson, Application of Nova Scotia Power
Inc., Page 5.

Mr. Huskilson refers to the evidence of UARB witness, John Chamberlain, in an earlier case.

- (1) Produce a copy of Mr. Chamberlain's complete evidence as given in that earlier case, including his direct evidence, cross-examination, redirect and any exhibits referred to in his testimony.

Responses IR-4: (1) The requested information is attached.

DATE FILED: December 31, 1999

IN THE MATTER OF THE PUBLIC UTILITIES ACT

R.S.N.S., 1989, c. 380, as amended

- and -

IN THE MATTER OF an Application of

Nova Scotia Power Incorporated

for approval of certain revisions to

its Rates, Charges, and Regulations

Prepared Testimony of John H. Chamberlin

on behalf of

Nova Scotia Utility and Review Board

December 5, 1995

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**NOVA SCOTIA UTILITY
AND REVIEW BOARD**

I. INTRODUCTION

In 1993 I was retained by the Nova Scotia Utility and Review Board (the Board) to provide testimony on cost of service and pricing issues related to Nova Scotia Power, Inc. (NSPI). In that testimony, which was filed on April 8, 1993, as part of the Generic Hearing, I discussed the beneficial aspects of time-of-use (TOU) rates and urged NSPI to consider adopting them. I also made several recommendations with regard to specific aspects of NSPI's proposed rate designs.

Since that time, NSPI has filed additional rate design materials and a study of NSPI's rate proposals was completed by consultant Douglas Bowman at the request of the Board. On August 17, 1995, NSPI filed an application for an overall rate increase of 3% and various other changes to current rate designs. In light of this new evidence, the Board asked me to review and comment on my previous recommendations. I was also asked to provide some general information on rate design issues and to comment on the implications for electricity pricing of recent industry restructuring initiatives.

My testimony is divided in to several sections. In Sections II and III, I address my previous recommendations; in Section IV, I discuss general rate design considerations; in Section V, I briefly outline the results of Hydro-Québec's recent TOU pilot, and in Section VI, I discuss growing competition in the electric utility industry.

1 The materials I reviewed as part of my assignment included:

- 2
- 3 ▪ Direct evidence and corresponding exhibits of A. E. Dominie, dated
- 4 August 17, 1995.
- 5 ▪ Direct evidence of T. F. MacDonald, G. K. Oickle, and Larry B.
- 6 Brockman, all dated August 17, 1995.
- 7 ▪ NSPI's March 13, 1995 report entitled "Innovative Rates—Interim Report
- 8 IR-R2" (with the exception of Appendixes B and C).
- 9 ▪ "A Survey of Studies of Time-of-Use Price Elasticities" prepared by
- 10 Steven Globerman, March 27, 1994.
- 11 ▪ Responses to Information Requests: NSUARB to NSPI Question 1 to 75
- 12 (excluding confidential responses), dated October 12, 1995.
- 13 ▪ "Report to the Nova Scotia Utility and Review Board Regarding
- 14 information filed by: Nova Scotia Power Incorporated" by C. Douglas
- 15 Bowman of CSA Energy Consultants (Bowman Report).
- 16

17 My qualifications in the area of rate design are presented in my resume which is
18 attached as an appendix to this testimony.

19

20 II. TIME-OF-USE RATES

21

22 In my previous testimony I discussed the benefits of time-of-use (TOU) rates and
23 recommended that NSPI study their potential in its service territory. I continue to

1 believe that TOU rates are applicable in NSPI's situation and that rates can be
2 designed that will improve the efficiency of current rate structures.

3
4 As I stated in my previous testimony, the primary purpose of TOU rates is to
5 improve the extent to which rates reflect the cost of producing electricity. Most
6 utilities have costs that vary by time of day or time of year in a relatively predictable
7 fashion. Prices that reflect these variations allow customers to make more efficient
8 decisions about their electricity purchases. These decisions are more efficient because
9 consumers are able to compare the utility's costs during different times of the day
10 with the value they place on electricity in those same time periods.

11
12 Although TOU price differentials encourage customers to shift consumption to off-
13 peak hours, load shifting is not required to justify TOU rates. If reductions in on-peak
14 consumption *do* occur, it is because customers are not willing to pay for generation
15 once they know its true cost. Any reduction in on-peak usage simply reflects the
16 inefficiency of existing rate structures—which typically under-price on-peak energy
17 and over-price off-peak power. If no load shifting occurs, it simply means that
18 consumers place a high value on electricity and are willing to pay the cost of
19 producing electricity during on-peak hours.

20
21 While all the parties in this proceeding support TOU rates in concept, NSPI and Mr.
22 Bowman disagree on the extent to which NSPI should implement them. Mr. Bowman
23 recommends that TOU rates be offered to all customer classes on a voluntary basis by

1 the beginning of 1997. Different TOU rate levels would apply in winter and non-
2 winter seasons. For small usage domestic customers, winter energy rates would range
3 from 4.0 cents/kWhr for off-peak energy use to 22.2 cents/kWh for on-peak energy.

4
5 NSPI is proposing to offer an experimental TOU rate option to its Residential and
6 Small General customers sometime in 1997. For its other customers, NSPI would
7 offer a voluntary seasonal demand charge. According to Mr. Dominie's direct
8 evidence: "The Time-of-Day aspect for demand charges would be accomplished
9 through the use of the billing demand as it occurs in the peak period only." This
10 proposal is subject to NSPI's ability to recover lost revenues through a revenue
11 recovery mechanism.

12
13 I have several comments on these proposals, including:

- 14
- 15 ▪ The extent to which seasonal demand charges are a substitute for TOU
 - 16 rates;
 - 17 ▪ Lost revenue recovery mechanisms;
 - 18 ▪ Voluntary versus mandatory TOU rates;
 - 19 ▪ The need for TOU rate experiments;
 - 20 ▪ TOU rate structures and revenue reconciliation issues; and
 - 21 ▪ Implementation timelines.
- 22
23

Seasonal Demand Charges as Substitutes for TOU Rates

First, while seasonal demand charges would improve NSPI's rate structures, they are not substitutes for seasonal TOU rates. Under the seasonal demand charge approach, customers are charged based on their single highest load occurring during on-peak hours. Once a demand level has been reached, a customer has no incentive to keep subsequent consumption below that level. TOU rates on the other hand, provide a continuing incentive to keep demand low during on-peak periods. The hourly charges reflect both marginal energy and capacity costs, enabling customers to make efficient decisions—each hour—about their use of electricity.

Lost Revenue Recovery Mechanisms

Although lost revenue recovery mechanisms are usually associated with demand-side management programs, I support establishing temporary mechanisms for innovative rate designs. Most utilities use the general rate case process to introduce new rate options. Revenues are developed by estimating the number of customers that will choose a new rate option and how a rate structure will affect participant load profiles. This process works well, so long as the utility can reasonably predict customer response. When responses are difficult to gauge, utilities will be hesitant about pursuing new options that could place revenues in jeopardy, no matter how innovative and potentially worthwhile they may be.

1 Lost revenue recovery mechanisms eliminate the revenue-related risks associated with
2 marketing innovative rates. These mechanisms also protect customers if any
3 overcollections should occur. Once a rate program is underway and customer
4 response can be reasonably predicted, the mechanism can be discontinued, and the
5 rate class can be treated like any other.

6
7 The temporary approach differs from ERAM¹-type mechanisms where utilities are
8 kept whole for all shortfalls in revenues—no matter what the source. ERAM
9 proponents have long held that recovery systems encourage utilities to experiment
10 with innovative rates. Opponents, however, worry that ERAM's eliminate too much
11 risk and do not provide incentives for utilities to operate efficiently. A temporary lost
12 revenue mechanism targeted at specific rate designs strikes a balance between these
13 two views. It encourages implementation of new ideas, without dramatically changing
14 the overall ratemaking process.

15 16 **Voluntary versus Mandatory rates**

17
18 In my previous testimony, I discussed the issues surrounding voluntary versus
19 mandatory TOU rates but did not take a position. Bowman and NSPI both recommend
20 voluntary TOU rates and NSPI also recommends that its proposed seasonal demand
21 option be voluntary.

22
23

¹ERAM stands for Electricity Rate Adjustment Mechanism.

1 From an efficiency perspective, mandatory TOU rates are preferable because they
2 provide all customers—not just those who might benefit—with price signals that
3 reflect the cost of production. From a practical standpoint, however, voluntary rates
4 are much easier to implement as any additional metering costs are borne only by
5 “volunteers.”

6
7 I can support voluntary TOU rates, provided revenue shortfalls are made up by
8 customers that do not choose to participate in the rate. This approach makes the
9 existing inefficient block rate structure less appealing over time and attracts a larger
10 and larger share of the customer population to TOU rates. Over the long run the
11 effect is the same as having instituted a mandatory rate program.

12
13 To illustrate what I mean, keep in mind that TOU rates benefit customers that
14 consume most of their energy off-peak—which translates into a lower cost of service.
15 Under block rates, however, these “off-peak” customers subsidize other customers
16 within the rate class where the cost of service is greater than average. As “off-peak”
17 customers migrate to voluntary TOU rates, the average cost of serving the remaining
18 block-rate customers rises. This in turn makes TOU rates attractive to another group.
19 The process continues until almost all customers find it advantageous to move to TOU
20 rates. By using voluntary rates and applying revenue shortfalls to existing block rates,
21 utilities can gradually “move” all customers to more efficient rate schedules.

Pilot TOU Programs

Utilities do not need to conduct pilot programs before adopting voluntary TOU rates. In fact most have not. The primary purpose of TOU rates—to provide more efficient price signals—can be accomplished without studying how customers will respond. As noted earlier the load shifting that occurs is simply a result of the inefficiency of the current rate schedule.

This is not to say that TOU pilots are without value. They provide laboratories for testing different ways to market rates and they measure the amount of load shifting that can be expected to occur for a particular program. Load shifting information is valuable to utilities without lost revenue recovery mechanisms because it gives them greater confidence in their customer response estimates. Unfortunately, TOU pilots take time and involve considerable expense. Hydro-Québec, for example, spent over \$1 million (Cdn) on its recent residential TOU pilot. For this reason, most utilities have foregone formal reviews and relied instead on reviews of other utilities' experiences and predictive models of customer behavior.

TOU Rate Structures and Revenue Reconciliation

For price signals to be efficient, they must present a reasonably accurate picture of the utility's marginal costs. The challenge for TOU rate design involves providing efficient price signals while at the same time recovering embedded revenue

1 requirements. Unfortunately, these two objectives cannot be “balanced;” both must be
2 met for the TOU rate to serve its purpose.

3
4 In its Interim Report IR-R2, NSPI determined that marginal cost values would need to
5 be adjusted substantially to recover its embedded revenue requirements. “When
6 marginal costs are reconciled using an equi-proportional reconciliation procedure, the
7 resulting rates bear little resemblance to marginal costs. This raises serious questions
8 as to whether the resultant rates are likely to create more economic efficiency.”²

9 NSPI is concerned that the reconciliation process makes implementation of TOU rates
10 impractical.

11
12 Bowman evaluated four methods for reconciling revenues—the multiplier (equi-
13 proportional), adder, customer charge, and “default” methods. Of these, the customer
14 charge approach produces price signals that are most closely aligned with marginal
15 costs. On-peak and off-peak rates reflect marginal costs in each season; the revenue
16 shortfall remaining is collected through a large monthly customer charge. For the
17 small usage domestic class, customer charges would rise from \$8.21 to \$31.29 per
18 month.

19
20 Because Bowman fears customers would find large customer charges unacceptable, he
21 favors the “default” method, which sets rates equal to marginal costs during off-peak
22 periods and collects the remaining revenue requirement by increasing on-peak

23 ²“Innovative Rates—Interim Report IR-R2,” March 13, 1995, p. 6.

1 charges. While this approach provides an efficient off-peak price, it sacrifices on-peak
2 price signals and would cause customers to reduce consumption unnecessarily. For
3 residential customers, for example, on peak rates would rise to 22.2 cents/kWh as
4 compared to 13.4 cents/kWh under the customer charge method. Customers
5 evaluating the cost of electricity against the value of other possible options would be
6 given a false impression about the long-term impact of their usage.

7
8 While Bowman's concerns about large customer charges are not unfounded, a
9 voluntary TOU rate should mitigate the situation somewhat. Presumably, customers
10 could be made aware of the size of the customer charge before signing up. NSPI
11 could also use parallel billing to help customers understand their savings. Under
12 parallel billing, customers are given a comparison of their monthly bill under both the
13 TOU and standard rate schedules.

14
15 Rather than increasing the customer charge, NSPI could use a "block" method to
16 reconcile revenue requirements. In this approach, each on-peak and off-peak period is
17 divided into two consumption blocks, say, for example, 200 kWh and all usage over
18 200 kWh. The small size of the first block ensures that most customers have some
19 usage beyond 200 kWh. Prices in the tailblock are set equal to marginal costs and any
20 remaining revenue requirements are collected through the first block price. The rate
21 appears as an inverted block rate during on-peak hours and a declining block rate
22 during off-peak periods. However, the size of the first block ensures that most
23 customers receive only the marginal-cost-based rate as a price signal.

1 Bowman evaluates the cost-effectiveness of the four reconciliation methods he studied
2 by comparing potential energy and capacity savings with NSPI's avoided costs. He
3 finds the greatest bill savings and reductions in MW and MWh under the "default"
4 method. This is not surprising as the default method applies the highest on-peak prices
5 of any method and one can assume that customers will respond to higher prices by
6 cutting back usage. He finds the customer charge method not cost-effective for small
7 and medium-sized customers.

8
9 I disagree, however, with the application of this type of cost/benefit analyses to rate
10 design. The primary objective of TOU rates is to improve the efficiency of price
11 signals, not to serve as a demand-side management program. Efficiency cannot be
12 measured through price elasticities or load reductions. In fact, depending on the
13 circumstances, a more efficient price signal could result in greater electricity usage.

14
15 Even if NSPI's purpose for TOU rates was load reduction, NSPI's generic avoided
16 costs would not be an appropriate evaluation tool. NSPI's avoided costs are developed
17 assuming a 50 MW reduction in load across all hours of the year. This is clearly not
18 the load profile change one would expect from TOU rates. TOU rates improve system
19 load factors, which lead to operational efficiencies. These benefits are not captured in
20 generic avoided cost calculations.

Implementation Timelines

Mr. Dominie states on Page 5 of his direct evidence that NSPI would not plan to begin its experimental TOU rate until after its new customer information system is completed in 1997. While NSPI might be able to implement TOU rates a few months earlier, a separate TOU rate effort could possibly delay the new information system and would result in duplicate capability (See Response to IR No. 29).

NSPI's timetable does not appear unrealistic. Hydro-Québec took six months to modify the billing and customer information systems supporting its TOU pilot. And because the rate was experimental, Hydro-Québec was able to take certain short cuts that would not have been possible if the option had been offered system-wide. Given that no specific tariffs have yet been filed, it does not seem unreasonable to expect a one-year development period. Furthermore, from a marketing perspective it would probably not be appropriate to start a new TOU program during the high-cost winter months. Thus, March 1997 is probably the earliest that a TOU rate program might be launched in earnest.

III. SEASONAL RATES AND DECLINING BLOCK RATES FOR DOMESTIC CUSTOMERS

In my previous testimony I recommended that NSPI pursue seasonal rates (non-time differentiated) for all customer classes. With regard to NSPI's proposal to offer

1 declining block rates to domestic customers, I did not find enough information to
2 justify them for both the summer and winter. Nothing I have reviewed in connection
3 with this current case has changed my position on these issues.

4 5 Seasonal Rates

6
7 In 1993 I looked at NSPI's embedded cost of service study and found significant
8 differences between summer and winter costs. In the Interim IR-R2, NSPI reports a
9 seasonal differential in avoided costs for the year 1996, ranging from 7.0% to 88%
10 depending on the customer class. For the year 2005, the differentials widen to a range
11 of 25% to 233%.³ Both of these pieces of information lead me to conclude that
12 seasonal rates would be preferable, from an efficiency standpoint, to flat rates.

13
14 In the IR-R2 report, NSPI reconciled seasonal avoided costs to embedded revenue
15 requirements using the equi-proportional method. For some classes, notably
16 Residential and Small General customers, the reconciliation process produced very
17 high winter rates relative to existing tariffs. This undesirable result might be remedied
18 by using a different reconciliation procedure as described above.

19
20

³Ibid., pg. 47-56.

Domestic Declining Block Rates

With regard to declining block rates for domestic customers, my previous concerns related to information, or lack thereof, about the cost of serving large- versus small-use customers. Declining block rates are considered efficient when large-use customers consume a higher proportion of energy during off-peak periods than other customers in a class. These types of customers usually exhibit higher-than-average load factors which translate into lower costs of service.

Declining block rates are not efficient when large customer usage is weighted toward on-peak periods. From the limited data available to me during the generic hearing, it appeared that large customers had higher-than-average load factors in the winter but not in the summer. This evidence argued against applying a declining block rate structure year-round.

This issue was outside of the scope of the IR-R2 study and so was not addressed there. In my review of other recently filed information I have found no additional support for domestic declining block rates. Therefore, my conclusions on this proposal have not changed.

IV. GENERAL RATE DESIGN CONSIDERATIONS

I would now like to turn to rate design issues of a general nature that the Board has asked me to address.

Balancing Multiple Objectives

The degree to which a particular rate design promotes economic efficiency depends on the price component customers rely on to evaluate purchase decisions. If this price reflects a utility's marginal cost, customers can compare the cost of producing the additional kWh they are considering buying with the value they expect to receive.

Value depends on the uses customers have for electricity and the prices of alternative forms of energy that might be available to them.

While of principal importance, economic efficiency is not the only objective of rate design. Other objectives include rate stability, simplicity (or understandability), practicality, the need to collect adequate revenues, and public goals like assisting low-income customers. Combining these multiple purposes into one rate schedule requires judgement and while there are no general criteria for measuring success, some utilities and commissions develop guidelines or rules of thumb to help decision making. For example, utilities commonly place a cap on the maximum rate increase applied to any one class. The cap ensures that a 3% average rate increase does not become a 15% rate increase for a particular group of customers. Some commissions

1 also establish revenue-to-cost targets to limit the amount of cross subsidization
2 occurring between classes.

3
4 Because utilities provide a public service and in most cases, customers have no other
5 choice of electricity supplier, public reaction to rate changes is a major consideration.
6 Bowman rejected the customer charge method for reconciling TOU rates because he
7 feared customers would find large monthly fixed charges unacceptable. And indeed,
8 although the rate would be voluntary, a large increase in the customer charge could
9 make the rate difficult to market.

10
11 We know that consumers develop expectations about what products “should” cost.
12 These expectations (or reference prices) are based on past experience and on other
13 prices customers may have been exposed too. For example, most people could easily
14 spend 50 cents to buy a pack of gum. But, if gum usually sells for a quarter, it’s
15 likely that a doubling of price would dramatically lower sales. This happens because
16 purchase decisions are influenced not only by what customers are willing to pay but
17 by what customers think sellers should reasonably charge. The same logic holds true
18 for utilities. When the Bonneville Power Administration raised its rates in the early 90s
19 from 1.5 to roughly 2.0 cents per kWh, it was met with public outrage. From an
20 outsider’s point of view, BPA was continuing to offer extremely low-cost power. But
21 from the customers standpoint, BPA had raised rates by 33%.

1 Thus increasing customer charges by a large amount, or any rate component for that
2 matter, can present a practical constraint. In the case of TOU rates for NSPI, this
3 means that other creative ways need to be investigated for reconciling revenue
4 requirements or that some departure from the goal of economic efficiency must be
5 accepted. However, I would caution against departing too far from marginal costs
6 when developing innovative rate designs. Without a reasonably close link to marginal
7 costs (or some other specific goal), it is difficult to establish how a new rate might
8 improve upon existing tariffs.

10 **Short-Run versus Long-Run Marginal Costs**

12 I indicated that for utility rates to be considered efficient they must reflect marginal
13 costs. Marginal costs can be measured over either the short run or long run. For rate
14 design purposes, the choice depends on the length of the contract or “compact” a
15 utility has with its customers. For example, if a utility sells power on the spot market,
16 short-run marginal costs are appropriate because there is no obligation to serve and no
17 need to make resource investments on a customer’s behalf. If the utility expects to
18 continue supplying the customer far into the future, then long-run marginal costs are
19 appropriate.

21 Long-run marginal costs provide better price signals when consumers make energy
22 decisions that have long-term consequences. For example, customers purchasing new
23 homes must choose between electricity or oil or some other form of space heating.

1 Electric rates that reflect long-run marginal costs enable the consumer to make a more
2 rational choice from society's point of view. Long-run marginal costs are also
3 appropriate when comparing alternative utility investments such as demand-side
4 management programs that have long-lasting effects.

5
6 Short-run and long-run concepts are not related to numbers of years but to a utility's
7 ability to change its capital stock. Short-run approaches measure changes in operating
8 costs assuming a utility's capacity resources cannot be expanded to meet increases in
9 peak demand. Short-run marginal costs include as fuel costs, materials and supplies,
10 and variable operating and maintenance expenses. They also factor in the cost
11 consequences of decreases in reliability.

12
13 Long-run approaches assume that utilities can add new plants to meet increases in
14 load or delay investment in new resources if loads fall. Long-run marginal costs
15 include both operating costs and capital costs.

16 17 **Methods used to Estimate Marginal Generation Capacity Costs**

18
19 Marginal costs are composed of generation, transmission, distribution, and customer
20 costs. Marginal generation costs have two components—energy and capacity. The
21 energy component reflects the fuel and variable operating costs associated with
22 producing an additional kWh in a given time period. The capacity component varies
23 depending on the approach. Under the long-run method, the capacity component

1 measures the costs of building and maintaining new plants to meet increases in
2 demand. Under the short-run approach, the capacity component measures the costs
3 associated with the degradation in reliability that results from an increase in load.

4
5 Marginal transmission and distribution costs measure the cost of increasing intertie
6 and distribution capacity as peak loads grow. Marginal customer costs include
7 administrative expenses and the cost of facilities needed to connect new customers to
8 the distribution grid. Almost all of the methods used to estimate these items rely on
9 long-run concepts, although with the advent of open access transmission wheeling,
10 utilities are beginning to explore short-run approaches.

11
12 Approaches to estimating the capacity component of marginal generation costs include
13 the:

- 14
- 15 ▪ Peaker method
- 16 ▪ Value-of-service method
- 17 ▪ System planning methods
- 18

19 The first two are usually considered short-run methods;⁴ system planning methods
20 are based on long-run principals.

21 ⁴Technically, the peaker method does not fit the short run definition because it assumes new capacity
22 can be constructed. The method was originally developed as a proxy for short-term marginal capacity
23 costs—where the question at hand was “What would customers be willing to pay to avoid an outage.”
24 Since the cost of a peaking unit represents the most customers would ever need to pay, it has come to
25 represent the upper limit for short-run marginal capacity costs.

1 The peaker method calculates marginal capacity costs using a utility's least-cost
2 capacity option—usually a combustion turbine or a pure capacity contract from
3 another utility. The method is based on the idea that power plants serve two
4 functions—supplying reliability and generating electricity—and that for the purposes of
5 marginal capacity cost calculations only the reliability function is relevant.

6
7 The peaker method poses the question: What resource would a utility choose if it
8 were interested solely in maintaining reliability? The answer is: the utility would
9 select the option requiring the lowest capital investment. Usually, this option is a
10 “peaking” unit such as a combustion turbine.

11
12 The method assumes that additional demand automatically increases the need for new
13 capacity. This assumption is valid only when a utility's actual reserve margin equals
14 its target. To compensate for this flaw, some jurisdictions allow utilities to adjust the
15 results downward whenever a utility has excess capacity.

16
17 The value-of-service (VOS) method calculates marginal generation capacity costs by
18 measuring the cost of outages or, alternatively, the amount consumers would be
19 willing to pay to avoid losing power. The VOS method assumes a utility cannot add
20 generating units to meet increases in load. As loads grow, reliability levels fall and
21 customers experience greater numbers of interruptions. The customer costs associated
22 with these interruptions are called outage or “shortage” costs.

1 Under the VOS method, marginal capacity costs are calculated by multiplying the
2 change in reliability (associated with a change in load) times customer outage costs.
3 Reliability is measured in terms of expected unserved energy (EUE). Outage costs are
4 measured by some utilities using customer surveys. Other utilities assume that
5 reliability criteria provide a reasonably accurate reflection of customer service
6 expectations. When utilities have excess capacity, changes in EUE brought about by a
7 change in load are very small. Under these circumstances the VOS produces a
8 relatively low marginal cost of capacity.

9
10 System Planning methods attempt to incorporate actual resource planning tools and
11 decision-making processes into marginal cost calculations. One particular approach,
12 called the Differential Revenue Requirements method, calculates marginal capacity
13 costs by analyzing the difference in cost between two resource plans, one with and
14 one without a hypothesized increase in load. Any operating savings achieved by
15 reconfiguring the resource mix are credited to capital costs. The logic here is that any
16 capital investment exceeding the cost of the utility's least-expensive alternative could
17 only be justified by energy savings. The results will equal the costs of a peaking unit
18 when a system is in equilibrium and will be less than a peaker unit when a system is
19 out of balance and efficiencies can be gained through reconfiguration.⁵

21 ⁵For additional information on marginal capacity cost methods see EPRI TR-105226, "Winning Retail
22 Strategies: Beyond Innovative Rate Design" June 1995, Ch. 3.

1 I generally prefer System Planning methods over other approaches, because they
2 provide long-run price signals and incorporate real-world planning considerations.

4 **Avoided Costs versus Marginal Costs**

6 To develop potential TOU options, Bowan relies on figures that blend avoided and
7 marginal costs together. Although for NSPI the figures are similar, there is no
8 conceptual reason why the two should be combined. Only marginal costs are relevant
9 for rate design purposes.

11 In blending avoided and marginal costs, Bowman follows the Board's direction to
12 incorporate the recommendations set out in NARUC's 1994 report entitled "Aligning
13 Rate Design Policies With Integrated Resource Planning." I disagree with the report's
14 conclusion that "marginal costs are not what is needed to align rate design policy with
15 IRP."⁶ On the contrary, as I have explained above, marginal costs allow consumers
16 to compare incremental value with incremental costs and thereby make efficient
17 energy choices. The purpose of the IRP process is to find the lowest-cost way to
18 serve those electricity needs.

20 ⁶See page 34, "Aligning Rate Design Policies with Integrated Resource Planning," National Association
21 of Regulatory Commissioners, Washington, DC, January 1994.

1 Marginal costs differ from avoided costs in two important ways:

- 2
3 1. Marginal costs are concerned with changes in loads as opposed to changes
4 in supply sources.
5
- 6 2. Marginal costs are concerned with small differences (“marginal
7 differences”) as opposed to large savings.
8

9 The term avoided costs refers to the reduction in utility costs that occur when loads
10 are supplied by another source—such as an independent power producer (IPP). A
11 demand-side management (DSM) program might also be an alternative source. In
12 order to calculate the maximum payments that should be made to an IPP or to
13 estimate the value of a demand-side program, a utility must identify the costs it avoids
14 by not supplying the load itself—hence the name avoided costs.
15

16 Avoided cost levels depend on the size and operating characteristics of the resource
17 under consideration. A 50 MW independent power plant, for example, will avoid
18 different costs than a thermal energy storage system. The avoided costs for the IPP
19 will not include a reserve margin allowance, because IPP purchases do not enable
20 utilities to escape reliability obligations. The thermal energy storage program, on the
21 other hand, will reduce peak demand—lowering the level of capacity needed to meet
22 both loads and reserve requirements.
23

1 When developing generic avoided costs, however, utilities usually make some
2 simplifying assumptions about total MW and MWh impacts. MW values depend on
3 the size of the utility and the nature of the program under consideration, but typically
4 range from 50 to 200 MW.

5
6 Avoided and marginal costs are often confused, because similar techniques are to
7 estimate them, but they differ in concept and can differ in result. Only marginal costs
8 are appropriate for rate design, because only marginal costs provide information about
9 the consequences of small changes in load.

10 11 **Elasticity Estimates**

12
13 Estimates of price elasticity are useful for predicting how customers will respond to
14 rate changes. Most utilities include some type of price coefficient in their load
15 forecasting models. These coefficients usually reflect the impact of past rate increases
16 on loads in total. Elasticities for specific rate proposals are difficult to estimate. They
17 depend on existing rate levels, the structure of the particular rate option under
18 consideration, and customer circumstances. Although industry studies have found
19 measurable responses to TOU rates, for example, the results vary widely and cannot
20 be generalized to a specific utility's situation. Dr. Globerman concludes that "it is
21 somewhat futile to seek precise guidance from existing studies of price elasticity if a
22 utility is contemplating a TOU tariff" (Page 28).

1 While precise guidance is not available, the evidence does suggest that response to
2 TOU rates is usually large enough to justify additional metering costs. Voluntary
3 TOU rates, where meter costs are paid for by participants, can mitigate concerns for
4 other ratepayers. The lack of good elasticity data points to the need for lost revenue
5 recovery mechanisms for innovative rates. It is difficult to predict the number of
6 customers that will sign up for a voluntary rate or the level of shifting that will
7 occur. Lost revenue recovery mechanism reduce the risk associated with introducing
8 new rate designs.

10 V. HYDRO-QUÉBEC'S RECENT TOU EXPERIMENT

11
12 In its recent two-year pilot (1993-1994), Hydro-Québec found that voluntary TOU
13 rates significantly reduced the peak loads of residential customers. Some of the
14 information learned may be applicable to Nova Scotia.

