NLH-200 PUB (Re: Page 6, lines 21-23)

The evidence states, "Under the Fixed Variable Method those costs that are fixed in nature are classified as demand-related. This includes depreciation, return on rate base and taxes. Variable costs are classified as energy. This includes fuel and O&M expenses".

Does EES mean that under this methodology all O&M expenses are classified as being energy-related or only O&M expenses that are related to the production of energy, such as boiler maintenance?

Response:

This statement discusses production costs and refers to O&M expenses that are related to production.

NLH-201 PUB (Re: Page 8, lines 2-3)

The evidence states, "While the precedent for Hydro is based on the load factor method, this is not the most common approach used today in ratemaking in North America", and on lines 15-16: "The peak credit is most theoretically correct in our opinion, as it accounts for what type of costs would be incurred to serve the demand component alone. It is also widely used and is representative of what occurs in market prices in those jurisdictions where there is ample competition on a wholesale basis".

Response:

This statement was based on our firm's experience with ratemaking and power supply contracting in many different jurisdictions. EES Consulting has not performed a specific survey of utilities in North America.

NLH-202 PUB (Re: NLH-201 PUB)

Please provide rationale to support the use of the peak credit method for hydraulic as well as thermal generating plan.

Response:

Hydraulic plant is difficult to classify because of the large capital cost and the fact that it serves both energy and peaking needs. The peak credit method establishes the value of the peaking capability of the hydro and other facilities and can therefore be used as a proxy to classify costs. It simulates a case where specific plants would be built for peaking alone and other types of plant would be used for base load energy.

NLH-203 PUB (Re: NLH-201 PUB)

Has EES investigated the circumstances regarding the method used by each utility with consideration of the type of generation each utility has as well as regulatory mandates, as applicable?

Response:

Please see the response to NLH-201 PUB. Our experience in some cases reflects knowledge of generation mix as well as regulatory mandates.

NLH-204 PUB (Re: Page 8, line 10)

EES states, "The base/intermediate/peak method has a sound theoretical rational…" Would EES agree that this statement is subjective and that the B-I-P method is itself controversial?

Response:

From our perspective, this approach is theoretically correct if units can be strictly identified as serving a base, intermediate or peak use. The controversy is a function of real life circumstances where plants cannot be so easily categorized. This is consistent with our concerns about how to treat a hydro system that serves both peak and base load functions.

NLH-205 PUB (Re: Pages 10-12)

To what extent would EES agree or disagree that the zero-intercept method most accurately achieves the goal of identifying the theoretical skeleton system needed to connect customers to a source of supply and that by virtue of the rather considerable data needed to properly employ this methodology, the minimum system approach is often used as a practical alternative.

Response:

We do not agree that a minimum system approach is valid only from a practical sense. The zero-intercept and minimum system approaches share a basic theory and differ primarily in the definition of what is required to "connect customers to a source of supply".

NLH-206 PUB (Re: Pages 11, 34-39)

In discussing the zero-intercept method, EES states, "It also has a potential problem that the zero-sized facility could result in a negative cost outcome". In its experience in performing zero-intercept regressions, does EES believe that all best-fit curves are necessarily linear throughout the entire range? Also, does EES believe it can be appropriate to adjust for observation points in which there are few units of property installed, on the permits that larger projects tend to have lower unit costs?

Response:

EES Consulting supports the use of minimum system in most circumstances and does not have vast experience in performing zero-intercept regressions. We do, however, have significant experience in regression analysis. Non-linear regressions may be appropriate in a zero-intercept approach and most likely are the best approach for defining the function of costs relative to equipment size. This does not rule out a negative outcome, however. We do not rule out adjusting for observation points with few units or property installed, but also find difficulty if there are relatively few points of data (e.g. only 3-5 different pole sizes) over which to perform a regression.

NLH-207 PUB (Re: Page 8, lines 20-25)

Please provide the evidence that was relied on for the statement that natural gas is available in Newfoundland and Labrador.

Response:

Please see EES Consulting's updated evidence, filed September 19, 2003, which clarifies the passage referenced above.

NLH-208 PUB (Re: Page 22, lines 21-23)

Please provide the evidence that was relied on that any Newfoundland Power generation is embedded in Hydro's service territory.

Response:

EES Consulting arrived at this conclusion after reviewing Hydro's application, and in particular Section 4 of the Stone & Webster Management Consultants evidence on a Rate Design for Newfoundland Power, which discussed a need to credit NP load data for NP generation. Page 6 of the SWMCI evidence states: "NP's generation benefits the island interconnected system and in Hydro's cost of service, a demand credit is given to NP to recognize this. With the introduction of a demand component to the NP rate, the treatment of the generation credit becomes more prominent and the question arises as to whether present methodology should be continued or perhaps a change is warranted". Unless NP generation provides some operational or cost advantage that cannot be replicated by Hydro, EES Consulting is unaware of any "benefits to the island interconnected system" that NP generation could provide except for being connected to Hydro infrastructure.

Furthermore, EES Consulting observed in Hydro's study entitled "Review of COS Assignment for the GNP, Doyles-Port aux Basques, and Burin Peninsula Assets" (pages 21 and 22 as well as Table 2-1 of JRH-3) that on the Burin peninsula, NP relies upon Hydro transmission to connect to the Island Interconnected system.

Finally, in its response to PUB-181 NLH, Hydro provided "actual recorded meter data for all points of supply between Hydro and NP", in which the associate documentation identified three meter points NP energy is delivered to the Hydro system: Boyd's Cove Terminal Station (BDC), Kings Point (KPT), and Seal Cove Road Terminal Station (SCR).

Therefore, EES Consulting concludes that at least some NP generation passes through Hydro infrastructure in the process of being delivered to NP load centres. To the extent that NP must rely on Hydro infrastructure at least some of the time, it is the position of EES Consulting that NP should be allocated the full cost of transmission.

There are two possible circumstances that would cause EES Consulting to modify its recommendation.

- If NP does not require Hydro infrastructure to deliver energy to NP load centres <u>at any time</u>, then EES Consulting would recommend that no generation credits be given to NP. If all NP generation is 'behind the fence', then the actual gross billing determinants would appropriately reflect NP's use of Hydro resources.

- If NP generation does flow through Hydro infrastructure but NP can demonstrate that (i) the flow is inadvertent and that NP could continue to deliver the power without the aid of Hydro infrastructure, and (ii) that NP does not benefit from improved reliability and operational flexibility of wheeling power through the Hydro system, then we would recommend that generation credits should apply to both transmission and generation.

However, EES Consulting has not observed any evidence put forward in this preceding that would suggest either scenario is occurring.

NLH-209 PUB (Re: Page 22, line 35)

Please provide the evidence that was relied on that the Holyrood plant is used as a peaking unit.

Response:

EES Consulting arrived at this conclusion that a portion of Holyrood is used as a peaking unit after reviewing Hydro's application, and in particular Section 6.2 of the Stone & Webster Management Consultants evidence on a Rate Design for Newfoundland Power. On page 11, SWMCI states "…Hydro should try to strike a balance between the demand and energy rate levels such that the demand rate satisfies the above criteria with the energy rate reflecting short-run marginal cost, in this case the fuel cost at Holyrood". This statement would suggest that in peak periods, an incremental demand for generation usually supplied from Holyrood.

EES Consulting also gained the impression that Holyrood generating facilities are primarily used for peak generating periods after reviewing Hydro's "East Coast Voltage Study", provided in its response to NP 121. On the first page of the executive summary, Hydro states: "Based on the load flow analysis and the cost estimates obtained, it is recommended that Unit No. 3 at Holyrood be utilized as a synchronous condenser for voltage support during periods of light and medium loads; that is, periods when generation is normally off at Holyrood."

In the context of page 22, line 35 of EES Consulting's evidence, the issue raised is Hydro's stated intent for the tail block rate to signal a higher incremental cost in periods of peak demand (found on page 11 of SWMCI). Where that incremental production originates, or even the value of that incremental cost, is of no consequence to EES Consulting's recommendations.

NLH-210 PUB (Re: Pages 23-25 on the Tail Block Rate)

Given that hydraulic generation is primarily increased for peak loads except during unusual circumstances when gas turbines are used as described in NP-172 NLH, explain how shifting energy consumption from on-peak hours to off-peak hours will change system energy costs.

Response:

Over the long run, a consistent and predictable shift in energy consumption from on peak to off peak hours will improve the overall system load factor and all else equal reduce the peak capacity that Hydro will need to deliver in times of peak demand. This will have two impacts on system planning. First, Hydro would be able to defer capital infrastructure projects that are intended to increase peak capacity. Second, Hydro may be able to invest more towards base-load generating technologies that can take advantage of greater economies of scale for a reduced per-kWh operating cost.

NLH-211 PUB (Re: Pages 26, lines 11-32)

Please show the $/kW-month rate that would apply using the example ratcheted billing determinants using the NP Native Peak Assumptions in the following table. Show the 2004 annual cost to NP using this example rate, the 2004 annual cost to NP if the actual peak was 100 MW over forecast and compare this to the SWMCI proposed method under the same conditions.

NP Native Peak Assumptions (MW)

	2003	2004
January	1157	1179
February	1099	1120
March	1007	1026
April	908	921
May	814	825
June	696	705
July	566	574
August	542	550
September	625	634
October	790	801
November	955	968
December	1108	1124

Response:

EES Consulting is unable to fully compare the two alternative methods with the data provided. The suggested ratchet framework requires at least three years of data from a consistent data source. With the data provided, EES Consulting would be able to begin calculating a one-year trailing ratchet beginning in 2004, or the proposed two-year ratchet beginning in 2005. However, EES Consulting has not been provided with Hydro's forecasted weather normalized billing determinants beyond 2003. Finally, the evidence of EES Consulting did not specifically advocate the 90% and 85% ratchet figures, but instead provided these as an illustrative example pending further discussion and analysis.

As a general principle however, EES Consulting would expect that a comparison of the two alternatives would differ depending upon the final ratchet percentage chosen. For example:

- A higher ratchet percentage would tend to be relatively more stable month-to-month as compared to Hydro's proposal and would reduce financial variability for peak demand forecast variances in off-peak months. For load variations that are less than 90% (or whatever percentage is chosen) of previous peak demand that is carried forward, the financial variability is eliminated. However a higher ratchet percentage will carry forward a larger financial impact due to a forecast variance in winter peak month. The duration of this financial impact would depend on the percentage of the two-year trailing ratchet.

- A lower ratchet percentage would tend to reduce the long-term financial impact arising from forecast variances in the winter peak month. However, this would forego some degree of month-to-month stability and introduce some financial variability caused by peak demand forecast variances in off-peak months.

NLH-212 PUB (Re Pages 33-35, regarding a NP Generation Tariff)

Is a NP Generation Tariff necessary for NP Generation within NP's service area? Please explain.

Response:

EES Consulting would not propose that there be a NP Generation Tariff for power that remains within NP service areas. EES Consulting's recommendations in this regard refer to power that requires the use of Hydro infrastructure to allow the energy to be delivered to NP load centres.

NLH-213 PUB (Re: Pages 33-35, regarding centralized dispatching)

Please explain how this is different form the current practice of Hydro as outlined in Exhibit JRH-3 Appendix A, given there is only one steam generating station, Holyrood, and Hydro dispatches NP thermal generation as per step 5 of the referenced instruction.

Response:

Centralized dispatching, as referenced in EES Consulting's evidence, is different from the current practice referenced in JRH-3 Appendix A in the following respects:

- Centralized dispatching would occur in all hours, not just in the event of a "system generation shortage".
- Centralized dispatching would be according to increasing order of short-run marginal cost (stacking order), subject to operational constraints, required reserves, and ancillary services.
- Short-run marginal cost of all generation available to the interconnected system, and the resulting stacking order, would be subject to Board review

Centralized dispatch would also be subject to contract and operational constraints.

Although not necessarily recommended in EES Consulting's evidence, it is also possible that the task of centralized dispatch could be assigned to a third party. This option, however, would not be necessary to resolve the issues discussed in EES Consulting's evidence.

IC-428 PUB

Provide expanded CVs of Gail Tabone and Nigel Chymko showing all appearances before regulatory boards and provide copies of all evidence filed in regulatory proceedings by either of them within the past three (3) years.

Response:

The following is a list of assignments related to cost of service and other regulatory issues for EES Consulting as a firm. Gail Tabone and/or Nigel Chymko were involved in all of these assignments. The list is broken into three categories:

- EES Consulting Participation in Regulated Proceedings
- Negotiated Settlements
- Public Utility District/Municipal/Cooperative COSA Work

In many of the regulated cases that made it to the hearing phase, the President of EES Consulting appeared as the witness. Ms. Tabone or Mr. Chymko completed most of the preparatory work. We have also listed cases where Ms. Tabone or Mr. Chymko were participants in negotiated settlements. As they were not heard in full by the appropriate regulatory body, no regulatory appearances were necessary. Finally, EES Consulting works for many municipal utilities, cooperatives and or public utility districts that are regulated by elected boards or councils. We have also included a list of those utilities where Ms. Tabone or Mr. Chymko completed work and presented COSA and rate design findings to the appropriate board or council.

EES Consulting Participation in Regulated Proceedings (Evidence filed at proceedings more relevant to the Hydro application is attached)

- Alberta's Transmission Administrator 1999-2000 Tariff Application
- Anchorage Municipal Light & Power (ML&P) before the Regulatory Commission of Alaska, on behalf of ML&P
- BC Gas 2000 Rate Application before the BCUC, on behalf of the BCUC
- BC Hydro before the BCUC, on behalf of West Kootenay Power
- BC Hydro before the British Columbia Utilities Commission (BCUC), on behalf of the Joint Industry Electricity Steering Committee (JIESC)
- City of Lethbridge before the Alberta Energy and Utilities Board (Genco And Disco 2000 Pool Price Deferral Accounts Proceeding) on behalf of the City of Lethbridge

- City of Red Deer before the Alberta Energy and Utilities Board (Genco And Disco 2000 Pool Price Deferral Accounts Proceeding) on behalf of the City of Red Deer
- Lethbridge Electric Utility before Lethbridge City Council (2000 Financial Policy Review, Cost of Service Analysis, and Rate Design) on behalf of the Lethbridge Electric Utility
- Montana Power Company before the Public Service Commission, on Behalf of Montana Power Company
- Pacific Gas & Electric Company before the Federal Energy Regulatory Commission, on behalf of Los Angeles Department of Water & Power
- Reliant Energy HL&P before the Public Utility Commission of Texas (PUCT), on Behalf of the City of Garland, TX
- Texas Municipal Power Authority (TMPA) before the PUCT, on Behalf of TMPA

Negotiated Settlements

- ACTO Electric 1999-2000 Tariff Application Phase I
- ACTO Electric 2001-02 Transmission Facility Owner Tariff Negotiated Settlement
- ACTO Electric Final Balance and Disposition of 1999 Deferral Accounts
- Alberta's Transmission Administrator 1998 Tariff Application Phase I
- Alberta's Transmission Administrator 2002 Tariff Application Phase I
- Alberta's Transmission Administrator 2003 Tariff Application Phase I (Pending Board Approval)
- Alberta's Transmission Administrator Article 24 (Ancillary Services) Transmission Must Run Compensation to Engage Energy for 2001 and 2002
- Bonneville Power Administration on behalf of Western Public Agencies Group, 2002 Wholesale Power Rate Proceeding
- Bonneville Power Administration on behalf of Western Public Agencies Group, Proposed Safety Net Cost Recovery Adjustment Clause Adjustment to 2002 Wholesale Power Rates
- Brazos Electric Power Cooperative before the PUCT, on behalf of City of Garland
- Centra Gas British Columbia before the BCUC on Behalf of Centra Gas British Columbia, Application for Approval of Rate Design and Proposed 2003 Rates
- Central Power & Light before the PUCT, on behalf of City of Garland
- City of San Antonio before the PUCT, on behalf of City of Garland

