British Columbia Utilities Commission

2001 Annual Report

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, British Columbia, Canada V6Z 2N3

Telephone (604) 660-4700; Facsimile (604) 660-1102
BC Toll Free: 1-800-663-1385

Internet E-mail: commission.secretary@bcuc.com
web site: http://www.bcuc.com

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
WEBSITE: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Vancouver, BC
June 2002

To the Lieutenant Governor in Council

MAY IT PLEASE YOUR HONOUR:

Pursuant to Section 13 of the Utilities Commission Act, I respectfully submit this Annual Report on the activities of the British Columbia Utilities Commission for the calendar year 2001.

This year's Annual Report also includes information specified in the Crown Agencies Secretariat's "Guidelines for Government Organizations 20001/02 Annual Reports". As such, this report is a companion document to the Commission's April 2001 Performance Plan.

PETER OSTERGAARD
Chair

Contents

Contents *(continued)*

Standard Abbreviations & Acronyms

UTILITY/APPLICANT

BC Gas Utility Ltd. (subsidiary of BC Gas Inc.)	BC Gas
British Columbia Hydro and Power Authority	BC Hydro
Centra Gas British Columbia Inc.	Centra Gas, Centra
Centra Gas Whistler Inc.	Centra Whistler
Central Heat Distribution Limited	CHDL
Federated Pipelines (Western) Ltd.	Federated
Hemlock Valley Electrical Services Limited	HVES
Pacific Northern Gas Ltd.	PNG, PNG-West
Pacific Northern Gas (N.E.) Ltd.	PNG (N.E.)
Plateau Pipe Line Ltd.	Plateau
Port Alice Gas Inc.	Port Alice Gas
Princeton Light and Power Company, Limited	PLP
Squamish Gas Co. Ltd.	Squamish Gas
Silversmith Light & Power Corporation	Silversmith
Stargas Utilities Ltd.	Stargas
Sun Peaks Utilities Co., Ltd.	Sun Peaks
Sun Rivers Services Corp.	Sun Rivers
The Corporation of the City of Nelson	City of Nelson
Trans Mountain Enterprises of British Columbia Limited	TME
Westcoast Energy Inc.	WEI, Westcoast
West Kootenay Power Ltd.[1]	WKP
UtiliCorp Networks Canada (British Columbia) Ltd.	UNC, UtiliCorp
The Yukon Electrical Company Limited	YECL

OTHER

Agent Billing and Collection for Transportation Service	ABC-T
Allowance for Funds Used During Construction	AFUDC
Alternative Dispute Resolution	ADR
Apartment Customer Rates	ACR
Certificate of Public Convenience and Necessity	CPCN
Electromagnetic Field	EMF
Gas Cost Reconciliation Account	GCRA
Independent Power Producers	IPPs
Large General Service	LGS
Natural Gas Vehicles	NGV
Oil and Gas Commission	OGC
Real Time Pricing	RTP
Return on Common Equity	ROE
Small General Service	SGS
Utilities Commission Act	the Act, UCA
Wholesale Transmission Service	WTS

1 On October 22, 2001 West Kootenay Power Ltd. changed its name to UtiliCorp Networks Canada (British Columbia) Ltd.

Organizational Overview

Introduction

The British Columbia Utilities Commission ("the Commission", "BCUC") is a regulatory agency of the Provincial Government, operating under and administering the *Utilities Commission Act* ("UCA", "the Act"). The Commission is responsible for ensuring that customers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities it regulates, that shareholders of these utilities are afforded a reasonable opportunity to earn a fair return on their invested capital, and that the competitive interests of BC businesses are not frustrated. It approves the construction of new facilities planned by utilities and their issuance of securities. The Commission's function is quasi-judicial and it has the power to make legally binding rulings. Decisions and Orders of the Commission may be appealed to the Court of Appeal on questions of law or jurisdiction.

The Commission also reviews energy-related matters referred to it by Cabinet. These inquiries usually involve public hearings, followed by a report and recommendations to Cabinet. In addition, under Part 7 of the *Pipeline Act*, the Commission establishes tolls and conditions of service for intraprovincial oil pipelines. The Commission also has responsibilities under the UCA for electricity transmission facilities and energy supply contracts, matters that are likely to become more active as the reorganization of the energy industry proceeds.

The Commission has been self-funded since 1988. Its costs are recovered primarily through a levy on the public utilities it regulates.

The Act provides for a Chair, one or more Deputy Chairs, up to seven Commissioners (including the Chair and Deputy Chair[s]), and temporary Commissioners. All are appointed by the Lieutenant Governor in Council. As of the end of December 2001, there were four temporary Commissioners and the Chair. The Commission staff of 19 is made up of professional engineers, accountants, economists, and administrative staff. The Commission's offices are located in Vancouver at 900 Howe Street.

The Vision

To be a leader in the regulation of energy providers within the mandate of the *Utilities Commission Act*, and to be respected for our independence, professionalism and competence.

The Mission

The Commission's mission is to ensure that ratepayers receive safe, reliable, and non-discriminatory energy services at fair rates from the utilities it regulates, that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital, and that the competitive interests of BC businesses are not frustrated.