15
16 Under the program, participants paid 12.78 cents/kWh for energy consumed on-peak
17 and 3.23 cents/kWh for off-peak energy. The on-peak period was defined as
18 6:00 A.M. to 11:00 A.M. and 3:00 P.M. to 10:00 P.M. during the weekdays of
19 December through March. The two-part on-peak period was intended to provide
20 customers with greater load shifting opportunities.

21
22 Because its marginal costs are close to average costs, Hydro-Québec did not have to
23 deal with reconciliation issues. The customer charge was not altered from the current

1 tariff. The rate was designed so that an average customer that did *not* change usage
2 would pay the same revenue to Hydro-Québec as would have been received under
3 standard rates. An average customer would benefit from the TOU rate only by
4 shifting or reducing electricity consumption.

5
6 Hydro-Québec found that its TOU rate significantly reduced on-peak consumption. It
7 had no statistically significant impact, however, on off-peak consumption. On
8 average, each participant reduced demand by 0.83 kW during the utility's 300 highest
9 load hours. The economic analysis predicted (with a 90% degree of confidence) that a
10 full-scale program would induce load reductions during these same hours by at least
11 0.36 kW on average. The analysis of persistence showed slightly larger impacts
12 during the second year of the experiment.

13
14 The TOU rate impacts were greater when customers installed load management
15 devices, such as electric water heater timers and space heater programmable
16 thermostats. Hydro-Québec plans to continue to promote load management devices as
17 it proceeds to full-scale implementation.

18 19 **VI. COMPETITION AND FLEXIBLE RATES**

20
21 Mr. McDonald describes structural changes taking place in the U.S. electric utility
22 industry and NSPI's need for pricing flexibility to respond to growing competition. I
23 concur with his comments and would add that several U.S. states are already

1 considering retail wheeling and unbundling traditional utility operations into “genco,”
2 “transco,” “disco,” and “retailco” type services. Power marketers are actively buying
3 and selling power on short-term markets and using risk-hedging tools to support
4 innovative contracts. In the second quarter of 1995, the 18 largest power marketers
5 together sold over 3,700 billion kWh. If retail wheeling occurs, and most observers
6 believe it is simply a matter of time, these same brokers will be free to focus on retail
7 markets.

8
9 Without changes in regulatory structures, traditional utilities will have difficulty
10 competing in the new environment. If they are not able to retain industrial loads,
11 residential and commercial customers will see rates rise. Many utilities are responding
12 now by negotiating long-term contracts with discounted rates for their “at-risk”
13 customers.

14
15 Although changes in the United States will not apply to Nova Scotia, NSPI will not be
16 immune from these events. Industrial customers in Nova Scotia will be pressing for
17 the same types of arrangements their southern competitors receive. And NSPI will be
18 expected to respond in a timely fashion.

19
20 One way to help NSPI compete would be for the Board to develop protocols for
21 Flexible Pricing. Under Flexible Pricing arrangements, regulatory commissions grant
22 utilities generic approval to negotiate rates with customers that have certain minimum
23 demands and can demonstrate access to competitively priced alternative sources of

1 power. The utility must follow regulatory guidelines concerning eligibility, price
2 floors, and, in some cases, contract terms.

3
4 Flexible Pricing eliminates case-by-case review, but does not eliminate regulatory
5 oversight. Utilities must document that a customer has a bona fide energy alternative
6 and some commissions require that utilities provide detailed transaction data, such as
7 breakdowns of demand and energy charges, data on the utility's short-term and long-
8 term marginal costs, and calculations showing that revenues under the contract will
9 exceed the utility's variable costs. Several commissions also require that stockholders
10 share a percentage of any lost revenues.

11
12 Although not all commissions have endorsed the concept, Indiana, Colorado, Iowa,
13 Connecticut, Illinois, and New York have adopted flexible rates. I believe the concept
14 is worthy of consideration here as well.

15 16 VII. SUMMARY

17
18 In summary, I continue to endorse TOU rates for reasons of efficiency and fairness.
19 While I expect TOU rates will result in either load shifting or load reduction, neither
20 is required for my support. If loads *did* change it would be because current rate
21 structures are less efficient than TOU rates. If loads *did not* change it would simply
22 indicate that consumers place a high value on electricity and are willing to pay the
23 actual cost of producing it.

1 I support NSPI's request for a lost revenue recovery mechanism, although I believe
2 special ratemaking should be applied only until customer response can be reasonably
3 estimated. I continue to support seasonal rates, but have not yet seen compelling
4 evidence for a year-round declining block domestic rate.

5
6 Finally, I encourage the Board to consider Flexible Pricing to help NSPI respond to
7 customer needs in an increasingly competitive environment.

Appendix A

RESUME OF JOHN H. CHAMBERLIN

JOHN H. CHAMBERLIN, Ph.D.

EXPERIENCE

(1985 to present)

Barakat & Chamberlin, Inc.

Director of the firm's strategic planning work for utilities. Has been instrumental in developing competitive business plans for utilities throughout the United States and Canada. Expertise includes resource planning, business planning, innovative products and pricing, market assessments and planning, interfuel competition, promotional practices, and performance-based incentive mechanisms. Much of current work focuses on emerging issues in the areas of regulatory restructuring, competitive assessment, and new product development. Has worked with more than 70 utilities to develop effective and profitable energy efficiency programs. Has prepared and presented testimony in more than 50 regulatory and civil proceedings in the United States and Canada and has helped design and implement ratemaking frameworks in numerous jurisdictions. Has also prepared and presented expert witness testimony in support of business litigation.

Senior Project Manager

Electric Power Research Institute

(1982 to 1985)

Developed, managed, and coordinated projects related to demand-side planning, rate design, load forecasting, and customer behavior and response. Major projects included the development of a short-term forecasting software package, the management of a large load-control experiment, and the development of a method for integrating rate design and load-management incentives. Also initiated a project designed to improve planning and analysis techniques for providing service options to utility customers.

Project Manager

ICF, Incorporated

(1979 to 1982)

Work centered on issues related to costs, rates, and load management for electric utilities. Major projects included the development of the first comprehensive textbooks concerning the calculation of marginal costs and marginal-cost-based rates. Developed the PURPA time-of-day and load-management guidelines and conducted several cost-benefit studies of load management. Developed and conducted a series of workshops on costing and ratemaking for utility and commission personnel.

Instructor

San Jose State University

Cybernetic Systems Program

(1979 to 1980)

Taught graduate courses in statistics and dynamic modeling.

Project Manager

Electric Power Research Institute

(1977 to 1979)

Developed and managed projects related to modeling, rate design, and forecasting the supply of electricity. A major project was the development of a generation expansion planning model and associated databases.

Economist
(1975 to 1977)

Hanford Engineering Development Laboratory

Involved in all aspects of modeling and forecasting electricity supply, demand, and power systems costs. Developed and applied load forecasting, production costing, expansion planning, and financial analysis models. Also performed cost-benefit analyses of advanced nuclear systems.

EDUCATION

Ph.D., Economics, Washington State University, 1976
M.A., Economics, Washington State University, 1975
B.A., Economics, California State University, 1972

AFFILIATIONS

American Economic Association
Association of Demand-Side Management Professionals
(Founding member; former Director and Treasurer)
Demand-Side Management Society, Association of Energy Engineers
Pacific Coast Electrical Association
Pacific Coast Gas Association

PUBLICATIONS

Books

"The Future of Integrated Resource Planning." *Electric Utilities Moving into the 21st Century*. Edited by Greg Enholm. 1994.

Demand-Side Management: Concepts and Methods (2nd Edition). With Clark W. Gellings. Lilburn, GA.: Fairmont Press, 1993.

"Forecasting Response to Innovative Rates" (Chapter 4) and "Uncertainty in Load Forecasting" (Chapter 5). *Demand Forecasting in the Electric Utility Industry*. Edited by C. W. Gellings. Lilburn, GA.: Fairmont Press, 1992.

Demand-Side Management Planning. With Clark W. Gellings. Lilburn, GA.: Fairmont Press, 1992.

"Converting from a Conservation Organization to a Marketing Mentality: Can the Two Coexist?" *Strategic Marketing for Electric Utilities*. Edited by C. W. Gellings and D. Limaye. Lilburn, GA.: Fairmont Press, 1988.

Demand-Side Management: Concepts and Methods. With Clark W. Gellings. Lilburn, GA.: Fairmont Press, 1987.

"Pricing for Conservation." *Electric Utility Conservation Programs*. Edited by C. W. Gellings and D. Limaye. With R. G. Uhler. Praeger, 1986.

"Ratemaking by Objective: A Framework for the Systematic Evaluation of Rate Design Alternatives." *Innovative Electric Rates*. Edited by S. V. Berg. With C. T. Dickson. Lexington Books, 1982.

"A Cost-Benefit Methodology for Evaluation of Load Management and Conservation Options." *Energy and Communications in Transition*. With A. Hakki. Michigan State University Press, 1981.

Conference Proceedings and Papers

"The Effect of Increasing Competition and Deregulation on IRP and DSM." In *Proceedings of the 7th National Demand-Side Management Conference*. With G. Collins and S. Shaffer. Cosponsored by Electric Power Research Institute, U.S. Department of Energy, and Edison Electric Institute. Dallas, TX, June 1995.

"Integrated Resource Planning in 2004?" *Proceedings of the 1994 ACEEE Summer Study on Energy Efficiency in Buildings*. With C. Melendy and J. Russ (SDG&E). Pacific Grove, CA, August 1994.

"Pricing Energy Services in a Competitive Market." *Proceedings of the 1994 ACEEE Summer Study on Energy Efficiency in Buildings*. Pacific Grove, CA, August 1994.

"The Role of Efficiency in Competitive Marketing." *Proceedings of the 1994 ACEEE Summer Study on Energy Efficiency in Buildings*. With S. Shaffer and C. Gellings. Pacific Grove, CA, August 1994.

"How Focusing on Value to Customers Changes a DSM Portfolio: One Utility's Example." DA/DSM Conference. With P. Herman. Orlando, FL, January 1994.

"Where Are DSM Financial Incentives Headed?" Exnet DSM Incentives Conference "What Works and What Doesn't." Arlington, VA, June 1993.

"Why All 'Good' Economists Reject the RIM Test." *Proceedings of the 6th National DSM Conference*. With P. Herman. Miami Beach, FL, March 1993.

"Using Demand-Side Management to Improve Customer Satisfaction and Competitiveness." Pacific Coast Electric Association Engineering and Operating Conference. With S. Mani. Irvine, CA, March 1993.

"Mitigating Rate Impacts of DSM Programs." Annual member meeting of the Association of Demand-Side Management Professionals, "Reaching Your Potential in DSM," Phoenix, AZ, December 1992.

"Gaining Momentum or Running Out of Steam? Utility Shareholder Incentive Mechanisms—Past, Present, and Future." *Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings*. With J. Brown and M. Reid. Pacific Grove, CA, August 1992.

"Demand-Side Management: The Next Generation." Rutgers 5th Annual Western Conference, Advanced Workshop in Regulation and Public Utility Economics. With A. Faruqi. San Diego, CA, July 1992.

"Is DSM Really Improving Social Welfare?" Western Economic Association 67th International Conference. With P. Herman. San Francisco, CA, July 1992.

"Evaluating and Selecting Energy Conservation Programs." Spring Workshop on Least-Cost Planning, Washington Gas and the D.C. Energy Office. With G. Wikler. Washington, D.C., April 1992.

"Demand-Side Management: The Winds of Change in the U.S.A." Presented at the Demand-Side Management: A Current and Future Resource conference sponsored by the Commission of the European Communities and the International Energy Agency. With C. Gellings and V. Rabl. Copenhagen, Denmark, October 1991.

Integrating Competition into Integrated Resource Planning. NARUC, Third National Conference on Integrated Utility Planning. With Dana Toulson. Santa Fe, NM, April 1991.

Current Designs of Regulatory Techniques to Encourage DSM. NARUC, Third National Conference on Integrated Utility Planning. With P. Hanser. Santa Fe, NM, April 1991.

"Demand-Side Management: The Winds of Change." *Proceedings of the Canadian Electrical Association National DSM Conference* (keynote address). With C. Gellings and V. Rabl. Toronto, Ontario, October 1990.

"The Impact of Demand-Side Management Programs on the U.S. Demand for Electricity, 1990–2010." *Proceedings of the Canadian Electrical Association National DSM Conference*. With S. Braithwait, A. Faruqi, K. Seiden, and R. Benjamin. Toronto, Ontario, October 1990.

"Cost Effectiveness Analysis Under Uncertainty." *Proceedings of the Canadian Electrical Association National DSM Conference*. With K. Seiden, A. Faruqi, and E. Ellingson. Toronto, Ontario, October 1990.

Introducing Market Focus Into Rate Design. Written for presentation at the Symposium on New Service Opportunities for Electric Utilities. EPRI and the University of California University Wide Energy Research Group. With K. Jensen. Berkeley, CA. September 1990.

"Financial Incentives for DSM Programs: A Review and Analysis of Utility Proposals." *Proceedings of the ACEEE Energy Efficiency in Buildings Summer Conference*, vol. 5. With M. Reid. Washington, D.C.: American Council for an Energy-Efficient Economy, August 1990.

"The Status of DSM Incentives." Background paper prepared for presentation at the EEI/EPRI workshop Regulatory Incentives for Demand-Side Management. With M. Reid. Washington, D.C., June 1990.

"Demand-Side Management: The Winds of Change." Prepared for keynote address. New Rules of Power—Meeting New Jersey's Electric Power Needs conference. With C. Gellings and V. Rabl. June 1990.

"Implementing Integrated Resource Planning Effectively." *Proceedings of the Canadian Electrical Association Western DSM Conference*. Winnipeg, May 1990.

"Cost Effectiveness Enlightenment: Which is the Right Test?" *Proceedings of the Argonne National Laboratory Energy Program Evaluation Conference*. With P. Herman. Chicago, August 1989.

"Managing Forecast Uncertainty: How Not to Bet the Company on a Point Forecast." Prepared for EPRI Forecasting Symposium. With A. Faruqi. Atlanta, Georgia, November 1988.

"Developing an Integrated Value-Based Planning Process." *Proceedings: 1987 Annual Review of Demand-Side Planning Research*. With W. Smith and P. Hanser. Palo Alto: Electric Power Research Institute (EPRI), September 1988.

"Developing Competitive Service Options." *Proceedings of the Energy Technology 15 Conference*. Washington, D.C., February 1988.

"Apples to Apples—Development of a Pricing Strategy: The Case of Non-utility Generation." *Proceedings of the EPRI Integrated Value-Based Planning Conference*. New Orleans, LA, December 1987.

"Customer Response to Innovative Rate Design." *Proceedings of the Energy Technology 13 Conference*. Washington, D.C., March 1986.

"The Design and Evaluation of Innovative Electric Rates." EA-4067, *Proceedings of the EPRI-CRIEPI Workshop on Energy Analysis*. June 1985.

"Reflecting Customer Needs in Demand-Side Management Planning." *Transactions of the IEEE*. With J. Flory. 1985.

"Pricing and Incentives." *IEEE Proceedings*, vol. 73, no. 10, October 1985. —

"Rate Design by Objective: A Pragmatic Approach." *Proceedings of the 1985 Rate Symposium*. Washington, D.C.: Institute for the Study of Regulation. February 1985.

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"Load Management: How Will Operators Want to Use It." *Transactions of the IEEE*. With W. Johnson, et al. 1983.

"Impacts of Time-of-Day Rates on Average Electricity Prices and Utility Load Factors." *Energy Technology IX, Proceedings of the Ninth Energy Technology Conference*. With C. T. Dickson and R. M. Spann. June 1982.

"The Effects of Fuel Costs on Rate Structures." *Transactions of the American Petroleum Institute*. With R. H. Males. Toronto, Ontario. May 1978.

"Customer Response to Changes in the Price of Electricity." *Proceedings of the American Nuclear Society*. Toronto, Ontario. June 1976.

"Development of Demand Functions and Their Inclusion in Linear Programming Forecasting Models." *Transactions of the American Nuclear Society*. June 1976.

"Forecasts of Electric Demand." *Transactions of the American Nuclear Society Winter Meeting*. San Francisco, California. November 1975.

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"Price Discrimination and Product Demand in the Electric Utility Industry." *Review of Business and Economic Research*. Fall 1977.

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Costs of Load Management to Society. Electric Utility Rate Design Study, RDS #76. EPRI, September 1980.

Cost-Benefit Methodology for Evaluation of Load Management Options. Electric Utility Rate Design Study, RDS #75. EPRI, April 1980.

The Problem of the Second Best and the Efficient Pricing of Electrical Power. Electric Utility Rate Design Study, RDS #70. EPRI, August 1979.

SELECTED PRESENTATIONS

"Lessons Learned from the California Experience." Regulatory Restructuring Conference sponsored by Electric Utility Consultants, Denver, CO, April 1995.

"Pricing and Rate Competition." Retail Wheeling Summit, New Orleans, LA, December 1994.

"Strategic Planning." Presentation in Mock Strategic Planning Session, Annual Membership Meeting, Association of Energy Service Professionals (formerly ADSMP), with P. Herman, Orlando, FL, December 1994.

"DSM in a Competitive Environment." Pursuit of Energy Efficiency Annual Conference, Iowa Association for Energy Efficiency, Des Moines, IA, October 1994.

"Competing in the New Market: Where Do Utilities Go from Here?" EXNET/Management Exchange, The California Regulatory Earthquake: Regulatory Restructuring of the Power Markets, San Francisco, CA, September 1994.

"Pricing in a Competitive World." Tennessee Valley Public Power Association Annual Meeting, Nashville, TN, May 1994.

"Visionary Panel: Where Do We Go from Here?" Panelist, Innovative Electricity Pricing Conference, Tampa, Florida, February 1994.

"Panel: DSM on Trial." Panelist, ADSMP 1993 Membership Meeting, San Diego, CA, December 1993.

"Regulatory Direction and Policy Issues." Demand-Side Management: Principles and Applications Seminar, Demand-Side Management Training Institute, San Francisco, CA, November 1993.

"You Got a Great-Looking Cart but without a Horse You Ain't Going Nowhere, Baby." Electric Power Software DSManager/IRP Manager Users Group, Minneapolis, MN, October 1993.

"Where Electricity Regulation Is Headed." Pennsylvania Electric Association, Hershey, PA, September 1993.

"DSM in the 21st Century: Megawatts or Memories?" Electricity Generation for the 21st Century Conference, Denver, CO, June 1993.

"Where Are DSM Incentives Headed: A Review of the Current Status and Future Directions." DSM Incentives Conference, Association of Demand-Side Management Professionals and EXNET (*Public Utilities Reports*), Washington, DC, June 1993.

"The Trade-off between All-Ratepayer Benefits and Rate Impacts: An Exploratory Study." Sixth National DSM Conference, Miami Beach, FL, March 1993.

"Mandatory Fuel-Switching: Why Not?" NARUC Conservation Committee panel presentation, Washington, DC, March 1993.

"DSM Cost Recovery and Incentives." Seminar sponsored by the Hawaii Public Utilities Commission, Honolulu, HI, October 1992.

"Profiting from Conservation." Edison Electric Institute Marketing Conference, Denver, CO, June 1992.

"Decoupling Profits from Sales." Edison Electric Institute Decoupling Workshop, with M. Reid, Washington, D.C., June 1992.

"Demand-Side Management: Is the Dream Still Alive?" First National DSM Conference, with C. Gellings and V. Rabl, Melbourne, Australia, May 1992.

"The DSM Experience: Policy and Practice." Public Utilities Research Center Annual Conference, University of Florida, Gainesville, FL, April 1992.

"Lighting Efficiency Strategies Forum." Panel presentation at the Lighting Efficiency Congress session of Globalcon' 92, San Jose, CA, March 1992.

"An Overview of DSM Incentive Regulation." NARUC's Staff Committee on Accounts meeting, Reno, NV, March 1992.

"Defining a Level Playing Field for Evaluating Demand and Supply Resources." Winter meeting of the Power Engineering Society of IEEE (Panel), New York, NY, January 1992.

"A National View of DSM Incentive Design." Association of Demand-Side Management Professionals annual meeting, San Antonio, TX, December 1991.

"Gas Wars: Using the Least-Cost Planning Process for Competitive Advantage." 5th National Demand-Side Management Conference "DSM—Building on Experience," EPRI/U.S. DOE/EEI, with D. Toulson (co-author), Boston, MA, July 1991.

"Integrating Competition Into Least-Cost Planning." 5th National Demand-Side Management Conference, with K. Jensen, Boston, MA June 1991.

"DSM Incentive Mechanisms: Current Designs of Regulatory Techniques." Northwest Electric Light and Power Association (NELPA) Conference, Portland, OR, May 1991.

"The New Electric Utility Industry of the 1990s." Association of Energy Engineers Worldcon '91 Conference and Expo on Energy and the Environment, Anaheim, CA, April 1991.

"Making Demand-Side Management Pay." Financial Forum panel, Pacific Coast Electrical Association, San Diego, CA, January 1991.

Workshop on Bonus Strategies, Association of Demand-Side Management Professionals annual meeting, Orlando, December 1990.

"Financial Incentives for DSM Programs." Utility-sponsored conservation seminar for senior management, Detroit, November 1990.

"Critical Issues in Demand-Side Programs." Panel presentation, Iowa Association for Energy Efficiency, Des Moines, October 1990.

"Financial Incentives for Demand-Side Management Programs." EEI Rate Research Committee meeting, Denver, September 1990.

"Regulatory Incentive Mechanisms for DSM: Why Are They Needed?" EPRI Innovations in Pricing and Planning Conference, Milwaukee, May 1990.

"Externalities: What Do We Know and What Can We Do With It?" Edison Electric Institute Environmental Emerging Issues Committee, with M. Mauldin, Madison, April 1990.

Marketing Evaluation Methodologies, Series of EPRI Workshops, Baltimore and Kansas City, Fall 1989.

"Starting from Scratch: Attempts at a Process Evaluation of LCRA's Power Saver Cycling Program." Electric Council of New England DSM conference, Boston, November 1989.

"Strategic Market Planning." California Public Utilities Commission workshop on market planning, San Francisco, September 1989.

"Long-Term Approaches to Solving the DSM Incentive Problem." EPRI/EEI conference, Denver, August 1989.

"Incentives for Demand-Side Management. Where Are We? Where Do We Go From Here?" Iowa Utilities Board, Des Moines, August 1989.

"Demand-Side Management Planning: Building on Experience." Canadian Electrical Association conference, St. John's, Newfoundland, May 1989.

"Competitive Bidding Strategies." American Public Power Association seminar, Scottsdale, April 1989.

"Incorporating Needs Impacts into Resource Planning: A Summary." EPRI/APA conference, with M. Mauldin, Atlanta, January 1989.

"Developing QF Pricing Strategies." Industrial and Utilities: Redefining the Relationship Conference, *Electric Utility Week* (McGraw-Hill), Chicago, November 1988.

"Developing Pricing Strategies for Potential Cogenerators." Electric Alternatives to Commercial Cogeneration Conference, EPRI/SDG&E, San Diego, October 1988.

"Pricing Electric Power and Services in a Dynamic Marketplace." Innovative Pricing (New Dimensions in Electricity Pricing) Conference, EPRI, with W. LeBlanc and W. Smith, Syracuse, September 1988.

"Rates to Meet the Demands of a Competitive Marketplace." American Public Power Association Customer Services and Communications Workshop, Marco Island, Florida, September 1988.

"Marginal Cost for Transmission Line Access." American Public Power Association Rates and Finance seminar, Austin, October 1988.

"Successful Service Providers (Rate Case Consultant)." Panel presentation, Pacific Gas and Electric Company Corporate Center and Shared Services Managers' meeting, San Ramon, CA, June 1988.

"Strategic Pricing: Rate Design For a Competitive Industry." Missouri Basin Municipal Power Authority, Sioux Falls, April 1988.

"The New Environment for U.S. Utilities: Perspectives of Competition and Change." CIGRE, Palo Alto, April 1988.

"Resource Planning Under Uncertainty." Inter-Utility Load Management Symposium (LADWP), Los Angeles, March 1988.

"The Great Rate Debate." California Municipal Utilities Marginal Cost Working Group, Los Angeles, January 1988.

"Innovative Utility Rates and Services that Benefit Utilities and Customers Alike." San Diego Energy Expo, November 1987.

"Cost Effectiveness Enlightenment: Which is the Right Test?" Lotus Consulting Group seminar, with P. Herman, October 1987.

"Value-Based Planning." International Association of Energy Economists Northern California chapter, September 1987.

"Integrated Value-Based Planning." EPRI DSM Review Conference, September 1987.

"Planning for Best Value." IEEE Summer Meeting, San Francisco, July 1987.

"Developing a Qualifying Pricing Strategy." California Municipal Utilities Marginal Cost Working Group, Los Angeles, July 1987.

"Competitive Rate Design." Bonneville Power Administration's Second Annual Futures Symposium, May 1987.

"Marginal Costing Methods and Developing a QF Pricing Strategy." California Municipal Utilities Marginal Cost Working Group, February 1987.

"Moving Toward Integrated Resource Planning: Understanding the Theory and Practice of Least-Cost Planning and Demand-Side Management." IEEE-Least-Cost Energy Planning in the Midwest: A Symposium, with C. W. Gellings, Chicago, February 1987.

"Integrated DSM Options with Resource Plans." Industry least-cost planning seminar, Boston, January 1987.

"Methodology for the Cost-Effectiveness Analysis of Load Growth/Retention Programs." Barakat and Chamberlin workshop, with Sam Barakat, Berkeley, California, September 1986.

"Increased Revenue Through Load Forecasting." National Rural Electric Cooperative Association (NRECA), September 1986.

"Strategic Rate Design." NRECA National Accounting and Finance Conference, August 1986.

"Customer Response to Innovative Rate Design." NRECA National Marketing Conference, Nashville, June 1986.

"Rates as a Marketing Strategy." 1986 NRECA Member Services and Communications Conference, June 1986.

"Load Forecasting: Why Do We Miss the Target?" APPA Engineering and Operations Workshop, with J. Clinton, Seattle, March 1986.

"DSM Impact Assessment." Workshop developed and presented by Barakat and Chamberlin in conjunction with Demand-Side Planning Workshop, Berkeley, California, March 1986.

"Developing Credible Forecasting Methods." IEEE Winter Power Meeting, 1984.

"Short Term Sales Forecasting Methods." ORSA-TMS Annual Meeting, 1984.

"Experimental Design of a Load Control Project." Fourth California Load Management Symposium, San Francisco, November 1984.

"Uncertainty in Load Forecasting." IEEE Summer meetings, 1984.

"Why Forecasting Is So Hard (And What Can Be Done About It)." IEEE/CFA Joint Conference on Consumer Affairs, October 1983.

"Modeling Changes in Utilities' Costs." Florida PSC Metering for Innovative Electric Rate Conference, July 1980.

COURSES AND LECTURES

Lecturer: "Rate Course" and "Innovative Pricing." Sponsored by EPRI, Tampa, FL, February 1994.

Lecturer: "Pricing as a Marketing Tool." Demand-Side Management Course, Center for Professional Advancement, Burlingame, Calif., April 1989.

"Integrated Resource Planning." American Public Power Association, 1987-1988.

"Advanced Rate Design: Rates as a Competitive Strategy." Two-day, in-house strategic training seminar for BC Hydro, October 1988.

"Demand-Side Management: Marketing, Planning, Technology, and Evaluation." Annual three-day course, Center for Professional Advancement, 1983-1988.

Director: "Advanced Rate Design." American Public Power Association, 1981-1988.

"Integrated Resource Planning." Kansas City Board of Public Utilities, January 1988.

Associate Director: "Demand Forecasting for Electric Power and Energy." Center for Professional Advancement, 1984-1987.

"Strategic Pricing." Center for Professional Advancement, December 1987.

"Forecasting Methods." Center for Professional Advancement, November 1987.

"Demand-Side Planning." American Public Power Association, 1986.

Lecturer: "Development of Marginal Costs." EEI Rate Fundamentals course, Indiana University, 1981-1985.

"Statistics" and "Dynamic Modeling." Graduate courses, Cybernetic Systems Program, San Jose State University, 1979-1981.

"Marginal Cost Rate Design." Course given to various groups (including students and industry analysts), 1979-present.

Rates and Costs Workshop. EPRI, 1979.

"Microeconomics." Washington State University, 1972-1975.

January 17, 1996 - 9:35 a.m.

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1 MR. ROBERTSON

2 Mr. Outhouse.

3 MR. OUTHOUSE

4 Thank you, Mr. Chairman. Mr. Chairman, the first
5 witness today will be Dr. John Chamberlin. He's
6 already seated in the witness box, I guess, and ready
7 to be sworn.