- Edmonton Power 1999 Direct Access Tariff
- Enstar Natural Gas Company before the Regulatory Commission of Alaska, on behalf of ML&P -Investigation into the 2000 Revenue Requirement and Cost of Service Studies
- EPCOR 2001-02 Transmission Facility Owner Tariff Negotiated Settlement
- Fifth Judicial District of the State of Idaho on behalf of the City of Heyburn—Support of the Heyburn Defendant's Memorandum in Opposition to Plaintiff's Application for Injunctive Order Pursuant to IRCP 65
- Northern Lights—Power Cost Allocation and Unit Cost Determination for Riley Creek Lumber Company
- PacifiCorp before the California Public Utilities Commission, on behalf of Nor-Cal
- Puget Sound Energy before the Washington Utilities and Transportation Commission, on behalf of AT&T and WorldCom
- South Texas Electric Cooperative before the PUCT, on behalf of City of Garland
- Toronto Hydro Electric System before the Ontario Energy Board Commission, on behalf of Toronto Hydro
- TransAlta 2001 Transmission Facility Owner Tariff Negotiated Settlement
- West Texas Utilities before the PUCT, on behalf of City of Garland

Public Utility District/Municipal/Cooperative COSA Work

- Anaheim Public Utilities
- Central Electric Cooperative
- Chelan PUD
- City of Anaheim
- City of Medicine Hat
- City of Red Deer
- Clark Public Utilities
- Emerald PUD
- Flathead Electric Cooperative
- Kootenai Electric
- Mason County PUD No. 3
- Northwest Territories
- Pend Oreille County PUD
- Peninsula Light Company
- Tacoma Public Utilities

SOAH DOCKET NO. 473-00-1017
P.U.C. DOCKET NO. 22352
AND
SOAH DOCKET NO. 473-00-1019
P.U.C. DOCKET NO. 22354

BEFORE THE

PUBLIC UTILITY COMMISSION OF TEXAS

TESTIMONY

OF

GARY S. SALEBA

ON BEHALF OF

THE CITY OF GARLAND

NOVEMBER 17, 2000

SOAH DOCKET NO. 473-00-1017
P.U.C. DOCKET NO. 22352
AND
SOAH DOCKET NO. 473-00-1019
P.U.C. DOCKET NO. 22354

BEFORE THE
PUBLIC UTILITY COMMISSION OF TEXAS

TESTIMONY
OF
GARY S. SALEBA

ON BEHALF OF
THE CITY OF GARLAND

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Gary S. Saleba. I am President of EES Consulting, Inc. My business address is 12011 Bel-Red Road, Suite 200, Bellevue, Washington 98005-2471.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I received a Bachelors of Arts degree in Economics and Mathematics from Franklin College in Indiana. I received my Masters of Business Administration in Finance from Butler University in Indiana. For the last 19 years, I have been a principal and owner of EES Consulting, Inc. or Economic and Engineering Services, Inc. My responsibilities have included supervision and preparation of electric, water, and natural gas studies in the areas of strategic planning, financial analysis, cost of service, rate design, load forecasting, load research, management evaluation studies, bond financing, and integrated resource planning. Prior to that, I was employed by National Management Consulting firm in a similar practice; and prior to that, I was employed as an economist with Indianapolis Power & Light Company.

I have provided expert witness testimony on cost of service, rates, power supply, and contract matters in a number of state jurisdictions as well as before the Federal Energy Regulatory Commission and Courts of Law. A summary of my professional experience and background is provided as Exhibit 1 to this Testimony.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of the City of Garland. The City of Garland pays transmission rates for use of the ERCOT transmission system and is interested in assuring that all costs placed into that ERCOT rate are just and reasonable.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review and assess the transmission costs arising from the UCOS applications filed by CP&L and WTU to ensure that only proper transmission costs for these two utilities are included in ERCOT transmission rates.

Q. WHAT AREAS DO YOU ADDRESS IN THIS TESTMONY?

A. This testimony addresses issues associated with both the WTU and CP&L UCOS applications. WTU's functionalization of Distribution Account 362 is discussed in Section II of my testimony. Capital additions proposed by WTU and CP&L are discussed in Sections III and IV, respectively. A summary of my testimony is provided in Section V.

II. WTU FUNCTIONALIZATION OF ACCOUNT 362

Q. HOW HAS WTU FUNCTIONALIZED THE DISTRIBUTION ACCOUNT 362 – STATION EQUIPMENT?

A. WTU appears to directly assign many of the costs contained in Account 362 to generation, transmission or distribution. The functionalization of WTU assets is discussed starting on page 27 of the Direct Testimony of Jeff C. Broad dated March 31, 2000. Mr. Broad provided a summary of functionalization methodologies for rate base items in EXHIBIT JCB-3. Page 2 of this exhibit contains the following information for distribution accounts:

360 – 373 – DISTRIBUTION

- Directly assigned to DD.
- Assigned FERC account 370 – Meters to MT
- Assigned FERC account 371 – Installations on Customer Premises to RS.

  This account contains non-roadway lighting.
- For ERCOT, some functionalizations were made to PG and TD to conform to ERCOT splits.

There is no further explanation beyond this listing. Mr. Broad also refers to Schedule II-F-a where detail is provided on the functionalization of accounts.

Q. WHAT DESCRIPTION IS PROVIDED IN SCHEDULE II-F-a RELATED TO THE FUNCTIONALIZATION OF ACCOUNT 362?

A. On page 16 of SCHEDULE II-F-a, WTU provides a description of the ERCOT_SPLIT_STUDY that was used to split substation assets along ERCOT rules. The description is as follows:

> Factor was calculated by taking assets at substations and assigning them to the appropriate SB7 functions along ERCOT rules. Where possible, assets were assigned directly to functions. Common assets were allocated to functions in the ratio of the directly assigned assets.

Q. IS FURTHER DESCRIPTION RELATED TO THE FUNCTIONALIZATION OF ACCOUNT 362 PROVIDED IN THE WORKPAPERS FOR SCHEDULE II-F-a?

A. Yes. Starting on page 55 of WP/SCHEDULE II-F-a, WTU provides detail on its ERCOT_STUDY, which includes Account 362. The description of the methodology is as follows:

> The starting point for the ERCOT_STUDY functionalization was the previous TCOS filing. This was in a MS Access database (CPL.MDB), and included detail buildup by property item of the DD/TD/PG split by substation.

The workpapers also provide detailed assignments of costs for each substation within Account 362.

Q. WHAT IS THE FUNCTIONALIZATION FACTOR RESULTING FROM THE METHODOLOGY DESCRIBED BY WTU?

A. Schedule II-F-a and II-F-b provide the calculations to develop the functionalization factor used for Account 362 for 1999. On page 36 of Schedule II-F-a, transmission is assigned $8,928,286 of Account 362 out of a total of $50,244,258. On page 38 of that schedule, another $3,692,866 is added to the transmission function on the basis of the ERCOT Split Study. This results in $12,621,152 of Account 362 assigned to transmission out of a total of $53,937,124, which is shown on page 1 of Schedule II-F-b. This is equivalent to a 23.4 percent functionalization factor, as shown in page 2 of Schedule II-F-b.

Q. DOES WTU USE THIS SAME FUNCTIONALIZATION FACTOR FOR ACCOUNT 362 IN ITS 2002 FORECAST TEST YEAR?

A. No. WTU has significantly changed the functionalization of Account 362 between the historic 1999 period and the forecast 2002 period. In 2002 the functionalization factor for transmission was changed to 80 percent. WTU has provided no evidence to support this change in the functionalization factor.

Q. WHERE DOES WTU PROVIDE THE FUNCTIONALIZATION FACTOR FOR ACCOUNT 362 FOR THE 2002 TEST YEAR?

A. For 2002, functionalization factors are provided in Schedule III-F. Page 2 of that schedule shows the functionalization factor of 80 percent for Account 362. This results in $49,344,795 out of $61,680,994 being functionalized to transmission, as shown on page 2 of Schedule III-J-1-U. WTU has not provided any workpapers to support Schedule III-F or any explanation of the significant shift of dollars in Account 362 to transmission.

Q. DOES WTU MAKE SIGNIFICANT CHANGES IN THE FUNCTIONALIZATION FACTORS FOR OTHER PLANT ACCOUNTS SHOWN ON SCHEDULE II-F AND III-F?

A. No. In comparing Schedule II-F-b and III-F, there are changes in some of the functionalization factors developed for specific accounts. For the most part, these changes are minor and are carried out to five significant digits in both 1999 and 2002. The exception is the factor for Account 362. The functionalization factor for transmission in 1999 is precisely shown as 0.00108 (0.108%) for generation, 0.23400 (23.4%) for transmission and 0.76492 (76.492%) for distribution. For 2002 this changes to 0.80000 (80%) for transmission and 0.20000 (20%) for distribution.

It is unclear why WTU provided a painstaking amount of detail to show the assignments of all of the items within Account 362 to support the development of the 1999 functionalization factor, and then used a simple 80 percent/20 percent split for the forecast year 2002.

Q. DOES THE 80 PRECENT FUNCTIONALIZATION FACTOR APPEAR TO BE REASONABLE?

A. No. The use of an 80 percent functionalization factor for Account 362 seems excessive relative to the factor used for 1999 and when compared to the functionalization of this account by other utilities. The following table compares WTU's functionalization factor for Account 362 to that resulting from other utility filings.

Table A

Utility	**Account 362 Percent Functionalized to Transmission**
WTU – 2002	80.0%
WTU – 1999	23.4%
CP&L – 2002	14.8%
Reliant – 2002	36.0%
TNMP – 2002	0%
TXU – 2002	16.0%
SPSC – 1999	0%
STEC – 2002	33.8%
Brazos – 1999	0.0%
San Antonio – 1999	32.6%

Given the excessive nature of the shift in costs to transmission in Account 362, and the lack of evidence to support the 2002 functionalization factor, the change in the functionalization factor should not be allowed.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE FUNCTIONALIZATION FACTOR TO BE USED FOR ACCOUNT 362?

A. I recommended that WTU not be allowed to use the 80 percent functionalization factor for Account 362 for the 2002 forecast test year due to the lack of evidence to support this factor and the unreasonableness of the results. The detailed functionalization factor of 23.4 percent developed for 1999 should be used for the 2002 forecast year.

III. WTU TRANSMISSION CAPITAL IMPROVEMENTS

Q. WHAT DOES WTU PROPOSE AS CAPITAL ADDITIONS FOR TRANSMISSION BETWEEN THE 1999 HISTORIC YEAR AND THE 2002 FORECAST TEST YEAR?

A. WTU initially proposed to add $102.8 million of new capital for transmission. This compares to existing transmission plant of $212 million, and represents a 48.5 percent increase in gross transmission plant over the three-year period. Of the total transmission capital additions, $61.6 million is associated with the construction of a 345 kV transmission line from the Morgan Creek Power Station to the Comanche Switching Station (Morgan-Comanche). The remainder of the new transmission projects relate to six NERC reliability projects.

Q. HAS ANYTHING CHANGED FROM WTU'S INITIAL PROPOSAL REGARDING ITS TRANSMISSION RATE BASE?

A. Yes. On page 14 of David Carpenter's Amended Direct Testimony dated October 2, 2000, he states that "WTU-EDC has agreed to sell th[e Morgan-Comanche] line to the Lower Colorado River Authority". Mr. Carpenter adds that WTU has not adjusted its projected level of transmission capital expenditures to reflect this sale since applications for transmission interconnection have been received since

WTU's initial application. These applications are from several companies wishing to construct wind generation projects in WTU's service territory.

Q. HOW HAS THIS ALTERED WTU'S TRANSMISSION RATE BASE?

A. It has not resulted in any change in the level of WTU's proposed additions to transmission plant, as can be seen when comparing Schedule III-B-1 from March, 2000 with Schedule III-B-1-(U) from November, 2000. Mr. Carpenter's testimony asserts that the costs associated with interconnecting these wind generation projects, estimated to be $80 million, would "more than offset" the reduced investment in the Morgan-Comanche project.

Q. WHAT EVIDENCE HAS WTU PROVIDED TO SUPPORT THE CLAIM THAT THE COST OF THE NEW TRANSMISSION PROJECTS WOULD OFFSET THE COSTS ASSOCIATED WITH THE LINES BEING SOLD TO LCRA?

A. To illustrate that the transmission costs associated with the wind generation projects would more than offset the reduction in plant value associated with the sale of the Morgan-Comanche project assets, Mr. Preston Kissman points out in the response to question 1-3 of San Antonio City Public Service's First RFI that approximately $15 million of the $61.6 million of plant associated with the Morgan-Comanche project would continue to be owned by WTU. This leaves a net reduction in transmission investment of $46.6 million. Mr. Kissman tries to provide additional evidence in the same response to San Antonio by referencing the *Security Study for New Generation in the Rio Pecos Region*, authored by AEP and dated July 17, 2000, and *The ERCOT Transmission Constraint Report*, released on October 1, 2000.

Q. WHAT INFORMATION IS PROVIDED IN THE AEP STUDY?

A. The AEP study starts off by asserting that they have received requests for interconnection from 4 different developers for a total of 900 MW of wind generation projects in west Texas. The study does not address whether these generating projects are necessary, economically viable or likely to proceed. Given the placement of these projects and the current loading of the transmission system in the affected west Texas transmission system, the study estimates the minimum level of transmission upgrades necessary to maintain system reliability at varying levels of export capability. In addition, the study estimates the cost and construction time involved with each project upgrade.

Q. DOES THIS PROVIDE ENOUGH INFORMATION TO CONFIRM WTU'S ASSERTION THAT THESE COSTS WILL OFFSET THE REDUCTION IN TRANSMISSION RATE BASE CAUSED BY THE SALE OF THE MORGAN-COMANCHE ASSETS?

A. No. Although project costs and timetables are provided as part of this study, it does not provide evidence as to when or whether these generation projects will actually be built. As mentioned earlier, the AEP study provides an estimate of the construction cost and timing for the necessary transmission plant improvements associated with these generation projects. This study references 25 separate projects necessary to ensure sufficient transmission capacity to handle the requested interconnected capacity. Nearly every transmission project will take 18 months or more to construct. About half of the total transmission investment will not be spent within the first 2 years. Given that WTU is only 2 years away from the date when plant must be placed into service in order to be included in rate base, unless development of the generation plant and its associated transmission commences soon it is unlikely that much, if any, of the transmission plant will actually be placed into service by December 31, 2002.

Q. WHAT GIVES YOU CONCERN THAT THE WIND GENERATION PROJECTS AND THE ASSOCIATED TRANSMISSION PROJECTS MENTIONED BY WTU WILL NOT BE CONSTRUCTED IN A TIMELY MANNER, IF AT ALL?

A. The aforementioned ERCOT study states on page 48 that "West Texas generation capacity currently exceeds peak loads by over 600 MW. Exports from West Texas are limited by post-contingency thermal loading limits of several 345 kV and 138 kV lines. The addition of a new IPP project and renewable generation will exacerbate the existing limitations. Light load in West Texas will also aggravate this constraint." This study appears to suggest that there is little need for new generating capacity in that area and that it would only add to transmission constraints on the system in that area.

Q. IS THERE ANYTHING ELSE IN THE ERCOT STUDY THAT CONCERNS YOU REGARDING THE REFERENCED WIND PROJECTS?

A. Yes. This study lists only one transmission project associated with a new renewable generating project in west Texas that has been recommended by ERCOT. This renewable project is being developed by Davis Mountains. The AEP study lists the developers of the 900 MW of wind projects and it does not appear that the project recommended by ERCOT is among those listed in the study. Not having the recommendation of ERCOT, adds to the speculative nature of this project and further calls into question whether the transmission costs associated with this wind project should be included in the transmission rate base of WTU.

Q. GIVEN THE SPECULATIVE NATURE OF THE WIND PROJECTS REFERENCED BY WTU, DO YOU RECOMMEND THAT THE TRANSMISSION COSTS ASSOCIATED WITH THESE PROJECTS BE INCLUDED IN THE TRANSMISSION RATE BASE OF WTU?