Our Values

The Commission is committed to realizing its vision and mission by:

- Applying regulatory principles, research and industry knowledge to resolve energy utility problems and render decisions that are timely, fair, workable and respected.
- Writing high quality decisions, reports and publications.
- Communicating in an effective and timely manner with co-workers, utilities, ratepayers, government and the public.
- Promoting learning, innovation, creativity, and the achievement of personal and professional goals.
- Building a work environment that fosters teamwork, cooperation, and respect for the diversity, skills and experience of individuals.

Commission Services

In addition to its regulatory responsibilities, the Commission provides the following services and assistance:

- reviews ratepayers' complaints about the actions of utilities;
- provides copies of documentation prepared by the Commission (e.g., Brochures, Guidelines, Orders, Decisions, etc.) at no charge. These documents are also posted to the Commission's web site: *http://www.bcuc.com*;
- provides access to regulated utilities' Tariffs;
- provides access to information filed in public hearings; and
- responds to requests for general information regarding utilities.

Regulatory Functions and Responsibilities

The Commission meets regularly to review staff recommendations, to authorize the issuance of Commission Orders or other directives considered necessary and in the public interest, to review complaints, and to conduct other necessary Commission business.

The regulatory tasks are carried out using an inter-disciplinary team approach. The team assigned to a task is normally composed of specialists from disciplines of engineering, accounting and economics and is advised, as appropriate, by legal counsel and specialist consultants retained by the Commission.

Over the last decade, the Commission has successfully reorganized, downsized and reduced its costs. Over the same period, the Commission has increased the effectiveness of its regulatory methods in an increasingly complex energy environment by streamlining its processes and adopting methods such as pre-hearing conferences, performance-based regulation and negotiated settlements.

Message from the Chair and Chief Executive Officer

In 2001/02, the BCUC achieved a number of successes as we implemented our first Performance Plan.

A key Commission function is establishing revenue requirements for public utilities and pipelines. Oral public hearings were necessary for particularly contentious applications by Pacific Northern Gas, whose revenues were severely affected by reduced industrial loads, and by Pembina Pipelines, owners of the common carrier oil pipeline from Taylor to Kamloops. A written hearing process reviewed aspects of the generic return on equity rate setting mechanism. A review of BC Gas' rate design to apportion utility revenue requirements fairly to different customer classes was successfully achieved by a negotiated settlement process.

2001/02 was characterized by an unusual level of proposed merger, acquisition, and divestiture activity. The Commission approved Duke Energy Corporation's share acquisition of Westcoast Energy's two affiliated gas utilities (Centra and PNG), and the subsequent purchase of Centra by BC Gas. A written hearing reviewed BC Gas' application to divest its customer care activities to a joint venture company with Enbridge Inc. After an oral hearing, the BCUC denied a West Kootenay Power application to sell its Kootenay River hydroelectric generation assets to Columbia Basin Trust and the Columbia Power Corporation.

Unprecedented natural gas commodity prices began to ease in the spring of 2001, with the North American economic downturn and with the return to more normal precipitation and temperatures along the West Coast. Prices, however, remain volatile. With stakeholder input, the BCUC developed and implemented a quarterly review mechanism of gas commodity costs designed, in part, to dampen rate swings.

The legislated BC Hydro rate freeze, which was scheduled to expire on September 30, 2001, was extended for up to 18 months to allow the new Provincial Government time to implement a new energy policy. Despite the freeze on existing rates, the Commission continued to work with BC Hydro and its customers to develop new demand response programs and new industrial service options that benefit both the utility and its customers.

The BCUC's services are essential and affordable, and delivered in a way that is cost effective. It is increasingly focussed on performance and results. The Commission tracks its cost and activity trends: indicators such as Commission expenditures, the cost of regulation per utility customer, and the cost of regulation per unit of energy sold are either constant or trending downward. The number of proceeding-days, directives issued, and complaints handled indicate levels of activity: these are generally constant or showing an upward trend. The BCUC also compares its costs with those of tribunals in other jurisdictions. The BCUC is among the most efficient energy utility regulators in North America, operating at cost and staffing levels that are significantly lower than comparable tribunals.

The BCUC awaits the release of the Government's energy policy, which may define new roles for the Commission in implementing the policy in functions such as electricity market design, transmission, and customer choice in natural gas providers. The Interim Report of the Energy Policy Task Force recommended that utility regulation in BC be based more on outcomes, which reinforces the BCUC's practice of encouraging multi-year performance-based rate making using negotiated settlement processes.

Looking forward, the BCUC expects that the new energy policy will give British Columbia an energy advantage by facilitating growth and diversification in energy production, while giving customers more choice and competition. This is consistent with the Commission's "public good" mandate of balancing the interests of utility customers and shareholders to ensure that:

- customers receive safe, reliable, and non-discriminatory energy services at fair rates;
- utility shareholders are afforded a reasonable opportunity to earn a fair return on their invested capital; and
- the competitive interests of BC businesses are enhanced by ensuring transmission and distribution monopolies do not frustrate competition.

I would like to thank all our staff and temporary Commissioners who made 2001 a success, especially those staff who helped to manage the extraordinarily high volumes of complaints from natural gas customers.

Peter Ostergaard
Chair and CEO

The Year in Review

During 2001, the Commission carried out its regulatory functions and responsibilities against the backdrop of continued continental integration in the energy markets and volatility in natural gas commodity prices.