8 MR. ROBERTSON

9 Okay.

10 DR. JOHN H. CHAMBERLIN, (Affirmed)

11 MR. OUTHOUSE

12 Mr. Chairman, Dr. Chamberlin's evidence has been pre-
13 filed. It will be marked as Exhibit ---

14 MR. ROBERTSON

15 That's number 68.

16 MS. GARBER

17 No, that's not the right. That's the numbers of the
18 witnesses.

19 MR. OUTHOUSE

20 It's got to be higher than that.

21 MR. ROBERTSON

22 Sorry. Number 82.

23 MR. OUTHOUSE

24 Number 82.

25 MR. ROBERTSON

1 That was the wrong one. I have three sets of numbers
2 here and sometimes I get confused.

3 EXHIBIT N-82 (ENTERED) - DIRECT EVIDENCE OF DR. JOHN
4 CHAMBERLIN

5 MR. OUTHOUSE

6 Mr. Chairman, Dr. Chamberlin's cv is attached to his
7 evidence. I don't want to run through his
8 qualifications. He's testified before. I would ---

9 MR. ROBERTSON

10 He's appeared before the board before and was
11 accepted as an expert witness.

12 MR. OUTHOUSE

13 Okay.

14 MR. MACDONNELL

15 No questions.

16 MR. ROBERTSON

17 No questions? Thank you.

18 MR. OUTHOUSE

19 All right. Good morning, Dr. Chamberlin.

20 DR. CHAMBERLIN

21 Good morning.

22 MR. OUTHOUSE

23 Dr. Chamberlin, as I've indicated to you, with a
24 couple of exceptions witnesses haven't been reading
25 in their pre-filed evidence, and I would ask that you

1 summarize your evidence for the board, if you would.

2 DR. CHAMBERLIN - DIRECT EVIDENCE

3 Thank you. In 1993, I testified in the board's
4 generic rate design hearing on pricing issues related
5 to Nova Scotia Power. Since that time a considerable
6 amount of new analysis has been presented to the
7 board. The board has asked me to review my previous
8 recommendations in light of the new information and
9 to provide some general comments on rate design
10 issues and the implications for electricity pricing
11 of recent industry restructuring. In my previous
12 testimony, I discussed the benefits of time-of-use
13 rates and recommended that Nova Scotia Power study
14 their potential for Nova Scotia. I continue to
15 believe that time-of-use rates are applicable in
16 NSPI's situation. I support time-of-use rates
17 because they improve the resource efficiency by
18 providing more accurate signals about the hourly cost
19 of producing power. While time-of-use rates may also
20 cause customers to shift load or conserve energy,
21 this response is simply a reflection of efficiency
22 improvements. Load shifting is not and should not be
23 the reason behind implementing TOU rates. Time-of-
24 use rates are superior to seasonal demand charges
25 because they provide continuing incentives each hour

1 of the day. Under seasonal demand charges, on the
2 other hand, customers are charged based on their
3 single highest load occurring during on-peak hours.
4 Once a demand level has been reached, a customer has
5 no incentive to keep subsequent consumption below
6 that level. Because customer response and revenue
7 impacts are difficult to gauge ahead of time, I
8 support establishing a temporary lost revenue
9 mechanism for time-of-use rates and other innovative
10 rate designs. A lost revenue mechanism would
11 eliminate many of the risks that make utilities
12 hesitate to pursue potential worthwhile options.
13 While mandatory time-of-use rates are preferable from
14 an efficiency perspective, I can support voluntary
15 rates provided revenue shortfalls are made up by
16 customers that choose not to participate in the TOU
17 program. This approach makes the existing
18 inefficient block rate structure less appealing over
19 time. Over the long run, the effect is the same as
20 having instituted a mandatory program, as more and
21 more customers volunteer or migrate to time-of-use
22 rates. The challenge in designing time-of-use rates
23 is to provide price signals that are based on
24 marginal costs while, at the same time, recovering
25 embedded cost revenue requirements. NSPI is

1 concerned that the reconciliation process makes
2 implementation of time-of-use rates impractical. Mr.
3 Bowman evaluated four methods for reconciling
4 revenues and recommended adopting what he called the
5 default method. Of the four methods he used, I
6 prefer the customer charge approach because it keeps
7 the hourly marginal cost price signals intact.
8 Another approach that could be followed involves
9 dividing each on and off-peak period into consumption
10 blocks. Only the last block, where a customer's
11 consumption falls, needs to be priced at marginal
12 cost. I do not believe NSPI needs to conduct an
13 experiment before implementing time-of-use rates.
14 NSPI can borrow data from other utility experiments
15 such as Hydro Quebec's recent pilot. The experiments
16 are only needed if TOU rates are viewed as DSM
17 programs or if revenue impacts need be estimated. As
18 I stated earlier, time-of-use rates should not be
19 considered as a DSM activity. They simply are a way
20 to improve the efficiency of price signals given to
21 customers. With a lost revenue recovery mechanism,
22 NSPI would be protected from any revenue
23 uncertainties, thereby eliminating the need for a
24 priori information on likely customer response to the
25 rates. While of principal importance, economic

1 efficiency is not the only objective of rate design.
2 Other objectives include rate stability, simplicity,
3 practicality, the need to collect adequate revenues,
4 and public goals like assisting low-income customers.
5 Combining these multiple purposes necessarily
6 requires a degree of judgment. However, when
7 developing innovative rates, I recommend against
8 departing too far from marginal cost goals. Without
9 a reasonably close link to marginal costs or some
10 other specific goal, it's difficult to establish how
11 a new rate might improve upon existing tariffs.
12 Marginal costs can be measured over either the short
13 run or the long run. For rate design purposes, the
14 choice depends on the length of the contract or the
15 "compact" that a utility has with its customers,
16 sometimes with respect to that individual load. If
17 a utility sells power on the spot market, for
18 example, then short-run marginal costs are
19 appropriate because there is no obligation to serve
20 and no need to make resource investments on a
21 customer's behalf. If the utility expects, however,
22 to continue supplying the customer far into the
23 future, then long-run marginal costs are appropriate.
24 I disagree with the notion that avoided costs and
25 marginal costs need to be blended for rates to be

DR. CHAMBERLIN - DIRECT EVIDENCE

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1 aligned with IRP. Only marginal costs are
2 appropriate for rate design because only marginal
3 costs provide information to customers about the
4 consequences of increasing or decreasing their load.
5 Avoided costs, as the term is defined by PURPA, looks
6 at the cost a utility would incur but for the
7 purchase of capacity and energy from an independent
8 power producer. Avoided costs then are concerned
9 with changes in supply costs, not changes in load.
10 Avoided cost is not a synonym for long-run marginal
11 cost. Mr. MacDonald describes structural changes
12 taking place in the U.S. electric industry and NSPI's
13 need for pricing flexibility to respond to growing
14 competition. I concur. One way to help NSPI compete
15 would be for the board to develop protocols for
16 flexible pricing which would eliminate case-by-case
17 review but not regulatory oversight. Several
18 commissions in the U.S. have endorsed the concept.
19 I believe it's worthy of consideration here as well.
20 That concludes my summary.

21 DIRECT EXAMINATION BY MR. OUTHOUSE

22 Q. Thank you, Dr. Chamberlin. Dr. Chamberlin, the only
23 question that I would have before cross-examination;
24 you said in your remarks that avoided cost is not
25 synonymous with long-run marginal cost. Can the two

1 be calculated in a similar manner?

2 A. They can be calculated in a similar manner, in which
3 case avoided costs are calculated -- if they're
4 calculated the same way as long-run marginal costs,
5 then those two concepts can be the same. But often
6 avoided costs refer to a specific thing, which is the
7 reduction in system costs that occurs if there is a
8 reduction in capacity.

9 Q. But if they're calculated on the same planning
10 assumptions on a forward-looking basis, they should
11 produce a similar result?

12 A. They could produce an identical result if they were
13 calculated the same.

14 Q. Okay.

15 A. The issue that I'm just taking issue with is the use
16 of avoided costs as a vehicle to calculate a specific
17 thing, which is what should you pay a qualifying
18 facility under PURPA. And that often is -- uses a
19 different approach, it takes place at a different
20 place in the planning cycle, and so on, as long-run
21 marginal costs. I don't dispute the idea of blending
22 long-run and short-run marginal costs. So, in that
23 circumstance, if avoided cost is calculated the same
24 way that long-run marginal costs are, then I think it
25 would be appropriate to blend that short-run marginal

DR. CHAMBERLIN, DIRECT EXAM. BY MR. OUTHUSE

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1 cost and the avoided cost or long-run marginal cost
2 signal, depending on several things including how
3 proximate is the need for the new capacity.

4 Q. Thank you, Dr. Chamberlin.

5 MR. ROBERTSON

6 Mr. Kehoe?

7 MR. KEHOE

8 Thank you, Mr. Chairman.

9 CROSS-EXAMINATION BY MR. KEHOE

10 Q. Good morning, Mr. Chamberlin.

11 A. Good morning.

12 Q. On page 13 of your evidence -- and it's not necessary
13 to turn it up -- you indicate:

14 "In 1993 I looked at NSPI's embedded cost of
15 service study and found significant
16 differences between summer and winter costs."

17 I believe that was in relation to seasonal concepts.
18 NSPI have indicated, I believe, that there's very
19 little difference in their seasonal energy costs.
20 So, I guess I'm having some difficulty rationalizing
21 those two comments. I believe it must be a demand-
22 related process. But could you explain where you see
23 the differences from an embedded perspective?

24 A. Do you mean today?

25 Q. Or on the basis of the 1993 analysis.

1 A. Well, it's been a couple of years since I looked at
2 that. I'm not sure that I can in detail. What I
3 recollect from a couple of years ago was that, as I
4 looked at NSPI's embedded cost of service study
5 itself, there were differences that were largely
6 demand-driven, as I recall, between summer and winter
7 costs.

8 Q. I guess my concern is that we're asking them to spend
9 money, real money, on time-of-use initiatives but
10 there should be real benefits. And I'm wondering if
11 the benefits are derived from the cost allocation
12 procedure. In other words, the fixed costs don't go
13 away in the summer, is my conclusion. So, are we
14 arbitrarily assigning fixed costs to the winter
15 period and then assuming if the consumption shifts
16 into summer those fixed costs would tend to
17 disappear, when, in reality, we would think that they
18 don't? We would assume they don't.

19 A. Well, I don't think it's an allocation issue at all.
20 I think it's an efficiency issue. I think if it is
21 winter peak load which drives the need for NSPI to
22 add new capacity, then the prices in the winter or
23 the winter peak ought to reflect that. And my
24 concern is that, if they don't, they're not
25 efficient. That is, they tell customers that it

1 doesn't cost any more to add load during the winter
2 on-peak hours than it does during the summer off-peak
3 hours. Now, if that's true, that's fine. There
4 shouldn't be a difference in the prices. But if it's
5 not true, if there is a difference in capacity need
6 that results from load at those different times, then
7 the prices should reflect that.

8 Q. I think your comments were in relation to embedded
9 cost of service. So, the forward-looking approach,
10 I think I understand that. And you're suggesting
11 that we would expend -- or Nova Scotia Power should
12 expend money on time-of-use initiatives to save
13 future costs. But if there's very little savings in
14 current costs because they have those same fixed
15 costs, anyway, would you think that we should be
16 cautious in spending too much money up front, as it
17 were?

18 A. Well, I think you should always be cautious about
19 spending money. I think, first of all, if I were to
20 use an embedded cost allocation method to design
21 rates, I would choose an allocation method which
22 reflected how the company added capacity. So, I
23 don't think it's whether capacity is used or not used
24 during different times of the year, I think -- I'd
25 say it's what load at which time or what kind of load

1 was responsible for adding the capacity that was
2 added. That's the thought process that I would use
3 to look at the appropriateness of a particular
4 embedded cost allocation method. If it has always
5 been winter peak, then I would tend to use a winter
6 peak oriented type allocation methodology.

7 Q. On page 15 -- and again it's not necessary to turn it
8 up -- you indicate one of the objectives of rate
9 design is public goals like assisting low-income
10 earners. Would you agree that NSPI's proposed third
11 block for the domestic class clearly breaks that
12 objective?

13 A. It would seem to to me. It would seem that the third
14 block isn't going to benefit low-income customers.
15 Without having studied it extensively, that would be
16 my reaction.

17 Q. I have two questions related to that. How far really
18 do you go to satisfy that objective? And where would
19 the revenue shortfall lie, in the same class or all
20 classes?

21 A. I don't know if I can answer the how far would I go
22 to reflect the objective of providing relief to low-
23 income customers in rates. Probably not very far, if
24 you're asking me personally. I think there are other
25 better ways to do it than to charge most customers

1 prices which are wrong or inefficient in order to
2 benefit a few customers. That wouldn't be what I
3 would tend to do. With respect to the question of
4 where would I seek to recover the revenue shortfall
5 that would result from the third block; if, in fact,
6 it's true that the third block would tend to result
7 in retaining space heating customers that would
8 otherwise be lost, if that's true, then the revenue
9 shortfall that resulted from that is a price that all
10 customers ought to pay in order -- because they --
11 all customers would receive the benefit from that.
12 If the resulting rate still provided a contribution
13 to margin over and above marginal costs so that it
14 was attractive to all customers to essentially pay to
15 retain the space heating customers, then I don't see
16 how that's any different from an industrial retention
17 program or any other. I would allocate the shortfall
18 over all customers.

19 Q. On page 21 in your discussion on marginal capacity
20 cost in the value of service method, I believe, you
21 have a reference to outage costs and that some
22 utilities measure these costs by customer surveys.
23 Are you aware of the results of any specific surveys?
24 Has that ever been put into a public -- to public
25 record anywhere?

1 A. Oh, sure. I think, sitting here today, I can recall
2 that Pacific Gas & Electric has done a significant
3 amount of customer outage cost surveys. Ontario
4 Hydro has done some here a couple of years ago.
5 EPRI, the Electric Power Research Institute, has
6 published several reports dealing with surveys of
7 utilities who have performed surveys of customer
8 outage costs. There have been -- I don't know --
9 probably a dozen or more that I can think of.

10 Q. I guess, somewhere in the evidence -- and don't ask
11 me to tell you where it was -- I seen those costs
12 reflected from Nova Scotia Power's perspective, I
13 believe, and there seemed to be very little
14 differences in outage costs, not significant in terms
15 of the numbers. And I guess my question is, would
16 you agree that domestic customers, for example, would
17 place significantly lower value on outage costs as
18 compared to a large industrial customer?

19 A. Well, let's see. I could agree with the following:
20 I think the evidence is that there is a substantial
21 variation even within classes as to the value of
22 avoided outages, probably is the way to say that.
23 And it depends -- for example, among residential
24 customers -- nobody at my house is home during the
25 day on a summer afternoon. If there is an outage, it

1 doesn't particularly affect us. If people are at
2 home and an air conditioner goes out on a hot summer
3 day, those customers would probably have paid more
4 than I would have to avoid that summer outage. So,
5 you get those kinds of variations. Some of the
6 outage numbers that I can recall seeing are for
7 particular kinds of industrial customers like
8 petrochemical firms and semi-conductor manufacturers
9 and things of that kind that have a high value of
10 reliability. Those outage cost numbers are very
11 high. They would pay -- and do pay, frankly -- a
12 substantial amount of money to avoid outages or blips
13 and surges and things like that by buying power
14 quality equipment. So, for those kinds of customer
15 outage cost estimates are very high. For others
16 they're smaller. So, I think it's probably fair to
17 say that there's a substantial variation within
18 classes and between classes of the value of
19 reliability.

20 Q. I think we'd assume -- we could make the assumption
21 that the domestic customers have a lower reliability,
22 whether they deserve it or not, just by virtue of
23 where they end up on the -- physically on the power
24 system. The low end of the distribution system is
25 inherently less reliable, I believe. But if

1 customers have different outage costs, is it fair --
2 equitable, if you like -- that they be assigned costs
3 for generation reserve at the same level as customers
4 with a higher outage cost?

5 A. Well, you know, I would turn it around. I would say
6 that the fair and equitable thing to do would be to
7 do two things. First of all, to make sure that the
8 price reflects the cost of reliability. Customers
9 can then make their own decisions about what level to
10 buy. And, secondly, to the extent that the system
11 can differentiate, unbundle reliability from the
12 basic service itself and give customers options about
13 what kind of reliability that they could buy, that
14 would be even better. That's essentially what an
15 interruptible rate is. It's an unbundling of
16 reliability from the basic package of service. It's
17 harder to do that for non-industrial customers, but
18 to the extent that it could be done, I would say that
19 would be the fair thing to do.

20 Q. So, you're reflecting the future cost of capacity and
21 saying, "Well, if you drive that capacity, then
22 presumably -- the capacity, of course, is driven by
23 reliability considerations. If you're prepared to
24 pay that value for incremental capacity, you must
25 presumably agree with the reliability standard." Is

1 that where you're coming from?

2 A. I'm not sure that I'm saying -- I don't think I'm
3 saying that you have to agree with the reliability
4 standard. What I'm saying is that the price should
5 reflect what it costs the system to maintain a level
6 of reliability. And if a customer chooses to buy it,
7 great. If not, then they have exercised that choice.

8 Q. Do you think there's any significance from an
9 historical perspective that domestic customers are on
10 the low end of the revenue-to-cost ratio? Do you
11 think these kinds of concepts, outage costs, would
12 play a role in terms of why historically domestic and
13 smaller customers end up on the low end of the
14 revenue-to-cost ratio? And I think it's almost
15 across the board in most jurisdictions, that's the
16 case, I believe.

17 A. Let me make sure I understand your question. When
18 you say "the low end of the revenue-to-cost ratio,"
19 do you -- would another way to say that be that
20 domestic customers produce a lower rate of return
21 than the other classes?

22 Q. Yes. That's a good one.

23 A. And so you're asking me whether the fact that -- (a)
24 is that generally true, and (b) is it generally true
25 because of a regulatory perception that domestic

1 customers have a lower value of reliability?

2 Q. Yeah. Is there some link there, historical?

3 A. I don't even think I can agree that it's generally

4 true. As I'm thinking through a number of

5 jurisdictions where I've worked, it's certainly not

6 always true. Frankly, I think it's -- I don't know

7 if I can attribute a particular reason. If you had

8 asked me to name the reasons I can think why that

9 might be true, that wouldn't have been one of them.

10 It may be true for lots of reasons, and that may even

11 be one of the reasons why it's true, but it's not one

12 that I would have thought of.

13 Q. I guess where I'm coming from is that we hear

14 arguments that the residential class are only paying

15 95% of the costs, or, the flip side in your analogy,

16 they're achieving a lower rate of return. But if we

17 could reflect reliability and outage costs in a cost

18 of service study, they, in fact, may be paying 100%

19 of their costs. It's just that there's no way to

20 mechanically put these costs into the cost of -- or

21 to reflect those lower values of outage costs in the

22 cost of service study.

23 A. You know, I'm concerned that the whole question sort

24 of presumes symmetry between pricing in cost

25 allocation. I mean, I -- if you really want to

1 answer that right, I think you'd have to first
2 believe that the allocation methods were appropriate
3 to begin with in each jurisdiction. And I wouldn't
4 agree that that's true. My concern is not with
5 allocation, it's with getting the price signals
6 right. And I think that's important because if the
7 prices don't reflect marginal costs, they're
8 inefficient and the whole system produces less value
9 than it can. I think that's the issue that I'm
10 concerned with.

11 Q. And I believe that question was posed to NSPI and I'm
12 sure the response was not -- didn't put me in my
13 particular direction. But I believe from the
14 embedded cost of service perspective the only
15 reflection of reliability would be the fact that the
16 demand cost for interruptible is forgiven. And I'm
17 just wondering is it fair only to reflect reliability
18 to a single group of customers or is it -- sorry, not
19 reliability, outage cost. And is there any way in a
20 cost of service study to reflect -- I think a concept
21 which we would generally agree is that small
22 customers have a lower value for outage costs and
23 therefore should contribute a lower amount to
24 reliability. They shouldn't contribute the same
25 amount if they have a lower value of outage costs.

1 A. I've heard you say that several times. I just don't
2 think I can agree with it. I wouldn't price it that
3 way. I would price it as to cost and let customers'
4 value choices drive their decisions about what to
5 buy, when to buy it and how much to buy. I would try
6 to unbundle reliability as much as possible to give
7 customers more and more choices about how to buy the
8 level of reliability that was equivalent to their
9 value. Without the choice, it's hard to do that.
10 But I think if you were to try to set prices priced
11 solely to value and not to cost, I think you could
12 get led down a lot of paths that you wouldn't like to
13 be down.

14 Q. You're probably right. Your testimony with respect
15 to the domestic third block, I guess I'm having some
16 difficulty rationalizing that testimony with your
17 testimony on flexible rates. You're opposing the
18 third block but, I believe, are in favour of flexible
19 rates such as long-term contracts at discounted rates
20 for at-risk customers. And I think you have a clause
21 that says provided the at-risk customers can
22 demonstrate access to competitively-priced
23 alternative sources of power. I don't believe I'd be
24 in favour of a domestic third block but I think I'd
25 have difficulty arguing that electric space heat

1 would not be considered at risk. How would you
2 rationalize your position on those two items?

3 A. Well, I think there's several differences. The
4 concern that I had with the third block is, first of
5 all, there's a better way to do it. And the better
6 way to do it is a time-of-use rate, because the costs
7 are more aligned with the load. Secondly, I had a
8 concern about the relationship between the third
9 block and the marginal costs, and particularly the
10 marginal costs during the winter on-peak season. The
11 difference between that and flexible rates -- I agree
12 that there's an element of similarity, the element
13 having to do with the incrementalness of the load,
14 the potential to lose the load. The kind of flexible
15 rate that I'm thinking of, though, is one which
16 essentially unbundles the obligation to serve from
17 the purchase of the electricity. One of the problems
18 with something like the third block rate is that to
19 the extent that you retain a customer you retain an
20 obligation to serve that customer over at least the
21 life of that equipment that's retained. So, if
22 that's a 15-year life or a 20-year life on a space
23 heating system, then the decision that you make today
24 affects the costs of all customers over the next 20
25 years. That's not the same as a lot of the special

1 rate contracts that are being written where there is
2 a commitment to provide a customer with energy and
3 capacity say over a 5-year period and not beyond.
4 And so there is a capacity commitment that is
5 different between those two that I think is
6 important. The issue that I was getting at with the
7 flexible rates is really, though, one of being able
8 to be responsive to customers in an increasingly
9 competitive environment. I'd agree with you if the
10 -- if part of what you're asking is, is it a good
11 idea to develop flexible rate concepts for customers
12 in all classes, I'd say sure.

13 Q. Fine. I think I can appreciate your argument. The
14 idea is that in the domestic class we'd be signing
15 that customer up for the long term or making the
16 commitment, whereas in the flexible rates for
17 typically load retention or whatever you have a time
18 frame and at the end of that time frame you go back
19 to paying the going rate. So, we're not giving him
20 a commitment for the long term. So, I can appreciate
21 that argument. On page 16, just a single comment:

22 "We know that consumers develop expectations
23 about what products 'should' cost."

24 And with the prevalence of excess capacity all over
25 North America that we're hearing about, is it

1 possible these so-called at-risk customers are just
2 really taking advantage of the utilities and
3 regulators? In other words, they have an expectation
4 of what the product should cost as opposed to
5 something else?

6 A. Yeah. I mean, I suppose you could say that, at least
7 part of that. I think you could say that a number of
8 customers who are aggressively seeking discounts
9 these days are taking advantage of the fact that
10 wholesale markets and spot markets and all those
11 kinds of markets are very competitive and very soft
12 today. I think the issue is what do you do about
13 that. I think there are two choices. One is you can
14 be responsive to it and try to find ways to retain
15 those customers, or you can say, "Well, go take
16 advantage of somebody else's spot market." And the
17 question to address is, are you better off letting
18 the customer go or is everybody better off finding
19 ways to keep him? I would think, as long as they're
20 paying, you know, over the marginal cost and that the
21 appropriate time commitment is addressed, that
22 everybody is better off by keeping him.

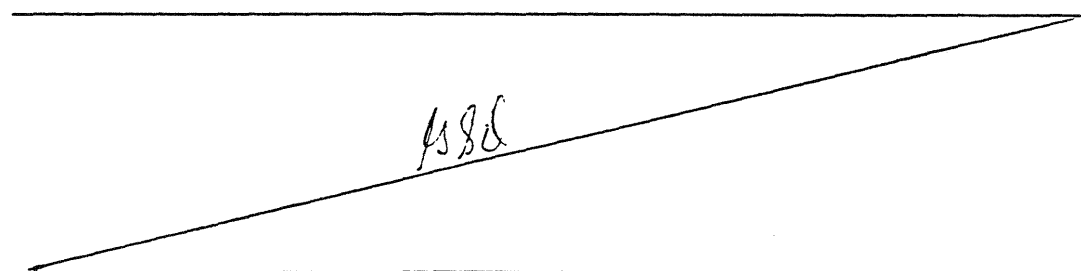
23 Q. I think one of the problems we seen in the economic
24 development rate hearing was that the so-called at-
25 risk customers were unwilling to share the cost of

1 the various inputs into their manufacturing process.

2 And I guess I'm suggesting, should these same
3 customers be able to claim confidentiality in terms
4 of their overall costs in order to demonstrate
5 problems from a competitive perspective? Is it fair
6 to ask for a lower electricity price because your
7 competitor has a lower electricity price when you
8 haven't given us the total equation? In fact, your
9 overall prices may be just as competitive as his,
10 you're looking at one isolated incident. What's your
11 feeling on our experience in that respect?

12 A. Well, let me make two observations. The first
13 observation is that most businesses that I am
14 familiar with regard their cost structure as among
15 the most important confidential pieces of business
16 information that they have. It's -- I know people
17 who are managers of energy purchasing, say, for large
18 manufacturers, who won't even discuss in public the
19 magnitude of their total energy bills worldwide, much
20 less a particular plant.

21
22
23
24
25



DR. CHAMBERLIN, CROSS-EXAM. BY MR. KEHOE

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1 A. And this is information which is -- they regard as
2 very important and highly confidential. That's the
3 first observation. The second observation is I don't
4 think it's a matter of fairness, I think it's a
5 matter of what happens. If you say to a customer
6 that, "You can't get a discount unless you reveal
7 your cost structure and cost information to your
8 competitors," then the risk is that the customer
9 says, "I don't want to deal with that situation and
10 I'll take my business some place else." The key
11 piece of information -- the key thing to know is, can
12 they take their business some place else? And if
13 they can, then why force them to do that.

14 Q. I guess, how would the board make a determination if,
15 in fact, the possibility of them taking their
16 business elsewhere is a real possibility as opposed
17 to, "I just want to take advantage of excess capacity
18 and everybody else is doing it, so I'm going to jump
19 on the bandwagon"?

20 A. Well, I'd say the first thing to ask is, is it
21 happening.

22 Q. Pardon me?

23 A. The first thing to ask is, is it happening. Are
24 customers shifting their consumption to some place
25 else? And there's lots of ways to do that. At least

1 in the U.S. there is a significantly increasing
2 amount of production that's shifted from one facility
3 to another throughout the country, throughout the
4 U.S., in order to take advantage of differences in
5 electricity prices. The air separation companies,
6 for example, in the United States describe themselves
7 as essentially retail wheelers. Those trucks that
8 you see running down highways essentially contain
9 tens of thousands of kilowatt hours and they just
10 ship them around the country to take advantage of
11 who's got the cheapest prices today. So, I mean, I
12 think it's -- there's only so much studying that you
13 can do. I'd say the truly important question is, is
14 it happening. Is production being shifted? Are
15 plants being moved out of the country? Out of the
16 province? Are there opportunities that are being
17 lost to increase employment or increase capacity in
18 facilities here? If you look around and you see that
19 those things are happening, then I would be -- I
20 wouldn't be concerned about individual
21 demonstrations, I would be aggressively trying to
22 keep those customers.

23 Q. If Nova Scotia Power has indicated in their load
24 forecast that they anticipate a disproportionately
25 higher load growth in the industrial sector, what

1 would that tell you about the current level of our
2 electricity rates for industrial load?

3 A. I don't know that it would tell me anything without
4 knowing a lot more than I do about what load growth
5 might have been -- like I say, I think the critical
6 question is, to what extent, if any, has the current
7 prices created opportunities where customers have
8 shifted production out of the province or out of the
9 country or not made decisions which have resulted in
10 increases in capacity here? To what extent have
11 there been plant closures and things of that kind?

12 Q. So, it would be incumbent on NSPI, I guess, to
13 demonstrate that to the board prior to granting the
14 flexibility we're referring to. There should be some
15 demonstration at least that this is occurring?

16 A. I would say it's an important consideration.

17 Q. Yes. Finally, on the marginal cost theory in
18 general; most of the testimony in this case centres
19 around pricing incremental energy at marginal cost to
20 promote efficiency. And I guess you would agree with
21 that process as well?

22 A. Yes. I think the principal thing you can do to make
23 prices and rates more efficient is to price all
24 customers' incremental usage always at marginal cost.
25 If you can do that, you've won.

1 Q. Well, that was my next question. That's exactly the
2 problem. It's all customers really should have --
3 from a fairness perspective and an efficiency
4 perspective, all customers really should have access
5 to those marginal kilowatt hours, or marginally
6 priced kilowatt hours.

7 A. Well, that's why I think time-of-use rates are a good
8 thing, because they go a long way towards pricing all
9 customers' incremental usage always at marginal cost.

10 Q. Now, if we made the assumption that NSPI was not
11 pushed into time-of-use rates, would it be reasonable
12 that the number of customer classes should increase?
13 Because it's very difficult if you have customer
14 classes with widely divergent customer
15 characteristics to price -- to give that embedded --
16 or that marginal cost signal.

17 A. Are you asking me, is an alternative to time-of-use
18 rates increasing the number of classes?

19 Q. Well, no. If the board doesn't push NSPI into time-
20 of-use, in other words they don't accept your
21 recommendation -- and certainly other people made the
22 same recommendation -- would you see that increasing
23 the number of customer classes would allow the rate
24 design to provide at least a few more kilowatt hours
25 of consumption at marginal cost?