A. No. Mr. Kissman explains on page 55 of his amended direct testimony, dated October 2, 2000, that projects that are "authorized by either the IPP or the ISO" are included in WTU's forecasted rate base, as are some projects not approved by the IPP or ISO, but "far enough along to have a reasonable expectation that authorization will be received." Mr. Kissman provides no evidence that the proposed wind generation projects have been "authorized by either the IPP of the

ISO", nor has he provided sufficient evidence suggesting that this project has "a reasonable expectation that authorization will be received." Therefore, by its own measure, WTU has not provided sufficient evidence to support the inclusion of these transmission project costs in its 2002 rate base and these costs should not be included in the transmission rate base of WTU.

Q. YOU MENTIONED THAT WTU WAS RETAINING $15.6 MILLION IN CAPITAL ADDITIONS ASSOCIATED WITH THE MORGAN-COMANCHE PROJECT. SHOULD THESE COSTS BE INCLUDED IN WTU'S TRANSMISSION RATE BASE?

A. No. In the response to question 1-5 of the Texas Industrial Energy Customers' First RFI, there is a list of transmission projects proposed to be included in the transmission rate base of WTU for 2002. As part of this list, WTU has provided the expected in-service date for each project. The in-service date for the Morgan-Comanche line, referred to in the data response as "Red Creek 345", is listed as May 2003. The monthly construction status report on the Texas PUC web site for September 2000 shows the in-service date as June 2003.

According to the Section III-B of the Unbundled Cost of Service Rate Filing Package, "Only plant in service projected to be in service at the end of the Forecast Year shall be allowed." Neither of the in-service dates projected for the Morgan-Comanche project meets the December 31, 2002 in-service deadline for inclusion in the 2002 forecast test year. Moreover, WTU has not provided any evidence that indicates when the portion of the Morgan-Comanche project that will be retained by WTU would be placed into service. Therefore, any and all costs associated with the Morgan-Comanche project should be excluded from WTU's transmission rate base.

Q. ARE THERE ANY OTHER TRANSMISSION PROJECTS THAT DO NOT MEET THE IN-SERVICE DEADLINE SET BY THE COMMISSION?

A. Yes. As provided in the response to question 1-5 of the Texas Industrial Energy Customers' First RFI, the Ft Lan Ozona 138 project was also not projected to be placed into service until May 2003. The cost associated with this project is $3 million. This project is clearly projected to be placed into service after the Commission deadline for inclusion in rate base and thus should be omitted from WTU's capital additions through the year 2002.

Q. WHAT DO YOU RECOMMEND REGARDING THE TRANSMISSION RATE BASE OF WTU?

A. First, the $61.6 million in plant investment associated with the Morgan-Comanche (a.k.a. "Red Creek") project should be excluded from the transmission rate base of WTU since it has not shown that this plant will be placed into service by the end of the 2002 test year. Second, transmission upgrade costs associated with the wind generating projects referenced by WTU should not be allowed to replace the cost of the Morgan-Comanche plant sold to LCRA in its transmission rate base due to the speculative nature of this project and the limited amount of time in which to place the necessary transmission plant into service. Third, the $3.0 million in plant investment associated with the Ft Lan Ozana 138 project should be excluded from transmission rate base since WTU has not shown that this plant will be placed into service by the end of the 2002 test year. Given the above, I recommend that transmission capital additions for WTU should be reduced by a total of $64.6 million for the 2002 forecast test year.

IV. CP&L TRANSMISSION CAPITAL IMPROVEMENTS

Q. WHAT DOES CP&L PROPOSE AS CAPITAL ADDITIONS FOR TRANSMISSION BETWEEN THE 1999 HISTORIC YEAR AND THE 2002 FORECAST TEST YEAR?

A. CP&L proposes to add $354.8 million of new transmission plant by year-end 2002, as shown in Schedule III-B-1-(U). This compares to existing transmission plant of $523.6 million, representing an increase of 67.8% in total gross transmission plant over a 3-year period. While this total level of plant additions appears to be high, many of the projects have approval by ERCOT and are currently underway.

Q. HOW DID CP&L DEVELOP ITS FORECAST OF TRANSMISSION PLANT ADDITIONS?

A. The process for developing transmission plant additions is discussed in the testimony of Preston Kissman dated March 31, 2000. He describes briefly that projects listed as IPP or ISO were derived from transmission planning studies done in cooperation with the ERCOT ISO. He further states that projects authorized by either the IPP or ISO were included based on the proposed in-service dates, and that some projects that are "far enough along to have a reasonable expectation that authorization will be received" are also included for 2002.

While CP&L has not provided testimony to support each of the major transmission capital additions included in the 2002 forecast year, there is some evidence provided in various RFI responses.

Q. DO THE SPECIFIC TRANSMISSION CAPITAL ADDITIONS FOR THE FORECAST YEAR 2002 APPEAR REASONABLE?

A. While the level of capital additions are very high relative to existing transmission plant, it appears that many of the projects have been reviewed and approved by the ERCOT ISO. There are, however, three projects where the forecast addition for 2002 is not fully supported by the specific project information provided by CP&L. These projects are the San Juan MVEC Tie, the Siera Verde STEC Tie and the Valley Export Constraint.

Q. PLEASE EXPLAIN WHY CP&L'S OWN INFORMATION DOES NOT SUPPORT THE INCLUSION OF THE SAN JUAN MVEC TIE AND THE SIERA VERDE TIE FOR 2002?

A. CP&L has provided information for each proposed transmission project in the response to question No. 1-12 of the Texas Industrial Energy Customers' First RFI. This table shows that the San Juan MVEC Tie and the Siera Verde Tie are both scheduled to have an in-service date of May, 2003. As these two projects are not projected to be in-service prior to December 1, 2002, they should not be included in the 2002 Rate Base, in accordance with the Unbundled Cost of Service Rate Filing Package instructions. The forecast costs for these two projects are equal to $12.5 million.

Q. PLEASE EXPLAIN WHY CP&L'S OWN INFORMATION FOR THE VALLEY EXPORT CONSTRAINTS PROJECT DOES NOT FULLY SUPPORT THE CAPITAL ADDITION?

A. The Valley Export Constraints project has a forecast cost listed as $76.0 million in the response to question No. 1-12 of the Texas Industrial Energy Customers' First RFI. In reviewing the approved budget for this project, the approved capital cost is only $56.2 million. The approved capital cost and project description were provided in the response to question No. 1-15a of TIEC's First RFI on pages 20-22 of the attachment. CP&L has not provided any explanation of the difference between the forecast amount included in 2002 and the approved budget. Because CP&L has only provided supporting documentation to justify a capital cost of $56.2 million, the additional $19.8 million in costs should not be allowed in the 2002 rate base.

Q. WHAT IS YOUR RECOMMENDATION FOR THE TRANSMISSION CAPITAL ADDITIONS PROPOSED BY CP&L?

A. I recommended that CP&L's addition to transmission plant be reduced by a total of $32.3 million. This includes $12.5 million for the San Juan MVEC Tie and the Siera Verde Tie and $19.8 million for the Valley Export Constraints project.

VII. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This following summarizes my testimony:

- WTU should not be allowed to functionalize 80 percent of costs for Account 362 to transmission for the 2002 forecast test year. Rather, the functionalization factor of 23.4 percent developed for 1999 should be used to functionalize the account to transmission.
- WTUs addition to transmission plant be reduced by a total of $64.6 million to reflect the elimination of $61.6 million in investment associated with the Morgan-Comanche line, and $3.0 million in plant investment associated with the Ft Lan Ozana 138 line, and that the transmission investment associated with speculative wind projects not be included in WTU's 2002 transmission rate base.
- CP&L's addition to transmission plant be reduced by a total of $32.3 million to reflect the elimination of the San Juan MVEC Tie and the Sierra Verde Tie

and a reduction of $19.8 million in the cost for the Valley Export Constraints project.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes. It does.

DEPARTMENT OF PUBLIC SERVICE REGULATION
MONTANA PUBLIC SERVICE COMMMISSION
DOCKET NO. D2001.10.144

REBUTTAL TESTIMONY OF GARY S. SALEBA ON BEHALF OF THE MONTAN POWER COMPANY

February 2002

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DOCKET NO. D2001.10.144

REBUTTAL TESTIMONY OF GARY S. SALEBA
ON BEHALF OF THE MONTAN POWER COMPANY

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Gary S. Saleba. I am President of EES Consulting, Inc. My business address is 12011 Bel-Red Road, Suite 200, Bellevue, Washington 98005-2471.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics and Mathematics from Franklin College in Indiana. I received my Masters of Business Administration in Finance from Butler University in Indiana. For the last 24 years, I have been a founding principal and owner of EES Consulting or Economic and Engineering Services, Inc. I have been President of the firm since 1997. My responsibilities have included supervision and preparation of electric, water, and natural gas studies in the areas of strategic planning, resource evaluation and procurement, financial analysis, cost of service, rate design, load forecasting, load research, management evaluation studies, bond financing, and integrated resource planning. Prior to that I was employed by R.W. Beck in Seattle in a similar practice from 1977 to 1978. From 1972 to 1977 I was employed as an Economist with Indianapolis Power & Light Company.

I have provided expert witness testimony on utility planning, cost of service, rates, power supply, and contract matters in a number of state and provincial jurisdictions as well as the Federal Energy Regulatory Commission, National Energy Board and various courts of law. A summary of my professional experience and background is provided as Exhibit GSS-1 to this testimony.

Q. WHAT EXPERIENCE DO YOU AND YOUR FIRM HAVE IN THE AREA OF POWER PROCUREMENT?

A. EES Consulting is a firm of professionals with offices in Bellevue and Spokane, Washington, Chicago, Illinois, Portland, Oregon, and Calgary, Alberta. We employ 45 professionals in the fields of economics, finance and engineering. Most of our employees have advanced degrees in their respective fields as well as previous experience working for utilities. Clients are primarily made up of electric, natural gas and water/wastewater utilities in the United States and Canada, large commercial and industrial customers using significant amounts of energy and water, and regulatory bodies.

My firm has evaluated energy supply alternatives for over 100 electric and natural gas clients during the past 10 years. A large portion of this activity has occurred since competition has been present for wholesale electric markets. The firm's experience includes work for utilities as well as commercial and industrial customers that have access to market energy. As the market for energy has evolved, our work has evolved from least cost and integrated resource planning to energy RFPs, monitoring energy markets and contract negotiations. While in some cases we have looked at the feasibility of generating power for sale into the market, the majority of the work has been related to energy needed to meet customer loads. I have supervised nearly all of these projects.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am testifying on behalf of the Montana Power Company (MPC). MPC retained my firm, EES Consulting, to conduct a Request for Proposals (RFP) for power supply in March of 2001 and evaluate the resulting proposals. This rebuttal testimony is being filed in conjunction with rebuttal testimony filed by Mr. Bill Pascoe and Mr. Dan Hickman on behalf of MPC.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to some of the issues raised in testimony submitted by various parties regarding the reasonableness of MPC's process to secure power supply contracts. Given my experience with MPC's RFP for power supply and my general experience in procuring power supply for many different utilities, I will respond to sections of the testimony of Dr. Wilson for the Montana Consumer Counsel (MCC) and Mr. Julian for Comanche Park, LLC (Comanche). Both Dr. Wilson and Mr. Julian raise concerns regarding the fact that MPC's final contracts were not a direct result of an RFP process. My testimony will address:

- How market trends influence the power procurement process
- Typical approaches to power supply procurement
- The value of as well as the disadvantages of an RFP process

Q. HOW IS THIS TESTIMONY ORGANIZED?

A. A background on the West Coast power market for 2001 is discussed in Section II. Generally accepted procurement practices are the subject of Section III. My summary and conclusions are provided in Section IV.

II. BACKGROUND ON POWER MARKET IN 2001

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF WHAT WAS OCCURRING IN THE POWER MARKET IN 2001 WHEN MPC WAS GOING THROUGH ITS POWER PROCUREMENT PROCESS.

A. There was a considerable amount of turmoil in the electric market during 2001, particularly on the West Coast. Prices were very volatile in 2001 with very high prices carrying over from late 2000 into the first half of 2001. Those utilities having to acquire power supply during this period were facing some very difficult decisions. The high prices seen in the market led to a shortage of equipment to generate power. Those entities that had access to an actual turbine that had been ordered had a distinct advantage. The high price of power in the market made generating projects very competitive if they could come on line in the near term. Over the long term, prices were expected to come down. Contracts for a longer term had a lower price than those with a short term. Projects that were a few years out from completion had a lower price than those with a near term on-line date. Both power offers from marketers and offers for actual generating projects were seen as being at risk for being snatched up by other parties because there was such a shortage of power supply relative to demand. This created a tremendous pressure for utilities to act quickly if necessary to sign contracts.

Conditions began to change by the summer of 2001. Several simultaneous factors led to an unexpected softening of prices. FERC implemented price caps, the California DWR completed purchasing 12,000 MW of power, California residents began to conserve power to avert rolling blackouts, weather conditions were milder than average and hydro conditions began to improve. At the same time, the economy started to recede and demand for electricity started to decline on the West Coast. Aluminum smelters shut down due to high electric prices, freeing up 1,300 MW of power in the Pacific Northwest. Prices started to fall dramatically and daily prices went from $223 per MWh in January to $43 per MWh in July. (Source: average monthly Dow Jones electricity price for the California-Oregon border as reported in the *Wall Street Journal.*) None of these factors could have been foreseen earlier in the year, and many of the factors were viewed as temporary. It was expected that if some of these conditions did not hold, prices would not remain at the levels seen during the late summer.

Given the wild fluctuations that had been seen in daily prices, the reduced prices in the market were a welcome change. However, the volatility seen during 2001 highlighted the inherent risk associated with prices in the electric market and there was a marked shift away from purchasing in the daily market or at index-based rates. While daily prices dropped by nearly $200 per MWh, prices for longer term contracts already had built in an expected reduction in prices in the outer years. Subsequently, prices for multiple-year contracts did not come down to the same degree. Similarly, new projects proposed to be built after 2001 did not have significant changes in costs as a result of the daily electric market, and in many cases were still well below market prices.

In the fall and winter of 2001/2002, additional unforeseen circumstances led to even lower prices in the spot market. Mild winter weather, much improved hydro conditions and the effects of September 11th events on the economy led prices to decline further to the level of $21 by December of 2001. (Source: average monthly Dow Jones electricity price for the California-Oregon border as reported in the *Wall Street Journal.*)

Because many of the conditions leading to reduced prices were temporary in nature, prices are expected to rise again when hydro and weather conditions return to normal, as the economy starts to rebound and as aluminum smelters begin to operate again.

Q. HOW DID THE MARKET SITUATION IN 2000/2001 IMPACT THE ABILITY TO PROCURE POWER SUPPLY FOR MPC AND OTHER UTILITIES?

A. Because of the volatility in prices, it was virtually impossible to find an offer with prices that were stable over a period of time. Early in the year, prices were at a level that was hard to swallow and those that did not have an urgent need to acquire power were wary of locking in all of their power needs at the high prices available. While 5 years ago sellers would keep prices open long enough to allow an evaluation process, offers during the 2000 to 2001 period were usually valid for only 24 hours and prices were refreshed on the day a contract was signed. Parties selling power out of designated generation projects would not take gas price risk and therefore prices were tied to the price of gas, which was also very volatile during 2001.

The inability to predict market prices and the inherent volatility in the market required that electric purchasers adopt a portfolio approach to procuring power that accounts for both price and price risk for new resources and contracts. As is the case with the stock market, it is impossible to buy low and sell high in every instance. It is necessary to keep options open, follow the market, and diversify the sources of power supply. Buying at different times, buying for different terms and buying from multiple sources generally is an accepted portfolio strategy to minimize risk while achieving a low cost. This approach applies to many different commodities. This approach does not necessarily lead to the absolutely lowest possible cost of power in the short run, but does protect the buyer from paying the highest possible cost of power.