Highlights in Operational and Financial Performance

Proceeding Days

The number of proceeding days rose in 2001 to a total of 35 (including workshops and pre-hearing conferences), boosted by the number of public hearing days that went up to 23, the highest since 1997. The turnaround was not so much a result of utilities and intervenors abandoning the more efficient regulatory tools that have been taking hold in the last few years, but rather it was due to the increased number of non-recurring events. Four such applications took up the 23 public hearing days. One involved the continuing viability of a utility faced with significant revenue reduction from its largest customer. The remaining three are issues related to: (i) a common carrier's toll level, its commitment to serve and its operational safety; (ii) the proposed terms of sale of a utility's hydroelectric plants, and the terms of the related power purchase agreement; and (iii) establishing distribution access tolls and tariffs for independent power producers.

The incentive regulation, negotiated settlement processes, and multi-year reviews implemented in past years will continue to ensure that the number of proceeding days is minimized, following the trend that began in 1997. The formal public hearing process will continue to be used in situations where the other techniques are not appropriate.

As noted elsewhere, Commission costs, in constant dollars, have trended downward over time while output has increased. Details and graphs are included in the section entitled *Performance Indicators* beginning on page 76.

Organizational Efficiency and Effectiveness

The staffing level at the Commission in 2001 stood at 19, as it had in the last three years. Staffing expenditure constituted around 60 percent of the Commission budget in 2001. The Commission has succeeded in maintaining or lowering its budget and core expenditures in real terms by moving away from traditional cost-of-service approach to performance-based regulation, offering potentially lower regulatory costs. At the same time, interest-based negotiation is proving more effective than regulatory confrontation in settling differences among market participants. This results-based practice has allowed the BCUC to keep its costs reasonable in terms of the services to ratepayers and utilities.

Pursuant to Section 118 of the UCA, the BCUC has the authority to grant cost awards to intervenors in a proceeding before the Commission. The Commission has issued Participant Assistance / Cost Award Guidelines to ensure that intervenors' submissions are useful, their efforts do not duplicate each other's, and costs claimed are reasonable. In 2001, the Commission issued 12 participant funding decisions totalling $159,278 in cost awards.

The costs of the Commission can be measured by cost per utility customer and cost per unit of energy sold. In fiscal 2001/02, the cost of regulation per customer is $0.95 (up from $0.88) largely reflecting the higher number of hearing days. The cost of regulation per gigajoule ("GJ") of energy sold is 0.6 cents.[1] The total expenditure for fiscal 2001/02 was $2.52 million against a projection of $3.3 million. Expenditures increased by 9 percent over the previous year as a result of the increase in hearing days from 8 to 23, and in proceeding days from 24 to 35.

Highlights in Natural Gas

British Columbia's deliveries of natural gas by suppliers are shown in Charts A and B.

With the volatility in gas commodity costs, the Commission addressed the challenges posed by the market during 2001 by reviewing the various regulatory mechanisms and established guidelines in order to mitigate the effects on ratepayers. Some of the monitoring mechanisms include:

- Price Risk Management Plan – A plan to manage commodity price volatility on behalf of customers of BC Gas and Centra Gas through the use of a diversified portfolio with respect to gas sourcing and pricing.

- Quarterly Reports on Gas Supply Cost – Quarterly reporting by gas utilities on Gas Cost Reconciliation Accounts, which are deferral accounts to stabilize rates. The rate change trigger mechanism includes a deadband in the ratio of gas cost recoveries to gas purchase costs and quarterly accumulation between 95 percent and 105 percent. A rate change would not normally occur for fluctuations within the deadband.

- During the year, the Commission directed BC Gas to prepare a report on the natural gas supply balance in the Pacific Northwest Region to initiate Regional Resource Planning discussion amongst stakeholders.

It is interesting to note that the revenues to natural gas utilities were up in 2001 by about 26 percent over 2000, largely due to the increase in the pass-through cost of the commodity. During the same period gas sales volumes decreased by about 8 percent.

Another initiative that continued during 2001 included coordination on the readiness of retail unbundling and potential choice in providers of the gas commodity for BC Gas' residential and small commercial customers.