DR. CHAMBERLIN, CROSS-EXAM. BY MR. KEHOE

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1 A. I guess you could do it that way. You can do it
2 other ways, too. You can block rates and have the
3 block structure reflect marginal cost of consumption
4 in those blocks. That's not as good a way as time-
5 of-use. But if it's done right, you could do it that
6 way. If you got the prices right with more classes,
7 I guess you could do it that way. If you just
8 developed additional tariff options within the same
9 classes, I guess you could do it that way. There's
10 probably a lot of different ways you could do it.

11 Q. NSPI are proposing to actually combine or move
12 classes around and basically, I believe, their intent
13 is to put customers which they believe have similar
14 characteristics together. But the current rate
15 design would indicate that some of the customers that
16 are being shifted are seeing huge increases and
17 decreases. Would that appear to you that we're
18 moving in the wrong direction, if time-of-use is not
19 an option?

20 A. Not necessarily. It could mean the opposite. It
21 could mean that the prices were very wrong to start
22 with and combining customers with like costs resulted
23 in big changes for some of them. I just didn't look
24 at it, but I don't -- I couldn't draw a conclusion
25 one way or another just from the fact that the price

DR. CHAMBERLIN, CROSS-EXAM. BY MR. KEHOE

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1 changes from the combination.

2 Q. But you'd agree if we had more classes instead of
3 less the rate design process would be easier ---

4 A. No.

5 Q. --- if it's non time-of-use?

6 A. That's not what I said. I said one way to get -- to
7 allow additional customers to see different marginal
8 costs consistent with their kind of -- with their
9 character of usage would be to create additional
10 classes if you price them right. You could create
11 the additional classes and price them wrong and come
12 up with the wrong result as well. It's getting the
13 prices right that matters.

14 Q. Thank you.

15 MR. ROBERTSON

16 Mr. Regan, are you -- no. You're satisfied. Mr.
17 MacDonnell?

18 MR. MACDONNELL

19 Thank you, Mr. Chair.

20 CROSS-EXAMINATION BY MR. MACDONNELL

21 Q. Dr. Chamberlin, can I conclude from your evidence
22 that you believe marginal costs are of paramount
23 importance for rate design?

24 A. I'm only hesitating over "paramount," whether you
25 mean the same thing by "paramount" that I do. I

1 think marginal ---

2 Q. If you'd like to substitute a word, that's fine.

3 A. I think reflecting marginal costs in the rates is a
4 very important thing to do. I think, the more
5 efficiency is an issue, it becomes almost the only
6 thing to do.

7 Q. Is it fair to say that the frequently-cited problem
8 with marginal cost-based rates is reconciliation to
9 the revenue requirement?

10 A. Sure. Yes.

11 Q. Do you agree that reconciliation is typically a two-
12 step process; first, determine the revenue
13 requirement by class, and then design rates to
14 recover the excess above marginal costs for each
15 class?

16 A. Yes, although there are differences in that, and the
17 differences being how the revenue requirement is
18 determined, whether it's a marginal cost-based
19 revenue requirement, as is done in California, for
20 example, or an embedded cost-based revenue
21 requirement, which you're then adjusting the marginal
22 cost-based prices, too. So, with that difference,
23 I'd agree. Those two steps have to be done one way
24 or another.

25 Q. Okay. Cost allocation is, therefore, an important

1 part of the reconciliation process?

2 A. Sure. Acknowledging that one way to do cost
3 allocation is marginal costs.

4 Q. Okay. Is there a necessity to be consistent between
5 the cost allocation study and rate design?

6 A. Well, if you want the price to be efficient, there
7 is.

8 Q. I'm supposing there -- supposing, for example, there
9 is a substantial difference between the embedded
10 energy costs in the cost allocation study and the
11 marginal energy costs reflected in rates. Using
12 NSPI's method whether the majority of fixed capital
13 costs are assigned to classes based on energy
14 consumption, if you start setting rates based on the
15 lower marginal costs, won't the increased energy
16 demand in that class attract more cost than the
17 revenue it produces?

18 A. Well, let me answer this way. If you're asking me if
19 the cost allocation produces a result that's very
20 different from the marginal costs, to begin with, and
21 then that class allocation is used to drive a
22 revenue-reconciled marginal cost, that marginal cost
23 won't be very efficient. It certainly won't be as
24 efficient as it could be in terms of a price.

25 Q. Okay. Under that scenario, in the event of a

1 shortfall who would pay for it?

2 A. If there's a revenue shortfall that results from an
3 incorrect price to start with, I guess stockholders
4 pay for it until the next rate case. And then it
5 depends on how the allocators are adjusted in the
6 subsequent rate case.

7 Q. All right. If the board were to deem it to be
8 appropriate to base rates on marginal costs, wouldn't
9 it make sense that the cost allocation study also be
10 performed on a marginal cost basis?

11 A. I think it could make sense. I don't think it has
12 to.

13 Q. Is it fair to say a sound cost of service study
14 methodology results in costs being assigned to a
15 class that at least recover the marginal energy and
16 marginal capacity cost of providing service to that
17 class?

18 A. I think you'd want to at least recover the marginal
19 energy cost. Whether you'd want to recover the
20 marginal capacity cost would depend on, for example,
21 whether it was long run or short run and the
22 relationship between the rates of return and some
23 other considerations as well. I don't think that --
24 the capacity part can be a problem. But certainly
25 you'd want to recover the marginal energy cost.

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MACDONNELL

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1 Q. Just on page 26 to 28 of your study -- I've been
2 asking most witnesses a couple of questions about
3 competition. That's the portion of your study
4 relating to flexible rates and competition. And you
5 conclude the concept of flexible rates is worthy of
6 consideration in Nova Scotia, but you add the caveat
7 that regulatory guidelines be established. Correct?

8 A. Yes.

9 Q. You would agree that the avoidance of undue
10 discrimination is a necessary goal of rate design?

11 A. Maybe. It gets more difficult to achieve that goal
12 the more competitive the market is. In a fully
13 competitive market if a company isn't discriminating
14 in the traditional sense that we mean it, it's not
15 going to survive. The market isn't fully
16 competitive, so the problem is a transitional one.
17 How do you deal with the need to discriminate? That
18 being a good thing in a competitive market but a bad
19 thing today during the transition. So, I think the
20 appropriate levels of discrimination are those which
21 are just sufficient to be able to keep customers and
22 to allow other customers to benefit from that, that
23 they're at least making a contribution to margin.

24 Q. So, given the current situation in Nova Scotia, you
25 would agree undue discrimination -- avoiding that is

1 a necessary goal?

2 A. Undue discrimination?

3 Q. Yes.

4 A. Well, undue discrimination is the amount of
5 discrimination that you exercised that you didn't
6 need to. I suppose, that's the way that I'd define
7 it. I don't know how much you need to in Nova Scotia
8 today. I haven't made a study of it. I'd say in the
9 U.S. there is more and more discrimination that's
10 happening and less of it is undue. It's required.

11 Q. Would you agree -- or what would be your opinion of
12 a situation where a utility -- where the Nova Scotia
13 utility, given the current situation, were able to
14 price two -- to price identical services to two
15 competing industrial customers differently?

16 A. That would concern me.

17 Q. You would feel that may constitute undue
18 discrimination?

19 A. I'd be concerned about it. Whether it was undue or
20 not, I don't know. There might be situations in
21 which it was due -- not to keep beating that, but
22 where it was due, necessary, beneficial kinds of
23 discrimination. But in general I'd be concerned with
24 it because I think the customers would be concerned.
25 Certainly the one -- if they were actually in very

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MACDONNELL

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1 like situations with respect to their competitive
2 alternatives and I were to cut a deal with one and
3 not the other, I would have done something harmful to
4 one of my customers.

5 MR. ROBERTSON

6 If you cut a deal with Customer "X" in Year "Y" and
7 then you cut a deal with Customer "Z" in Year "A,"
8 they're necessarily going to be different because
9 conditions are different. Is that considered to be
10 discrimination?

11 DR. CHAMBERLIN

12 I'd be concerned with that.

13 MR. ROBERTSON

14 In other words, you would go back and turn around and
15 adjust the first contract you entered into with a
16 customer?

17 DR. CHAMBERLIN

18 That might sound like a foolish thing to do ---

19 MR. ROBERTSON

20 Well, yes.

21 DR. CHAMBERLIN

22 --- but that's what companies in competitive markets
23 do all the time. The worst thing a company in a
24 competitive market can do is make -- is save their
25 best deals for other than their best customers.

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MACDONNELL

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1 MR. ROBERTSON

2 Well, of course, a good deal may exist because of
3 over-capacity at one point in time.

4 DR. CHAMBERLIN

5 Sure. I think this is part of the transition
6 problem. I think part of the transition problem is
7 that we're used to thinking of deals as being 10
8 years or 15 years or 20 years in nature. That's
9 where these situations come up. I think, as the
10 market becomes more competitive, what's happening is
11 these deals are much shorter term in nature. And as
12 that continues to happen, that becomes less of a
13 problem.

14 MR. ROBERTSON

15 But there are customers who want long-term deals, and
16 when you give them that deal, well, shouldn't they
17 live with it?

18 DR. CHAMBERLIN

19 Yeah. But then it's a ---

20 MR. ROBERTSON

21 If they insist on it at a point in time.

22 DR. CHAMBERLIN

23 But in that circumstance I'd argue that those are
24 really different deals. Suppose that last year I had
25 -- I saw a window of opportunity to provide a

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MACDONNELL

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1 customer with a 10-year contract at 4 cents, and that
2 was because I could go to wholesale markets and
3 acquire 3.8 cent capacity for them and I made that
4 deal to them. And that today or next year a very
5 similar customer from the same industry came to me
6 and asked for some kind of a deal and the best deal
7 that I could make for him at that time was 4.3 cents
8 with a 5-year contract. I think those are really
9 different things.

10 MR. ROBERTSON

11 Well, that's what I'm getting at, you know, that all
12 deals -- that most deals are somewhat different.

13 DR. CHAMBERLIN

14 Yeah.

15 MR. ROBERTSON

16 Therefore, you can't just say, well, you know, is it
17 discrimination because you've done one thing one time
18 and another thing at a different time.

19 DR. CHAMBERLIN

20 Yeah. I think that this situation that I've just
21 described is not a situation of discrimination.

22 MR. ROBERTSON

23 No. No, I don't think so either.

24 DR. CHAMBERLIN

25 I think the situation of discrimination would be if

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MACDONNELL

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1 I said to the second customer, "I'm not going to
2 undertake to find a deal for you," having done it
3 last year. So, it's not the numbers so much as how
4 do I respond to it.

5 MR. ROBERTSON

6 That's right. Thank you.

7 BY MR. MACDONNELL

8 Q. If the second customer did not have the option of,
9 for example, shifting manufacturing elsewhere that
10 the first customer had, you may well not make the
11 same effort to find a good deal. Is that correct?

12 A. If, by shifting operations elsewhere, you mean all of
13 the ways that a customer could take their load some
14 place else, I would agree. I think that's really
15 where the challenge is today, is that the markets are
16 increasingly competitive on the fringe and the fringe
17 is broadening throughout the whole customer base.
18 So, you change fundamentally from how you deal with
19 the business from one in which you have an obligation
20 to serve those customers, and discrimination and all
21 those kinds of issues are the key drivers to one in
22 which you are trying to make the best deals that you
23 can for the customers that have choices. I think
24 that's the fundamental problem.

25 Q. In a truly competitive situation, two identical --

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MACDONNELL

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1 two competitors in the same general location
2 demanding identical service would probably face very
3 similar rates. Do you agree?

4 A. Sure.

5 Q. If they took an equally intelligent approach to the
6 marketplace.

7 A. Well, I'm presuming that they are on pre-transition
8 kinds of rates that are on standard tariffs, and they
9 ought to be -- under the old rules, they ought to be
10 charged the same.

11 Q. Okay. Those are my questions. Thank you, doctor.

12 MR. ROBERTSON

13 Is it Mr. MacDougall or Mr. Cooper?

14 MR. MACDOUGALL

15 Mr. MacDougall.

16 MR. ROBERTSON

17 Okay.

18 MR. MACDOUGALL

19 Thank you, Mr. Chair.

20 CROSS-EXAMINATION BY MR. MACDOUGALL

21 Q. Dr. Chamberlin, I guess it's fair to say from your
22 pre-filed evidence and your testimony today that you
23 are in favour of time-of-use rates.

24 A. Yes.

25 Q. Isn't it true to say that time-of-use rates generally

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MACDOUGALL

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1 charge more for on-peak usage than they do for off-
2 peak usage?

3 A. Yes, they generally do, because it's generally --
4 almost by definition, it's on-peak usage which is
5 higher than off-peak. That's why it's on-peak. And
6 it's the higher usage that results in the need to add
7 capacity and the higher-cost plants.

8 Q. At page 3, line 12 of your testimony -- and I don't
9 think there's any need for you really to turn it up
10 -- you state:

11 "Although time-of-use price differentials
12 encourage customers to shift consumption to
13 off-peak hours, load shifting is not required
14 to justify rates."

15 And you've also mentioned that in your testimony
16 earlier today.

17 A. Right.

18 Q. When you say "load shifting is not required to
19 justify time-of-use rates," can we infer from that
20 that you take it that it is appropriate to charge
21 more for on-peak usage than for off-peak usage?

22 A. I think it's appropriate to charge the marginal cost
23 of the usage, whatever it is. Presuming the marginal
24 cost is higher, then the price should be higher.

25 Q. Which will generally be the case in time-of-use

1 rates?

2 A. Yes.

3 Q. Is that differential reflective of the difference in
4 the cost to serve on-peak load versus off-peak load?

5 A. Well, it should be. That's the point.

6 Q. So, you're essentially saying that even if nobody
7 does anything as a result of the changes in the
8 rates, it's still appropriate to charge more for on-
9 peak because it costs more to serve on-peak?

10 A. Right.

11 Q. Do you think it is appropriate to give one signal
12 with the cost allocation process and another signal
13 with the rate design process? And I know you touched
14 on that a bit earlier.

15 A. Well, of course, the cost allocation process only
16 works out into the market through the rate design
17 process. So, I'd say it slightly differently. I'd
18 say that the more you screw up the prices with the
19 cost allocation methodology, the worse the prices are
20 going to be.

21 Q. Can we just take a little hypothetical. If a
22 customer uses one more kilowatt hour at 3:00 a.m. in
23 some summer evening, what additional cost would he be
24 imposing on the NSPI system?

25 A. You want the specific number or the concept?

1 Q. No, just ---

2 A. The concept?

3 Q. --- the concept.

4 A. Presuming there's sufficient capacity available, that
5 is everything isn't down for maintenance or something
6 else, it's just the system lambda, it's the increased
7 energy cost by whatever unit gets bumped up another
8 kilowatt during that hour.

9 Q. Essentially, the marginal cost of fuel?

10 A. Yeah, and losses and other things associated with it,
11 but essentially that.

12 Q. But there's no influence on capital cost by that
13 extra usage at that time?

14 A. It seems unlikely.

15 Q. Whereas under the Stutz -- Dr. Stutz's approach and
16 Mr. Bowman's methodology, the cost of capital having
17 been allocated over all of the hours in the year, the
18 8,760 hours, would include a capital charge during
19 the summer because their approach treats every hour
20 as equally responsible for the 65% of fixed costs
21 classified to energy.

22 A. Are you asking me whether I reviewed the cost
23 allocation studies that were done by Stutz and
24 Bowman?

25 Q. Well, and their approach to the fact that those cost

1 allocation studies would reflect 65% of fixed costs
2 classified to energy.

3 A. I didn't review them, though. So, I'm -- I mean, in
4 concept if -- I'll agree with this. In concept if
5 capacity costs have been allocated to energy in the
6 allocation study, then, as that would work through
7 the allocation process, the allocation to energy
8 would be too high. It would be higher than the
9 marginal costs for it. Now, whether the price ends
10 up still being too high depends on the revenue
11 reconciliation and how that's done, things like that.
12 So, I don't think the connection is as
13 straightforward as you're indicating but the ---

14 Q. No. But if it was reflected in the rate design.

15 A. Well, but there's two things going on. There's an
16 allocation happening and then there's a revenue
17 reconciliation that's happening. So, it may be that
18 the energy cost gets -- is over-allocated from my
19 perspective in that it includes some capacity. That
20 would be bad. On the other hand, if the revenue
21 reconciliation process tended to raise that to that
22 level or above it, then it wouldn't matter. So,
23 that's why I mean the connection isn't as direct.

24 Q. Now, to move to a different subject. Do you agree
25 that competition is coming in the electric industry?

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MACDOUGALL

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1 A. Well, it certainly is in the United States and every
2 place else that I've spent any time looking.

3 Q. So, if we have competition in the electrical
4 industry, is it your opinion that we would have some
5 customers who would only want to buy on the spot
6 market?

7 A. Well, I think that's even true today. There are some
8 customers who would prefer, and, in fact, are finding
9 ways to buy on the spot market.

10 Q. And is that primarily because those customers are
11 really only concerned about price and they don't
12 really care about length of term and other factors?

13 A. I don't think I'd say it quite that way. I think, in
14 general, the customers that I can think of that are
15 buying on the spot market are, as if they were buying
16 on the spot market, getting a price that way. I
17 think they certainly have a concern about short-term
18 energy costs. I think they also have a belief that
19 capacity has been over-built and that the cost of
20 acquiring new capacity today is falling compared to
21 the last few years through combined-cycle plants and
22 things like that, and that utilities haven't
23 responded very aggressively to their needs. So, I
24 think it's more a question of -- rather than just
25 being concerned about the next year, I think it's

1 more of an issue of believing they can take care of
2 capacity requirements and needs in the long run
3 through contracting mechanisms and things like that.

4 Q. Would you expect an interruptible customer to be the
5 type of customer who would buy on the spot market?

6 A. I suppose, in general, I think that's true. But,
7 again, I think an interruptible customer, to my mind,
8 is slightly different than that. An interruptible
9 customer is one that is able to sell back their
10 reliability to their utility. They don't need it.
11 And many of those interruptible customers are ones
12 who are willing to do that for short periods of time
13 rather than for long periods of time. So, the
14 difference is some of what we talked about, customers
15 who believe they can take care of firm capacity needs
16 over the long run and interruptible customers might
17 want their firm capacity needs taken care of over the
18 long run but are still able to give up that
19 reliability for short periods of time.

20 Q. So, what would be the appropriate price to charge
21 that interruptible customer?

22 A. Well, I think the -- it depends on the contract
23 dealing with interruption. And there are all kinds
24 of interruptible contracts that describe the
25 frequency and the amount of notice that has to be

1 given and the duration of the interruption, how many
2 times you can do it, things like that. But for a
3 customer -- what I think of as a perfect
4 interruptible customer, one that the utility can
5 interrupt any time they want for as long as they want
6 to as many times as they want to ---

7 Q. And can I say that's the situation generally in Nova
8 Scotia.

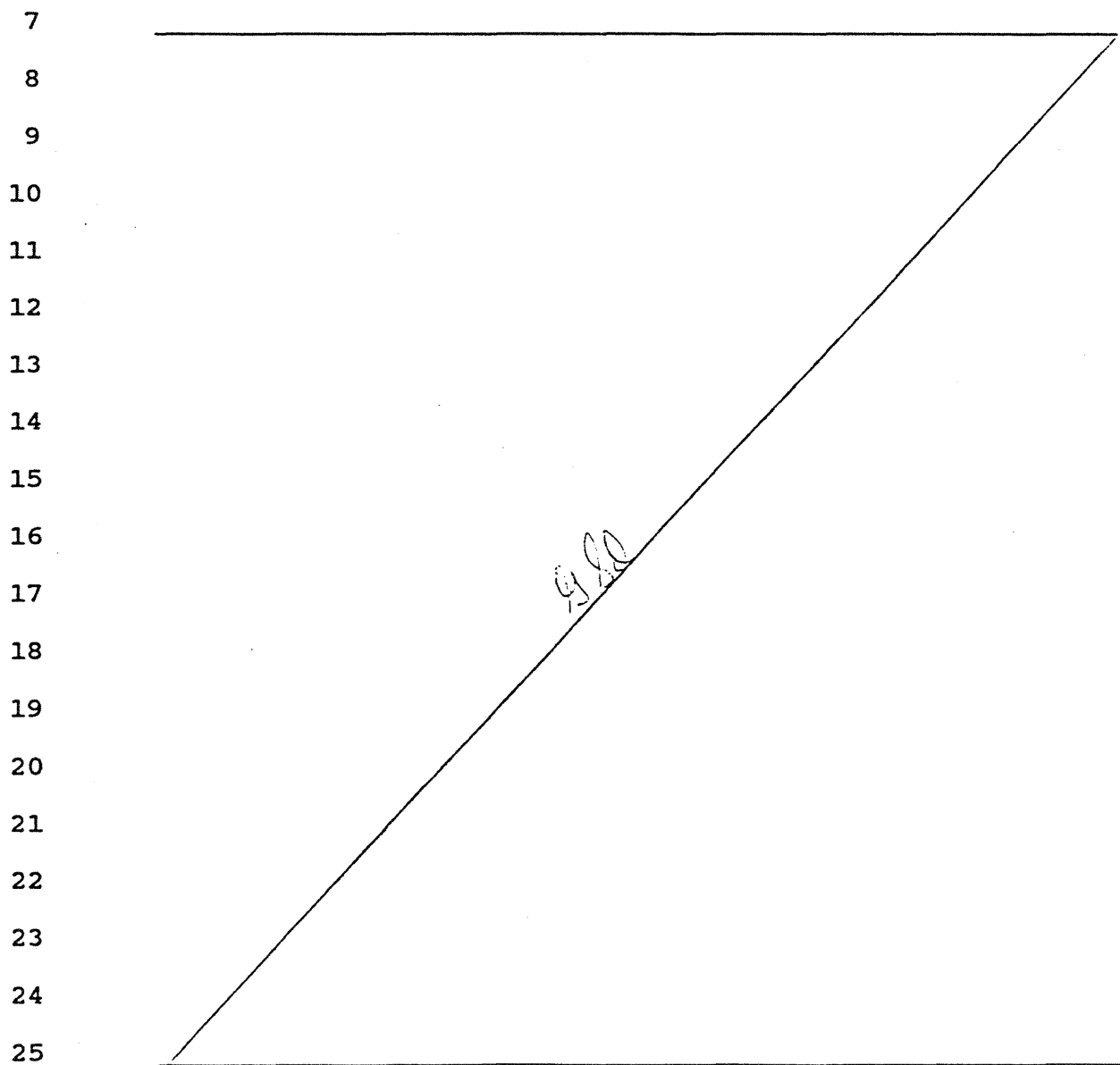
9 A. Okay. If that's the situation, then you'd have to
10 ask what's the value of that interruptibility to the
11 utility, and it's the marginal cost of capacity.

12 Q. So, it would be the short-run marginal cost?

13 A. Well, it depends on the contract. If the contract is
14 one year in length with that customer, then I think
15 it's the short-run marginal capacity cost. If the
16 contract is 20 years in length with that customer,
17 it's the long-run marginal capacity cost. It all
18 comes to the issue of the nature of the compact that
19 you're addressing with the customer. If you're
20 saying to the customer, you know, "We can interrupt
21 you just this year, but if you come to us next year
22 and say you want to be a full-requirements, regular
23 customer without interruptibility," then I'd say the
24 value that you've provided that customer is
25 equivalent to the short-run capacity costs. But if

1 they say, "If the deal is you can interrupt me this
2 year, next year and for the next 18 years," then that
3 customer is a peaker or equivalently whatever the
4 cost of capacity is over the long run.

5 Q. Are you aware of what Nova Scotia Power's short-run
6 marginal costs for 1996 would be?



DR. CHAMBERLIN, CROSS-EXAM. BY MR. MacDOUGALL

2790

1 A. It's addressed in several people's testimony, and
2 disagreed about, so -- I have done a study myself.

3 Q. If you didn't, I was going to say, an approximation
4 would be about three cents (\$0.03) I think. But it
5 has been disagreed in various testimony. And I
6 could ---

7 A. Well, it talked about -- it talked about the three
8 and a half cents (\$0.035) or so marginal energy
9 cost. I've seen that, yes.

10 Q. So would you agree, that that would be the
11 appropriate price to charge interruptible customers
12 right now, if they were one who should be charged
13 on the basis of short-run marginal cost?

14 A. Oh, I would do it the other way. I would say,
15 "What tariff is the customer operating under?" And
16 I would provide the customer with a discount or a
17 credit, that was equal to the nature of the
18 capacity deal I made with them, with respect to
19 interruptibility. The next step better, is to
20 charge them under a time of use rate regular
21 tariff, which reflects the -- the marginal cost of
22 energy and capacity in different times of the year,
23 and time of day, and provide them with a discount
24 for interruptibility that was consistent with the
25 nature of the deal. Is it a one-year deal, or a

DR. CHAMBERLIN, CROSS-EXAM. BY MR. MacDOUGALL

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1 10-year deal?

2 MR. MacDOUGALL

3 That's all my questions, Mr. Chair. Thank you very
4 much, Dr. Chamberlin.

5 MR. ROBERTSON

6 Mr. Campbell?

7 MR. CAMPBELL

8 Thank you, Mr. Chairman.

9 CROSS-EXAMINATION BY MR. CAMPBELL

10 Q. Dr. Chamberlin, I'd like to follow up on a question
11 that my Friend Mr. Outhouse asked you, back when
12 you began your testimony. And he asked you about
13 whether avoided costs can be calculated in the same
14 way as long-run costs. And your answer was, you
15 could do it that way, and if you would, then
16 avoided cost would be the same as long-run cost.
17 But that's not your understanding of at least a
18 traditional notion of avoided costs under PURPA.
19 What I'm getting at is the question of
20 nomenclature. We've ---

21 A. Of what? Excuse me?

22 Q. Labels. Nomenclature.

23 A. Oh, okay.

24 Q. We've been talking about short-run cost and
25 long-run cost, and sometimes, not understanding

1 each other. Is it correct that there are a whole
2 variety of methodologies for calculating marginal
3 costs, that each incorporate different elements of
4 short-run and longer-run cost, that reflect future
5 increments of lumpy capital in different ways, and
6 as a result of these different methodologies, you
7 can get a whole range of estimates?

8 A. Yes.

9 Q. And they get characterized as short-run or
10 long-run.

11 A. Well they get categorized in three ways. The
12 distinction that I was making, is there's three
13 categories of kinds of marginal or avoided cost.
14 There's avoided cost, there's short-run marginal
15 cost, and there's long-run marginal cost. Those
16 are just categories. Now there's a bunch of
17 methods that you can use to calculate any of those
18 three things. And occasionally, one method can be
19 used to calculate all three of those things. So
20 there's -- I'm making a distinction between a
21 method and a category.

22 Q. Okay. Is it fair to say that it's necessary to
23 have an understanding of the methodology you're
24 talking about, to perform an analysis, that it can
25 be misleading just to use the label?

1 A. Yes.

2 Q. Sir, in part 2 of your evidence, you talk about the
3 time of use rates proposed by NSPI, and by Mr.
4 Bowman. And on page 3, at line 12, you say, as you
5 do elsewhere in your evidence, that:

6 "TOU rates are desirable on efficiency
7 grounds, even if you experience no load
8 shifting."

9 A. Yes.

10 Q. However, as a practical matter, wouldn't you want
11 assurance that the tangible benefits to the utility
12 and its customers are at least enough to offset the
13 incremental cost of metering, and administration?

14 A. Sure. It costs something to replace existing
15 meters with time of use meters. There's no
16 doubting that. The distinction that I'm making, is
17 that if -- is that if you use that -- if you think
18 of time of use rates as a demand-side program, and
19 justify it by the value of the shift of load, I
20 think you've made a mistake. I think you choose
21 the wrong rates, I think you make wrong decisions
22 about it. I think it's the -- it's the efficiency
23 that you're trying to achieve, not the load
24 shifting. Whatever load shifting occurs, occurs.
25 If the price is right, then that's the right amount

1 of load shifting, whether it's none, or a lot. So
2 there -- I agree that I'm making an assumption in
3 my testimony, that -- that the rates themselves are
4 cost effective; that is, the efficiency gains are
5 enough to pay for the cost of the meter. But the
6 reason I don't put it that way, is that the
7 efficiency gains don't have to come from the shift
8 in the load itself. In fact, from an efficiency,
9 or an economic perspective, efficiency gains can
10 come from increases in load. The value to
11 customers that result from increasing off-peak
12 usage, if that's what happens. That efficiency
13 gain could pay for the meter costs as well.

14 Q. Let me see. On page 11, you're talking about the
15 test that Mr. Bowman uses to evaluate his different
16 reconciliation methods. You indicate that you
17 don't favour the use of cost/benefit analysis. Is
18 that the point you're just making?

19 A. Yeah. Yeah, because that test counts increases in
20 off-peak usage as negative things, as bad things.
21 But in fact, if customers buy more electricity off
22 peak, as long as they're paying the cost of it,
23 that's a good thing. It's not a bad thing. It's
24 worth it to them. And if they're paying the
25 company an amount at least as great as it cost them

1 to produce that electricity off peak, everybody
2 benefits from it. The cost/benefit method doesn't
3 address that. It says it's across, when in fact,
4 it's above.

5 Q. You identify Mr. Bowman's concern about the use of
6 the customer charge method, which you indicated you
7 felt was a better one, because it might make the
8 promotion of the time of use rate unpalatable, if
9 there's a large customer charge embedded? Did I
10 misunderstand what you were saying?