Q. WHAT WAS THE RESULT FOR OTHER UTILITIES THAT SIGNED POWER SUPPLY AGREEMENTS IN 2001?

A. One interesting case is the Department of Water Resources (DWR) in California. During 2001, DWR purchased over 12,000 MW of power for terms ranging from 4 months to 11 years (Source: May 31, 2001 DWR Report, "Update of California DWR Power Purchase Contract Efforts".) This power was purchased on behalf of PG&E, SCE and SDG&E, to save the customers in California from being exposed to daily prices in the market. DWR issued a request for bids in January and again in February. A total of 39 sealed bids for power supply were received in the first round, most of which were announced as being compliant with the request. Contracts were signed during the February to April period of 2001.

The DWR experience contrasts with the MPC process in many ways. Once MPC announced its intention to purchase power supply, it issued the March RFP. Given the level of prices received, MPC chose to explore other opportunities and conducted serious negotiations with PPLM rather than simply taking the lowest priced proposals out of the RFP. By looking at further opportunities rather than signing contracts based on the first RFP, and signing contracts at different times, MPC significantly reduced the cost of its power supply contracts. By watching the market closely, rejecting all offers when market prices were high, and remaining flexible, MPC was able to adapt to and take advantage of the changing market and shield itself from market aberrations. This compares with DWR, which followed a more structured request for bid process, received sealed bids and then quickly negotiated contracts as a result of prices which have proven to be too high.

III. MPC PROCESS FOLLOWS GENERALLY ACCEPTED PROCEDURES

Q. WHAT STANDARD SHOULD BE USED FOR ASSESSING MPC'S PRUDENCY OF ITS POWER SUPPLY PORTFOLIO CONTRACTS?

A. The standard set by Montana law is that MPC should follow "Industry Accepted Procurement Practices" (IAPP). Like other utilities and customers purchasing their own power supply, MPC should attempt to procure the best price and lowest risk overall portfolio, and should ensure that the power is of a shape and reliability level that is satisfactory. There are, however, no set guidelines available to utilities to define IAPP. IAPP is not rigid, covers a range of acceptable methods used by various utilities and customers and varies by timing and location. IAPP has been evolving through time as the industry has changed, and will likely continue to evolve.

Q. DOES IAPP FOR PROCURING POWER SUPPLY CONTRACTS DIFFER FROM THOSE FOR OTHER TYPES OF UTILITY PRODUCTS?

A. Yes, power supply procurement cannot be compared to many other types of products purchased by a utility, such as poles or transformers. While power supply is a commodity to some extent, there are numerous attributes to different power products than need to be accounted for. One kWh delivered to the MPC system in a certain hour would be comparable to another kWh, but power is purchased in much bigger blocks than that. While sometimes a very defined product is requested, as was the case in MPC's October RFP, often a utility considers the shape of the products along with other factors. In addition, there are numerous ways to price power that need to be considered when comparing alternatives. In the RFPs that were issued, as well as in the other offers considered, many different factors needed to be accounted for to provide a meaningful comparison. It is rare that two identical products are offered under a similar pricing structure. MPC was faced with the task of procuring the best mix of products to serve customer load, while at the same time there is a great deal of uncertainty about the load at any given time. This is very different than knowing you need one hundred 45-foot poles that need to be delivered in a certain month. Because of these differences, it is difficult to conduct a process requesting firm bids, as is often the case with other types of more standardized products.

Q. HAS IAPP FOR PROCURING POWER SUPPLY CONTRACTS BEEN THE SAME THROUGHOUT TIME?

A. No. There has been an evolution in what would be considered IAPP due to the evolving electric industry. My firm has been involved in power supply planning and procurement for the past 24 years and we have seen significant changes during that time. The following is a rough chronology of changes in power supply procurement that we have practiced in the electric industry:

- During the 1980's, utilities were vertically integrated and generally built their own generation. Generating resources had a long lead time and the resources of choice were coal plants with standardized natural gas plants becoming increasingly more feasible. Utilities generally performed *Least Cost Planning (LCP)* which compared different types of generating options with the necessary transmission lines included.

- The first half of the 1990's saw the movement towards *Integrated Resource Planning (IRP)*. In addition to considering the cost of generating alternatives, conservation options were included as resource alternatives in an IRP. In addition, more elaborate modeling was done in an attempt to quantify environmental and other social issues when comparing options to address the trade-offs between pure economic cost and costs to environment.
- By the mid-1990's a wholesale power market had emerged as a result of open transmission access and while market purchases were incorporated into IRP by some utilities, there was a shift away from IRP. Market prices were low on the West Coast due to surplus capacity. Even if utilities used an IRP process to consider market purchases compared to building new resources, they started to use a competitive process to acquire market contracts.
- During the late 1990's most utilities had the belief that all power could be supplied through the market. Independent Power Producers emerged and were building natural gas plants with much shorter lead times, so long term planning was not as critical. IRPs became a thing of the past as utilities were not building new resources. In Montana, California and Alberta restructuring had taken place and the incumbent's generation was being sold. Power prices were relatively stable. RFPs were commonly used to secure power contracts from marketers or Independent Power Producers.

- During 2000 and 2001 power prices became extremely volatile, as previously discussed. The economy was growing rapidly while few new power plants had been built on the West Coast. This made the RFP process difficult as prices changed on a daily basis and power was in short supply.
- Towards the end of 2001 and carrying over into 2002 prices stabilized but the collapse of Enron led to concerns about counter party risk. An increased amount of diversification and a greater emphasis on creditworthiness are now being incorporated into the power procurement process.

Q. PLEASE DEFINE WHAT YOU WOULD CONSIDER TO BE IAPP FOR THE PERIOD DURING WHICH MPC EXPLORED AND ACQUIRED POWER SUPPLY.

A. IAPP cannot be defined as one specific process that must be strictly adhered to by each and every utility. The approach used needs to match the needs of the utilities and the current conditions. I would consider IAPP to encompass five basic steps:

1. **Explore** market for power supply products and prices
2. **Collect** offers or proposals from various parties
3. **Analyze** the proposals or offers for price and other factors
4. **Negotiate** the best contract with the preferred parties
5. **Anticipate** sudden changes in the market and remain flexible

These five basic steps can be achieved through a number of methods. **Exploring** options can be done through a planning process with research on prices of various alternatives, through an RFP process, by calling several different respected power suppliers to get the latest forward prices for power, or by watching the index prices and futures contracts at various trading hubs. **Collecting** proposals or offers can be done through an RFP, by corresponding with specific parties that have previously expressed an interest and are known to have the necessary power supply, or by accepting unsolicited proposals. **Analyzing** proposals and offers must account for all of the different attributes and all costs required to provide a full requirements product to customers must be considered. **Negotiating** power contracts needs to allow for changing prices from selected proposers, trade-offs between pricing and terms for the product, the opportunity to secure a better deal, and the ability to change to another supplier if the negotiations are not going well. **Anticipating** sudden changes means remaining receptive to new offers as prices change and new facilities drop off or become available.

It is clear that MPC did follow these steps. Several different approaches were used to explore pricing and collect proposals throughout a period of time, all of which are within the industry standards. Analysis considered other relevant factors, not just price. MPC appears to have taken its negotiations seriously and allowed for flexibility in its procurement process, thereby improving its price and terms beyond what was originally submitted.

Q. DID MPC FOLLOW A PROCESS THAT MEETS "INDUSTRY ACCEPTED PROCURMENT PRACTICES" FOR PROCURING POWER SUPPLY CONTRACTS?

A. Yes. Given my firm's experience with numerous utilities, what has been done by other utilities in the region, and what is feasible when dealing with a fluid market for power supply, MPC's process was appropriate and is very similar to what is done elsewhere in the utility industry.

Q. IS AN RFP ALWAYS THE BEST APPROACH TO SECURING POWER SUPPLY?

A. While an RFP is a useful tool in identifying potential power supplies, it cannot be relied on exclusively in many circumstances. In the past, we have issued numerous RFPs for power supply with various degrees of success. My firm issued an RFP for MPC in March of 2001 to determine what types of products were available at the time. We compared the results to one another and made recommendations comparing the various proposals. In the end, the policy decision needed to be made by MPC as to whether any of the proposals were worthy of signing contracts. The final contracts negotiated by MPC are much better than the proposals submitted in the March RFP. There are some drawbacks with a rigid RFP that need to be considered when making decisions, as follows:

- Responses are sometimes scarce since some suppliers are reluctant to respond to an RFP because they are a great deal of effort for a low chance of success and RFPs may be used for unfair price disclosure.
- Purchasing opportunities that come along after the RFP may be better than proposals received and should not be excluded.

- Proposers generally hold prices open for only 24 hours, making it difficult to have sufficient time to compare proposals and negotiate contract terms before prices change.
- Because proposals are not binding, the proposer may submit a low price that they cannot deliver once contracting begins.
- There are so many different variations on how power can be provided (shape, term, etc.) that it is difficult to account for all of those variations through an RFP process.

Further, I have always held to the belief that if a feasible unsolicited offer comes along even though it is outside the RFP process, it should be considered along with other proposals. Turning down a good proposal just because it does not meet the timeline set in the RFP or is different than what was requested may not be in the retail customers' best interests. Conversely, entering into a contract just because it is the best offer resulting from an RFP is not wise if there is no urgent need to sign a contract at that moment. For these reasons and market reasons discussed earlier, a less rigid process for procuring power has become the standard in the industry. Generally, IAPP for power procurement has evolved into a process much different from a formal bidding process like that used in government or in the construction industry. Even in those cases where RFPs are used to assist in procuring power, the issuer is looking for proposals that can be used as a starting point for contract negotiations rather than firm bids that will be the basis for the contract.

Q. DID MPC FOLLOW A PROCESS FOR PROCURING POWER SUPPLY THAT IS IN KEEPING WITH OTHER UTILITIES?

A. Given our own experience in 2001 and previous years along with what we have seen within the industry, MPC did follow a power supply strategy that is in keeping with other utilities. In fact, MPC issued three RFP's for power supply, talked to many parties outside the RFP process, and considered all of its options before signing power supply contracts. This process is similar, but perhaps more extensive, than that used by other parties in acquiring power, as shown by some actual examples discussed below.

Flathead Electric Cooperative (FEC) signed a power supply contract with PacifiCorp for 70 MW in August of 2001. FEC was facing exposure to market prices for this portion of the load and so locking it in was seen as beneficial given the high and volatile market prices seen earlier in the year. At market prices of $200 per MWh, the cost of the contract to FEC would be $10.4 million per month. FEC locked in with PacifiCorp at an average price of $43 per MWh, which reduces costs to about $2.2 million per month. My firm assisted FEC in the power procurement process. FEC was not done through an RFP process but several different options were explored, including purchasing power from a designated generating resource. Options were based on unsolicited proposals and contacts within the industry. At the time, FEC got a contract that was more than competitive and provided some unique benefits to FEC. While FEC did not buy power at the lowest point in the market, it did eliminate the exposure to market prices that had been in excess of $200 per MWh.

Clark Public Utilities (CPU) in Vancouver, Washington faced a shortage of power of 140 MW for the months of July and August of 2001. Again, my firm assisted CPU in securing power supply. A request was sent out to certain parties that had the potential to supply the large block of power for those months and a contract was eventually signed with Kaiser Aluminum to shift supply to CPU. There was no RFP process and few parties had sufficient quantities for sale at the time. CPU went on to lease 50 MW of gas-fired reciprocating engines to meet the remaining shortfall of power in the summer and because of the fierce competition and changing market, it did not have the time to run an RFP process before signing a lease. At the time, purchasers were outbidding each other to get generators. The output from the generators was in the range of $150 per MWh, which was lower than the market price at the time. These generators filled a gap that CPU had in its portfolio for the summer months and allowed CPU to reduce its price volatility and reliability risks by locking in the price.

Even in those cases where power was obtained through an RFP process, like Snohomish PUD, there is a negotiation process that occurs after the selection of finalists from the RFP is announced. Because prices in a proposal typically last for only 24 hours, there is no way to treat an RFP like a formal bid and sign a contract directly from the proposals. Negotiations need to occur to lock in the price and any other terms that are desired, and often the resulting contract is much different than the original proposal.

There are numerous other parties in the region that acquired short-term or long-term power supply that signed contracts without following a strict RFP process due to the market situation at the time and the shortcomings of an RFP process. Some of these utilities include the Bonneville Power Administration, Nor-Cal Electric Authority, UtiliCorp Networks Canada, Enmax, Epcor, Atco, the City of Tacoma, the Western Public Agencies Group, Mason County PUD #3, Peninsula Light Company, and Benton REA. In addition, there have been several large industrial customers that acquired resources or contracts during the past year that did not go through an RFP or bid process, including Bellingham Cold Storage.

Q. WITNESS ROBERT C. JULIAN ON BEHALF OF COMANCHE PARK LLC CRITICIZES MPC'S PROCURMENT PROCESS IN HIS DIRECT TESTIMONY. DO YOU AGREE WITH HIS CRITICISMS?

A. No. Mr. Julian repeatedly refers to a competitive bidding process, and complains that MPC did not provide an adequate scope for new generation contracts. Mr. Julian appears to think that power supply can be acquired through a strict bidding process and that MPC should have set the specific scope for new generation. MPC was following the IAPP at the time, as discussed earlier, by considering all types of power supply options. Power can come from many different sources and often a utility is looking to proposers to develop a creative proposal rather than relying on a rigid specification of a product. MPC needed to consider all of its options and account for different attributes of the power supply proposals when making a decision. As discussed earlier, the evolution of IAPP for power supply procurement has moved away from a more formal process due to changes in the electric industry. An RFP, by definition, is a request for proposals. It is not a request for bids such as generally used in the construction industry or in government procurement, and cannot be treated as such. However, building a specific power plant could be put out to bid, much like construction of an office building or substation. This bidding process is appropriate for the developer of the generating project once they have committed to proceed with a project, not for the utility purchasing the output of the resource.

Q. WITNESS JOHN W. WILSON OF THE MONTANA CONSUMER COUNSEL SUGGESTS MPC SHOULD HAVE CONDUCTED A MORE WELL STRUCTURED AND ORGANIZED PROCUREMENT PROCESS IN HIS DIRECT TESTIMONY. DO YOU AGREE WITH HIS SUGGESTION?

A. No. Dr. Wilson suggested that the MPC process was not well structured and organized and criticized MPC's lack of a least cost planning analysis to ensure the selected portfolio met the criteria under a range of market price conditions. It appears that Dr. Wilson was expecting a model that considered all of the different parameters of a power supply portfolio under a whole range of market conditions, and that this model would show that the MPC portfolio was the least cost mix of resources in most, if not all conditions. Again, this approach no longer falls under IAPP for power supply procurement. The type of least cost planning or integrated resource planning suggested by Dr. Wilson is no longer the standard approach for the reasons discussed earlier. MPC was working in a period when prices were changing very rapidly. By the time you could run a model to fully evaluate all of the different attributes of a proposal the price could change, the resource could have been sold elsewhere or the resource could have been transferred to a new owner with different interests. There was also insufficient time to complete this type of analysis once MPC had clear authority to proceed with securing default supply.

Furthermore, Dr. Wilson claims that the higher price paid for generation contracts signed by MPC when compared to 5-year supply contracts are not justified. Dr. Wilson apparently is not all that concerned about the bargaining strength of PPLM at the time MPC was procuring power. Having been through the RFP process with MPC and based on my knowledge of the electricity market on the West Coast, it was very clear to me that MPC had very little leverage against PPLM at the beginning of the process without new generation being built in the state. While there were a number of proposals made to MPC, most of them required the addition of new generation. Because of transmission constraints, the addition of new generation would limit PPLM's market to sell power outside of Montana, limiting their access to the market. This was viewed as a way to place negotiating pressure on PPLM to reduce the price for MPC to something below the market price. Conversely, developers of new projects in Montana did not have a large number of opportunities to sell power to parties other than MPC or large customers in the state due to those same transmission constraints. Projects would not likely get built without a firm sales contract to MPC, leaving MPC in an advantageous bargaining position.