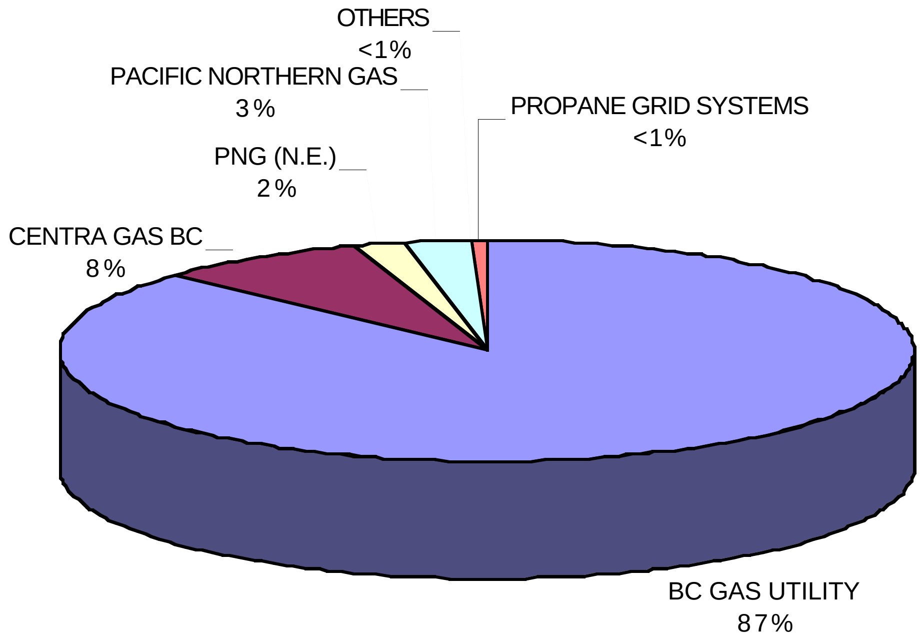
At the end of 2001, the Commission was in the process of reviewing the BC Gas multi-year 1998-2001 Performance-Based Rates ("PBR") Plan for the purpose of estimating the applicable incentives under the Capital Incentive Mechanism, the Earnings Sharing Mechanism and the Demand Side Management incentive mechanism. Another incentive mechanism continually monitored by the BCUC during the year was the Gas Supply Mitigation Incentive Plan, which is an incentive for the resale of surplus Firm customer commodity and for mitigation of transport and storage assets to the benefit of both the utility and its customers. The Commission also reviewed UtiliCorp's revenue requirement under its multi-year PBR plan.

---

1 Total expenditure for 2001/02 of $2,520,000 ÷ calendar 2001 energy sales, as shown on pages 48 and 49, converted to GJ.

2001 DOMESTIC GAS SALES
Market Share by Number of Customers

Chart A



2001 DOMESTIC GAS SALES -
Market Share by Revenue

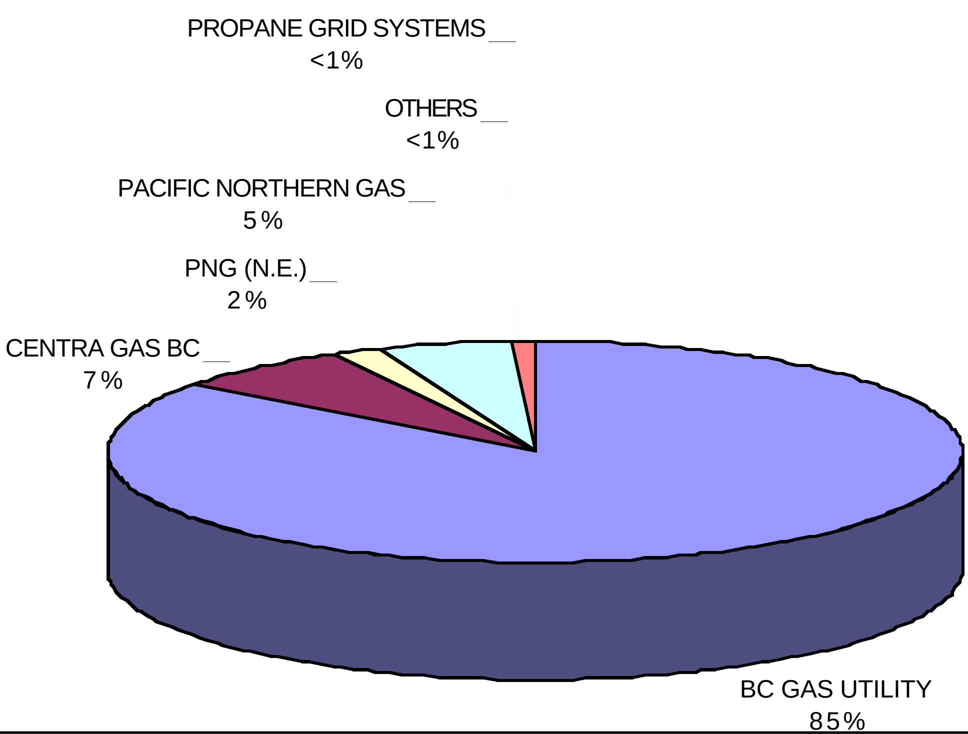


Chart B

Other major rate applications reviewed during the year were PNG's 2001 Revenue Requirements and a related Load Retention Rate Application by PNG's largest customer, Methanex Corporation. The Commission also completed a Rate Design Review for BC Gas by way of a Negotiated Settlement Process in 2001.

Highlights in Electricity

British Columbia's deliveries of electricity by suppliers are shown in Charts C and D.

BC Hydro has over 90 percent of the market share in domestic electricity sales. The legislated rate freeze on electricity rates to all customers was extended during the year for up to another 18 months, until the end of March 2003.

The continental integration of the energy market continued its momentum in 2001. Towards the end of the year, the government's Task Force on Energy Policy issued a draft Interim Report. In the draft report, the Task Force proposed a framework for reform in the electricity markets.

During the year, the Commission continued to explore harmonization, standardization, and streamlining of regulation with other regulators. Some highlights of the functions are:

- Review of Quarterly Reports on Export Trade – Electricity export trade revenues potentially benefit both ratepayers and taxpayers, but also hold the potential for harm to ratepayers. Subsequently, export trade activities are reviewed for the purposes of revenue forecasting; compliance with the code of conduct by non-regulated activities; and oversight of reservoir inflows, market and operating strategy scenarios.