11 A. Well, that's part of it. But the principal
12 difference is that Mr. Bowman, in -- his
13 recommendation and mine, is that he wants to keep
14 the off-peak prices at marginal cost, or as close
15 to that as possible, and put all the revenue need
16 essentially in the on-peak charge. I think that
17 results in an on-peak cost which is way too high.
18 So I'd like to see a time of use rate in which both
19 the peak and the off-peak charges look more like
20 marginal cost. One way to do it is the customer
21 charge method. Another way to do it, is to keep
22 the customer charge where it is, but to block the
23 time of use prices themselves. I suggested that as
24 a possibility. It's certainly not the only one.
25 Another way is to move the off-peak prices up a

1 little bit, and the on-peak prices down a little.

2 Q. To the extent that the size of the customer charge
3 would inhibit migration to the time of use rate,
4 could you not mitigate that, by making sure that
5 the customer charge was the same in whatever we're
6 calling the non-time of use rate, and the time of
7 use rate?

8 A. Yes.

9 Q. All right, sir. Part 3 of your evidence deals with
10 the proposals for non-time of use rates, the
11 seasonal or regular blocked rates. And you comment
12 on NSPI's proposal to implement a declining block
13 rate structure for the domestic class. On page 14,
14 beginning at line 5, you say that:

15 "Declining block rates are considered
16 efficient when large-use customers consume
17 a higher proportion of energy during
18 off-peak periods, than other customers in a
19 class. These types of customers usually
20 exhibit higher than average load factors,
21 which translate into lower cost of
22 service."

23 Could you explain that please, the process or the
24 concept you're referring to here?

25 A. Well, suppose you decide not to implement time of

1 use rate, and still want to adopt the principal of
2 getting marginal costs reflected in the prices for
3 marginal usage, for as many customers as possible.
4 Suppose that's what you do. If small customers in
5 a class tended to have most of their consumption,
6 say 60 percent, on peak, and large customers in a
7 class tended to have most of their consumption, say
8 60 percent, off peak, then on average, smaller
9 customers would be more expensive to serve than
10 larger customers. And so the rate ought to be
11 declining block. That would be an efficient price.
12 All you're saying is that customers that end their
13 usage in the first block, ought to see the marginal
14 cost at what's the margin for them, their
15 incremental use. And customers that end their
16 usage in the second block, ought to see that lower
17 marginal price. What you're trying to do is get
18 the -- you're trying to use a block structure to
19 essentially create two classes, a small class and a
20 large class, within the broad umbrella of the
21 domestic class.

22 Q. Could you distribute this Exhibit, Dr. Chamberlin?
23 You'll recognize it as a paper which you
24 co-authored ---

25 A. Yeah.

DR. CHAMBERLIN, CROSS-EXAM. BY MR. CAMPBELL

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1 Q. --- discussing this very subject, the ---

2 A. Yeah.

3 MR. ROBERTSON

4 N-83.

5 EXHIBIT N-83 (ENTERED) - ARTICLE: EFFICIENT BLOCK RATE

6 STRUCTURES: RETHINKING CONVENTIONAL WISDOM

7 BY MR. CAMPBELL

8 Q. And after a mathematical derivation, which I'm sure
9 is thoroughly riveting, you reach three general
10 rules on page 58, the second last page of the
11 article. Before we look at those, I'd like you to
12 turn up Mr. Dominie's Supplementary Evidence. Have
13 you had a chance to see Mr. Dominie's Supplementary
14 Evidence on this subject?

15 A. I don't have -- I don't have it with me. I'm not
16 sure whether I've seen it or not.

17 Q. The material at page 6, sir, that has the
18 coincident load factors for the different usage
19 blocks of the domestic rate. If you haven't had a
20 chance to read it, certainly take time to have a
21 look at it.

22 A. I haven't seen it, but I'm looking at it now.
23 Okay.

24 Q. Okay? Can we have a look now, at your three
25 general rules about when a flat rate, or an

1 inverted block, or a declining block start to be
2 appropriate?

3 A. Okay.

4 Q. Page 58 you say:

5 "A flat rate is efficient whenever the
6 price responsiveness of large and small
7 users is the same, and the marginal cost of
8 serving them are equal."

9 I take it that is not demonstrated here. The
10 response to this seems to be different in the upper
11 block.

12 A. No, this -- this evidence of Mr. Dominie suggests
13 nothing about responsiveness. Responsiveness has
14 to do with elasticity.

15 Q. All right.

16 A. So he's -- this evidence is suggesting -- there are
17 some questions about how the coincident load factor
18 is calculated. It's suggesting that the load
19 factor is smaller in the -- is smaller in the
20 second block, and bigger -- higher, especially
21 higher in the third block. So it deals with the --
22 potentially with the load factor issues, rather
23 than the responsiveness issue.

24 Q. All right.

25 A. Now I want to back up and explain that, because

1 that's important.

2 Q. All right.

3 A. From a theoretical point of view, there are two
4 things that you want to -- that you need to know,
5 in order to get the revenue reconciliation process
6 right. One is, you need to know what the marginal
7 costs are for different kinds of usage. But the
8 second is, you need to know what the elasticity is
9 for different kinds of usage. Now, why do you need
10 to know what the elasticity is? It's because
11 you're not so much worrying about what the prices
12 are at the end of the day. What you're worrying
13 about, is getting the resource allocation right.
14 So for example, if you had two customers, or kinds
15 of usage, one of which was very responsive; that
16 is, a small change in price induced that customer
17 to change his consumption substantially; and
18 another whose usage was very non-responsive, didn't
19 care what happened to the price, he was always
20 going to use the same amount of electricity; in
21 that circumstance -- and if you had to adjust the
22 prices, you'd want to adjust the price the least
23 for the customer that was very responsive, and the
24 most for the customer that was non-responsive.
25 Why? Because if you adjust the prices the same for

1 the two of them, that one very responsive customer
2 is going to use a lot more or less of that thing.
3 They're going to move a lot farther from what that
4 optimal allocation of resources would be. They'll
5 use way too much electricity if you drop the price
6 a little bit to that customer, or use way too
7 little electricity if you raise the price a little.
8 So it's that -- here, I'm -- this point #1 is
9 dealing with the responsiveness issue.

10 Q. Okay. Can we take it that there is other evidence
11 in this proceeding, that there is considerable
12 responsiveness for those in the third block,
13 considerable elasticity, those being the electric
14 heat customers generally, who have alternative
15 fuels, and who are voting with their feet?

16 A. If you told me that the elasticity of those
17 customers, electric heat customers in general, was
18 greater than the elasticity for the other
19 customers, that wouldn't surprise me.

20 Q. Yes, okay. And the higher load factor, what can we
21 deduce about cost from that?

22 A. Well, if there is a difference in -- between
23 on-peak and off-peak costs, and if you have two
24 kinds of customers, one that has a very high load
25 factor, and the other has a very small load factor,

1 then the high load factor customer is going to use
2 disproportionately more of the cheaper electricity.
3 So if you're averaging the prices, then the average
4 price would be lower for the high load factor
5 customer.

6 Q. Can we jump right to your Rule #3 that says:

7 "A declining block structure is almost
8 always efficient if the marginal cost of
9 large users is less than the marginal cost
10 of small users."

11 A. Yeah.

12 Q. And here, of course, you have no elasticity
13 qualification in that one.

14 A. Right. But it was the result of the simulations
15 that we had done. Basically what we found, is that
16 although there's been lots of articles written
17 about the importance of knowing elasticity
18 estimates of different kinds of customers, that we
19 found, just when we looked at it, in fact, it
20 doesn't matter very much, that it's -- in terms of
21 whether or not -- how block structures ought to be
22 created, whether they're inverted or declining,
23 that it was the marginal cost differences that
24 really drive the efficiency results.

25 Q. Given the indication then, of the substantial

1 difference in load factor in the third block, would
2 that tend to support a declining block price
3 structure?

4 A. Well, just looking at it, it would tend to support
5 a -- it would seem -- this part alone would seem to
6 tend to support in the winter, a rate structure
7 which was, I guess, opposite of U shaped, N shaped.
8 It would seem to go up a little.

9 Q. A slight take-up from the middle and ---

10 A. Yeah, go up a little bit in the middle, and then go
11 down at the end. If they weren't seasonally
12 differentiated, if they were just non-seasonal
13 differentiated rates, it would -- a flat, or
14 slightly U-shaped one. The concern that I had, was
15 that I really didn't know enough. And I didn't
16 think, in the materials that I had seen, that -- I
17 think you can make, and ought to make, a cost-based
18 justification for a block rate structure. A think
19 block rates structures, if you're not going to use
20 time of use rates, can get you there, or at least
21 get you part of the way there. I just was
22 concerned, in the materials that I saw, I didn't
23 see what I'd consider to be an appropriate
24 justification for any particular block structure,
25 much less the one that was proposed. This would

1 seem to support, sort of, the -- at least the drop
2 in the third block. But I'd want to know some
3 other things as well, like what the marginal costs
4 were, and the relationship between that block and
5 marginal costs and things like that. But it helps.

6 Q. But provided the third block price exceeded
7 marginal cost, then that would be an appropriate
8 thing, at least in the winter.

9 A. Well, the question would be, which marginal cost?
10 The concern that I have over the third block, has
11 got to do with an issue that we were discussing
12 earlier this morning. And that's the nature of the
13 Agreement. If an electric heating customer could
14 be dropped at such time that there was a capacity
15 need, because you say to that customer, "I'm not
16 going to serve you with electric heat any more,"
17 then I think that third block only should cover
18 short-run marginal cost. That's -- that would be
19 the nature of the Agreement, just like with the
20 industrial development rate, or the interruptible
21 rate. If the nature of the deal was, "We're going
22 to continue with our obligation to serve for 20
23 years, or the life of that equipment," then I'd
24 want that third block to cover long-run marginal
25 cost. And if it did, I think that would be

1 sufficient.

2 Q. But there's no rate commitment for 20 years.

3 A. No, but -- but it's more than that. There is a
4 cost consequence that results. For example,
5 suppose the rate only covered short-run marginal
6 cost, and in two years, you make a commitment to
7 add new capacity, and that gets added over the
8 years. I would regard that third block as not
9 efficient, in the sense that it induced customers
10 to -- it told customers that the price is three and
11 a half cents (\$0.035) or something, when in fact,
12 the price might be thirteen cents (\$0.13), or eight
13 and a half cents (\$0.085), or one of the various
14 other numbers that people are talking about, as the
15 long-run marginal capacity cost. I'd say the more
16 important, the more near term, is the need to add
17 capacity, the closer, more proximate is that
18 decision, the more I think the prices ought to
19 cover the long-run marginal cost, rather than the
20 short-run marginal cost.

21 Q. Thank you sir. Sir, part 4 of your evidence, you
22 discuss competition and flexible rates. And you
23 discuss similar matters in a paper, of which you're
24 the co-author, which is provided, as the first
25 attachment to NSPI Information Request 1. Do you

DR. CHAMBERLIN, CROSS-EXAM. BY MR. CAMPBELL

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1 have the Information Request with you?

2 A. Yeah. Are you referring to the paper, "Effects of
3 Competition in Deregulation on IRP"?

4 Q. Yes.

5 A. Yes, I have it.

6 Q. In the abstract to that paper, which is on the
7 first page ---

8 MR. HARRIS

9 Which IR is that?

10 MR. CAMPBELL

11 This is NSPI IR-1.

12 MR. OUTHUSE

13 It's under 42 in my book. Not in the large book.

14 MR. ROBERTSON

15 It's in the small book.

16 MS. GARBER

17 42?

18 MR. ROBERTSON

19 42.

20 MR. CAMPBELL

21 Have you found it, Mr. Chairman? These were three
22 papers attached to IR-1. It is the first of the
23 three.

24 MS. GARBER

25 Which page?

DR. CHAMBERLIN, CROSS-EXAM. BY MR. CAMPBELL

2807

1 MR. CAMPBELL

2 Page 1.

3 BY MR. CAMPBELL

4 Q. Doctor, you say:

5 "Under any scenario of the future, which
6 includes full retail access, traditional
7 integrated resource planning, IRP, and DSM
8 programs will have little value, and will
9 likely be eliminated. In scenarios in
10 which more limited access is available,
11 some aspects of IRP and DSM may survive.
12 In any case, DSM programs must change, to
13 focus on delivering customer value."

14 Could you briefly explain why competition is
15 driving these things, and what you mean by focusing
16 on customer value?

17 A. Sure. Briefly?

18 Q. Well, you have a flight to catch, don't you?

19 A. No. Eventually. There are lots of reasons. But I
20 think here, are the important ones. As the markets
21 in the U.S., and in other parts of the world --
22 some markets in Europe and the Pacific Rim -- as
23 they become more competitive, it's become plain
24 that the concept of the vertically integrated
25 utility has to go away. You can't create

1 competitive wholesale markets, and allow retail
2 customers access, in one way or another, to those
3 markets, and preserve the fiction of a vertically
4 integrated utility. The problem with that, is that
5 if the vertically integrated utility -- if you
6 think about its generation business, its wholesale
7 business, if it acts in any way different than if
8 it were -- if it divested itself of that generation
9 business, and drove prices to retail customers off
10 the wholesale market costs, if it did anything
11 different, it would lose. So one of the things
12 that's happening, is that as markets become more
13 competitive, utilities are at least functionally
14 divesting the generation business. The retail
15 business becomes one of essentially acting as
16 brokers to customers, giving them access to
17 wholesale pools. But the generation costs, the
18 power costs, are driven off the wholesale pool, not
19 whatever happens to be on some embedded cost
20 revenue requirements books of a utility. So in a
21 full access world, the problem with IRP, is that
22 you continue to operate as though you were
23 vertically an upgraded utility, making decisions
24 for customers over 20 years, and that they could be
25 -- you could somehow insulate yourself from those

1 competitive wholesale pressures. And similarly,
2 the problem with DSM, as it's been practiced at
3 least in the U.S., and the -- in many parts of
4 Canada that I'm familiar with, there's
5 fundamentally a cross-subsidy that occurs. You put
6 programs into the market that benefit certain
7 customers, and you assume that other customers are
8 willing to pay for that, or at least, in fact, you
9 charge other customers for that. So as the market
10 becomes more competitive, the concept of IRP has to
11 crash, fundamentally because you have to break the
12 tie between the generation part of the business,
13 and the retail part of the business. The comment
14 that I made about customer value, is really related
15 to the broader proposition, that in a competitive
16 world, if you do anything at all that doesn't
17 directly affect customer value, and directly
18 increase customer value, you shouldn't be doing it.
19 Somebody else has the opportunity to give the
20 customers the same value that you're doing then, at
21 lower cost, because they're not doing those things
22 that don't directly contribute to positive customer
23 value. So in any competitive business, it's -- all
24 the restructuring that's going on is all getting at
25 driving out things that don't directly add to

DR. CHAMBERLIN, CROSS-EXAM. BY MR. CAMPBELL

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1 customer value, because if you don't do it,
2 somebody else will.

3 Q. Sir, on the second page of the paper, you discuss
4 the retail competition which is emerging in the
5 States. And you say that:

6 "Much of the growing concern over
7 competition in the retail electric utility
8 industry, centres around when and if retail
9 wheeling will become a reality. Even
10 without retail wheeling, utilities face
11 numerous threats to their native loads, and
12 these threats are increasing."

13 And you list some of the sources of that
14 competition, which exists even in the absence of
15 retail wheeling. Is it your point that these
16 competitive pressures exist today, and can only be
17 expected to increase as the move to wholesale and
18 retail wheeling takes place in other jurisdictions?

19 A. Yes. I think it's a mistake to think there's a
20 bright line that consists of the decision, "Do we
21 allow retail access or not? If we don't, the
22 market's protected, and non-competitive. If we do,
23 the market's fully competitive." In fact, there's
24 -- the market has never been fully protected. But
25 over the -- particularly since PURPA and then EPACT

DR. CHAMBERLIN, CROSS-EXAM. BY MR. CAMPBELL

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1 in the U.S., the markets are increasingly
2 competitive. There are increasing ways that
3 customers are finding to essentially act as if they
4 were getting retail access. And those things are
5 happening, and the pressures are growing in
6 earnest.

7 Q. Sir, the second paper that was appended to that IR,
8 was written by your colleagues, I guess. You
9 weren't listed as an author. But I take it you
10 agree with your colleagues?

11 A. Yeah. Originally, I was scheduled to give the
12 paper, so I'd have had to have agreed with it. I
13 ended up not giving it, but ---

14 Q. You have some ownership of it.

15 A. Yeah, some.

16 Q. The title is "Integrated Resource Planning in
17 2004," with a significant question mark after it.
18 In fact, I'm going to refer you to sort of the
19 second paragraph of the Introduction. And about
20 halfway through, the paper says:

21 "However, IRP is becoming obsolete as
22 quickly as it gained prominence. In many
23 States, particularly those where
24 collaboration drives the planning process,
25 the single IRP cycle last for more than a

DR. CHAMBERLIN, CROSS-EXAM. BY MR. CAMPBELL

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1 year, and costs millions of dollars. Many
2 have concluded that IRP is so complicated,
3 detailed, time consuming and costly, that
4 it is not a viable decision-making tool."

5 Could you comment on that thought?

6 A. Sure. Well, the comment is driven directly by the
7 previous issue that we were discussing. The
8 benefits from an IRP process essentially require
9 that the concepts behind IRP remain fundamentally
10 consistent with the nature of the business. If you
11 believe that the markets are increasingly
12 competitive, that they will increasingly become
13 competitive, and that the link between the supply
14 side and the demand side gets broken by the market,
15 then IRP is a fiction. It leads you to do things
16 that are not in the company's interest, and not in
17 customers' interests. So that these comments that
18 you see here, flow directly from the issues that we
19 were just discussing.

20 MR. ROBERTSON

21 Mr. Harris, you have some questions?

22 MR. HARRIS

23 Just a couple, or just a few.

24 CROSS-EXAMINATION BY MR. HARRIS

25 Q. I suppose picking up from the last discussion, with

1 respect to competition, and what the implications
2 of competition are for regulation, and for the
3 industry as a whole, that's certainly been a theme
4 in this Hearing thus far. And I guess it's for us
5 to ultimately assess where we stand in Nova Scotia,
6 with respect to competition at the present time,
7 and where things are going to go. And whether our
8 perceptions are right or wrong, they will
9 undoubtedly colour or views with respect to a
10 number of the issues before us. If I can just
11 summarize a couple of sub-themes that I've got out
12 of the proceedings so far, one is that assuming
13 competition is present to some extent in Nova
14 Scotia now, and there's no real electricity to
15 electricity competition, as the phrase has been
16 used, but there are other types, as you've outlined
17 in these articles here, other aspects of relevance
18 of competition present. And clearly, we're getting
19 a consensus from all experts that we've heard thus
20 far in this proceeding, that the competition, in
21 terms of the generation level, is present, or will
22 work its way through the system in its various
23 ways, as you've pointed out, even if we don't have
24 immediate retail wheeling in the next couple of
25 years. Anyway, one fallout from that is that it's

1 being suggested to us that if there's any alignment
2 of rates to take place, it should be with the kind
3 of rates that might be expected to prevail in a
4 competitive marketplace. And my understanding of
5 what you're saying, is that you would agree with
6 that, and would perhaps go one step further and
7 say, even if we don't have competition in the
8 immediate future, rates should be, quotes, "aligned
9 with marginal cost, because that is the efficient
10 way of doing things." Those rates based on
11 marginal cost give efficient price signals. And
12 that, in itself, is sufficient reason to go to
13 marginal costs, or to a considerable agree, to use
14 this word, align rates with marginal cost, so that
15 with or without competition, that would be your
16 position with respect to rate design.

17 A. Yes. I think by doing that, customers make the
18 right choices with respect of investments that the
19 company will make, and that you get the most --
20 society as a whole gets the most output from the
21 limited resources that are available.

22 Q. And of course, in a competitive marketplace, a
23 competitive market, there would be a tendency for
24 rates to reflect short-run marginal cost. But your
25 view is that for rate-making purposes in the

1 present environment, long-run marginal costs can be
2 considered as well.

3 A. Yeah. I would consider them both. I actually
4 disagree with the notion that in competitive
5 markets, rates are based only on short-run marginal
6 costs. I think there's a -- in our market, in the
7 electricity market, there's a bigger difference
8 between short-run costs and long-run costs, than is
9 typically the case.

10 Q. I don't know if you had a chance to look at Hethie
11 Parmesano's evidence before us. But she might
12 differ from you then, I guess, in that respect.

13 A. I think she does. I think we differ on several
14 areas. One is, I think there is a bigger
15 difference here than there is in other markets. I
16 think what you'd like to do, if you were
17 unconstrained, if you could do anything you wanted,
18 what you'd like to do, is you'd like to find the
19 price that would be the equilibrium price, the
20 price after adjustments. I mean, the problem here
21 is, the short-run price is very low. The long-run
22 price, if we ever get there, is high. And so, Dr.
23 Parmesano would say, "Charge the low price now, and
24 then over time, you'll charge a higher price,
25 reflecting the long-run capacity you need. And

1 then if that means customers decrease their usage,
2 because they don't like the high price, so be it."
3 Well, when the "so be it" happens, there'll be an
4 even different cost. And finally, in theory, you
5 would get to this equilibrium price. I think that
6 equilibrium price can be gotten to quicker, just by
7 blending the short-run and the long-run concepts.
8 And there's a second problem, and that's -- where
9 she and I disagree. And that's that in this
10 market, as it's presently constituted, there is a
11 relatively long lead time between -- long
12 difference between short run and long run, a
13 seven-year lead time, or a 10-year lead time, to
14 build a new plant. By the time the commitment is
15 made, it's almost too late to reflect that price,
16 to give customers an option to adjust. And I think
17 as markets become more competitive, one thing that
18 happens is, that difference goes away. It goes
19 away because there are lots of contracts that get
20 written into the market for capacity compacts of
21 lots of different durations. Some customers buy
22 three-year contracts, other customers buy 10-year
23 contracts, other customers buy one-year contracts.
24 There are futures markets that smooth the
25 difference between the short run and the long run.

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1 You have opportunities to hedge the differences
2 between short run and long run, by selling and
3 buying in futures markets. So that difference gets
4 small. And so in the competitive market, I'd say
5 prices generally reflect that short-run cost. But
6 they also reflect long-run considerations, by
7 virtue of things like futures markets. We don't
8 have that yet. And so I think the way you deal
9 with it, is you have some reflection of long-run
10 marginal costs in the short-run price signals. And
11 the more immediate is the need for capacity, or the
12 closer you get to the decision point, the more the
13 long run matters.

14 Q. Now, the effect of this on the costing issue, rate
15 making versus in -- based on marginal cost in a
16 second. But the second theme seems to be one that
17 Mr. Campbell referred to a minute ago, that in a
18 competitive marketplace, there's very little room
19 for IRP as we have known it. I think some
20 witnesses have said, "This doesn't mean that
21 utilities won't plan." It's just that there's no
22 place left for I guess what we might call a
23 collaborative regulatory involvement in that
24 planning exercise. And Mr. Campbell has taken some
25 delight I suspect, in quoting your sentences a

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1 couple of minutes ago about, IRP is becoming
2 obsolete as quickly as it gained prominence, and so
3 on, complicated detail, time consuming. And I
4 guess everybody agrees. And the suggestion has
5 been made by Mr. MacDonald that that indeed
6 characterizes the IRP process that is presently
7 underway in Nova Scotia. It's overly complex, it's
8 overly costly. And I suppose the next step in the
9 chain, that we are, therefore, to jump to the --
10 well, not jump perhaps -- but to reach the
11 conclusion that we should -- no one has actually
12 said this -- but I would take it that the
13 implication is that, given that competition is
14 coming we should put a stop to the present IRP
15 planning exercise that is underway here in Nova
16 Scotia. I suppose everyone swallows their losses,
17 and it all just goes away, and we leave planning to
18 the utility, and withdraw any regulatory
19 involvement in the process. That seems to be what
20 the implication is some of the testimony we've
21 heard so far. And some of the witnesses, again,
22 have taken delight in pointing out how regulators
23 have got it wrong when it came to calculating
24 long-run avoided costs, and the disasters that
25 befell jurisdictions such as New York, and

1 Massachusetts, and perhaps California, in that
2 utilities were required to buy far more power from
3 independent power producers than they needed, or
4 that was economically justified, in retrospect, all
5 because of mistakes made by regulators in
6 calculating long-run avoided costs. And the lesson
7 for us, is that you'll probably never get it right,
8 when you require utilities to plan for long periods
9 into the future. And why spend great sums of money
10 at this point, on futile exercises, which could
11 ultimately cause more harm than good? So I guess
12 I'm really looking for some advice as to, if one
13 accepts that there is a degree of competition, even
14 in Nova Scotia, albeit not electricity to
15 electricity competition, and that we are not immune
16 to trends elsewhere, and even if we don't get
17 either wholesale or retail wheeling in the
18 immediate future, more and more of the utility's
19 customers will have options, even conceivably,
20 self-generation, although without natural gas, I
21 find that a little difficult to place too much
22 weight on. But in any event, competition is
23 coming. And what advice can you give us, with
24 respect to where we proceed with the IRP project
25 that is presently underway here in Nova Scotia?

1 A. Well, understanding that I'm not very familiar with
2 the IRP process here in Nova Scotia, but of course,
3 I'm ---

4 Q. Assume that ---

5 A. --- very familiar with it in ---

6 Q. --- it has some considerable parallels, and
7 similarities to the projects and processes that
8 have been followed in the United States.

9 A. Maybe the best way to answer that, is to tell you
10 what my concerns specifically are with the IRP
11 process, as it's generally practiced today, and I
12 think as you do it, and what I would do
13 differently. My concerns aren't particularly
14 theoretical in nature. They're that, as -- if you
15 get to the place that the market is fully
16 competitive, in addition to the things that I
17 mentioned in my discussion earlier this morning,
18 the fundamental problem is that if the IRP process
19 results in anything different than what the market
20 would yield, it's wrong, in my opinion. It's wrong
21 because the market yields the set of services, and
22 nature of services, and quality, and cost that
23 customers want to pay for it. That's in a very
24 competitive market. Now the challenge is, the
25 market isn't yet very competitive. So part of your

1 decision, is your assessment about how fast it's
2 becoming competitive here, and how you can manage
3 that. I think the things that are most wrong with
4 the IRP process, other than requiring the adoption
5 of resources which are other than what customers
6 want to buy, I think the things that are wrong
7 about it, are that it has this assumption of --
8 this 20-year planning arising assumption, or
9 30-year planning arising assumption. I think it
10 would be nonsensical to make a decision today,
11 assuming that markets are going to unchange, not
12 become very competitive, over the next 20 or 30
13 years. I think at least you have to admit the
14 possibility that markets will be very competitive,
15 whether you want them to be or not, over -- at some
16 point within the next 20 or 30 years. For my
17 personal planning purposes, I think in the U.S. at
18 least, it's, you know, three or four years. And
19 things are happening today already, that are very
20 competitive. So it's the planning arising. The
21 second is, anything you can do in the meantime, in
22 the transition, which results in what would be the
23 market outcomes, I think those are the right
24 things. And those are things like getting the
25 prices right. It's significantly unbundling

1 service, allowing customers not to buy reliability
2 if they don't want to buy it. Allow them to buy in
3 a variety of expanded service product kinds of
4 ways. And maybe most fundamentally, it's getting
5 the costs out. The thing that you see happening in
6 the U.S., as utilities restructure, and unbundle,
7 is doing everything they can to drive costs down
8 30, 40, 50 percent, or more, because if they don't,
9 they'll lose. I think what you're trying to do --
10 I think what you tried to do in the old IRP process
11 was right. It was to try to mimic -- is try to get
12 utilities to be more responsive to costs, and to
13 what customers want. I think the thing that I've
14 been impressed about more than anything else, the
15 extent to which costs are much higher than they
16 would be in a competitive market. And the variety
17 and nature of service options are much smaller than
18 they would be in a competitive market. So those
19 two things, I'd look at those.

20 Q. Are you in a position to confirm that there has
21 been a downgrading, if that's the word, of emphasis
22 on IRP, and processes in the U.S. in the last year
23 or so? Certainly, the passage quoted to us from a
24 pronouncement of a California Public Utilities
25 Commission, that they are going to -- I believe

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1 they're going to ignore the IRP programs that are
2 underway, or have been felt. But I get that
3 impression. They're not going to -- perhaps it's
4 going so far as they will no longer require the
5 utilities to file IRPs with them, with the Public
6 Utilities Commission. And I'm wondering if this is
7 a widespread regulatory reaction in the United
8 States yet, or is California ---

9 A. Well, it's more than ---

10 Q. --- perhaps an exception? And I think someone
11 mentioned Arkansas as another State that is doing
12 away with its IRP.