Finally, if Dr. Wilson wishes to compare generation contracts with 5-year power supply contracts, it is important that the comparison is done properly. This type of comparison must evaluate offers available at the exact same time since prices were changing every day, it must consider the entire term so that a 10-year term is compared to 10 years of market contracts, it must consider how the resource will fit into the portfolio, and it must consider the impact of each option to MPC's overall purchasing abilities.

IV. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony supports MPC's position that it entered into prudent power supply contracts by following industry accepted practices and made the best decisions based on the information available at the time. More specifically:

- The market for electric power has changed through time and 2001 was a time of extreme volatility.
- The condition of the electric power market drives the process required to secure resources and contracts. The IAPP for power acquisition has evolved through time as the market has changed.
- MPC followed current IAPP in securing power supply.
- MPC had a process for acquiring power that was consistent with other utilities in the region.
- It would not have been current IAPP for MPC to conduct a stringent bidding process for power supply.
- It would not have been current IAPP for MPC to conduct a more formal and lengthy least cost planning model and process to secure power supply.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

PROFESSIONAL EXPERIENCE AND BACKGROUND OF

GARY S. SALEBA

EDUCATION

MBA, Finance
Butler University
Indianapolis, Indiana

BA, Economics and Mathematics
Franklin College
Franklin, Indiana

EMPLOYMENT

October 1978 to Present	EES Consulting, Inc. P.O. Box 52810-2810 Bellevue, Washington 98015 Engineering and Management Consulting Firm
Position:	President
Responsibilities:	Overall supervision and quality control responsibilities for all of EES Consulting's electric, water, wastewater and natural gas engagements in the areas of strategic planning, financial analysis, cost of service, rate design, load forecasting, load research, management evaluation studies, bond financing, integrated resource planning and overall utility operations. Overall responsibility for firm's offices in Seattle, Portland, Spokane and Calgary.
Activities:	Supervised comprehensive resource acquisition, RFPs for power and natural supplies and power and gas contracting. Performed integrated resource planning studies, average embedded and marginal cost of service studies, technical assessments and financial planning studies for electric, water, gas and wastewater utility clients. Participated in strategic planning and demand side management analyses. Project manager for construction of 248 MW gas turbine, and acquisition of over $1 billion of utility service territory and equipment. Supervised engineer's reports for over $5 billion in revenue bonds. Developed and verified interclass usage data. Numerous testimony presentations before regulatory bodies on utility economics, strategic planning, finance and utility operations. Presentation of power procurement, management audit, forecasting, cost of service, integrated resource planning, financial management, and rate design seminars for the American Public

	Power Association, American Water Works Association, Northwest Public Power Association and Municipal Electric Association of Ontario. Past Board member of Northwest Public Power Association. Past Chairman of Financial Planning Committee and Management Division of the American Water Works Association.
October 1977 to October 1978	R.W. Beck Seattle, Washington
Position:	Supervising Economist
Responsibilities:	Analyzed various energy related topics to determine economic impacts. Reviewed utility financial activities.
Activities:	Participated in several utility rate/financial regulatory proceedings. Provided clients with critique of issues, position papers and expert testimony on the topics of cost of service, rate design, utility finance, automatic adjustment factors, sales perspectives and class load characteristics. Conceptualized load forecasting models and assisted in economic and environmental impact analyses.
June 1972 to October 1977	Indianapolis Power & Light Company P.O. Box 1595 B Indianapolis, Indiana 46206 Investor-owned Utility
Position:	Economist, Department of Rates and Regulatory Affairs
Responsibilities:	Provided general economic and rate expertise in Rates, Regulatory Affairs, Customer Service and Engineering Design Departments.
Activities:	Calculated retail and wholesale electric and steam class revenue requirements and rates. Prepared expert testimony and exhibits for state and federal agencies regarding rate design theory, application of rates and revenues generated from rates. Determined long range revenue and peak demand projections. Supervised comprehensive load research program. Supported thermal plant Environmental Impact Statements. Provided industrial liaison.

PARTIAL LIST OF CLIENTS FOR WHOM RESOURCE PLANNING AND ENERGY ACQUISTION PROJECTS HAVE BEEN PERFORMED BY GARY S. SALEBA

University of Alberta, Canada
Amalgamated Sugar Company, Idaho
Atco, Canada
City of Anaheim, California
Municipality of Anchorage, Light & Power, Alaska
Bellingham Cold Storage, Washington
Benton County PUD, Washington
Benton County REA, Washington
Birmingham Steel Corporation, Washington
Cascade Natural Gas, Washington
Centra Gas Company, Canada
City of Cerritos, California
Clallam County PUD, Washington
Clark Public Utilities, Washington
City of Ellensburg, Washington
Coachella Valley Water District, California
Emerald Public Utility District, Oregon
ENERconnect, Inc., Canada
Enmax, Canada
Flathead Electric Cooperative, Montana
Fred Meyer, Inc., Oregon
Glacier Electric Cooperative, Montana
Grays Harbor County PUD, Washington
HDR Engineering, Washington
Intermountain Gas, Idaho
Iron Mountain Quarry, Washington
Klickitat County PUD, Washington
Kootenai Electric Cooperative, Idaho
Lewis County PUD, Washington
City of Lethbridge, Canada
Lower Valley Power & Light, Wyoming
Mason County PUD No. 1, Washington
Mason County PUD No. 3, Washington
City of Medicine Hat, Canada
Miami-Dade Water and Sewer Department, Florida
Municipal Electric Association, Canada
Gas Company of New Mexico, New Mexico
Nor-Cal Electric Authority, California
Northern Wasco PUD, Oregon

Northwest Territories Power Corporation, Canada
Okanogan County PUD, Washington
Oregon Restaurant Association, Oregon
Pacific County PUD, Washington
City of Palo Alto, California
Parkland Power & Light, Washington
Pend Oreille County PUD, Washington
Peninsula Light Company, Washington
Pierce County Cooperatives Assoc., Washington
City of Port Angeles, Washington
Potomac Electric Power Company, D.C.
Public Institutional Consumers of Alberta, Canada
City of Red Deer, Canada
City of Richland, Washington
Port of Ridgefield, Washington
City of San Marcos, California
Seattle Times, Washington
SHE America, Washington
City of Shoreline, Washington
Snohomish County PUD, Washington
Springfield Utility Board, Oregon
City of Tacoma, Washington
West Kootenay Power and Light, Canada
Western Montana G&T, Montana
Western Public Agencies Group, Washington
Weyerhaeuser, Inc., Washington
Village of Winnetka, Illinois
Yucaipa Valley Water District, California

Proceeding Related to
British Columbia Hydro and Power Authority

Testimony of Gary S. Saleba

on behalf of
the Joint Industry Electricity Steering Committee

July 2003

Testimony of Gary S. Saleba
EES Consulting, Inc.
On Behalf of JIESC

Introduction

This testimony is being presented on behalf of the Joint Industry Electricity Steering Committee ("the JIESC") as part of the proceeding relating to British Columbia Hydro and Power Authority (BC Hydro) Proposal Regarding a Heritage Contract, Stepped Rates and Access Principles. Gary Saleba is the President of EES Consulting, Inc. and his resume is provided as Exhibit A. Mr. Saleba has reviewed the options for rate design for the industrial customers of BC Hydro and this evidence presents the rate design that is most appropriate for this application.

The topics to be addressed in this testimony include:

- Background on the Issue
- Theoretical Considerations
- Rate Precedents
- The JIESC Proposal
- Critique of BC Hydro June 27th Further Proposal
- Recommendations

Background on Industrial Rate Design in BC

BC Hydro is proposing a change to the rates for its industrial customers pursuant to government directives stemming from the government's 2003 Energy Plan. Generally, a new approach is considered desirable to provide price signals to industrial customers based on the availability of a limited amount of low-cost resources and to provide opportunities for independent power producers ("IPPs"). For load beyond that base amount, the cost of generation is higher and should be reflected in some manner. This allows industrial customers to make economic decisions in terms of consumption, use of power from BC Hydro and acquisition of power from other sources.

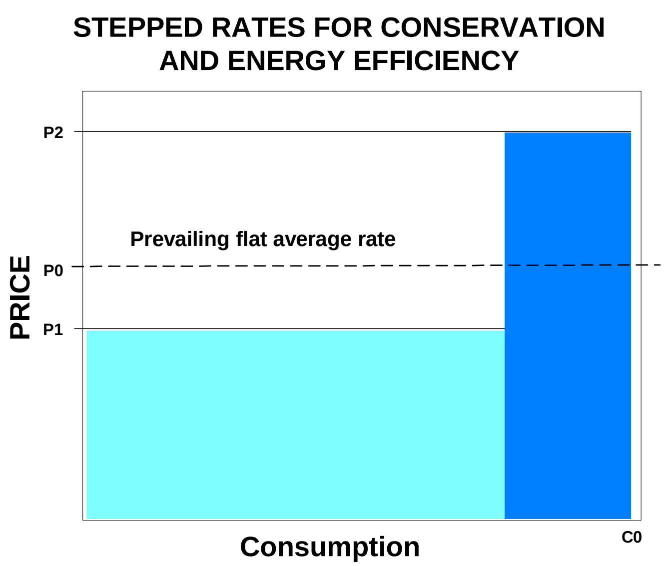
The current Rate Schedule (RS) 1821 calls for a demand charge of $4.441 per kVa and a flat energy rate of 2.599 cents per kWh. It is expected that the new approach will result in a customer's total electricity cost remaining consistent with that cost under the current rate schedule where his usage remains constant.

The 2003 Energy Plan specifically calls for stepped rates for industrial and large commercial customers. This is taken to be limited to transmission voltage customers, including the RS 1821 customers.

The basic requirements for a stepped rate were set out in the following section of the Energy Plan and the accompanying illustration and explanation, found on page 33:

> **Policy Action #21 (new): New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.**
>
> *The BC Utilities Commission will conduct a hearing to develop new stepped and time-of-use pricing for BC Hydro's industrial and large commercial customers. As a principle, for stepped rates, the last block of energy consumed should reflect the cost of new supply. This will encourage these customers to meet part of their electricity needs through conservation and energy efficiency, or from other sources (self-generation or IPP purchases), where they can do so cost-effectively. To keep rates low overall, the stepped rate structure will be revenue-neutral (see box). Time-of-use rates will encourage customers who can manage the timing of their electricity use to shift consumption to low-priced off-peak periods. Both rate structures will benefit British Columbians by deferring the environmental impacts of new power development.*
>
> *The BC Utilities Commission has approved time-of-use pricing and stepped fixed charges for Aquila Networks Canada customers, and time-of-use pilots for large BC Hydro customers. Given the administrative costs of rate design and the metering investment required for time-of-use rates, these alternative rate structures tend to be less feasible for small customers. Stepped rates will be initially applied to large rate customers. They may be applied, at a later date, to other customer classes.*

Figure 1



> *A revenue-neutral two-step electricity rate charges less for the first block of electricity consumed (P1), and more for the second block (P2), relative to the prevailing fl at average rate (P0). At the higher price P2, the consumer has a greater incentive to cut back on electricity use, or to invest in cost effective energy efficiency for that portion of consumption. At the existing consumption level C0, the total cost to the consumer and the total revenue to the distribution company offering the rate are unchanged.*

Other related goals stemming from the Energy Plan include the preservation of benefits from low cost Heritage resources, the acquisition of power supply on a least-cost basis, encouragement of a market for power for Independent Power Producers, and the ability for large customers to select their own supplier.

It is very clear from the Energy Plan that stepped rates are the directed approach. While a shopping credit or another approach may meet some of the objectives, stepped rates have the ability to send the appropriate price signals to meet all of the desired goals and have a much higher degree of customer acceptance than BC Hydro's preferred shopping credit. Prior to BC Hydro filing its Further Proposal on June 27, 2003, the parties had been involved in a consultative process. That process did not lead to a consensus or a settlement.

<u>Theoretical Considerations</u>

Stepped rates are simple to understand and can be designed to provide both cost-based rates and marginal cost signals related to new power supply. For BC Hydro customers, stepped rates match well theoretically with the existing power supply resource issues.

There are three basic types of rates, including declining block rates, flat rates or stepped rates. Stepped rates are sometimes referred to as inverted block rates or tiered rates. The following describes the appropriate circumstances for each type of rate:

Declining block rates indicate that rates are lower for a higher level of consumption. These rates are appropriate when there is a surplus of power supply available. These rates are applicable in the circumstances where power plants are already built, when it is cost-effective to oversize units due to economies of scale, and when there are high fixed costs associated with resources. In these cases, it is not costly to generate additional energy and the fixed costs can be spread over more sales. The price signal for declining block rates encourages customers to use more power. This creates more efficient use of the fixed resources and reflects the lower marginal cost associated with increased consumption.

Flat rates have no differential between blocks and are currently in place for BC Hydro's industrial customers. Flat rates are most appropriate when a utility or region is close to load/resource balance. From a cost basis, flat rates are appropriate when costs do not differ greatly based on the level of consumption. In terms of price signals, flat rates do not encourage consumption however they also do not provide a signal to conserve energy.

Stepped rates are most appropriate when there is a shortage of resources and when the cost of new resources is higher than the cost of existing resources. As proposed in the 2003 Energy Plan, the rates for the 2nd block should reflect the cost of new resources. This provides the appropriate price signal to customers so that they face the incremental cost of power as they are making decisions on their consumption level. If the price signal facing customers is an average of existing and new resources, the customer has an incentive to increase consumption. However, the revenues do not cover the higher costs that must be paid by the utility to acquire more power, leading to higher costs for all customers. Stepped rates also allow each customer to receive an appropriate share of the existing low-cost resources.

BC Hydro's resource situation is in this last category. Over time they have shifted from having a surplus of power, to load resource balance, to the current need to acquire additional resources. It follows, therefore, that they should be shifting from flat rates to stepped rates. This way the amount of load that is above the current level of existing resources will pay for the cost of those new resources.

From the perspective of equity, BC Hydro's customers have paid for the capital cost associated with the existing resources over the past many years through electric rates. BC Hydro's customers should therefore have the right to the low cost resources in the future. By selling the first block of power at low rates associated with the existing resources, customers will receive the benefits associated with those resources at a comparable level as in the past.

If stepped rates are put in place, customers will face the higher rate for additional load levels. They will be responding to that higher rate when making decisions in load levels. This will promote decreased use of power and conservation decisions that will be made on the basis of the cost of acquiring new resources. Even though rates will be set to be revenue neutral, the elasticity impact will be tied to a rate increase, likely leading to reduced consumption levels. This will in turn reduce the need for resource acquisition and reduce costs for all customers.

Finally, the concept of stepped rates is consistent with the concept of Heritage contracts. The government is proposing that customers of BC Hydro all have a right to a share of the benefits from the low cost existing hydro plants.

<u>Rate Precedents</u>

Stepped rates are commonplace as a retail rate design tool and are also seen in some wholesale power pricing methods. At the retail level, many utilities have stepped rates for residential and small commercial classes. For industrial customers stepped rates are less common due to the administrative burden of setting blocks for customers with different sizes within the class. For wholesale sales, particularly for utilities or agencies with large amounts of hydroelectric facilities, it is common to have low cost power available on the basis of an allocation or differentiated pricing.

Western Area Power Administration

The Western Area Power Administration (WAPA) markets power from federally-owned projects to customers in the Southwestern and Midwestern U.S. By law, WAPA is directed to first offer this power to "preference" customers, with the remainder, if any, being sold to any wishing to purchase what is left. As this power is predominantly generated by low-cost hydroelectric facilities, its highly sought-after resources cannot meet all of the needs of those entitled to service from WAPA. As such, a method for sharing the benefits of this low-cost power among those entitled to service was needed.