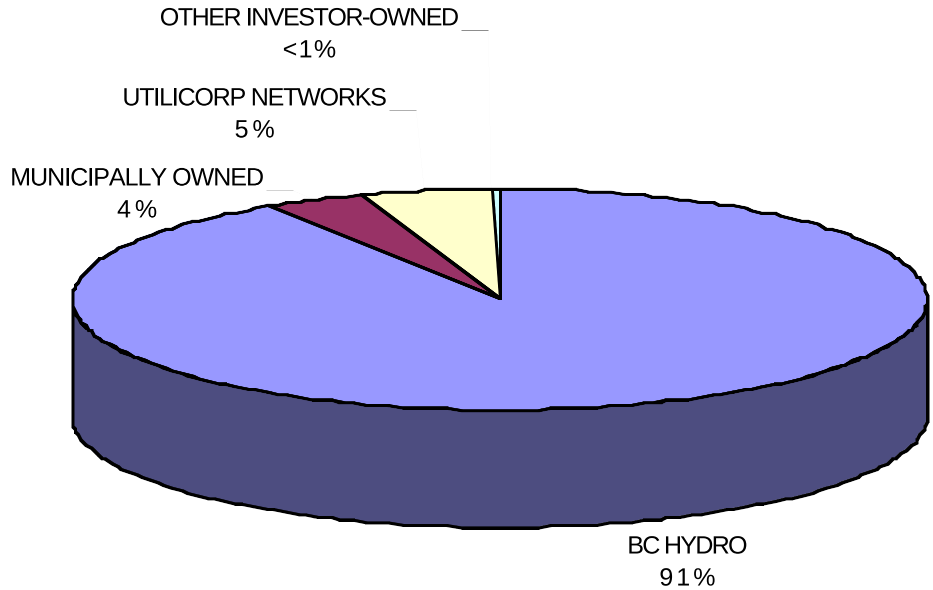
- Review of utilities' proposals to participate in the Regional Transmission Organization ("RTO West") – to ensure an efficient and reliable transmission system in BC with non-discriminatory access and rates.

The Commission convened a hearing to clarify and establish the basis for export market access through the BC Hydro distribution system for cogeneration proposals that would involve greenhouse operations and independent power producers. The Commission approved a set of tolls and tariffs for such access.

The Commission rendered a decision on the transfer of assets by West Kootenay Power (now UtiliCorp Networks) stipulating that the terms of sale must be restructured in order to provide for the sharing of the proceeds with customers. West Kootenay Power subsequently decided not to proceed with the sale.

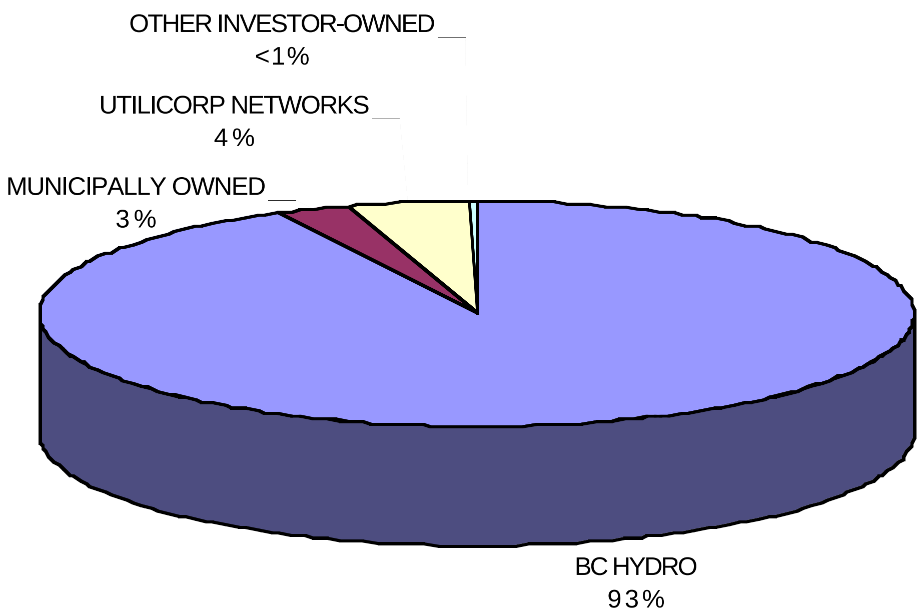
2001 DOMESTIC ELECTRICITY SALES
Market Share by Number of Customers

Chart C



2001 DOMESTIC ELECTRICITY SALES
Market Share by Revenue

Chart D



Report on Performance

The Commission has responsibility for setting rates and ensuring that consumers in British Columbia have access to reliable energy supplies from utilities at just and reasonable prices. The BCUC also has a mandate to deal with customer complaints of unfair treatment by utilities.