13 A. I think I should say first that there is a -- as
14 you can understand, a variety of different
15 perspectives about what to do with IRP and DSM
16 activities in the U.S. Probably every Commission
17 in the U.S. has a somewhat different view of it.
18 But certainly, from the point of view of the
19 utility companies with whom we work -- not the
20 Commissions but the companies with whom we work --
21 there is a significant change in the last year and
22 half or two years, devoted towards eliminating or
23 substantially changing the DSM programs that
24 they've been offering, away from broad-based kinds
25 of rebate programs, and towards enhanced efficiency

1 options that are paid for by the participants, the
2 people that buy it, so that you align costs with
3 value, in that sense. With respect to Commissions,
4 there are several examples. Arkansas is a good
5 example of a Commission which, a couple of years
6 ago, went out and did a fairly prescriptive IRP
7 process. And I think in November or early December
8 -- I forget the exact date -- but within the last
9 couple of months, had formally adopted a -- I think
10 it's a two-paragraph IRP standard, replacing the
11 old 30-page one. And it essentially requires the
12 utility to file with them, their plans, and provide
13 some justification for it, but without being
14 prescriptive at all about how to calculate things,
15 and what methods to use, and so on. It basically
16 tells the utilities in Arkansas that they'll look
17 at the plans, and respond to them in some way, but
18 they won't -- there is no more formal approval
19 process, and things like that. I'd say most
20 Commissions are reconsidering their views of IRP.
21 That doesn't mean that they will subsequently go
22 the Arkansas or the California route. But I think
23 there's a lot of reconsideration. Maybe the best
24 piece of evidence that I can think of, is the
25 number of Commissions which have decided not to

1 adopt the EPACT IRP standards.

2 Q. The EPACT?

3 A. Energy Policy Act in 1992, like PURPA in 1978,
4 proposes and requires that each Commission consider
5 things, and consider whether or not to adopt
6 several standards. One of them is the integrated
7 resource planning standard. I think there's about
8 a dozen Commissions now, that have decided not to
9 adopt the IRP standard. That doesn't mean that
10 they've said that IRP is wrong or inappropriate.
11 Most of them have said things like, "In today's
12 increasingly competitive market, we don't think we
13 need to adopt that standard. Whatever we do is
14 sufficient." I just believe that the fundamental
15 thing is that as you get to a very competitive
16 market, you can't use the planning process as it's
17 been used in the past. You can't use it to create
18 DSM programs that customers don't want to pay for,
19 or to create -- to force a company to buy resources
20 which are uneconomical. It just puts him at a
21 competitive disadvantage, and somebody else makes
22 the sale. So it doesn't happen.

23 Q. And was that, in essence, why you -- well, I want
24 to get into three categories of marginal costs I
25 think you said short-run, long-run, and avoided

1 costs. Avoided costs that are a category of
2 marginal costs, as you see it, rather than a method
3 of calculating marginal costs?

4 A. Well, almost. I wouldn't say that they're a
5 category of marginal cost. They're a separate
6 category by itself.

7 Q. The cost.

8 A. Yeah. Avoided costs are the costs a system doesn't
9 incur, but for -- because it doesn't have to
10 acquire a certain amount of capacity. So it's a
11 change in cost, with respect to a change in
12 capacity, whereas marginal cost is a change in
13 cost, with respect to change in the load. Now you
14 could use the same methodology. Often you don't.
15 Often, different methodologies are used. They're
16 calculated at different times in the planning
17 cycle, and the answers are different.
18 Conceptually, they're a little bit different.
19 That's why I have listed them as separate
20 categories.

21 Q. I guess we all have problems with terminology and
22 semantics in this Hearing. Mr. Bowman, as I
23 understand it, has used the term "avoided costs,"
24 and has purported, I gather, to blend short-run
25 margin cost and avoided cost. But it may well be

1 that he has calculated his avoided costs in a
2 manner that you would approve, and that he is
3 really talking long-run marginal costs. I'm not
4 sure. Do you happen to know?

5 A. I think he's really talking about long-run marginal
6 costs. I don't think we have a disagreement.

7 Q. You've looked at his evidence. And from what you
8 can gather, while he's using the terminology
9 "avoided costs," he's really talking -- you would
10 view them as long ---

11 A. I think what he means -- I think what he means, in
12 my context, is long-run marginal costs. I don't
13 think we have a disagreement about that. I'm not
14 sure either one of us have studied in detail, the
15 methods the company has used to calculate long-run
16 marginal costs. So setting that -- setting the
17 specific number in the methodology aside, I don't
18 think we have a disagreement about -- about the
19 category.

20 Q. And I gather you do disagree then, with Dr. Stutz,
21 in that you don't view the purpose of the marginal
22 cost rate to be the long-run or short-run, to
23 somehow have some affect on the long-run planning
24 of the utility, in terms of deferring construction
25 of peaking plant, for example. That may be a

1 by-product of rate design, but it is not the reason
2 for costing, for example, and adopting time of use
3 marginal cost rates for example?

4 A. No, I think it's a mistake to think about the time
5 of use rates as if they were a DSM activity, and
6 evaluate them that way, and judge them on the
7 performance -- how well they do -- work at shifting
8 load. I think the -- I think the issue is getting
9 the price right so the customer isn't paying more
10 or less than it costs the utility to acquire that
11 capacity.

12 Q. That, in itself, is sufficient justification for
13 marginal cost based rates.

14 A. Yes.

15 Q. Is there any place in the scheme of things for time
16 of use rates, based on embedded costs?

17 A. Sure. The problem with that is, how do you judge
18 which set of embedded cost time of use rates you
19 should adopt. I would say you can use embedded
20 cost methodologies, and develop a number of
21 different embedded cost based time of use rates.
22 I'd pick the one that most looked like the marginal
23 cost ones. That would make the most sense to me.
24 Those would be the efficient ones. If you did
25 something different, then they would be better, the

1 closer they were towards those marginal cost runs.

2 Q. So if you were working up a set of time of use
3 rates, you would want to know what the marginal
4 costs are, at various times through the year, in
5 order to judge just how good, how effective, or how
6 valid these proposed time of use rates are, that
7 are essentially based on embedded costs.

8 A. Yes. And then the more -- if I were you, I would
9 judge these -- I would decide whether or not I
10 could -- I should approve a set of embedded cost
11 rates that were -- that showed some slight
12 variation in -- between peak and off-peak, but not
13 nearly as much as the marginal cost ones did, for
14 example. I would decide whether or not to adopt
15 those, based on how protective I thought the
16 markets would continue to be. If I thought the
17 markets would continue to be protected for 10
18 years, then I'd probably think hard about the rate
19 continuity issues, and rate stability issues, and
20 things like that, and adopt rates that have smaller
21 differentials, based on embedded costs. But if the
22 markets become very competitive very quickly, then
23 you can't do that, because the markets themselves
24 set the prices. And if the company gets them
25 right, then the company wins, and everybody wins.

1 To the extent the company adopts prices which are
2 wrong, they just get adjusted by the market.
3 That's what that sort of market does. It sets
4 prices.

5 Q. You talked about revenue recovery mechanisms in
6 your evidence. I take it they are only an issue if
7 you adopt voluntary as opposed to mandatory time of
8 use rates?

9 A. Well, they're a little bit of an issue, even with
10 mandatory time of use rates. The issue really is,
11 is there a good way to know, as you set the rates,
12 what the change in consumption would be, what the
13 load shift would be, because without knowing that,
14 you can't get the billing units right, to calculate
15 the rate right. Now there are really two things
16 you can do. The first thing you can do, is spend a
17 bunch of money doing an experiment, so that you can
18 calculate the elasticities that you need to
19 estimate what the load shifts would be. My
20 experience has been, you can do that, and when you
21 get done doing it, you won't know a whole lot more
22 than you know today. It's just very difficulty
23 statistically, to find those. And even if you got
24 it right, what you got right was what they were two
25 years ago. It's not necessarily what they're going

1 to be next year. So what do you do as an
2 alternative? You develop a revenue recovery
3 mechanism, just a holding account, or deferral
4 account, that you use to collect the difference
5 between what you assumed an adjustment would be,
6 and what it actually turns out to be, and then
7 build that back into rates at, you know, the next
8 rate case, or next adjustment time. You've
9 accomplished the same thing, without spending all
10 the experiment money.

11 Q. At the next Rate Hearing, you can make the
12 adjustment. You no longer need the separate
13 account.

14 A. Well, every time you go through another rate
15 process, you'll have more information about what
16 the adjustments will be. And in fact, it won't
17 take but a couple of years to have a pretty good
18 basis for knowing what the units will be under time
19 of use rates. So if it were me, I would have a
20 revenue recovery account, which I would expect to
21 phase out over two or three years, as it wasn't
22 needed any more. The only reason you have it, is
23 to avoid having to be precise about what the
24 expected change in the billing units will be after
25 you put the rates in place.

1 Q. You mentioned, when it comes to revenue
2 reconciliation methods, you prefer the customer
3 charge to the default method, that I guess Mr.
4 Bowman prefers, because you want a clear signal to
5 the user, as to the marginal cost, both in the peak
6 period and in the off-peak period. The practical
7 objection being made to that approach is, I gather,
8 that the customer charge will be perceived to be
9 too high. And I suppose this applies in the case
10 of voluntary rates, at least, particularly. And
11 therefore, presumably, customers will be afraid to
12 go on the rate, when they see a twenty-five (\$25),
13 thirty dollar (\$30) a customer charge up front,
14 when they aren't sure themselves what the rate will
15 do for them. So maybe it'll come down to a
16 practical consideration more than philosophy. We
17 have to balance off the practical concerns against
18 the purity that you would wish for. Although I
19 think you did suggest that there could be some
20 blending of this. You could have some default in
21 some customer charge to ---

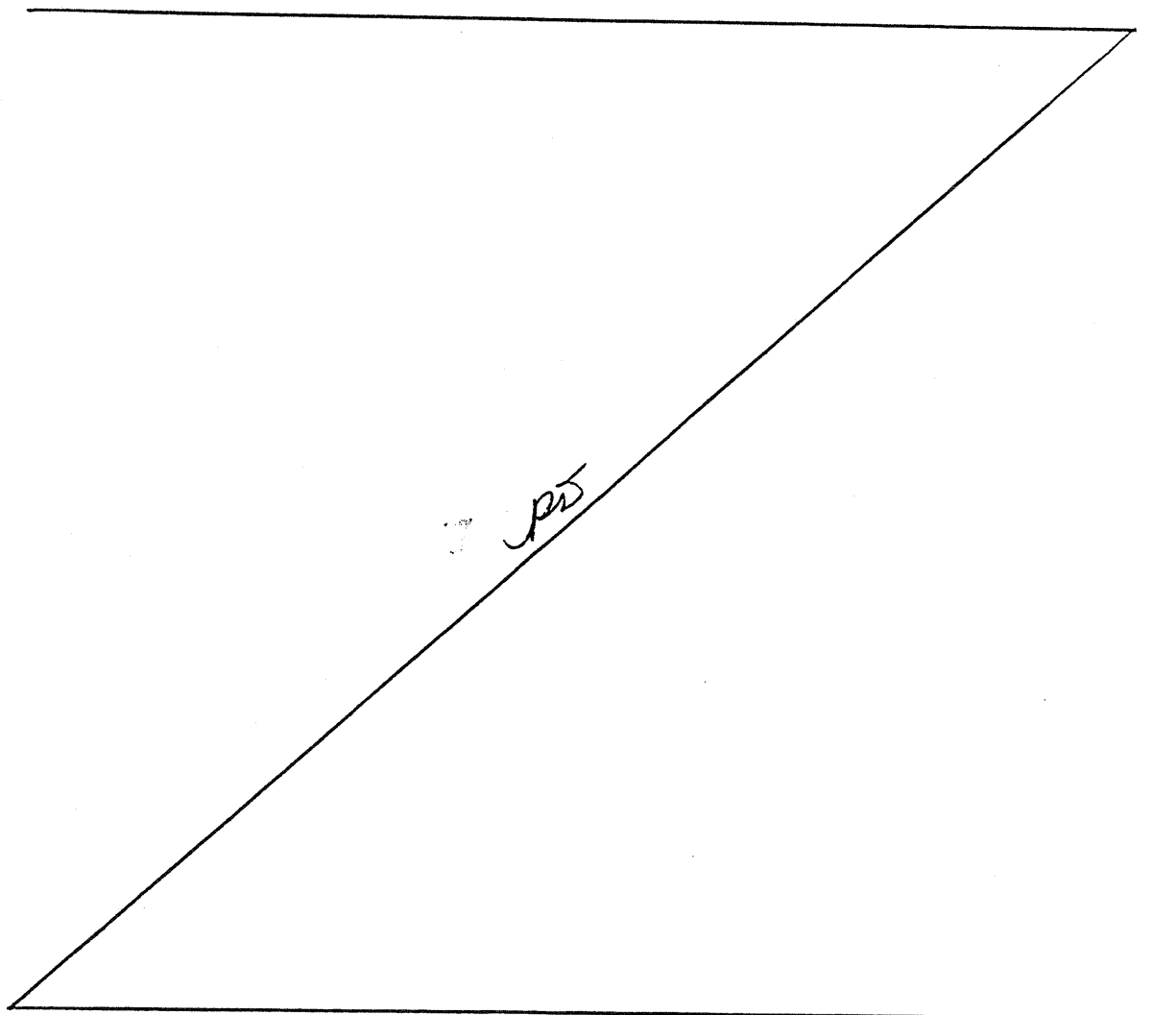
22 A. Yeah, I think the problem I had with Mr. Bowman's
23 suggestion on the default side, was I think,
24 although it gets the off-peak price right, it gets
25 the on-peak price substantially wrong. The one

1 piece of evidence that dominates from all the
2 empirical studies on response to time of use rates,
3 is that the response that occurs isn't a load
4 shifting, so much as a conservation approach.
5 People respond to the on-peak price. So if I were
6 going to get just one price right, the one I'd want
7 to get most right is the on-peak price. That's the
8 one that's driving the capacity need. That's the
9 one that's driving the customers' decisions about
10 what kind of heating system to use, and whether to
11 insulate additionally, or whatever else. I think
12 that's the one most important to get right. In the
13 case for Nova Scotia Power, I think the difference
14 between marginal cost and embedded cost is pretty
15 significant. It's a bigger revenue reconciliation
16 problem than it typically is. So -- and I
17 certainly think the practical matters apply here.
18 But I think there's a lot of things you can do.
19 The default method is one. It's not the one that I
20 would -- I would try to get the prices righter in
21 all the periods. One way to do it is with a
22 customer charge. Another way to do it is with the
23 block time of use structure, whether you flow the
24 revenue reconciliation in the first couple of
25 hundred kilowatt hours. That's the way that I

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1 suggested, at least look at it. I think it makes
2 some sense. It's a particularly useful thing to do
3 if no customers end up in that first block, if it's
4 small enough. But you know, there's other things
5 that you could do as well. You could adjust both
6 sets of prices, adjust the default prices up a bit,
7 and on-peak prices down a bit, and come up with --
8 I think that would be a better answer as well.



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2 But certainly my experience has been customers look
3 at and respond to the on-peak price.

4 Q. Well, it certainly makes sense. This is sort of a
5 very general question in my mind when it comes to
6 producing -- developing new rates, let's say a slate
7 of time of use rates; in your experience, who does
8 this; that is to say, is it the regulator and
9 regulatory staff that comes up with these rates? Or
10 is it the utility? Or is it some kind of back and
11 forth process, "collaborative"? It strikes me that
12 the utility people have the expertise, when all is
13 said and done, to develop rates, that one has to, to
14 some degree at least, defer to the utility rate
15 designer's judgement, for example as to whether the
16 default method is superior to the customer charge
17 method, or some other method, or some blending. And
18 I guess I'm just asking the very general question,
19 perhaps, in your experience, how do rate get made, I
20 guess? Who does it, and perhaps desirably how
21 should they be developed? Should they be prescribed
22 from on high by the regulator? Or should the
23 regulator perhaps content himself with giving very
24 general directions such as, time of use rates will
25 be based on seasonality and time of day elements,

1 and they will be based on marginal costs. And then
2 leave it to the judgement of the utilities to decide
3 what blend of long-run, short-run marginal costs
4 should be used, and what revenue reconciliation
5 methodology should be used?

6 A. Yes. Two questions; how was it done, and how should
7 it be done. I think it's -- well, nothing is
8 universal, but it's much more universally true that
9 companies make the rates under the general
10 prescriptive set of guidelines, and under the review
11 of a regulatory body. I also think that's the right
12 way. I think certainly as the market becomes more
13 competitive, it has to be done, because to the
14 extent -- because then the market is setting the
15 price, which, of course, is I think the most
16 efficient thing to do. Some other bad things happen
17 from that, but in terms of efficiency, that's ---

18 Q. I guess regulators from time to time feel that if
19 they don't take the lead, nothing will happen. And
20 they have that perception as to how things should
21 evolve, and I suppose that explains the adoption of
22 DSM. I get the impression that regulators were in
23 the forefront of promoting DSM and IRP.

24 A. Well, I think there's two good examples. I think
25 it's true that Commissions were in the forefront of

1 developing DSM activities, encouraging utilities to
2 do it, mandating it in many circumstances. I think
3 the programmes that got developed produced some
4 useful things, and some not so useful things. It's
5 no longer the case that Commissions are driving the
6 development of efficiency activities on the part of
7 utilities. There are about thirty utilities in the
8 United States now that have set up what we call
9 super escolar subsidiaries, for profit subsidiaries,
10 that are providing efficiency services for customers
11 in their markets and beyond.

12 Q. Nova Scotia Power is apparently involved in that
13 process of setting up such a company, as well.

14 A. So that's -- I mean, I think that's an example of --
15 there were few utilities that developed -- in my
16 experience that developed DSM activities unless they
17 were, at least, strongly encouraged to do so by
18 Commissions. But Commissions are out of the game,
19 and different kinds of programmes are -- not totally
20 out of the game -- but different kinds of programmes
21 are being much more strongly pursued today by
22 utilities on a for profit basis. The same is true
23 with time of use rates. There really aren't that
24 many utilities that I can think of that took the
25 initiative in the development of time of use rates.

1 Much of it was encouraged by Commissions. Some of
2 it was encouraged, in the U.S., by federal
3 legislation, PURPA. As markets become more
4 competitive though, utilities now are strongly in
5 the forefront in the development of the ultimate
6 time of use rates, which is a real time pricing
7 process. I think a couple of years ago there
8 weren't but a handful, maybe half a dozen, utilities
9 in the U.S. that had RTP programmes. The last count
10 I saw was over thirty, that they have developed and
11 approved RTP prices. They're taking the initiative
12 because that's how they see they need to respond to
13 the competitiveness of the market. You can't try to
14 sell a produce for five cents year round when
15 somebody else can sell it for three cents part of
16 the time, because that somebody else will make the
17 sale.

18 Q. So as you see it, the marketplace will take care of
19 a lot of these issues, as competition becomes
20 entrenched.

21 A. Yes. I think that one of the attractive features of
22 a competitive market is that it requires survivors
23 -- of the service providers who are survivors, it
24 requires them to give customers what they want,
25 because if they don't do it, somebody else will.

DR. CHAMBERLIN, CROSS-EXAM. BY MR. HARRIS

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1 Part of that is unbundling of services and
2 unbundling of costs and prices.

3 Q. Mr. Kehoe, or someone, mentioned revenue cost ratio
4 targets that this Board had used, and I guess you've
5 expressed those in terms of return to each customer
6 class. Am I -- are these targets still used; are
7 they still widespread in the U.S. in terms of
8 regulators expecting -- using this as a test of
9 fairness of customer rates in a general sense, that
10 each class should recover its share of embedded
11 costs, no more, no less? Is that an approach that
12 is ---

13 A. Yes. Although they're not always targets.
14 Sometimes they're just analyses.

15 Q. They're tests, checks.

16 A. Yes. And I'd say that's widely true. It's only not
17 true in jurisdictions where Commissions have gone --
18 as part of the transition to competitive markets
19 have gone to a performance base rate making
20 approach, where the rate of return is helpful in
21 setting up the initial price. But after that, the
22 cost of service issue goes away. The price then is
23 allowed to change according to the PVR index, which
24 is typically something like the rate of inflation
25 minus a productivity index. And then the

1 contribution to margin, or the class rate of return,
2 or the revenue cost, that's something that happens;
3 that's the result of the market rather than, you
4 know, how you set the price.

5 Q. I guess what I was leading up to is whether you have
6 any views as to whether a target -- and we have
7 issued a target range of ninety-five to a hundred
8 and five cost recovery per class, and whether that
9 is a reasonable target range, or is that something
10 that is so much entrenched or bound up in the
11 concept of fairness that you, as an expert, would
12 not want to suggest whether that's right or wrong?

13 A. I think it is -- I mean, it's fundamentally a
14 fairness issue; it's not a pricing issue. The
15 pricing issue is turned around. In my business, I
16 don't set out -- I don't set prices to different
17 markets trying to get the rate of return from each
18 of those markets the same. I set prices based on
19 what I think I can recover in those markets, and the
20 rate of return is what it is.

21 Q. That's getting back to this discrimination kind of
22 argument point that ---

23 A. Exactly.

24 Q. I think that's all; thanks very much.

25 MR. ROBERTSON

1 Ms. Garber?

2 MS. GARBER

3 No, thank you.

4 MR. ROBERTSON

5 Mr. McManus?

6 CROSS-EXAMINATION BY MR. MCMANUS

7 Q. This Board at the moment, and for some number of
8 years, has operated under the mandate to approve
9 capital investments at least some of the time. I
10 presume that that obligation will continue until the
11 (inaudible due to coughing) mandate is removed,
12 which might be kind of helpful, because it would
13 relieve us of a burden of having to check it, and it
14 also makes it easier to disallow things from the
15 rate base.

16 A. I mean, I -- let me separate that. I think that
17 this Commission, that it's appropriate to continue
18 to review capital budgets and capital expenditures.
19 Even in a competitive market, I'd think it would be
20 appropriate for some entity, whether it's you or
21 some other entity, to approve things like siding,
22 and other public interest aspects of, say, a new
23 power plant. But the issue of recovery in a
24 competitive market shifts from you to the market.
25 And the risk ought to shift, as well. If the

1 company makes the right decision about whether or
2 not a plant can be profitably constructed and sold
3 to the market, that right decision means it will get
4 recovery plus a profit. If it makes a wrong
5 decision, it won't get recovery. So I think that
6 aspect of it shifts as the market becomes
7 competitive.

8 Q. Okay. In terms of long-term planning, as long as
9 that mandate exists, then I guess we're stuck with
10 the need to examine the long-term planning.

11 A. I would think so.

12 Q. If the market becomes competitive in generation,
13 then presumably the only thing that we would have to
14 look at in detail would be concerns related to
15 transmission; maybe distribution, I'm not sure.

16 A. Well, I think partly -- I don't mean to try to dodge
17 around the question, but one of the concerns I have
18 in my mind is what happens to the company as the
19 market becomes competitive.

20 Q. That's something I was going to ask you.

21 A. I think that whether the divestiture is legal or
22 fictional, divestiture happens. I think there
23 really are four different parts of the business, and
24 they're all fundamentally different. There's a
25 wholesale generation market; there's a transmission

1 market; there's a distribution wires market; and
2 there's a retail services market; those are all
3 different entities in different markets. And I
4 think you have to think about the appropriateness --
5 the appropriate nature, kind and character of
6 regulation in each of those markets. To my mind,
7 there's no need to regulate a competitive wholesale
8 market. The market takes care of itself.

9 Q. Which is generation.

10 A. Which is generation. I think there's also no need
11 to regulate any competitive retail services market.

12 Q. If it's competitive.

13 A. If it's competitive.

14 Q. Okay.

15 A. I think there is a continuing need to regulate a
16 transmission business and a distribution business,
17 but I wouldn't do it on a cost of service basis, I
18 would do it on a performance based rate making
19 basis.

20 Q. I guess if it were -- if generation were
21 unregulated, I'd behave like a really good
22 capitalist and try and lock up a bunch of customers,
23 I'd have lunch with George Cooper and so on, and say
24 "What kind of deal can we cut?" so I can go to the
25 bankers to get the funds to build my plant, and not

1 have any interruption from other competitors. That
2 aside, how do you see the transition to the
3 marketplace that you're talking about, or the
4 environment you're talking about, occurring? What
5 kinds of impacts related to that do you see?

6 A. Are you concerned with the possibility that the
7 company breaks out its most attractive cheapest
8 power available to its largest customers, or some
9 deal is cut that makes the service unattractive to
10 the remaining customers?

11 Q. I suppose that's a possibility, is it?

12 A. Well, I think the things to be concerned about in
13 that regard are setting up re-regulation structures
14 which try to minimize the potential for that kind of
15 discrimination. And you can do that in different
16 ways. I don't know that anybody has the greatest
17 answer. The phase-in approach that the California
18 Commission is using isn't bad, where phase --
19 instead of happening on the phase-in direct access
20 basis, with industrials first going down to the
21 smallest customers later, phase-in is happening over
22 five years with equal amounts of customers from
23 different classes being phased into the market. I
24 frankly think that the whole market is going to get
25 phased in faster than that schedule by necessity,

1 but that's the way that structure is set up. You
2 know, I think the real protection is with something
3 like a price cap. That's why I think PVRs are a
4 useful transition approach. You have to get from a
5 cost of service world to a market world. If you try
6 to live in a cost of service world during the
7 transition, I think there's the potential for
8 special deals being made in other things. I think
9 what you want to be concerned with is people's
10 prices don't go up, or one group of customers'
11 prices don't go up as a result of a loss of access
12 to cheaper power. So you regulate that with the
13 price; you say here's the phase-in regulatory
14 approach where prices are kept at what they are
15 today, and, you know, access is phased in by all
16 customers over some schedule.

17 Q. If you go the price cap route, is there a need to
18 ensure that there isn't a milking operation at work
19 so that the assets just slowly vanish over time and
20 there's just the shell left?

21 A. Well, I think not; but I'm trying to decide why I
22 think not. It's because the assumption that I'm
23 making is that the market is competitive. To me,
24 that means that there are other suppliers standing
25 ready and actively serving a market. So if one

1 company decides to milk its assets and withdraw them
2 from service, I don't know that I care. What I care
3 about is the customers, if that were to happen,
4 because customers are getting equivalent or better
5 service from the other suppliers.

6 Q. That's assuming that the operators in the market
7 haven't tried to make sure that competition is, in
8 fact, restricted.

9 A. Yeah. And I can think of all kinds of bad things
10 that might happen if competition isn't aggressive, I
11 mean, if there's limited amounts of competition. I
12 mean, there are all kinds of things that you could
13 think of of ways that people could take advantage of
14 that system, and people would be hurt as a result.
15 I think my feeling is the response to that is to be
16 aggressive about promoting competition. It seems to
17 me that you get the right result faster by doing
18 that.

19 Q. Okay. Thank you.

20 CROSS-EXAMINATION BY MR. ROBERTSON

21 Q. I guess Mr. Harris has asked all the questions that
22 I had on IRP, and practically all on time of use,
23 too, I guess. But I guess you think that it may be
24 appropriate to have a less efficient time of use
25 rate by lowering the winter peak and compensating by

1 raising the off-peak?

2 A. Yes. I think what's important is I wouldn't be
3 lowering the winter peak below the cost.

4 Q. No.

5 A. I would be reducing it below the revenue reconciled
6 rate which is substantially above the cost.

7 Q. Okay. You also suggested we should be developing
8 protocols for flexible pricing. Shouldn't that be
9 coming from the utility? Shouldn't the utility be
10 approaching the Board and saying, "We have a plan;
11 we would like to get into this competitive age; and
12 we would like to take a look at the way in which we
13 set our prices"? And if that is the case, shouldn't
14 we somehow have a mechanism to make sure that they
15 really are really correct in the way in which they
16 develop this pricing by saying, "Well, maybe the
17 shareholders should share part of the cost if
18 there's any loss because of the rates that are set"?

19 A. Well, I think at least two things about that. I
20 think that the company ought to be -- if it's not
21 considering about how it's going to respond broadly
22 to increasing competitiveness, that it ought to.
23 And that it ought to be developing initiatives to
24 take to you about how it intends to be price
25 competitive. I think, at the same time, that you

DR. CHAMBERLIN, CROSS-EXAM. BY MR. ROBERTSON

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1 should be thinking about how you're going to deal
2 with that on a broader-based basis than you do
3 today, otherwise everything happens -- everything is
4 unique, and you have to think through issues of
5 fairness and responsiveness and things like that
6 with respect to each issue, and the company then
7 needs to guess about how you're going to respond to
8 those. And most importantly, if everything is done
9 on a unique basis, the length of time between the
10 need for the price and when it can be contracted
11 with the customer is way too long. I've certainly
12 been involved in circumstances where special deals
13 -- even under a pre-approved framework for flexible
14 pricing, special deals still take eighteen months,
15 just to work through the internal processes. That's
16 ridiculous.

17 Q. Because of a lot of considerations that have to be
18 taken into account. They've got to come to us with
19 a lot of information in order for us to judge
20 whether or not it's appropriate.

21 A. Exactly. They have to produce the information, and
22 they have to take it to you and then there's a
23 Hearing and so on. I think, just thinking through
24 ways in which -- this is going to happen; this is
25 not going to go away; it's going to happen with more

DR. CHAMBERLIN, CROSS-EXAM. BY MR. ROBERTSON

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1 and more frequency, and you need to have a point of
2 view about how you're going to respond to that.
3 With respect to the aspect of your question about
4 should part of the plan consider whether
5 shareholders absorb some of the costs of these
6 options, I'd say sure, as long as it was symmetric.
7 I think part of the deal is that it needs to be
8 symmetric, that the shareholders then, that means,
9 have an opportunity to do better under some
10 circumstances.

11 Q. I wasn't thinking of sharing the gains as much as I
12 was thinking of looking after the losses because of
13 the other customers, the utility that would be
14 absorbing it if the shareholders didn't have some
15 stake in it.