To share the benefits of the low-cost resources marketed by WAPA, a method was created whereby preference customers would get a predetermined allocation of WAPA's resources for a fixed period at the cost of production. The remaining electrical needs, if any, are the responsibility of WAPA's customers to cover. As the availability of comparably priced resources in the area served by WAPA is limited, it can be assumed that the incremental power purchased to meet the needs of WAPA's customers are higher than the embedded cost of its hydro resources. This, in effect, creates a tiered pricing framework for WAPA's customers.

The WAPA experience is very analogous to that of BC Hydro in its effort to apportion limited low-cost hydro resources across a greater load. Except whereas BC Hydro is proposing to procure additional resources to meet its customers' needs in some cases, WAPA leaves that responsibility entirely with its customers. Otherwise, the WAPA experience closely mirrors that of BC Hydro and its proposal to offer tiered rates to its industrial customers.

Bonneville Power Administration

The Bonneville Power Administration (BPA) markets power from federally-owned projects to customers in the Northwestern U.S. As with WAPA, the power sold by BPA is predominantly generated by low-cost hydroelectric facilities. In the past, BPA had a considerable surplus of resources to meet the regions electricity needs. However, more recently, the demand has outstripped its supply of low-cost resources. This has prompted BPA to investigate means for sharing the benefits of its low-cost hydroelectric power among those entitled to it. Several of the solutions proposed and implemented by BPA serve as useful examples in the context of BC Hydro's stepped rate discussions.

The first example pertains to increases in wholesale loads presently served by BPA. In the late 1990's, BPA oversaw a "Subscription" process, whereby its customers indicated the level of service desired under BPA's traditional low-cost power rate structure. Customers were generally limited in the amount they subscribed to the levels historically served by BPA, although customers historically taking full service were allowed to continue taking this level of service (including load growth). As part of the rate structure created immediately following the Subscription process, BPA implemented a "Targeted Adjustment Charge," or TAC. The TAC applies to any load materially in excess of that subscribed by BPA's customers during the rate period. The TAC was set at a level so as to impose the full incremental cost of acquiring new resources on the unanticipated higher level of loads. Therefore, BPA created a structure that was designed to share the historic low-cost resources fairly and to charge its customers for incrementally higher levels of usage. This tiered rate structure is analogous to the stepped rates proposed by BC Hydro.

As another example, with the recent experience of BPA from the Subscription process, BPA and its customers have engaged extensively in discussions on how best to allocate the benefits of the resources marketed by BPA after 2006. As part of this "regional dialogue," the concepts of allocating the BPA's low-cost resources and implementing a tiered rate structure have been discussed. As demand for BPA's low-cost hydro resources grow, either or both of these concepts are likely to be part of the plan ultimately adopted by BPA to fairly allocate its scarce and valuable resources.

<u>The JIESC Proposal</u>

The JIESC made a stepped rate proposal during the consultations. During the discussions the original recommendation evolved to the point that it now contains the following key elements. Note that these elements were submitted in draft form on July 3, 2003.

1. Tier 1 is based on the amount of, and actual cost of, existing Heritage Hydro resources.

    - The amount of Tier 1 will decline as a percent of total CBL as new high cost resources are acquired by BC Hydro over time.

2. Tier 2 is based on the amount of, and actual cost of, all other BC Hydro resources.

    - It will be weighted heavily with natural gas resources and accordingly will reflect the actual cost of new supply acquired by BC Hydro as required by the Energy Plan rather than a theoretical cost for new resources or a market-based index

3. Initially, the weighted average of Tier 1 and Tier 2 rates and volumes will equal the weighted average rate for RS 1821 customers. However, if making the Tier 1 & 2 elements cost-based leads to a rate that varies from RS 1821, the cost-based rates should be implemented.

4. The CBL shall be negotiated by individual customers with BC Hydro and supervised by the British Columbia Utilities Commission (BCUC). It will be based on past experience adjusted for anomalies. This is consistent with real-time pricing (RS 1848) experience and can work.

5. The CBL may be adjusted for increases or decreases in production which exceed a dead band zone of plus or minus 10 percent. This will remove the need for auditing of minor changes in use. The CBL will continue unchanged unless there is a change in production. This will allow relatively long term investments in energy efficiency to be made by customers. Incentives to invest in energy efficiency are greater when the term associated the savings is longer.

6. Programs such as PowerSmart and Customer Based Generation (CBG) initiatives will continue, and a similar focused IPP initiative could be implemented. This will allow the stepped rates to provide incentives for undefined and smaller measures and leave PowerSmart and the other programs to deal with larger targeted initiatives.

7. Rate stability and predictability must be taken into account in designing stepped rates.

8. Customers should be able to aggregate loads at different plants as this will make some demand side management or generation projects more economic. Detailed conditions for aggregation should be decided within the context of rate design proceedings.

9. Demand charges should be calculated as they currently are, that is based on actual demand incurred and not on a CBL based demand.

10. BC Hydro should move to implement a targeted voluntary time-of-use rate (TOU) on the same schedule as the stepped rates proposal.

Critique of BC Hydro's June 27th Further Proposal

On June 27th BC hydro filed its Further Proposal, in which it sets out its views on stepped rates. While the proposal contains some of the major elements of stepped rates, it differs substantially from the key principles set forth by the JIESC. The fundamental difference between the JIESC proposal and the BC Hydro proposal is that BC Hydro would set both the Tier 1 amounts and the Tier 2 rate on a basis inconsistent with actual costs and resources. While the concept of stepped rates is beneficial in providing proper price signals, the appropriate approach must be equitable, predictable and reflect the cost of providing service. The following provides discussion on the major elements of the BC Hydro proposal, followed by some comments on the more minor issues.

Tier 2 Rate Level[1]

BC Hydro has proposed a Tier 2 rate based on contracts at Mid-Columbia Exchange ("Mid-C") rather than the costs of all non–Heritage resources. This has several disadvantages:

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[1] Response to BC Hydro June 27, 2003 Further Proposal Section 2.1

1. It is not cost-based and more easily subject to variation in the future thereby creating a speculative atmosphere rather than one in which resource decisions are the result of thoughtful, well-considered and long-term planning.

2. It is highly unlikely that customers make decisions to invest in demand-side management (DSM) measures on the basis of the projected price of power in the coming year. Therefore, the conservation objectives underlying the Energy Plan policy directives may be undermined by the uncertainty created by using such a short-term and risky measure.

3. It is highly unlikely that IPPs make resources investments on the basis of the projected price of power in the coming year. Therefore, the ability of IPPs to successfully compete for deals with industrial customers, another fundamental component of the Energy Plan, will be hampered by the unnecessarily short pricing period.

4. Forward markets have been shown to be easily manipulated and forward price reporting is far from an exact science. Together with the short-term planning horizon imposed in BC Hydro's plan, relying on these markets only exacerbates the speculative and risky environment in which industrial customers will be asked to make important, long-term resource decision.

The JIESC has put forth the position that actual costs be used. I believe this is consistent with the past practice of rates based on embedded costs, will lead to an equitable allocation of costs and will still provide the desired price signals. Further, this will provide a verifiable, predictable and stable approach for setting the Tier 1 and Tier 2 rates. The existing portfolio of non-Heritage resources, which is heavily weighted to natural gas, will reflect the cost of new supply as required by the energy policy. If the Tier 2 rate is marginally below the cost of new resources this will ease resale of surplus electricity, and reduce the risk to BC Hydro, if customers do reduce their requirements.

To the extent that forward pricing is necessary to calculate the upcoming Tier 2 rate, it should solely apply to that portion of the Tier 2 resources that BC Hydro expects to procure through the market. As a majority of the Tier 2 resources are existing, long-term resources already in service, even if BC Hydro intends to augment its resource base entirely with market purchases, the cost of these purchases (when melded with the existing Tier 2 resource base) should have relatively little impact on the Tier 2 rate.

Tier 1/Tier 2 Split[2]

BC Hydro is suggesting that an arbitrary 90/10 split be used to apportion Tier 1 and Tier 2 resources. The JIESC has taken a position opposing this, preferring a split based on the actual amount of Heritage and non-Heritage resources. BC Hydro suggests that using actual resources will lead to an 83/17 split. This number is not supported in the material

[2] Response to BC Hydro June 27, 2003 Further Proposal Section 2.2

provided by BC Hydro to date and seems very high relative to past estimates, which were in the range of 87 to 90 percent for Tier 1.

Basing the tier split and prices on actual costs and resources will lead to rates that reflect actual costs and opportunities. Until such time as a verifiable identification and quantification of the Heritage resources are made in a detailed rate design review, I believe it is appropriate to set a 90 percent Tier 1 split as a proxy.

While this leaves only 10 percent as an initial percent of load subject to the higher Tier 2 rate, this amount will grow over time as load growth on the system occurs and the Heritage hydro resources become a smaller fraction of the total amount used to serve loads. For example, assuming the loads on the system grow an average of 2 percent per year, the amount of load subject to the Tier 2 rate would be about 25 percent by year 10. After 20 years, this would increase to about 40 percent of the total.

***Determination of CBLs*[3]**

The JIESC has taken the position that CBLs should be determined based on three-year historic consumption, adjusted for anomalies. Further, CBLs should only be adjusted to reflect major changes in production, with a 10 percent dead band around the CBL, within which CBLs are not adjusted for production changes. This will provide a reasonable way of avoiding frequent applications for CBL adjustments by customers or BC Hydro. The JIESC members do not accept BC Hydro's suggestion that a CBL be determined for peak demand as well.

These recommendations will provide for ease of administration of the stepped rates and will avoid the short-term price signals associated with immediate changes in the CBL. I believe it would be unfortunate if customers were discouraged from making prudent short-term operational changes on the basis of potentially losing long-term benefits of Heritage resources.

The JIESC members have taken a position in support of the continuation of PowerSmart and CBG programs to capture opportunities that are too big to be captured by the stepped rate structure. Furthermore, there should be no double accounting of benefits and there is a need and a place for similar programs to provide opportunities for IPPs.

Consistent with the JIESC position, I support aggregation of loads. Without aggregation, investments in some projects may be made uneconomic, frustrating the intent of the Energy Plan to allow customers to respond effectively to the price signals being presented to them under stepped rates. BC Hydro's suggestion that aggregation would make it easier for customers with multiple accounts to avoid the Tier 2 rate is unsupported

[3] Response to BC Hydro June 27, 2003 Further Proposal Section 2.3

Retail Access Principles[4]

BC Hydro proposes that direct access to IPPs not be permitted until mid-2005. Better access to markets for IPPs was a fundamental element of the Energy Plan and should not be ignored. I agree with the JIESC position that it is unacceptable for BC Hydro not to make any recommendations at this time. Without a plan to provide access to customers, the application of Tier 2 price signals will not provide its full benefit. The ability to access alternative supplies for a portion of load is a key element in both the WAPA and BPA precedents discussed earlier. Given the small amount of Tier 2 energy that IPPs would likely be competing for and, therefore, the limited amount of risk imposed by allowing IPPs access, there does not appear to be any need for defined access principles at this time.

In the future, requirements for access to alternative supplies will need to be addressed in more detail by the BCUC. Well-defined rules and regulations for access will need to be established using a balanced approach. Access will need to be established in a manner that creates real opportunities for alternate suppliers and allows the certainty necessary for the customer to make the necessary commitments. At the same time, reasonable rules regarding notification and duration will need to be established to protect remaining customers. By having a clear policy direction now with respect to access, BC Hydro can also make the appropriate decisions with respect to risk and planning of future resources.

To support its delay of retail access, BC Hydro asserts that more defined ancillary services need to be developed before retail access can begin. However, it can be noted that RS 1821 rates already include transmission and, furthermore, the demand charge under this schedule is very similar to the Wholesale Transmission Service (WTS) demand charge. With little difference between the demand charges in the RS 1821 and the WTS rates, it can be assumed that the revenues collected by the WTS demand charge should cover all the needed ancillary services required to transmit power from IPPs to industrial customers. Accordingly, customers should be able to use their contract to transmit purchased IPP energy to their load.

Lost Revenue Deferral Account[5]

The JIESC has indicated its support of BC Hydro's position that a Tier 2 deferral account is not necessary and goes one step further by submitting that such an account would be counter productive, if JIESC's cost-based rate design is adopted.

If rates are cost-based, variations from anticipated results should be minimal, and most likely positive. To the extent there are negative variations, they are incurred to gain efficiencies for the system as a whole and should be absorbed by the system, not retroactively recovered from the customers who are doing what they have been asked to do for the benefit of all.

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4 Response to BC Hydro June 27, 2003 Further Proposal Sections 3 & 4

5 Response to BC Hydro June 27, 2003 Further Proposal Section 2.4

Margins[6]

BC Hydro points to margin neutrality as one of its three basic principles for acceptable stepped rate design. The concern over margin neutrality is overstated. The intent of stepped rates is to change behavior. This may temporarily change margins one way or another for short time periods, but not significantly. Due to differences between the market price and the Tier 2 price there will inevitably be fluctuations in BC Hydro's margins. However, BC Hydro has not suggested that, in the longer term, there is any reason to believe that the resources supporting Tier 2 are over priced. Accordingly, these resources can be freed up to meet system growth or can be sold in the market for reasonable cost recovery.

Duration of the Electricity Service Agreement[7]

BC Hydro proposes that the customers' commitment to take supply from BC Hydro reflect the term and pricing used to determine the Tier 2 rate. This proposal defies reason. A vast majority of the power purchased under the proposed stepped rates will be at low Tier 1 rates. It is unlikely that BC Hydro's RS 1821 customers would be able to obtain replacement power at a price comparable to Tier 1 levels. Therefore, it is unlikely that these customers will remove their entire load from BC Hydro. To the extent that a customer displaces Tier 2 power, BC Hydro should be able to recover most of its foregone rate revenue through sales of such power to other BC Hydro customers or the market. Therefore, there is no need for any change to the duration of the Energy Service Agreement.

Standby Rates[8]

RS 1880 provides interruptible standby power to customers with generation behind the meter. It has been an important factor in encouraging such generation that has benefited all customers by displacing the need for higher cost resources. RS 1880 must be continued for all exiting customers and new customers in a similar position.

Energy Imbalance[9]

This issue must be addressed by BC Hydro. In the absence of a workable suggestion by BC Hydro, the BCUC should require crediting or charging any energy imbalances at the Tier 2 rate.

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[6] Response to BC Hydro June 27, 2003 Further Proposal Section 1

[7] Response to BC Hydro June 27, 2003 Further Proposal Section 4.3

[8] Response to BC Hydro June 27, 2003 Further Proposal Section 4.1

[9] Response to BC Hydro June 27, 2003 Further Proposal Section 4.2

***Shopping Credit*[10]**

BC Hydro hints that the concept of a shopping credit method may need to be revisited when retail access is introduced. The JIESC position opposes a shopping credit methodology preferring cost-based methodology. I believe the shopping credit approach is counter to the 2003 Energy Plan and does not provide the equity and predictability associated with the stepped rate proposal. BC Hydro notes that "consultations have made it apparent that there is little support for the shopping credit approach among stakeholders." This lack of support is the primary reason BC Hydro is electing not to pursue this approach at this time. BC Hydro has not shown why stakeholder support would change under retail access and, therefore, has provided no basis for resurrecting such a proposal in the future.

Recommendations

I have reviewed the JIESC Draft Outline of Basic Positions on stepped rates and agree with the position that has been taken. By establishing stepped rates based on the actual resource portfolio of BC Hydro, the following goals will be met:

- The 2003 Energy Plan directive will be followed
- Customers will be provided with an equitable amount of cost-based Heritage power
- Customers will receive the appropriate price signal to match the resources that are actually being procured
- Tier 1 and Tier 2 rates will be verifiable and predictable
- There will be no need to adjust Tier 1 and Tier 2 rate levels frequently to reflect short-term changes in the market

Further, the application of stepped rates reflects the current resource situation of BC Hydro and is the proper theoretical design. Stepped rates are consistent with the general rate design of many other utilities as well as for BPA and WAPA, who have similar resource profiles. A commitment to stepped rates for a minimum of three years, rather than a one-year trial period, will provide the desired price signals to promote energy efficiency and alternate power sources.