To effectively deliver its core business, the Commission has organized its regulatory functions by area of activity that are built on the knowledge of its inter-disciplinary teams. The primary areas of activities are:

(1) Revenue Requirements
(2) Rate Design
(3) Capital Projects Review
(4) Oversight of Energy Commodity Cost and Competitive Market Development
(5) Safety and Reliability
(6) Complaints

It is the aim of the Commission to deliver the above core services in an efficient and effective manner without incurring unnecessary costs and burdensome regulatory requirements. The following tables present the goals, strategies and performance measures that have been established for each of the BCUC's core services and the actual 2001 results of those intended goals and performances. The Strategies, Activities and Performance Measures and Targets are from the Commission's April 2001 Performance Plan. The right-hand column summarizes what was actually achieved, and if applicable, how and why actual results varied from the intended results. This is followed by a table comparing the BCUC's staffing and funding levels, and cost per capita, with similar tribunals in other jurisdictions.

Core Services, Goals, Strategies, Performance Measures/Targets And Actual Results

CORE SERVICE (1): Revenue Requirements

Strategy: The Commission has been a leader in Canada in implementing incentive regulation, which includes quality of service targets and financial incentives, along with requirements to improve customer satisfaction. Multi-year reviews and negotiated settlements have resulted in reduced Commission costs.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Returns on Equity Review aspects of the generic return on equity (ROE) multi-year rate-setting mechanism for investor-own utilities.	• Written hearing process May-September 2001. • Commission Decision, with well-articulated reasons in the Fall, in time for December 2001 Order for 2002 rates of return.	A written hearing was established in June 2001 and completed in September. Commission Order No. G-109-01 with attached reasons was issued in October 2001. The Order provided a minor amendment to the ROE automatic adjustment mechanism. Letter No. L-43-01 dated November 26, 2001 provided the benchmark ROE calculated under the amended formula that was used to establish the actual allowed ROEs for 2002 for the major gas and electrical utilities.
Pacific Northern Gas – 2001 Revenue Requirements PNG's revenues have been severely affected by the Methanex plant closure and its gas rates are becoming less competitive with electricity. Methanex has applied for a load retention rate. An oral public hearing was held in Terrace and Vancouver in March 2001.	• Commission Decision, with well-articulated reasons, by mid-May 2001.	PNG and Methanex continued their negotiations for a mutually acceptable load retention rate based on the principles set out in the Commission's May 2001 Decision. Following a public hearing held in Terrace and Vancouver in March 2002 on the 2002 Revenue Requirement Application, PNG and Methanex reached an agreement on a load retention rate. PNG filed a revised 2002 application, which was reviewed at a second public hearing in May 2002.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
BC Hydro – 2002 Revenue Requirements Rate freeze legislation ends September 30, 2001. BC Hydro's revenue requirements application for 2002 is expected in the fall, followed by an oral public hearing.	• Extensive, thorough oral public hearing process. • Timely Commission Decision with well-articulated reasons. • Public process. • Timely Commission Decision with well-articulated reasons.	No hearing was held as the BC Hydro rate freeze legislation was extended to no later than March 31, 2003.
BC Gas – 2002 Revenue Requirements The multi-year PBR expires in 2001 and BC Gas was expected to file its application in September 2001, followed by an oral public hearing or negotiated settlement process, or both, in November.	• A oral public hearing process or NSP • Timely Commission Decision, with well-articulated reasons.	BC Gas withdrew its application on November 1, 2001 due primarily to its anticipated acquisition of Centra Gas. Following a review of intervenor comments and additional information provided by BC Gas, the Commission approved the withdrawal and directed BC Gas to file its revenue requirements for 2003 by May 31, 2002.
Pembina Oil Pipeline Revenue Requirements and Supervision of Service This common carrier oil pipeline between Taylor and Kamloops suffered a major break in August 2000. Repairs and upgrades may raise tolls, and Pembina wants to shut or sell all or part of the line, possibly affecting the viability of BC's two refineries and netbacks for northeast BC oil producers.	• Extensive, thorough oral public hearing in April 2001. • Commission Decision with well-articulated reasons in June 2001.	The Commission issued a decision on June 26, 2001 (Order No. P-3-01) establishing permanent tolls for Pembina. On August 25, 2001, Pembina applied to the Commission for reconsideration of the Commission's decision and a stay of orders and directions in the decision. This application was subsequently denied by the Commission in its Reconsideration Decision on October 19. A chambers judge further denied Pembina's leave to appeal Order No. P-3-01 and a subsequent application by Pembina to vary the decision to deny the leave to appeal was dismissed by the Court of Appeal on April 11, 2002.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Revenue Requirements for Smaller Utilities Applications for revised revenues are expected from several small utilities, such as Port Alice, Centra Whistler, Sun Peaks, and Stargas.	• Timely review and approval of fair, just and reasonable rates for the utilities in question.	During 2001 the Commission received applications for rate changes from Stargas, Sun Peaks, Squamish Gas, Port Alice Gas, and Sun Rivers. The Commission reviewed the applications and approved rate increases or decreases as appropriate. Interim 2002 rates were set for Centra Whistler, and a regulatory timetable and negotiated settlement process were established to determine permanent rates.