16 A. There's certainly a substantial amount of precedent
17 for the point of view that shareholders participate
18 in the consequences of the discounting that happens.

19 Q. I believe utilities are sharp and so on, and they
20 should be rewarded in some manner for the way in
21 which they can penetrate a market and make a better
22 return on their endeavours.

23 MR. ROBERTSON

24 Anything?

25 MR. MCMANUS

1 Just one last question; relative to the model you
2 were talking about just a few moments ago, where
3 transmission distribution would be regulated, can
4 that be sufficient to ensure that the obligation to
5 serve is met?

6 DR. CHAMBERLIN

7 I suppose it could, but I don't think it has to.
8 Just by saying that transmission and distribution is
9 regulated I think what you -- I think what that
10 implies necessarily is that all customers are
11 connected; I don't think it implies, necessarily,
12 that all customers get all the power that they might
13 want to buy.

14 MR. MCMANUS

15 No, I'm thinking of ensuring that the person in the
16 small village who is connected stays connected.

17 DR. CHAMBERLIN

18 I think that regulation of the distribution service
19 business implies that any customer that wants to be
20 connected -- and the way that I would regulate it is
21 a mandatory access. I think that -- I think the
22 obligation to serve changes, but I think the
23 obligation to have access doesn't change; I don't
24 see how it changes.

25 MR. MCMANUS

1 Thank you.

2 MR. ROBERTSON

3 Anything arising from Board questions? Mr. Kehoe?

4 MR. KEHOE

5 Nothing, thank you, Mr. Chairman.

6 MR. ROBERTSON

7 Mr. Outhouse.

8 MR. OUTHOUSE

9 I have one question, Mr. Chairman. Dr. Chamberlin,
10 Mr. Campbell referred you to your article on
11 efficient block rate structures, ten eighty-three.
12 And in particular he focused, or I think he
13 attempted to focus, on item #3 on page 58:

14 "A declining block structure is almost
15 always efficient if the marginal cost of
16 large users is less than the marginal cost
17 of small users."

18 I think you've seen Dr. Parmesano's evidence, and if
19 you haven't, you can take it from me that in her
20 evidence she has indicated that on her calculation
21 of short-run marginal cost, that that short-run
22 marginal cost of serving the third block in the
23 winter peak, winter three-month peak, is eight point
24 four cents. And I'm sure you're familiar with Dr.
25 Parmesano's methodologies. NSPI is proposing to

1 charge for that third block, in the winter months on
2 a non time differentiated basis, six cents per
3 kilowatt hour. Is it your belief that that price
4 could be efficient under any circumstance?

5 DR. CHAMBERLIN

6 I'd be sceptical. I mean, there are some other
7 issues that confound it principally being that the
8 declining block rate itself is by definition non
9 time differentiated.

10 MR. OUTHOUSE

11 Yes.

12 DR. CHAMBERLIN

13 And so that means it averages across peak and off-
14 peak periods. And so I haven't done the average
15 calculation, so I don't know, but, like I say, I'd
16 be sceptical of that. But the other thing here is
17 that in looking at whether an efficient rate should
18 be declining or inverted doesn't depend on just the
19 proportion of energy. It also depends upon the
20 contribution towards capacities. It's contribution
21 -- it's the (coincidentness) of the load as well --
22 which affects capacity, as well as the proportion of
23 energy that's on and off-peak. So I just didn't see
24 enough in the evidence that I looked at to tell
25 whether the rate ought to be -- if it were just to

1 be blocked, whether it ought to be inverted or
2 declining in the winter. I'd be a little sceptical
3 that a declining block rate, particularly as steeply
4 now as it would be proposed, is appropriate and
5 efficient, given what I know; but I think I haven't
6 seen enough to be definitive about it.

7 MR. OUTHOUSE

8 Thank you, Dr. Chamberlin.

9 MR. ROBERTSON

10 Thank you very much, Dr. Chamberlin. I think it's
11 probably appropriate that we break for lunch, and
12 come back at 1:45, if that's okay.

13

14 --- Upon recessing

15

16

NSURB

EXHIBIT #

N-868

N-83

Efficient Block Rate Structures: Rethinking Conventional Wisdom

The supposed inefficiency of declining block rates is greatly exaggerated. In fact, evidence shows that rates that vary significantly from the cost of service — e.g., as they might for winter heating customers of a summer peaking utility — worsen economic efficiency.

John Chamberlin and Ken Seiden

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Before the 1970s, declining block rate structures, in which unit prices decline with increasing consumption, were in wide use in the electric utility industry. Since then, however, utilities have generally replaced these structures with flat or inverted rate structures. The advocates of change advanced two reasons for new rate designs.

First, declining block rates were characterized as "inequitable" because smaller users pay average prices that are greater than those that larger users pay. Many regarded this disparity as unfair,

particularly where there is a strong positive relationship between income and consumption.

Second and most important, opponents argued that declining block rates led to a wasteful increase in the consumption of electricity and were therefore inefficient. Regulatory commissions across the country have espoused this view. The Florida Public Service Commission, for example, ruled that inverted rates are "intuitively" conservation-oriented.¹ Commissions in South Carolina, Michigan, Washington, Idaho, California, Oregon, and the Dis-

strict of Columbia have stated that inverted rates promote economic efficiency.² A recent survey of rate structures in the U.S. found that no commission has allowed a utility to return to a declining rate structure.³ In this paper, we show that the efficiency criticism of declining block rates has been incorrectly applied, and has therefore led to poor policy choices.

The economic efficiency argument for inverted block rates rests on the assumption that costs are rising over time, and that marginal costs are therefore greater than average costs. Under these circumstances, efficient pricing rules are thought to require inverted rates. Consider, however, a class of residential customers in which larger users (e.g., those with central air conditioning and electric heating) use a great proportion of their electricity in the summer during the daily peak period and use a greater proportion of their electricity in the winter during the off-peak, nighttime period. Further, if capacity costs are incurred by the utility primarily in response to summer peak demands, economic efficiency requires that these capacity costs be reflected in inverted rates or TOU rates in the summer.⁴ An attempt to promote economic efficiency and conservation by inverting both summer and winter rates will, because of the fixed revenue requirement, result in underpricing summer demand relative to cost. Since summer demand is underpriced, it will grow faster than it would otherwise, leading to the construction of economi-

cally unnecessary generation plants. In addition to failing to promote summer conservation, such a year-around application of inverted rates discourages the efficient use of cheaper, off-peak energy in the winter.

We obtained seasonal peak information for 14 investor-owned utilities in the seven jurisdictions identified above to determine whether in practice the rationale for inverted rates has been applied too broadly. Residential cus-

The efficiency criticism of declining block rates has been incorrectly applied, and has therefore led to poor policy choices.

tomers in each service area face inverted block tariffs in both the summer and winter seasons.

The load data indicate that 12 of these utilities have summer and winter peaks that differ in magnitude by at least 10%. In 1990, seasonal peak ratios for these utilities varied from 0.65 to 0.9, with an average of 0.8. In absolute terms, seasonal peak demand differences ranged from 125 to 5,200 MW, with an average of 1,500 MW. The difference exceeded 500 MW at nine utilities. To provide for growth in annual peak demands, most utilities' capacity expansion

plans rely on additional combustion turbines, ranging in size from 50 to 250 MW. Given larger differences in seasonal peaks, it is extremely unlikely that these 12 utilities require new combustion turbines to meet peak loads in the off-peak season. In these instances little, if any, of the long-run marginal capacity costs can be allocated to the off-peak season. Overall marginal costs in the off-peak season are dominated by short-run marginal costs, which are less than average costs.

In the following section we review briefly the role of marginal costs in optimal tariff design, and the efficient pricing rules developed by economists when marginal cost pricing fails to yield appropriate revenues. We will show that when marginal costs are less than average costs, the design of economically efficient block rate structures depends primarily on variations in marginal costs within a rate class, with price elasticities of demand exerting a secondary influence on economic efficiency.

I. Marginal Costs and Block Rate Structures

A. Balancing Competing Objectives

In choosing a desirable rate structure from the available alternatives, electric utilities and their regulators balance objectives that often compete with one another. The Public Utility Regulatory Policies Act of 1978 established three broad objectives for the pricing of electricity:

- Conservation of energy by users of electricity,
- Efficiency in the use of utility facilities and resources, and
- Equitable rates to consumers.

In instances where rising marginal costs exceed average costs, proponents of inverted rates argue that these tariff structures can meet all three PURPA objectives. Prices for tail blocks are set at or near marginal costs to achieve the efficiency objective. Rates are lower in the initial blocks to keep class revenues at their required levels, and the ensuing inverted block structure discourages electricity consumption and furthers the conservation goals of PURPA. Finally, inverted block rate structures are seen as more equitable because of the assumption that necessities are served by the initial blocks of consumption, with discretionary consumption occurring in the tail blocks.

PURPA also set rate standards to discourage utilities from using declining block tariffs. It is notable, however, that PURPA explicitly recognized that variations in marginal costs *within* a customer class could lead to efficient declining block rate structures. The act addressed declining block rate structures through the following standard:

The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric customers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that

such utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period.⁵

B. Economic Efficiency and the Inverse Elasticity Rule

Given the desirability of marginal cost pricing to meet the goal of economic efficiency, how *should* regulators and utilities design rate structures when prices set equal



to marginal costs fail to yield appropriate revenues?⁶ Faced with such a situation, economists have offered two efficient pricing solutions: (1) price at marginal cost for all customer subclasses and subsidize the utility if rates fail to meet revenue requirements; or (2) use "perfect price discrimination" across all subclasses so that all units of consumption, rather than just the last unit consumed, are priced at marginal cost.⁷

Of course, neither approach is workable in practice. Both suffer from political deficiencies, and the

information requirements of perfect price discrimination are overwhelming. Given unworkable efficiency solutions, economists have used a number of "second-best" solutions to develop rate structures that meet revenue requirements while minimizing distortions in resource allocation.⁸ The simplest of these solutions is the equal proportions rule, where the prices to all customers in a class deviate from marginal costs by the same proportion. Although this method is the easiest to implement, in practice it ignores differences in customer demand that a utility could use to further reduce allocative inefficiencies. Another second-best alternative proposed by economists, the inverse elasticity rule, uses information on both marginal costs and price elasticities to minimize the resource distortions caused by price deviations from marginal cost.

Frank Ramsey first proposed this second-best rule in 1927.⁹ Ramsey was interested in devising an excise tax structure that minimized resource distortions (i.e., levels of consumption in the absence of taxes). Ramsey's analysis indicated that quantities purchased under an excise tax should deviate by the same proportion from quantities purchased without taxation. Since quantity distortions are greater in more elastic markets, the second-best tax structure encompasses tax rates that are inversely proportional to the price elasticity of demand in each market. Stated differently, equal proportional

deviations from marginal cost prices cause *unequal* proportional deviations from optimal levels of consumption if elasticities differ across markets; whereas the application of the inverse elasticity rule causes *equal* proportional deviations in consumption across markets, minimizing the extent of resource distortions.

Over time Ramsey's approach has been improved on and reformulated for other applications, including public utility pricing. As an example, consider the well-known inverse elasticity equilibrium condition

$$\frac{P_i - MC_i}{P_i} = \frac{k}{E_i}$$

where "i" refers to each market, "P" is the price, "MC" is the marginal cost, "E" is the (positive value) of the price-elasticity of demand, and "k" is a constant reflecting the need to raise prices over marginal costs to meet a particular revenue requirement.¹⁰

The equilibrium condition indicates that price deviations from marginal cost in each market should be inversely proportional to the price elasticity of demand. Suppose there are two markets for electricity, 1 and 2, with independent demands and identical marginal costs. Solving the above equilibrium expression for P_i ,

$$P_i = \frac{MC_i}{(1 - k/E_i)}$$

and using the values $k = 0.2$, $MC_1 = MC_2 = 1¢$, and $E_1 = 0.5$ and $E_2 = 0.2$, then $P_1 = 1.11$ and $P_2 = 1.33$. Since Market 2 is less price elastic than Market 1, the second

best solution calls for P_2 to exceed P_1 .

More recent research on the design of second-best, non-linear tariffs for public utilities has extended the inverse elasticity rule to increments of consumption within a market or class of customers.¹¹ In this context incremental blocks of consumption can be thought of as separate "markets," where total class demand within each block is equal to the increment of consumption times



the number of consumers willing to purchase it. Given independent demands among consumers, the inverse elasticity rule is still applicable, with the subscript "i" now referring to different groups of consumers within a class rather than distinct markets. In the above numerical example small users would be placed in group 1 and large users would be placed in group 2. Prices P_1 and P_2 are associated with incremental blocks of consumption, and the second-best solution calls for an inverted block tariff.

C. Variations in Class Marginal Costs

Unfortunately, users of the inverse elasticity rule have sometimes focused more on differences in elasticities than on differences in marginal costs.¹² When marginal costs vary among customer groups within a rate class, application of the inverse elasticity rule does not necessarily imply that the less elastic group gets the higher price. A more general rule is that the percentage deviation from marginal cost pricing should decline with increases in the price elasticity of demand. If $MC_1 = 1.5$ in the numerical example above, then $P_1 = 1.67$.

P_1 still has a smaller percentage markup over marginal cost relative to P_2 because the price elasticity of demand is lower for group 1 customers, but the second-best solution now calls for a declining block tariff because the higher marginal cost of supplying to group 1 outweighs the price elasticity differences.

Within the inverse elasticity rule framework, general rules for block tariffs are determined by comparing relative marginal costs to relative price elasticities. Specifically, let $MC_2 = aMC_1$ and $E_2 = bE_1$, and solve for a , the ratio of marginal costs of group 2 to group 1. The shape of the block rate structure is then given by:

$$P_2 \begin{cases} \leq & P_1 \text{ if } a \leq \frac{b - k/E_1}{b - k/E_1} \\ > & \end{cases}$$

Figure 1 contains the results of numerical simulations of this equation. The vertical axis repre-

ents variation in the parameter a , the marginal cost of group 2 relative to group 1, and the horizontal axis represents variation in the parameter b , the elasticity of group 2 relative to group 1. Three values of k are presented, representing realistic price markups over marginal costs when prices at marginal costs fail to provide the revenue requirement. Each solid line shows the combinations of relative marginal costs and rela-

tive elasticities, given the value of k , where the best rate structure is $P_2 = P_1$, or a flat rate tariff. In the area above each solid line, the best rate structure is $P_2 > P_1$, or an inverted block tariff; in the area below each solid line, the best rate structure is $P_2 < P_1$, or a declining block tariff.

The case where $MC_2 = MC_1$ ($a = 1.0$) is shown by the middle dashed line in Figure 1. If marginal cost does not vary with con-

sumption, a declining block rate will be efficient if the elasticity of the large users is greater than the elasticity of small users, and an inverted block rate will be efficient if the elasticity of large users is less than the elasticity of small users. More broadly, Figure 1 demonstrates that three general rules can be applied to structure block tariffs when prices at marginal costs fall short of a utility's revenue requirements:

(1) A flat rate is efficient whenever the price responsiveness of large and small users is the same and the marginal costs of serving them are equal. The solid lines indicate that flat rates can also be efficient if marginal costs or elasticities differ, but the different cost of serving the incremental loads of large and small customers is offset by different sensitivities to price levels.

(2) An inverted rate structure is almost always efficient if the marginal cost of large users is greater than the marginal cost of small users. As shown by the shaded area above the dashed line in Figure 1, an exception may occur when the elasticity of large users is greater than the elasticity of small users and the relative difference in elasticity between large and small users is greater than the relative difference in marginal costs. If this exception occurs, declining block rates or flat rates are efficient.

(3) A declining block structure is almost always efficient if the marginal cost of large users is less than the marginal cost of small users. As shown by the shaded area below the dashed line in Figure 1, an exception may occur when the

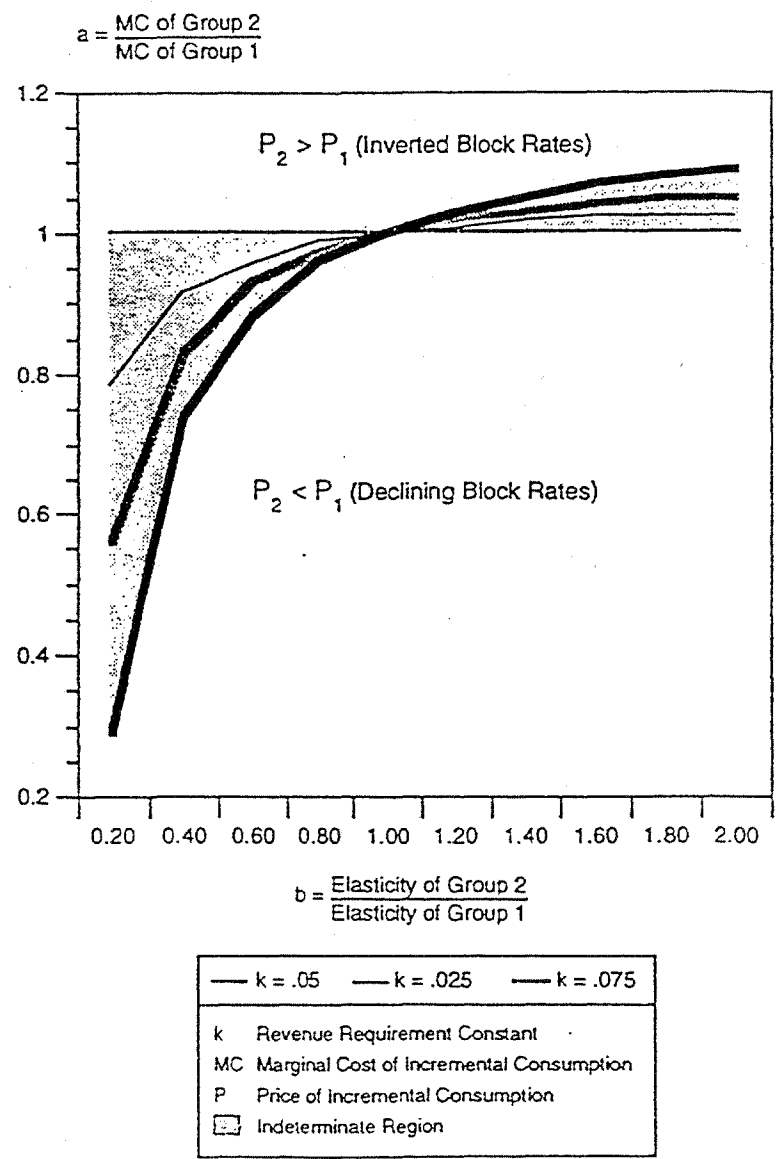


Figure 1: Second-Best Block Rate Structure

elasticity of large users is less than the elasticity of small users and the relative difference in elasticity between large and small users is greater than the relative difference in marginal costs. If this exception occurs, inverted block rates or flat rates are efficient.

To summarize, when marginal costs fall short of embedded revenue requirements, the design of economically efficient block rate structures depends primarily on the relative costs of meeting incremental loads of different customers within a rate class, with variations in class elasticities exerting a secondary influence on the tariff structure.

II. Marginal Costs, Rate Design, and Conservation

Our primary conclusion from this analysis is this: *Economic efficiency cannot be promoted by the design of rate structures which deviate significantly from cost.*

If larger users are less expensive to serve than smaller users, economic efficiency is worsened by inverted block rate structures. In practical terms, prices to large users are overstated, and prices to small users are understated.

Returning to the example of efficient winter rate structures for a summer peaking utility, it is likely that the major factor separating the residential class into distinct groups is the presence of electric heat. Since customers with electric heat tend to use a greater proportion of their electricity during the off-peak, nighttime period, the

marginal cost of large residential users is less than the marginal

cost of small users, and economic efficiency in the winter is most likely achieved through a declining block rate that will improve the winter load factor.

In fact, it is possible that in this situation all three PURPA rate objectives — conservation, efficiency, and equity — are furthered by declining block rates in the winter. Efficiency and conservation goals — particularly delaying or reducing the utility's generation capacity expansion



requirements — can now be better achieved through the summer rate structure since summer demand no longer has to be underpriced to meet the utility's fixed revenue requirement. A lower winter tail block may be viewed as equitable if heat is seen as a necessity and if it is recognized that most residential customers with electric heat cannot afford to switch to alternative fuels. ■

Endnotes:

1. Fla. Pub. Serv. Comm., Docket No. 830465-E1, July, 1984.

2. Bracewell & Patterson, Survey of U.S. Jurisdictions with Inverted Block Rates (prepared for British Columbia Hydro, May 1991).

3. *Id.*

4. Time-of-use (TOU) rate structures are preferred to block rate structures if the additional benefits (usage response) of TOU prices outweigh the additional metering costs. The preponderance of TOU demand and/or energy structures for industrial and large commercial classes throughout North America suggests that TOU pricing is cost effective for the largest users. TOU structures for the small commercial and residential classes are less popular, which suggests that in many instances block rate structures are a better vehicle for promoting economic efficiency.

5. Public Utility Regulatory Policies Act of 1978 (PURPA), Sec. 111(d).

6. When marginal costs are greater than average costs economic efficiency can be achieved by setting prices equal to marginal cost for each customer group and taxing the utility to keep revenues at required levels.

7. See A.E. KAHN, *THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS* (J. Wiley 1970).

8. See J.C. BONBRIGHT, A.L. DANIELSEN and D.R. KAMERSCHEN, *PRINCIPLES OF PUBLIC UTILITY RATES* (Pub. Util. Repts. 2nd ed. 1988).

9. F.P. Ramsey, *A Contribution to the Theory of Taxation*, 37 *ECON. J.* 47-61 (1927).

10. See S.J. BROWN AND D.S. SIBLEY, *THE THEORY OF PUBLIC UTILITY PRICING* (Cambridge U. Press 1986).

11. *Id.*

12. This issue was hotly debated more than 20 years ago. See W.J. Baumol and D. F. Bradford, *Optimal Departures from Marginal Cost Pricing*, 60 *AM. ECON. REV.*, 265-83 (1970), and A.P. Lerner, *On Optimal Taxes With an Untaxable Sector*, 60 *AM. ECON. REV.* 284-94 (1970).

**THE EFFECTS OF COMPETITION
AND DEREGULATION ON IRP AND DSM**
Dr. John Chamberlin, Greg Collins, and Susan Shaffer
Barakat & Chamberlin, Inc.

Abstract

The rapidly emerging competitive environment in the electric utility industry is already having a profound impact on utility planning practices and the implementation of demand side management (DSM) programs. The prospect of open choice for customers, together with regulatory uncertainty and increasing cost pressure, has undermined the foundation for utility activities on the demand side. As industry restructuring unfolds continues, these impacts will be even more extensive.

Under any scenario of the future which includes full retail access, traditional integrated resource planning (IRP) and DSM programs will have little value and will likely be eliminated. In scenarios in which more limited access is available, some aspects of IRP and DSM may survive. In any case, DSM programs must change to focus on delivering customer value.

Utilities will have to decide in which portion of an increasingly unbundled industry they can best compete. Some will choose the commodity market, while others will look to a value-added retail strategy.

The planning reference for utilities who see themselves as competing mainly in the commodity electricity market will be solely on cost. The loss of the link between the generation and end use provided by vertical integration will mean that these utilities will act more like independent power producers. The notion of meeting a predefined demand forecast at the lowest cost will have little meaning.

Utilities who pursue a value-added retail strategy will work to satisfy customers by providing DSM as one of many services that meet a wider range of customer needs.

Introduction

The passage of the Energy Policy Act of 1992 virtually eliminated any doubt that electric utility deregulation was on the horizon. Open wholesale transmission access is already a reality, and many states are starting to consider and experiment with retail wheeling. The increased deregulation of the electric utility industry has led to the emergence of competition in the industry.

This paper addresses what deregulation means to utilities as they try to plan for the future. More specifically, how should utilities' strategies for demand-side management (DSM) change in the face of a competitive electric utility industry?

Retail Competition

Much of the growing concern over competition in the retail electric utility industry centers around when and if retail wheeling will become a reality. Even without retail wheeling, utilities face numerous threats to their native loads and these threats are increasing.

Competition in the retail electricity market already exists in a variety of forms:

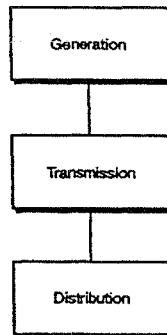
- Gas may be substituted for electric power;
- Energy service companies provide DSM measures in exchange for a share of the savings;
- Cogeneration and self-generation are becoming commonplace;
- Utilities draw customers away from other service territories by offering lower rates overall or special economic development rate discounts;
- Other countries offer lower electric rates and cheaper labor;
- Municipalization may increase in response to EPACT and as a strategy to protect consumers from rate hikes; and
- Sophisticated small, local generating systems, such as photovoltaics and fuel cells are entering commercialization.

Retail wheeling, although still much debated, appears to be inevitable in some form. However, most predictions are clouded by uncertainty over the form retail wheeling will assume and when it will occur. Retail wheeling, when does it occur, will be different from state to state. Arizona, California, Connecticut, Michigan, Missouri, New Hampshire, New Jersey, New Mexico, New York, Pennsylvania, Texas, Vermont, and Wisconsin have already taken steps to consider retail wheeling.

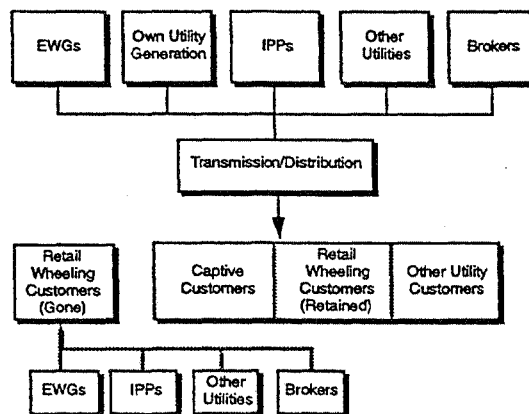
While state PUC and legislative initiatives have so far been in the forefront of retail wheeling initiatives, many utilities are rethinking their position on retail wheeling. For electric utilities, particularly those with excess generation and transmission capacity, retail wheeling represents an opportunity to expand loads, increase load factors, and increase revenue and profits. Utilities themselves may ultimately become the biggest advocates of retail wheeling. As an example, a vice president of marketing for a large East Coast utility recently reported that he got seven calls in one week from customers in an adjacent state wanting to be on his utility's system.

Figure A
Electric Utility Industry Structures

Regulated (Today)—Vertically Integrated



Unregulated (Future)—Unbundled Services



What Will a Competitive Utility Marketplace Look Like?

Up to now, electric utilities, as regulated monopolies, have been granted the exclusive right to sell electricity within a certain geographic area. This franchise right is granted by a state public utility commission. As shown in Figure A, the electricity industry consists of three basic sectors: generation, transmission, and distribution. Traditionally, these three sectors have been vertically integrated.

[Figure A here]

The concept of IRP and DSM make inherent sense for a vertically integrated electric utility system. Utilities use IRP to select the lowest cost mix of supply- and demand-side resources to meet projected customer loads. Because IRP identifies the lowest cost resource mix, customers should be indifferent as to whether their energy service needs are met by a supply- or demand-side option.

We believe, however, that as the electric utility industry becomes deregulated, increasing competition and the emergence of nonutility generators will result in the industry moving away from a vertically integrated structure and toward an unbundling of the electric utility industry. Structurally, electric utilities will likely change in two possible directions (see Figure A):

1. They will disaggregate into their component parts—generation, transmission, and distribution (as in the deregulated natural gas industry)—with the distribution company being the point of contact with the customer; or
2. They will split into regulated and deregulated market segments (similar to the “core” and “noncore” customers of gas utilities).

The key issue that is still unresolved is what components, if any, will still be regulated, and by whom—the state or FERC?

With generation and distribution services unbundled and equal access guaranteed, electricity brokers and other utilities will become a significant new competitive threat. Energy brokers will buy huge blocks of electricity at low cost and resell electricity to customers at lower prices than those customers could obtain if they purchased the power directly from their utility. Lower-cost utilities will attempt to underprice the local utility to obtain market share. Energy service companies and other utilities may package low-cost wholesale power with value-added services or attractive financing terms.

In an unbundled electric utility environment, each utility will be faced with four distinct customer segments:

1. Captive customers who do not have access to retail wheeling and which the utility is obligated to serve;

2. Eligible customers of retail wheeling who have decided to remain on the utility system;
3. Eligible customers of retail wheeling who have decided to leave the utility system; and
4. Former customers of other utilities with access to retail wheeling who now purchase energy from the utility.

The generation components of utilities that decide to compete as wholesale generators will strive to be the low-cost provider of electricity by creating efficient production systems with few frills. Their product will be commodity electricity. These utilities will attract large customers and other utilities looking for the best price on energy. Their competitors will be cogenerators, independent power producers, EWGs, energy brokers, and other utilities. If these utilities are able to design, build, and operate power plants at lower costs than those of IPPs or other generators, then utilities will continue to play a role in power generation sales.

Utilities that are not able to reduce their costs will discard their costly generating systems and purchase power on the open market at the lowest cost available. Electric utilities will likely achieve lower operating costs through restructuring, layoffs, and mergers designed to take advantage of long-term economies of scale. As these changes take place, it will become difficult to tell the difference between IPPs, EWGs, power brokers, and utilities.