The Tier 1 rate should be tied to the cost of the hydro-based Heritage resources and the amount of power available at the Tier 1 rate should be based on the output associated with the hydro-based Heritage resources. For each industrial customer, a CBL should be established. A three-year average historical usage should be used to calculate the individual CBL for each customer, with adjustments made for anomalies. CBLs should only be adjusted for changes in production subject to the 10 percent dead band. The percent BC Hydro's heritage hydro resources bear to its total resources should be applied to the CBL to determine the breaking point between the lower and upper block charge.

[10] Response to BC Hydro June 27, 2003 Further Proposal Section 1.3

The Tier 2 rate should be based on the cost of all other Heritage or non-Heritage resources. Both Tier 1 and Tier 2 rates should be tied directly to the cost of the respective resources and should be reset on a periodic basis after a Commission review. The rate should not automatically change as the costs of the resources change.

Demand charges should continue and should be set on the basis of non-power supply related costs. The demand charge should be a flat charge per kW-month billed on the basis of total metered demand levels whether the power is supplied by BC Hydro or an IPP. Stepped charges should not apply to the demand charge, as it is not intended to cover generation or power supply costs.

The use of stepped rates does not preclude the potential for TOU rates.

Summary and Conclusions

This testimony has addressed the key issues relating to the use of stepped rates for industrial customers of BC Hydro. In particular, we make the following observations:

- Policy Action #21 of the Energy Plan calls for a stepped rate approach for industrial and large commercial customers of BC Hydro. This approach has gained greater customers acceptance than BC Hydro's preferred shopping credit method.

- Policy Action #1 of the Energy Plan calls for the preservation of benefits from BC Hydro's low cost existing generation. The JIESC proposal captures these benefits in the design of the Tier 1 rate, and will incorporate the results of the Heritage contract outcome.

- Policy Action #9 of the Energy Plan promotes the acquisition of new supply on a least-cost basis. With stepped rates, customers will have the incentive to select the least cost resource among IPP purchases, customer-owned generation, and energy efficiency.

- Policy Action #13 of the Energy Plan seeks new power plants from the private sector while Policy Action #14 enables large customers to choose an alternate supplier. By allowing large customers to access the market for a portion of load, IPPs will have a market for selling power from new projects and customers will have an opportunity to make their own choices.

- From a theoretical standpoint, given BC Hydro's shortage of low-cost Heritage resources, a stepped rate structure is the most appropriate, as it allows customers to face the true cost of their incremental usage and will cause them to consume (or conserve) accordingly.

- The use of a stepped rate design is common and is used by large U.S. hydro-based utilities that, like BC Hydro, are faced with supplementing their low-cost resource base with higher-cost resource to meet their load obligations.

- The JIESC proposal provides a stepped rate design, consistent with the intent of Policy Action #21 of the Energy Plan. This proposal allocates a portion of Heritage resources to customers and charges these customers the actual cost of these, and non-Heritage, resources.

- BC Hydro's Further Proposal advances a stepped rate method that does not base incremental rates on the actual cost to BC Hydro. Further, it arbitrarily assigns a 90/10 split between Tier 1 and Tier 2 resources and does not provide access to IPPs.

- Ultimately, any proposal adopted by BC Hydro should reflect the actual cost it incurs to serve load (inclusive for each tier) and the tiers should reflect the actual split between Heritage and non-Heritage resources.

Exhibit A

PROFESSIONAL EXPERIENCE AND BACKGROUND OF

GARY S. SALEBA

EDUCATION

MBA, Finance
Butler University
Indianapolis, Indiana

BA, Economics and Mathematics
Franklin College
Franklin, Indiana

EMPLOYMENT

October 1978 to Present	EES Consulting, Inc. 570 Kirkland Way, Suite 200 Kirkland, Washington 98033 Registered Professional Engineering and Management Consulting Firm
Position:	President
Responsibilities:	Overall supervision and quality control responsibilities for all of EES Consulting's electric, water, wastewater and natural gas engagements in the areas of strategic planning, financial analysis, cost of service, rate design, load forecasting, load research, management evaluation studies, bond financing, integrated resource planning and overall utility operations. Overall responsibility for firm's offices in Kirkland, Portland, Spokane, Calgary and southern California.
Activities:	Supervised several integrated resource planning studies, average embedded and marginal cost of service studies, technical assessments and financial planning studies for electric, water, gas and wastewater utility clients. Participated in comprehensive resource acquisition, strategic planning and demand side management analyses. Developed and verified interclass usage data. Conceptualized and implemented compliance programs for the Public Utility Regulatory Policies Act and the Energy Policy Act of 1992. Numerous testimony presentations before regulatory bodies on utility economics, strategic planning, finance and utility operations. Contract negotiation and energy conservation assessments. Presentation of management audit, forecasting, cost of service, integrated resource planning, financial management, and rate design seminars for the American Public Power Association, American Water Works

	Association, and Northwest Public Power Association. Past Board member of Northwest Public Power Association and ENERconnect, Ltd. Past Chairman of Financial Management Committee and Management Division of the American Water Works Association. Project manager for construction of 248 MW gas turbine, and acquisition of over $500 million of utility service territory and equipment. Supervised engineer's report for over $5 billion in revenue bonds.
October 1977 to October 1978	National Management Consulting Firm
Position:	Supervising Economist
Responsibilities:	Analyzed various energy related topics to determine economic impacts. Reviewed utility financial activities.
Activities:	Participated in several utility rate/financial regulatory proceedings. Provided clients with critique of issues, position papers and expert testimony on the topics of cost of service, rate design, utility finance, automatic adjustment factors, sales perspectives and class load characteristics. Conceptualized load forecasting models and assisted in economic and environmental impact analyses.
June 1972 to October 1977	Indianapolis Power & Light Company P.O. Box 1595 B Indianapolis, Indiana 46206 Investor-owned Utility
Position:	Economist, Department of Rates and Regulatory Affairs
Responsibilities:	Provided general economic and rate expertise in Rates, Regulatory Affairs, Customer Service and Engineering Design Departments.
Activities:	Calculated retail and wholesale electric and steam class revenue requirements and rates. Prepared expert testimony and exhibits for state and federal agencies regarding rate design theory, application of rates and revenues generated from rates. Determined long range revenue and peak demand projections. Supervised comprehensive load research program. Supported thermal plant Environmental Impact Statements. Provided industrial liaison.

Exhibit A

PARTIAL LIST OF CLIENTS FOR WHOM FINANCIAL, OPERATIONAL, STRATEGIC PLANNING AND ALLOCATIONAL/RATE ANALYSES PROJECTS HAVE BEEN PERFORMED BY GARY S. SALEBA

CANADA

British Columbia

Gold River Hydro Corporation
Anyox Hydro Corporation
Alcan, Ltd.
*Princeton Power & Light
*West Kootenay Power
*Ministry of Fisheries
Crows Nest Resources
Highland Valley Copper
*Council of Forest Industries
Crestbrook Industries
Royal Oak Mines
UtiliCorp Canada
*Centra Gas

Alberta

*University of Alberta
*City of Lethbridge
*City of Red Deer
City of Medicine Hat
Ocelot Chemicals
Aqualta
City of Calgary—Water and Wastewater Utilities

Manitoba

*Manitoba Legal Aid

Ontario

Bradford West
ENERconnect, Inc.
Ontario Hydro
*Municipal Electric Association
North York Hydro
Toronto Hydro
*Ottawa Hydro
Electricity Distributors Association

Northwest Territories

*Northwest Territories Power Corporation

Exhibit A

UNITED STATES OF AMERICA

Indiana

*Indianapolis Power & Light Company

Wisconsin

*Wisconsin Manufacturing Association
Polk-Burnett Cooperative

Illinois

*City of Highland
City of Collinsville
City of Peru
City of Winnetka

Colorado

*CFI Steel
*Moon Lake Electric Association
City of Denver - Wastewater
*Denver Water Board

Idaho

Kootenai Electric
*Northern Lights
Salmon River Cooperative
Prairie Power and Light
*Department of Energy
City of Moscow
Fall River Cooperative
Lower Valley Power & Light
*Industrial Customers of Idaho Power
Clearwater Power & Light
City of Heyburn

Iowa

*City of Iowa City

Missouri

*General Motor, Inc.

North Dakota

City of Watford City

Connecticut

City of Groton

Utah

*Moon Lake Electric Association
Utah Association of Municipal Power Systems

Florida

City of Pompano Beach
Florida Public Service Commission
Dade County Water and Wastewater Utilities

Arizona

*Tucson Electric Power
City of Dodge
City of Page
Navopache Electric Cooperative

Wyoming

*Lower Valley Power and Light

Alabama

City of Birmingham Water and Wastewater

Texas

City of League City
City of Brownsville
*City of Lubbock
Pedernales Electric Cooperative
City of San Antonio
*Texas Municipal Power Agency

Kentucky

*Kentucky-American Water Company

South Dakota

Black Hills Electric Cooperative

Minnesota

Polk-Burnett Electric Coop

Exhibit A

Montana

Montana Associated Cooperatives
Sun River Electric Cooperative
*Montana Power Company
Colstrip Community Center
Flathead Electric Cooperative
Glacier Electric Cooperative
Vigilante Electric Cooperative
Montana Electric Cooperative Association
Western Montana G&T
Northwestern Energy, Inc.

Arkansas

City of North Little Rock

California

City of Palm Springs
City of Moreno Valley
City of Indian Wells
City of San Bernardino
*City of Corona
City of Redding
*Sacramento Municipal Utilities Board
City of Burbank
*State of California - Department of Water Resources
*Turlock Irrigation District
*City of Palo Alto
City of Anaheim
El Dorado Irrigation District
City of Glendale
*City of Pasadena
City of Roseville
Yucaipa Valley Water District
*Los Angeles Department of Water and Power
Nor–Cal Electric Authority
Jefferson JPA
City of San Marcos
City of Cerritos
Coachella Valley Association of Governments
California Power Authority
Santa Clara Valley Water District

Oregon

*Emerald PUD
Clackamas Water District
Central Lincoln PUD
*Springfield Utility Board
Tri-Cities Service District
City of Portland

<u>Oregon</u> (cont'd)

City of Gladstone
City of West Linn
City of Oregon City
*Public Power Council
Central Electric Cooperative
Warm Springs Energy Cooperative
Northern Wasco PUD
West Oregon Cooperative

<u>Alaska</u>

City of Barrow
City of Wrangell
*Alaska Public Service Commission
*Municipal Light and Power

<u>Washington</u>

TrendWest Resorts
Weyerhaeuser Corporation
Costco
*Pend Oreille County PUD
City of Richland
Industrial Customers of Grant County
*Benton REA
Seattle City Light
*Clark Public Utilities
City of Blaine
*Snohomish County PUD
*City of Port Angeles
*Clallam County PUD
Chelan County PUD
*City of Tacoma Electric, Water and Rail Utilities
*Mason County PUD No. 3
*Peninsula Light Company
Washington Utilities and Transportation Commission
*Grays Harbor County PUD
*Pacific County PUD
City of Gig Harbor
Ferry County PUD
*City of Ellensburg
City of Redmond
Grant County PUD
*Klickitat County PUD
Cascade Natural Gas
*Building Owner's Management Association
City of Kennewick
Daishowa Corporation
Seattle Water Department
City of Bellingham

Washington (cont'd)

*US Ecology, Inc.
*City of Cheney
*City of Yakima
City of Bellevue
City of Shoreline
Douglas County PUD
AT&T
WorldCom
City of Toppenish
City of Shoreline

OTHERS

American Public Power Association
American Water Works Association
Northwest Public Power Association
California Municipal Utilities Association

*Prepared Expert Testimony

IC-429 PUB

Provide details of the participation by EES Consulting or any of its employees or associates in the 1993 Cost of Service Methodology Hearing affecting Newfoundland and Labrador Hydro and the 2001 General Rate Hearing affecting Newfoundland and Labrador Hydro.

Response:

EES Consulting did not participate in the 1993 Cost of Service Methodology Hearing or in the 2001 General Rate Hearing.

IC-430 PUB

Provide a complete list of the "other electrical utilities that (EES) have experience with" as referred to at lines 9 to 10 of Section 2.1 on page 6 of the Evidence and provide details of the classification of costs between demand and energy components for each such utility.

Response:

The following is a list of utilities that EES Consulting has worked for or been involved with in terms of COSA studies. The list provides the methodology and the results of the power supply classification.

IC-430 PUB	
Utility	Classification Methodology
City of Tacoma, Washington	Peak Credit Methodology;18% demand related, 82% energy related
Bonneville Power Administration	Classification by Market Prices/Marginal cost; 10% demand related, 90% energy related
Puget Sound Energy, Washington	Peak Credit Methodology; 16% demand related, 84% energy related
BC Hydro, BC	100% of Burrard Thermal was classified as energy, 100% of diesel generation classified as demand, dams & reservoir facilities are 100% energy, while other hydro facilities are classified as demand. Resulting in 23% demand related, 77% energy related
Anchorage ML&P, Alaska	Load Factor Method and Fixed/Variable considered. Load Factor method used. 29% demand related, 71% energy related
PacifiCorp	Marginal Cost/Peak Credit; 25% demand related, 75% energy related
Northwest Territories Power, NWT	60% Demand/40% energy for Hydro resources, 100% demand diesel units & 100% energy for Fuel holders
Various Bonneville Power Authority (BPA) Utility Customers	Classification based on BPA wholesale rates. Demand charges as 100% demand related, energy charges as 100% energy related, load shaping and load regulating as 100% energy related; Overall 15-25% demand related, 75-85% energy related depending on utility
City of Lompoc, California	As historic purchase power costs, 75% demand related, 25% energy related

IC-431 PUB

What percentage of utilities in North America which classify costs between demand and energy components use each of:

- ***Fixed/variable method***
- ***Base/intermediate/peak method***
- ***Peak credit method***

Response:

Please refer to NLH-201 PUB.

IC-432 PUB

Has there any change in circumstance or facts surrounding the issue of Generation Classification since either the 1993 Cost of Service Methodology Hearing or the 2002 Board Order justifying re-opening of those issues?

Response:

EES Consulting has not seen any particular changes in facts surrounding Generation Classification for NLH but have seen changes and trends in the treatment of this issue in other jurisdictions. As this is our first opportunity to provide assistance to the Board, it was our duty to report our experience and professional opinion related to this matter.

IC-433 PUB

Clarify what is intended to be conveyed by the sentence at lines 11 to 13 of page 8 which reads, "in the case of Hydro the majority of systems only have one resource that meets all of the power supply needs".

Response:

The base/intermediate/peak methodology requires that generating units can be ranked based on unit costs and specifically classified based on dispatch order. In the case of NLH, many of the isolated communities rely on one generating resource that serves the entire base, intermediate and peak needs of the customer load. It is therefore impossible to classify them as distinctly related to only one function.

IC-434 PUB

What is it in the "impacts associated with the change" as referred to at line 11 of page 9 that favours implementation of the Peak Credit Method?

Response:

The impacts that were referred to are the changes in the amount of demand-related costs across systems. Theoretically, an isolated system should have higher demand related production costs as compared to an interconnected system. The impact of using the Peak Credit methodology accomplishes that goal and therefore supports the usage of the methodology.

IC-435 PUB

In relation to lines 19 to 20 at page 11 of the Evidence, please provide a list of the integrated utilities in North America which rely on the Minimum System, which rely on the Zero Intercept System and which rely on any other system.

Response:

Our statements were based on our firm’s experience with ratemaking in many different jurisdictions. EES Consulting has not performed a specific survey of utilities in North America.

IC-436 PUB

Please provide an estimate of the cost of the updated Minimum System Study referred to at line 14 on page 12 of the Evidence.

Response:

Since EES Consulting does not know the exact data that NLH has available already, it is not possible to estimate the cost of undertaking a minimum system analysis. If all of the data is readily available, a minimum system study should not take more than 8-12 hours of labour.