CORE SERVICE (2) Rate Design

Strategy: The Commission undertakes periodic rate design reviews to apportion the revenue requirement fairly to different classes of customer, while ensuring there is no undue discrimination in the rate structures of the utilities. The Commission tries to avoid rate shock to any customer class as it modifies a utility's rate design. The Commission also encourages the development of new services to customers in response to commodity competition and changing customer needs.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
BC Gas Rate Design In February 2001, BC Gas applied for rate design changes and increases resulting from the Southern Crossing Pipeline. A workshop and pre-hearing conference will be followed by a negotiated settlement process, a public hearing, or both.	• Public process (negotiated settlement, oral hearing, or both) commensurate with BC Gas, stakeholder, and Commission's preferences. • Timely Commission Decision, with well-articulated reasons.	Following a workshop and pre-hearing conference, the Commission, at the request of intervenors, directed Commission staff to hire and manage an independent rate design consultant to validate BC Gas' Cost of Service study. Following the circulation of the consultant's report to intervenors and submissions by intervenors to the Commission, a negotiated settlement process was established. By Order No. G-116-01, the Commission approved the resulting negotiated settlement agreement.
Centra Gas Rate Design Centra Gas, on Vancouver Island, becomes subject to conventional cost of service regulation in 2003. It needs to apply for a cost of service allocation method and rate design framework to be used in determining customer class rates. The rate design may also affect tolls to the pulp and paper mills and co-generation plants.	• Oral public hearing, likely in fall 2001. • Timely Commission Decision, with well-articulated reasons.	At year end, Centra had not filed a final rate design application, caused in part by its extensive consultations with stakeholders regarding its cost of service analysis. Centra filed its Cost of Service Allocation Study in May 2002 and has stated that it will file a rate design application by July 30, 2002.
BC Hydro Rate Design High load factor industrial customers have been unable to have their rates reviewed because of the rate freeze. Other alleged rate design inequities are expected to be raised at the revenue requirements proceeding. This may prompt a Rate Design Application from BC Hydro in early 2002.	• Oral public hearing, likely in spring 2002. • Timely Commission Decision, with well-articulated reasons.	On August 21, 2001, the provincial government extended the current freeze on electricity rates to no later than March 31, 2003. This postponed the requirement for a revenue requirements proceeding and delayed the Commission's ability to address potential rate design inequities.

CORE SERVICE (3): Capital Project Reviews

Strategy: The invested plant of a utility may account for up to 75 percent of the utility cost paid by customers. The Commission ensures timely reviews of the capital projects through applications for Certificates of Public Convenience and Necessity, while providing for an appropriate level of public input. The Commission must ensure that utilities take advantage of technological innovations to lower costs to ratepayers and improve the quality of services. These include enhanced customer information systems, turbine/generator improvements, new pipe installation methods and energy efficiency programs that can reduce or delay supply-side capital projects.

Major Activity	Performance Measures and Targets	Actual Results and/or Implications For the Year 2001 and Beyond
Gas Supply to Southwestern British Columbia Regional price spikes may be indicative of an imminent shortfall in gas deliverability to the Lower Mainland/Vancouver Island. If so, solutions may involve new and/or expanded pipelines, and/or LNG storage.	• Problem definition by Commission survey of key utilities and producers. • Directions to BC Gas.	In January 2001, in response to unprecedented price volatility reported by the Sumas Index, the Commission solicited information from regulated utilities and others about the current natural gas market environment. BC Gas, in its response, offered to prepare a report on the natural gas resource balance in the Pacific Northwest. The Commission accepted BC Gas' offer to prepare such a report with a full representation of stakeholders. The report was submitted in July 2001. In August 2001, the Premier of British Columbia established a Task Force to develop an energy policy framework for BC that effectively superseded the need for further Commission review at this time.
Okanagan Electricity Transmission Reinforcement UtiliCorp Networks Canada (formerly West Kootenay Power) supply to the Kelowna-Osoyoos corridor may need to be improved by either a new transmission line from the Kootenays or a new substation connected to the BC Hydro grid.	• Oral public hearing in the service area, in response to UNC's application • Timely Commission Decision, with well-articulated reasons.	UNC recently signed a Memorandum of Understanding with BC Hydro on supply reinforcement issues in the region. UNC intends to file an application by September 2002 to construct the substation.

CORE SERVICE (4): Oversight of Energy Commodity Costs, Services, and Competitive Market Development