As competition takes hold in the wholesale power market, there will be increased reliance on market forces to meet bulk power needs. This reliance on market forces will likely involve:

- New entrants into the electric generation market
- Utility mergers and acquisitions and the associated downsizing
- Highly integrated operation of various power pools
- Substantial bulk power trading among electric systems

With the separation of generation from the transmission and distribution systems, the link between generation and the end-use customer's demand is removed. We believe that the absence of this link will bring about the collapse of IRP as we know it today. Instead, system planning will be replaced with market or customer-service planning in order to attract and retain wholesale generation market share.

The Role Of DSM

For utilities competing in the unbundled wholesale generation market, DSM will make little sense in the long run. In a commodity wholesale market, where one competitor's product is indistinguishable from another's, price is the main source of competition. As long as a utility can produce energy at a price low enough that customers want to purchase it, they will.

In the near term, however, DSM may have a transitional role in the wholesale generation market. In the transition period during which a utility becomes a wholesale provider, the

utility may find DSM an effective means to free up capacity and energy for sale in more lucrative wholesale markets.

To reflect the true value of DSM in this scenario, DSM must be valued at the opportunity cost of off-system sales rather than at the utility's marginal cost. Thus, low-cost utilities with excess capacity, which have had only limited use for DSM in the past, may want to implement DSM to free up capacity for sale, at least as long as the cost of DSM is below the cost of commodity electricity prices. To make this scenario possible, FERC will have to fully embrace market-based wholesale electric rates, a trend that continues to emerge.

Utilities that continue to compete in the retail (or transmission and distribution) energy market will find DSM of more use in a deregulated market. But, as shown in Table 1, we believe utilities will shift away from the traditional DSM rebate programs of the past and toward using DSM as a value-added service.

Table 1
RETAIL ACCESS ALTERNATIVES AND DSM

Retail Access Alternatives	Noncaptive Customers	Captive Customers
Full scale, immediate	Value-added DSM, participant-paid DSM only	Not applicable
Full scale, phase in	Value-added DSM, participant-paid DSM only	DSM used for competitive positioning, captive customer focused with value-added, phase in
Largest customers only	Value-added DSM, participant-paid DSM only	Traditional DSM, but with lower value
Limited MWs or % of load	Value-added DSM, participant-paid DSM only	Traditional DSM, but greater concern about avoiding cross-subsidization

In a limited retail access environment, the traditional concepts of IRP and DSM planning will still remain for a utility's captive customers. But with the generation and transmission/distribution systems unbundled, the value of DSM as a means of reducing generation costs is negated for the T&D entity; any decrease in customer consumption will be met with a corresponding decrease in wholesale generation purchases by the customer's utility. As a result, all DSM will become (at best) RIM neutral from a generation cost standpoint.

Instead, DSM will be valued for its transmission and distribution cost savings, or for the value it may add to customer service. Utilities that once provided the same service throughout their service territory will take varying transmission and distribution costs into consideration in their DSM marketing and will package different services by community to take advantage of variable profitability.

We also think that utilities will place greater emphasis on minimizing the cross-subsidization of DSM costs in situations where retail access is limited to a specific amount of generation capacity as it will be unclear to the utility exactly which customers will choose to avail themselves of retail access.

Under the full-scale, phase-in retail access scenario, utilities will use DSM in the short term as a competitive positioning tool. They will use it to build end-use market share against alternative fuels by promoting equipment like heat pumps. They may also use it to install smart meters, fiber optics, or other technologies that will prepare utilities to compete in the upcoming unregulated market.

Utilities will implement DSM programs for noncaptive customers only if they are profitable (both to the utility and the customer). Costly rebate programs that allocate their costs to nonparticipants and increase rates will have no place in this market. Technology transfer programs that benefit society as a whole, but are borne by participating utilities, will also have no place in this market. Instead, utilities will design DSM programs that minimize rate increases and maximize customer value.

For noncaptive customers, utilities will find DSM most effective as part of a value-added service strategy. They will compete by packaging DSM services (e.g., audits, recommissioning, financing, and efficiency investments) with commodity electricity. To be successful, utilities must ensure that the DSM services they offer provide more value to participants than what they cost. DSM programs will increasingly focus on overcoming specific market barriers (e.g., performance risks, first cost) rather than relying solely on rebates to overwhelm the customer. Some utilities (or energy service companies) will sell energy services directly by owning end-use equipment and providing cooling, heating, lighting, and motor power at contract terms.

In order to keep rates down for noncaptive customers, we see two main options for paying for the cost of DSM programs:

1. DSM program participants pay for the value of the services they receive.
2. DSM costs are bundled and recovered through the sale of energy services.

In the end, competition and the unbundling of electric utility services will force retail power suppliers to become more market driven. They will have to recognize their different end-use markets and customer segments. Widespread price differences and product differentiation will emerge as electricity becomes both a commodity product and a value-added service.

The Future of Demand-Side Management

In the previous section, we presented our argument that DSM as we know it today will have a significantly different place in the unbundled, competitive marketplace of the future. At the generation level, where electricity will be a commodity resource, we see no role for DSM at all. In the retail transmission and distribution market, we see DSM evolving into a value-

added service that will allow utilities to target unique markets and provide the vehicle for product and price differentiation in the marketplace.

In the commodity generation market, there is much concern over the demise of DSM from an environmental and social perspective. Will the conservationists', environmentalists', and social service arguments of the benefits of DSM fall on deaf ears in a deregulated market driven solely by price?

We think so, and as such, a whole new set of environmental and social policy procedures are likely to emerge. The environmental and social benefits of utility-sponsored DSM programs will likely be replaced with legislation on appliance efficiency standards, building codes, low-income energy savings programs, and research grants such as the Golden Carrot program. Funding or subsidization for these efforts may be left to the market to bear, or legislators could impose energy conservation or social taxes or levies on consumers, transmission/distribution utilities, or wholesale generators. For example, regulators could impose distribution access charges and force utilities to collect these fees and pass them on to a state or collaborative organization for DSM funding and implementation.

In the retail transmission/distribution market, DSM programs will still exist, but will evolve into value-added services. Customer service will be the key to survival in a fully competitive marketplace. A new breed of educated and informed energy consumers will demand a wide selection of energy types, rates, and service options. Utilities will offer a menu of options that customers can use to customize their service. Each customer will attach its own value to cost, time of use, reliability, power quality, design assistance, and environmental concerns.

Energy efficiency will become one of many services that utilities sell to customers along with commodity electricity. DSM programs will likely become more individualized and customized. The programs will increasingly focus on overcoming specific market barriers (such as risk, power quality, convenience, and product quality) rather than relying solely on rebates to entice the customer into participation.

Many utilities are already using value-added strategies in their DSM offerings. For example:

- Audit programs are helping customers identify attractive energy savings opportunities;
- Direct installation programs for small commercial and residential customers are reducing the hassle associated with shopping for and installing new technologies;
- Financing programs for government, schools, and other institutional organizations are overcoming their problems in raising up-front capital; and
- Design assistance programs are allowing builders to evaluate the energy savings potential of new construction and technology alternatives.

Removing cross-subsidies from accompanying rebate payments can turn these services into appropriate products for a competitive market.

As competition increases, DSM programs will come to be seen not as ends in themselves but as part of the utility service marketing process. DSM programs will focus on new, emerging, and specialized technologies; the goal of these programs will be to move the market, educate the public for long-term energy efficiency, and overcome customers' market barriers. In their resource and strategic planning efforts, utilities will rely more and more on understanding customer usage patterns and energy service needs. This approach will contrast with past efforts, where DSM planners focused mostly on understanding and meeting utility load shape objectives. The fundamental characteristic of successful DSM programs in a competitive environment will be a focus on meeting customers needs.

We also expect that as the marketplace becomes more competitive, some utilities will turn their attention to selling energy services directly, by owning end-use equipment and providing cooling, heating, lighting, and motor power at contract terms. These utilities will operate the equipment and sell the desired services to customers for a set fee.

Few utilities today sell energy services; most sell kilowatt-hours. The best example to date of a utility whose marketing strategy is to sell energy services is Wisconsin Electric Power Company in Milwaukee. In Wisconsin Electric's experimental End-Use Pricing Project, supermarkets pay a fixed service fee in exchange for refrigeration and air conditioning. The energy service contract includes:

- The use of utility-owned refrigeration equipment
- Provision of equipment operating and maintenance services
- The energy required to operate the system

For companies that decide to provide energy services, DSM and energy efficiency will be as integral to the sale as the electricity itself. Wisconsin Electric installed efficient equipment to increase its margins on its energy service contracts. Since the profitability of a contract is determined by life-cycle costs, not first costs, efficient equipment is a sensible choice. Wisconsin Electric has effectively retained for itself the long-term dollar benefits of DSM normally reaped by participants in traditional rebate programs.

The possibilities for providing energy services that save energy and increase profits are virtually endless. Centra Gas provides hot water services to residential customers. Centra Gas purchases, installs, and maintains the gas water heaters and charges its customers a monthly rental charge for the service. Electric utilities could easily implement a similar program. The key question here is whether or not customers will be willing to buy these services.

Providing end-use services (instead of kilowatt-hours) removes the last great barrier to energy conservation: building managers or factory owners have no worry about payback from investments in efficient equipment because they get immediate payback in the form of lower bills. Furthermore, the utilities that take an energy services approach have an incentive to install the most efficient equipment because it will maximize their profits.

What Does this Mean for Future Utility Planning?

First and foremost, to meet competition head on, a utility must decide what business it wants to be in. To thrive in a competitive market, it must understand its customers' business objectives and then assess its own capabilities and constraints to determine which customer needs it can most efficiently and profitably meet. Customer intelligence is the key to understanding customer needs; competitor intelligence is the key to identifying the customer needs that a utility can fill competitively.

If a utility chooses to compete in a competitive retail marketplace, it must become more customer-driven. It must be able to answer the customer when they ask, "Why should I buy power from you?"

In short, a utility will have to strive to achieve product and service differentiation; it cannot simply bring power to its customers' meters. Rather, the utility must also provide information and expertise in all processes and equipment using energy and possibly provide end-use services directly to its customers. In some cases, these service options will be provided by utility staff; in more specialized cases, utility-sponsored energy service companies will provide the services.

Competition will necessarily change the relevance of IRP for utilities. In a competitive market, consumers will choose their energy suppliers on the basis of the value they receive for the dollars they expend. For any energy supplier to be competitive, it must be free to consider value explicitly in developing its energy service offerings. Regulators cannot rely on traditional IRP without putting utilities at a competitive disadvantage.

In a competitive marketplace, traditional IRP will lead to incorrect conclusions because it does not look at the full set of legitimate costs and benefits, or put another way, because it does not take into account customer value. Customers in a deregulated marketplace will gravitate to suppliers that provide the most value. If a utility does not incorporate customer value into its planning process, it will be dangerously disadvantaged.

As for DSM, its role as a utility resource option will be eliminated in a competitive marketplace. Instead, it will evolve into a customer value-added service. We see several possible roles for this "redefined" concept of value-added DSM:

- DSM will be used as part of a package of services designed to provide customers with the flexibility they need to control their own energy services usage and costs;
- Utilities will use DSM and energy-efficient technologies and practices to sell energy services to customers as efficiently as possible in order to maximize utility profit margins;
- DSM will still be used to promote strategic load growth;

- Traditional DSM programs may still remain for captive customers not eligible for retail wheeling, although the value of these programs to the utility may change; and
- DSM will become a value-added service that customers will be willing to pay for.

Equally as important for utilities to consider are the aspects of “traditional” DSM that will fall by the wayside in a competitive marketplace. These include:

- Individual utilities will no longer pursue market and technology transformation projects on their own. The funds they would expend to develop new technologies and marketing infrastructures would benefit all customers and energy providers, putting them at a competitive disadvantage.
- Broad-based rebate programs that raise rates will no longer be part of utilities’ DSM portfolios.
- There will be no cross-subsidization of DSM costs by nonparticipants. DSM will be provided on a cost-causer pays arrangement only.

1999

NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-5: Evidence of M. E. Whalen, Application of Nova Scotia Power Inc., Page 8.

In purporting to illustrate the "benefit to NSPI's customers of a load retention rate", M. E. Whalen assumes that 20% of NSPI's large industrial (including interruptible and industrial expansion) and large commercial customer load will be supplied by customers using an alternate supply.

- (1) Is the assumption that 20% of these customers will switch to an alternate energy source the percentage that NSPI believes will actually switch?
- (2) If the answer to (1) is "no", provide details of all assumptions NSPI has made in considering the likelihood of customers in those classes switching, including:
 - (a) The actual percentages NSPI estimate will switch to an alternate energy source, and
 - (b) The details of the pricing scenarios that NSPI expects will result in these percentage estimates.
- (3) If the answer to (1) is "yes", provide details of all assumptions NSPI has made in concluding 20% will switch, including details of the pricing scenario(s) resulting in that number switching.
- (4) Why was a price reduction of 10% assumed for purposes of the illustration in M. E. Whalen's evidence?

DATE FILED: December 31, 1999

1999

NSPI-P-871

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

- Response IR-5:**
- (1) No. The 20% referred to in Mr. Whalen's evidence refers to percentage of customer load, and not to the number of customers. It has been used for illustrative purposes only.
 - (2)
 - (a) NSPI has not produced specific scenarios to estimate the percentages requested. We are aware of three or four customers considering alternate supply options for all or part of their load, but there are as yet no firm proposals.
 - (b) Assuming that the "pricing scenarios" referred to in the question refer to the customer's costs associated with providing an alternate supply, no firm scenarios have been brought forward to date. The load retention rate would be determined on a case by case basis only after full review of any such alternate supply proposal.
 - (3) N/A.
 - (4) The 10% electricity price reduction referred to was used for illustrative purposes only.

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-6: Evidence of M. E. Whalen, Application of Nova Scotia Power Inc., Page 8.

In purporting to “illustrate the benefit to NSPI’s customers of a load retention rate”, the evidence indicates that if 20% of large industrial and commercial customers use an alternative energy supply there will be a decrease in the contribution by those classes of customers towards NSPI’s fixed costs and that “all else being equal, this difference (\$13.5 million) would have to be absorbed by other customers”.

- (1) Would the “absorption” of this decreased contribution to fixed costs by other customers be through an increase in rates those other customers pay?
- (2) If the answer to (1) is “no”, explain how other customers will “absorb” the difference?
- (3) Are the customers NSPI proposes will absorb this loss:
 - (a) Other customers who remain in the large industrial commercial classes?
 - (b) Customers other than large industrial and commercial?
 - (c) If the answer to (b) is “yes”, detail all classes of customers that NSPI expects to “absorb” this loss.
 - (d) Does NSPI propose that residential customers will absorb any portion of the loss?

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-6: (e) If the answer to (d) is "yes", why should residential and other customers subsidize the reduction of rates to NSPI's large industrial and commercial customers proposed in the Load Retention Rate?

(4) Does NSPI agree that even with a price reduction as proposed in the illustration, there is a loss that NSPI proposes will have to be absorbed by other customers?

Response IR-6: This question assumes the customer leaves the system. The whole purpose of this rate is to avoid losses such as those referred to in the preamble. NSPI's objective is to keep prices stable for all customers and the load retention rate helps us achieve this.

(1) Yes, assuming "all else is equal"; i.e., if there are no offsetting measures taken by NSPI to reduce costs and/or increase sales.

(2) N/A.

(3) a) This will be determined in a rate case, as appropriate.

b) See (a) above.

c) See (a) above.

d) See (a) above.

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a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

- Response IR-6:**
- e) The load retention rate will be offered only if the conditions of Availability Clause (1) are satisfied. Under those conditions, the load retention rate minimizes the impact on all other customers. NSPI does not consider this a subsidy. To the extent any customer load is lost, system costs will continue to be classified and allocated in accordance with the Board's approved cost of service methodology.
 - (4) Yes, "all else being equal". However, in this case, it is more likely that impacts can be offset because they are much smaller. As noted above, NSPI's objective is to maintain price stability for all customers, and the load retention rate will help us achieve that.

DATE FILED: December 31, 1999

1999

NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of
a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-7: Evidence of M. E. Whalen, Application of Nova Scotia Power Inc., Page
9.

The evidence of M. E. Whalen refers to a recent survey conducted by
NSPI for this Application.

- (1) Provide a copy of the survey questionnaire.
- (2) Provide the names and addresses of all the utilities who were
contacted for purposes of the survey.
- (3) Provide a list of all the utilities who have responded to the survey
as of the date the Response to this Information Request is due.
- (4) Provide a copy of all survey responses received.

- Response IR-7:**
- (1) The questionnaire is attached.
 - (2) The names and addresses are attached in Table Sempra IR-7A. This
list includes all utilities listed in response to Irving-IR-6. This list has
been updated to include Central Maine Power, EPCOR, TransAlta,
and Portland General Electric, which had been missed on the first list.
 - (3) A list is attached in Table Sempra IR-7B.
 - (4) See response to Irving-IR-6(b). The utilities were not made aware
that their individual responses might be made public, and as a result,
NSPI prepared Table A (December 6 application and evidence) to
summarize the responses.

DATE FILED: December 31, 1999

Subject: RATE SURVEY INFORMATION REQUEST

SEMPRA IR-7(1)

Mr. ,

Nova Scotia Power Inc. is gathering information on Load Retention, Standby Service and Real Time Price tariffs. We are asking for your assistance in providing us with information on the above from your company. Please, fill in the answers in the questionnaire below and e-mail it back to me. Please provide additional details if possible.

1. Load Retention Tariffs

Do you currently offer, or are you planning to offer, a Load Retention Tariff ? If yes, could you please describe briefly what process your company uses to evaluate applications for this rate? Was an independent third party involved?

2. Standby Firm Rates

Do you currently have standby rates in effect or are you in the process in implementing any in the near future?

3. Real Time Pricing.

Does your company currently have any RTP tariffs in effect or are you planning to implement such pricing in the near future?

If any of the information requested above is available on your web site please provide the web address. If you are not the right person to answer the above questions please pass this e-mail to those who can.

Please respond to Mr. Barrie Clark at the above e-mail address. (barrie.clark@nspower.ca). Thank you for your timely response. Your assistance is appreciated.

Bob Boutilier

Manager, Rates & Forecasting
Nova Scotia Power Inc
(902) 428-6531

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NOVA SCOTIA UTILITY AND REVIEW BOARD

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TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Table Sempra IR-7A

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TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Table Sempra IR-7A

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Table Sempira IR-7A

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

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TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Table Sempra IR-7A

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Table Sempra IR-7A

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NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **SEMPRA ATLANTIC GAS INC.**

FROM: **NSPI**

Table Sempra IR-7B

Alabama Power Company	Allegheny Power	Alliant Utilities
Alliant Gas & Electric Company	Ameren Services	AmerenCips
American Electric Power Service Corp.	Arizona Public Service Company	B.C. Hydro
Baltimore Gas and Electric	Carolina Power and Light Company	Central and South West Services, Inc.
Central Maine Power	Commonwealth Edison Company	Consumers Energy
Duke Energy Corp.	Edmonton Power (EPCOR)	El Paso Electric Company
Entergy Services, Inc.	Hawaiian Electric Company, Inc.	Idaho Power Company
Indianapolis Power & Light Co.	Kansas City Power & Light Co.	MidAmerican Energy Co.
New England Electric System	Niagara Mohawk Power Corp.	Northern States Power Co. (WI)
Northern Indiana Public Svc. Co.	OG&E Electric Services	Ontario Hydro
Otter Tail Power Co.	PECO Energy Co.	Portland General Electric
Potomac Electric Power Company	PP&L, Inc.	Public Service Electric & Gas Co.
Puget Sound Energy	Quebec Hydro	Southern Company Services, Inc.
Southern California Edison Co.	Southwestern Electric Power Co.	St. Joseph Light & Power Company
Tampa Electric Company	TXU Business Services	United Illuminating Company
West Texas Utilities Company	Western Resources Inc.	Wisconsin Electric Power Company

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-8: Evidence of M. E. Whalen, Application of Nova Scotia Power Inc., Page
9.

The evidence of M. E. Whalen refers to the 1991 Electric Power
Research Institute (EPRI) Survey of Innovative Rates.

(1) Provide a copy of the 1991 Electric Power Research Institute
(EPRI) Survey of Innovative Rates.

Response IR-8: (1) See response to UARB-IR-20.

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-9: Application of Nova Scotia Power Inc. for a Load Retention Rate.

NSPI proposes a Load Retention Rate be granted to certain customers.

- (1) Does NSPI plan to offer the Load Retention Rate to customers for a fixed term?
- (2) If the answer to (2) is "yes", please provide details as to the anticipated length of time for which the Load Retention Rate will be offered to a customer of customers in months and/or years.
- (3) When evaluating the benefits of offering the Load Retention Rate to a customer for a short or long term period, are there different costs, or differences in costs, which would be included in NSPI's evaluating of offering the Load Retention Rate for either time period.
- (4) If the answer to (3) is "yes", please provide details as to the different costs or the differences in costs which are to be evaluated.
- (5) Does NSPI expect the UARB to evaluate the Load Retention Rate being offered to a customer for one (1) year in a different manner than the UARB would consider the Load Retention Rate being offered to a customer for a five (5)-year period or any other period longer than one (1) year?

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-9: (6) If the answer to (5) is “yes”, what difference does NSPI expect
that the UARB shall consider when evaluating the impact of the
Load Retention Rate offered to a customer for such different time
periods?

Response IR-9: (1) See response to UARB-IR-11.

(2) See above.

(3) No. NSPI expects to evaluate the load retention rate over the long
term. This analysis will include the short term and the term of the rate
will likely be influenced by that, but it will be determined on a case
by case basis. There will, however, be only one evaluation
methodology.

(4) N/A.

(5) Yes.

(6) The primary difference would be an evaluation of risks. The longer
the term, the greater the risks to NSPI. However, this would be
addressed in the implementation phase of the rate and the UARB
would have an opportunity to review how this had been assessed and
incorporated into the rate.

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-10: Attachment "A", Paragraph 8, Application by Nova Scotia Power Inc.
for a Load Retention Rate.

NSPI lists "appropriate factors" that shall be evaluated to determine the
cost of the alternate supply to a customer.

- (1) Does NSPI have any guidelines, examples, prototypes, conceptual or detailed models, or any other material, documents, models or aids that disclose the manner, significance, or weight to be given to any or all of these factors when determining the cost to the customer of the alternate supply?
- (2) If the answer to (1) is "yes", please provide any guidelines, examples, prototypes, conceptual or detailed models, or any other material, documents, models or aids relied upon, used or in the possession of NSPI.

Response IR-10:

- (1) No. Each of them will be assessed, as appropriate, on a case by case basis.
- (2) N/A.

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-11: Attachment "A", Paragraph 1, Application by Nova Scotia Power Inc. for a Load Retention Rate.

NSPI proposes that the customer shall apply in writing to take service under the Load Retention Rate.

- (1) Will NSPI, its employees, agents or representatives, assist or provide advice in any manner whatsoever to customers when preparing such applications?
- (2) If the answer to (1) is "yes", please describe in detail the nature and kind of advice and/or assistance to be provided to customers when filing an application.
- (3) Will NSPI require customers to provide mandatory and/or a standard set of information when filing an application?
- (4) If the answer to (3) is "yes", please describe in detail the nature of the mandatory and/or standard information to be provided by a customer as part of the application.

Response IR-11: (1) Yes.

(2) This advice would be of a general nature, as requested by the customer, with respect to interpretations of the rate, the process and procedures required, etc. This is similar to the kind of advice that NSPI regularly provides to customers applying for service.

(3) Yes.

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of
a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Response IR-11: (4) The items specified in response to UARB Interrogatory 8 will be
required.

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NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of
a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-12: Application by Nova Scotia Power Inc. for a Load Retention Rate.

NSPI proposes that the price, terms and conditions shall be established jointly by NSPI and the customer and submitted to the UARB for approval.

- (1) Does NSPI have any concrete guidelines which shall be uniformly applicable to customers seeking the load retention rate?
- (2) If the answer to (1) is "yes", please provide a detailed description of the guidelines.
- (3) Does NSPI think it appropriate for the UARB to establish a floor so as to ensure that other customers are not disadvantaged as a result of certain customers receiving service pursuant to a Load Retention Rate?
- (4) If the answer to (3) is "yes", please explain why. If the answer is "no", please explain why not.
- (5) Does NSPI think it appropriate for the UARB to establish limitations on terms and conditions under which all customers taking service under the Load Retention Rate shall receive service?
- (6) If the answer to (5) is "yes", what terms and conditions does NSPI think are appropriate? If the answer is "no", why does NSPI think it inappropriate for the Board to impose such limitations on the terms and conditions?

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-12: (7) Is NSPI aware of any guidelines adopted by any regulatory agency in any other jurisdiction imposing limits on the terms and conditions to be offered to customers taking service under a load retention rate?

(8) If the answer to (7) is "yes", please provide all information of which NSPI is aware showing the jurisdiction where any such terms and conditions may be imposed and providing detailed information on the nature and extent of any such terms and conditions.

Response IR-12: (1) The guidelines which shall apply are as stated in the Availability section of the Proposed Load Retention Rate.

(2) See above.

(3) Availability Clause (1), bullets 2 and 3, of the Proposed Load Retention Rate determine the floor. This will be determined on a case by case basis and will be submitted to the UARB for final approval.

(4) In order for other electric customers to be better off by offering a particular load retention rate to a customer, the revenue received under this rate must recover all incremental costs of serving the customer as well as a contribution to fixed costs. This will be demonstrated to the UARB upon seeking final approval.

(5) No.

(6) These limitations are already stated in the Proposed Load Retention Rate.

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FROM: NSPI

- Response IR-12:** (7) Yes. As shown in the response to UARB-IR-19, several of the rate schedules include clauses that limit the term, maximum reduction in rate, types of facilities that are eligible, number of contracts that can be entered into, etc.
- (8) See response to UARB-IR-19 and UARB-IR-20.

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-13: Application by Nova Scotia Power Inc. for a Load Retention Rate.

NSPI proposes that each application shall be approved by the UARB and, when there is a disagreement between the customer and NSPI, then the customer may ask the UARB to adjudicate.

- (1) How does NSPI propose that the UARB should evaluate whether such an application is appropriate or reasonable if the only parties aware of the submission to the UARB and before the UARB are the customer and NSPI?
- (2) Since NSPI has proposed that any revenue shortfall resulting from the implementation of a Load Retention Rate shall be re-allocated to other customers, does NSPI consider it appropriate for such other customers to be represented before the UARB when the UARB is making the decision pursuant to any such application?
- (3) If the answer to (2) is "no", please provide detailed reasons for this position on the part of NSPI.
- (4) Does NSPI think it appropriate for its shareholders to bear the risk incurred when offering discounts by way of a Load Retention Rate?
- (5) If the answer to (4) is "yes", please outline how and to what extent NSPI shareholders would be at risk. If the answer is "no", please explain why persons other than the shareholders should bear the risk of such a business decision by NSPI.

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-13: (6) Is NSPI of the opinion that re-allocation of revenue shortfalls resulting from the application of the Load Retention Rate to its other customers is an appropriate regulatory mechanism for an electrical utility to use when responding to competitive conditions?

(7) If the answer to (6) is "yes", please explain why in detail.

Response IR-13: (1) The preamble to this question refers to Paragraph (4) of Attachment A. In that circumstance, the UARB is adjudicating whether the information provided by the customer is sufficient to warrant a detailed evaluation of a load retention rate for that customer. The items specified in response to UARB Interrogatory 8 will serve as a guide to this.

(2) Yes. This hearing provides an opportunity for all customers to make representation to the Board with respect to the load retention rate concept, and any reallocation of revenue shortfalls among customers would take place during a rate case where all customers again have that opportunity.

(3) N/A.

(4) No.

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FROM: NSPI

Response IR-13: (5) The risk to be managed is the risk that significant load will be lost to the system as a result of a large customer switching to an alternate supply. This loss of load to the system may be to the detriment of all other customers given that the loss of contribution to fixed costs would have to be absorbed by remaining customers. The risk to be managed is therefore not a function of the business decision of NSPI to seek a load retention rate; rather, the decision to seek a load retention rate is a remedial response to outside competitive forces. The rate would allow NSPI to have the ability to mitigate this potential harm to the remaining customers in cases where retaining a customer with a viable alternative, at a reduced rate, is better than losing the customer in question. It is the remaining customers that ultimately bear the risk when others choose to use an alternate source of energy. NSPI's business decision to seek the proposed rate is meant to allow it to reduce this real risk to its customers. It is not taking a risk for potential shareholder benefit.

(6) Yes.

(7) See (5) above.

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RESPONSE TO INFORMATION REQUEST

TO: SEMPRA ATLANTIC GAS INC.

FROM: NSPI

Question IR-14: Attachment "A", paragraphs 10 and 11, Application by Nova Scotia
Power Inc. for a Load Retention Rate.

NSPI proposes to compare and assess the impact on other customers of
losing a customer load with the effect of mitigating such a loss by
offering the customer in question a Load Retention Rate.

- (1) Please provide all information respecting NSPI's marginal costs,
including but not limited to, marginal customer related costs,
marginal distribution costs, marginal transmission costs and
marginal generation costs.
- (2) In providing information respecting the marginal costs, please
identify and segregate capital and operating expenses.
- (3) Please define the time frame used in calculating each of the
aforementioned marginal costs.
- (4) Does NSPI incorporate the cost of capital when determining the
net benefit to be derived from offering a customer the Load
Retention Rate?

- Response IR-14:**
- (1) See Response to UARB Interrogatory 26.
 - (2) See Response to UARB Interrogatory 26.
 - (3) See Response to UARB Interrogatory 26.
 - (4) Yes.

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