IC-437 PUB

In relation to the Evidence at lines 39 to 41 of page 11, please provide a list of all of the utilities in Canada which use the Minimum System and a list of those which use some other system.

Response:

Please see IC-435 PUB.

IC-438 PUB

How does EES Consulting justify imposing an additional $1.5 million per year of costs on the Industrial Customers arising out of the interconnection of the Great Northern Peninsula, when such interconnection has no impact on the operations of the Industrial Customers of their demands upon the electrical system.

Response:

Based on NLH's report, it is EES Consulting's understanding that all customers in the interconnected system benefit from the generation resources on the GNP. This benefit cannot be obtained without the related transmission facilities. Therefore, as stated in our testimony, generation facilities and related transmission facilities should be assigned in a similar manner.

IC-439 PUB

Provide all documents, working papers, studies and operational data which EES Consulting relies upon in making the statement that "all customers on the Island Interconnected System benefits (sic) from the resources in" the Great Northern Peninsula, Doyles-Port aux Basques and the Burin Peninsula.

Response:

Please refer to NLH exhibit JRH-3 "Review of COS Assignment for the GNP, Doyles-Port aux Basque and Burin Peninsula Assets" page 16, section 3.3.

IC-440 PUB

Please confirm that the proposed Equivalent Peaker method alone, as proposed by EES, results in a 3.8% extra costs to industrial customers per Exhibit C page 2.

Response:

Based on the sample data used and the modification done in NLH's COS model, this is confirmed.

IC-441 PUB

Please confirm that EES has calculated that the sum of the Peak Credit, NCP and Minimum System method result in 2.8% extra costs to industrial customers per page 5. Since NCP and Minimum system have no impact on industrial customers, please explain the difference between the 2.8% extra costs for IC in this table and the reported 3.8% impact from Exhibit C page 2. Please provide all calculations and quantifications to arrive at these percentages.

Response:

Table 1 of EES Consulting's evidence did not get updated in the final version of the evidence. The results in Table 1 of EES Consulting's evidence have therefore been updated and are provided below.

IC-441 PUB
Table 1 (Rev) of EES Consulting Evidence

System	Residential	Commercial	Industrial	Newfoundland Power
Island Interconnected	-1.3%	2.1%	3.8%	-0.8%
Island Isolated	3.7%	-9.6%	0.0%	N/A
Labrador Isolated	4.9%	-7.6%	0.0%	N/A
L'Anse au Loup	-0.8%	1.5%	0.0%	N/A
Labrador Interconnected	-3.1%	3.5%	3.4%	N/A
Total	0.2%	-1.0%	3.7%	-0.8%

IC-442 PUB

Please confirm that EES has not quantified the impact on each customer and zone from its recommendation to assign the GNP transmission (and other radial transmission) as common.

Response:

At this time, EES Consulting has not quantified the impact of the recommendation to reassign the GNP transmission. There was insufficient data available to quantify this impact.

IC-443 PUB

Please indicate the source of the reported 19 percent of costs allocated to demand at page 6, line 8 for the Island Interconnected System (also shown in Table 1). Please reconcile this EES reported figure with the system load factor of 57.90% reported in RDG-1 Rev. 1, Schedule 4.2 (also shown in Schedule 4.1 of RDG-1 Rev 1).

Response:

The 19% was calculated by adding the production related O&M, fuel and power purchases expenses to obtain power supply costs and determining the percentage classified as production demand. For the Island Interconnected System the calculation is shown below, with data references to the COS schedules.

IC-443 PUB, Table A

	Total Amount ($)	Production Demand ($)	
Subtotal Production	25,331,834	13,290,007	Schedule 2.4A, line 7
Fuels-No. 6 Fuel	84,819,538	--	Schedule 2.1A, line 2
Fuels-Diesel	54,612	--	Schedule 2.1A, line 3
Fuels-Gas Turbine	265,277	265,277	Schedule 2.1A, line 4
Power Purchases - CF(L)Co	--	--	Schedule 2.1A, line 5
Power Purchases-Other	29,928,330	12,420,675	Schedule 2.1A, line 6
Total generation	$140,399,591	$25,975,959	

The generation costs calculation above results in a 19% of generation costs classified as demand under the methodology proposed by Hydro for the Island Interconnected System.

The following table provides the cost data and percentages calculated for the 5 systems.

IC-443 PUB, Table B						
	Total Dollars	Production Demand	Share	Total Dollars	Production Demand	Share
Island Interconnected	$140,399,591	$25,975,959	18.5%	$140,399,591	$30,698,572	21.9%
Island Isolated	$3,805,310	$1,105,417	29.0%	$3,805,310	$2,415,097	63.5%
Labrador Isolated	$10,433,759	$1,767,174	16.9%	$10,433,759	$4,550,974	43.6%
L'Anse au Loup	$1,218,103	$337,335	27.7%	$1,218,103	$337,335	27.7%
Labrador Interconnected	$2,793,269	$1,347,501	48.2%	$2,793,269	$591,147	21.2%
Total	$158,650,032	$30,533,386	19.2%	$158,650,032	$38,593,125	24.3%

The calculation provided above adds generation O&M, fuel and purchase power and determines the percentage of power costs that are classified to demand. The load factor of 57.90% is only used to classify some of the production cost items. Therefore, the overall production demand classification is lower than the one suggested by the load factor cited.

IC-444 PUB

Please confirm that EES proposes to classify 22% of all Island Interconnected hydro, Holyrood, diesel and gas turbines and hydraulic-related transmission line plant costs 22% to demand, as well as all fuels consumed and all O&M per Exhibit C page 3.

Response:

EES Consulting proposes to use a Peak Credit methodology to classify all production related costs. The 22% calculated based on available data provides reasonable and expected results. EES Consulting Exhibit C page 3 provides the functionalization and classification ratios used for generation, fuel and transmission & terminals under the proposed Peak Credit methodology.

IC-445 PUB

Please confirm that the EES proposed 22% ratio for demand:energy classification is set out in at Exhibit C pages 4-5 of the EES evidence. Please confirm that these figures are based on the relative costs (including plant, fuel and O&M) for a natural gas fired SCCT compared to a natural gas fired CCCT, and all data is from a company called PacifiCorp. Please confirm that no data from Newfoundland was used in determining the 22% ratio.

Response:

The calculated percentage used for the Peak Credit method was determined from readily available data. The objective of the Peak Credit method is to determine the cost of providing peaking service. Because the methodology does not use actual costs, but rather the relationship between costs for a base resource and a peaking unit, using data from available sources is appropriate. The only exception is if it is believed that the circumstances in Newfoundland and Labrador significantly alter the cost relationship between a base resource and a peaking unit, then actual data will have to be gathered before the percentage relationship can be determined.

IC-446 PUB

Please confirm that the data used in the PacifiCorp review, which is the basis of EES calculations at pages 4-5 of Exhibit C, reflects a mix of supply side resources that do not contain either hydro or oil fired generation. Please confirm that 18 of the 28 options reviewed are based on natural gas.

Response:

The intent of a peak credit calculation is to look at differentials between pure peaking and pure baseload generating resources. By its nature, it does not relate to the embedded resources in a system that are used to serve both peak and energy needs. Therefore, we used information that is generic in nature rather than specific to resources used by NLH. The PacifiCorp information was published data that reflects our own findings with respect to plant costs. The primary differences relate to the capital cost and heat rate associated with different type plants. While the options examined are designed as natural gas units, they can be used to burn oil or aviation fuel. Therefore the generic capital cost and heat rate data is appropriate. If NLH has completed internal integrated resource plans or feasibility studies for new generation on its system that can be clearly defined as peaking or baseload units, those costs could be readily substituted for the generic costs we used calculation the peak credit factor.

IC-447 PUB

Please confirm at page 8 of the EES evidence that a gas-fired simple-cycle combustion turbine (SCCT) is the resource of choice relevant to Newfoundland for new peaking units.

Response:

Please see IC-446 PUB.

IC-448 PUB

Please confirm that the SCCT units referred to by EES, at page 8 are fired by natural gas. Please confirm that the statement "gas is currently available for generation within both the Island and Labrador Interconnected systems and thus the peak credit method will work well to classify the costs of hydropower, diesel units and contracts in these areas" sets out the basis EES uses for determining that the peak credit method is appropriate.

Response:

Please refer to NLH-207 PUB.

IC-449 PUB

Please provide any basis or support for any regulated Canadian utilities that use the Peak Credit method to classify generation costs to demand and energy in their cost of service procedures.

Response:

Please see NLH-201 PUB.

IC-450 PUB

Please provide any basis or support for the statement that "an effort to shift consumption, even though it equally contributes to lower system costs at times of peak demand, is not rewarded under this proposed rate structure at page 23. How does shifting use on Hydro's system from peak times to less-peak times contribute to lower costs? Please provide all analysis and quantification that EES has prepared on this topic.

Response

EES Consulting believes the answer to how the tail block rate does not provide an effective price signal to reduce or shift demand is found in Section 8.2 (page 23 line 35 to page 24 line 5) of EES Consulting's evidence. For a discussion of how shifting consumption from on peak hours to off peak hours may affect overall system costs, please refer to NLH-210 PUB.

EES Consulting has not prepared analysis or evidence as to whether or not winter peak demand is a primary driver of Hydro system costs. As noted in the evidence of EES Consulting (page 22, line 39 to page 23, line 7), this issue was largely resolved in the Board's P.U. 7 2002 decision.

CA-225 PUB

On page 8, lines 20 to 25 of the Evidence of EES Consulting, it is stated that gas is currently available for generation within both the Island and Labrador Interconnected Systems. Please provide support for this statement.

Response:

Please refer to NLH-207 PUB.

CA-226 PUB

On page 8, lines 2 to 3 of the Evidence of EES Consulting, it is stated that the load factor method is not the most common approach used today in ratemaking in North America. On line 9 of the same page, it is stated that the load factor method is simplistic as well as dated in its use. Please provide support for these statements, showing the jurisdictions that use either the load factor or peak credit methods, and indicating if the jurisdictions are primarily hydro-based systems such as Hydro. In addition, please show each jurisdiction that formerly used the load factor method and has since changed to another method.

Response:

Please see NLH-201 PUB.

CA-227 PUB

On page 11, lines 39 to 40 of the Evidence of EES Consulting, it is stated that the minimum system method is the most widely accepted method across Canada. Please provide support for this statement, showing the jurisdictions that use this method. In addition, please provide a comparison of the customer charges derived in the cost of service study with the actual customer charge being levied on consumers.

Response:

Please see response IC-435 PUB

CA-228 PUB

On page 19, lines 18 to 25 of the Evidence of EES Consulting, it is stated that Hydro has not provided a clear case for directly assigning transmission facilities in the GNP and Doyles-Port aux Basque areas. If the only reason for building the GNP transmission line was to bring lower-cost energy to Rural Customers, and the generation that originally resided on the peninsula were removed from service following completion of the transmission line, would it be clear that the transmission line facilities should be assigned directly to Rural?

Response:

EES Consulting believes that generation resources and the associated transmission facilities should be assigned in a similar manner. In the current proposal this is not the case. Anyone who benefits from the generation resource should also pay for the delivery of those benefits.

CA-229 PUB

On page 22, line 35 of the Evidence of EES Consulting, it is stated that EES understands that the Holyrood generation station is used as a peaking unit. Please provide support and justification for this understanding.

Response:

Please see NLH-209 PUB

CA-230 PUB

On page 24, lines 8 to 11 of the Evidence of EES Consulting, it is stated that energy charges in the NP rate should be based on time-of-use, but it is not viewed as having broad support at this time, nor is it operationally realistic to implement for the 2004 tariff. What is the basis for the statement that time-of-use does not have broad support? If it did have broad support, would EES recommend a time-of-use rate for immediate implementation, as soon as the "operational" issues were addressed? What are these "operational" issues that EES is referring to?

EES Consulting has arrived at the conclusion that time-of-use rates do not have broad support upon its review of the Board Order P.U. 7 dated June 7, 2002, Hydro's 2004 rate application, and information requests to date. On page 151 of P.U. 7, for example, the Board expresses its decision to defer examination of such rate design options and "will continue to monitor this situation with a view to determining an opportune time to act on this initiative". Of the more than 1,000 RFIs submitted before intervenor evidence, EES Consulting is aware of seven instances where the subject of time of use rates is raised. The bulk of these questions have been raised by a single intervenor.

If the concept of time-of-use rates did have broad support, EES Consulting would strongly consider endorsing a time of use rate proposal under the following conditions:

- the customer is interval metered
- the rate provides an appropriate price signal of a utility cost that is known to vary with the time of day

In the context of a rate for NP, for example, a time of use rate could reflect higher production costs during hours of peak demand as peak generating units are brought on-line.

Among the general operational issues that Hydro would need to resolve to implement such rates are metering and billing. For example, EES Consulting does take note that from Hydro's response to PUB-181 NLH that not all delivery points to NP load centres are currently interval metered. Certainly, either the installation of appropriate interval meters or an agreement on a reasonable estimation method would be one necessary operational issue that would need to be resolved before a time of use rate could be applied to NP.

NP-283 PUB

On page 8, lines 9 to 13 indicate that the base/intermediate/peak method has a sound theoretical rationale. What jurisdictions use this method for classifying generation costs?

Response:

Please see responses to NLH-201 PUB and NLH-203 PUB.

NP-284 PUB

With reference to Table 2 on page 9 please provide the calculation that determined the percent demand related costs under the current load factor method for each of the five systems listed.

Please see the answer to IC-443 PUB.

NP-285 PUB

With reference to Page 25, lines 39 and 40, is it appropriate for Newfoundland Power to pass on to its customers the cost it incurs to meet the overall peak demand of its customers.

Response:

Yes.

NP-286 PUB

With reference to Page 26, lines 16 to 20, the Sample Rate as shown in Exhibit RDG-2 has a ratchet that will result in NP's monthly demand reflecting the annual maximum native load. Please confirm that the $700,000 referred to on line 19 is an estimate of the monthly impact on NP rate revenues if the actual peak were 100 MW over forecast, and that the estimate annual impact would be 12 times that amount, or $8.4 million (3.3 percent of total annual NP rate revenues based on the $258 million reported in Schedule 1.2 of Exhibit RDG-1)?

Response:

EES Consulting unable to confirm that the annual impact of a 100 MW forecast variance is $8.4 million. The annual impact strongly depends on the specific ratchet level, which EES Consulting recommends only be chosen pending further discussion and analysis by participating parties. However, there are three factors that would make the total annual impact less than $8.4 million:

- If the forecast variance did not occur at the winter peak, the financial impact would not be felt for a full 12 months. There may even be no financial impact at all if the forecast variance does not exceed 90% (or whatever ratchet level is chosen) of the winter peak.
- Even if the forecast variance occurred at the system peak, only 90% (or whatever ratchet level is eventually chosen) of the 100 MW forecast variance would be carried forward into future billing periods.
- If the sum of billing determinants under a ratchet framework is less than the sum of Hydro's forecast weather normalized billing determinants, then the per-kW rate will be need to be lower to collect the same amount of revenues. Thus, the value of a 100 MW forecast variance would also be lower.

For a more detailed discussion on comparing a ratchet framework to the proposed weather normalized billing determinant, please refer to NLH-211 PUB.

NP-287 PUB

Does EES Consulting believe that NP should operate its high cost peaking units when there is lower cost generation available on the Island Interconnected System?

Response:

Please refer to the discussion found in the evidence of EES Consulting (page 33, line 33 to page 34, line 3) and NLH-213 PUB for our recommended first-best option regarding the dispatch of generating units available to the Island Interconnected system.

NP-288 PUB

With reference to page 30 lines 7 and 8, since Newfoundland Power's generation does not require Hydro transmission facilities to reach Newfoundland Power's load centres, does this change EES Consulting's concern with the CP allocator for transmission costs?

Response

Please refer to NLH-208 PUB.