Strategy: The Commission must be proactive in the provision of appropriate new services to meet the needs of utility customers. The advent of commodity competition for large natural gas customers led to a myriad of new services and rate options. The same situation is unfolding as competition develops in electricity. The Commission is proposing to implement choice in natural gas supply at the residential level by providing customers with the option of buying gas from marketers, but continuing to be delivered and billed by the utility. The Commission is also implementing new electricity services, including real-time pricing options, price dispatched curtailment options, standby rates, time-of-use rates and green power rates for some residential customers.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Utility Gas Procurement Oversight The Commission requires gas utilities to provide annual gas contracting plans, price risk management plans, and individual supply contracts with producers for approval. With volatile gas costs, the Commission wishes to become more proactive in ensuring utilities plan for reliable supplies at reasonable costs.	• Development and implementation of new Guidelines for quarterly review of gas costs. • Approved Gas Contracting Plans, Price Risk Management Plans, and Supply Contracts for BC Gas, PNG, and Centra. • Approved Gas Supply Mitigation Incentive Plan for BC Gas for 2001/02 gas year. • Periodic hedging program reports showing quantified benefits from BC Gas, PNG, and Centra.	In February 2001 the Commission issued and implemented Guidelines for reviewing and adjusting, if necessary, gas utilities' gas cost recovery rates on a quarterly basis. On June 11, 2001 the Commission accepted PNG's Gas Contracting Plan and Gas Supply Price Management Plan for the 2001/02 period subject to certain conditions (Letter No. L-16-01). On June 12, 2001 the Commission accepted the 2001/02 Gas Supply Annual Contracting Management Plan of BC Gas subject to the utility filing additional information and BC Gas' Gas Price Management Strategy (Letter No. L-15-01). On June 11, 2001, the Commission accepted Centra's 2001/2002 Gas Contracting Plan and 2001/2002 Gas Supply Management Program for the year ending October 31, 2002 (Letter No. L-17-01). On November 15, 2001, the Commission approved a new Gas Supply Mitigation Incentive Plan for BC Gas (Order No. G-124-01). The Commission also reviewed and provided feedback to the utilities on several hedging reports.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Agent Billing and Collection for Transportation Service Option Gas utility customer information systems will soon enable non-utility suppliers to offer various price and term options for small customers who wish to buy gas from brokers and marketers. The BCUC, BC Gas, marketers, and consumer representatives are working towards implementation in late 2002.	• Target date for introduction is November 2002. • Code of conduct and consumer protection legislation (licensing and bonding) by summer 2002. • Resolution of franchise fee issue with local governments by summer 2002.	The Commission accepted BC Gas' deferred implementation date (Letter No. L-6-01) in view of the fact that changes to the UCA would be necessary. Because licensing and bonding of marketers are considered to be prerequisites to service unbundling, the Commission will continue to communicate with the Ministry of Energy and Mines on the proposed legislative changes. The Commission submitted a Request for Legislation with draft UCA amendments in the summer of 2001.
BC Hydro Export Trade Electricity export trade revenues potentially benefit both ratepayers and taxpayers. Export trade activities need to be reviewed for the purposes of revenue forecasting, compliance with the code of conduct by non-regulated activities, and oversight of reservoir inflows, market, and operating strategy scenarios.	• Quarterly Reports on Export Trade, including actual and forecast trade costs, revenues, forward commitments, reservoir levels, market prices, and operating strategies under a variety of scenarios of reservoir inflows and market prices.	The Commission directed BC Hydro on the information to be included in its quarterly reports (Letter No. L-4-01). The Commission reviews the reports as filed.
West Kootenay Power Sale of Generation Assets to Columbia Power WKP wants to sell its four Kootenay River hydro plants to companies held by Columbia Power and the Columbia Basin Trust. The BCUC must review the proposed sale to determine if it is in the interests of WKP's ratepayers.	• Oral public hearing in the service territory in late May 2001. • Timely Commission Decision, with well-articulated reasons.	The hearing adjourned in mid-July. The Commission rendered its Decision on October 26, 2001 by Order No. G-112-01. The Commission declined to approve the transfer of assets unless the conditions stipulated were met. WKP sub-sequently abandoned its intention to transfer the assets.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Transmission and Distribution System Access Distributed generation proponents are requesting access to BC Hydro's distribution and transmission system in order to sell electricity within or outside BC. In response to concerns and complaints from Independent Power Producers (IPP), BC Hydro's Wholesale Transmission Services tariff may also warrant review and fine-tuning.	• Oral public hearing on distributed generation access in May 2001. • Timely Commission Decision, with well-articulated reasons.	At the conclusion of the hearing, the Commission established, in June 2001, a set of rates and conditions for access to the distribution system by IPPs (Order No. G-52-01). The Commission further ordered a report on the use of the distribution system by IPPs and the costs and benefits of distributed generation to the transmission system to be filed by December 31, 2002.
Electricity Sales by Self-Generators Large industries (mostly pulp mills) with self-generating capacity want to sell their power at market prices, perhaps taking their increased load requirements from BC Hydro at (lower) regulated rates. This is the most recent example of market-related proposals that raise obligation-to-serve and tariff interpretation issues.	• Develop a new tariff, tariff supplement, or Commission Guidelines after due process, provided the initiative is consistent with government policy and legislation.	The Commission directed BC Hydro to allow industrial customers with idle self-generation capability to sell excess self-generated electricity, provided the self-generating customers do not arbitrage between embedded cost utility service and market prices (Order No. G-38-01). By the same Order, BC Hydro is not required to supply any additional power at its embedded cost of service to any customer selling self-generating output to the market.
Regional Transmission Organization Formation The formalization of "RTOs" in the United States is meant to increase system operating efficiencies (i.e. lower costs) and improve reliability (i.e. reduce outages). BC Hydro and WKP may propose transfer of operational control of their transmission systems to a BC Independent Grid Operator, which would be a public utility regulated by the BCUC, in part to participate more effectively in the RTO being established in the western U.S.	• Review of any proposals to participate in RTO West, to ensure BC electricity customers benefit.	During 2001, the Commission continued to monitor and participate in discussions about the specific structure the RTO West would take, and its effects on electricity policy and regulation. The Commission is a member of the newly formed Western Electricity Coordinating Council.

CORE SERVICE (5): Safety and Reliability

Strategy: Utility equipment should be designed, operated, and maintained to provide safe and reliable service to customers. Some of the natural gas and electricity plant is aging to the point where increased inspections, maintenance, and renewal plans are required.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
BC Gas System Reliability The Commission is working with BC Gas to develop a strategy for inspection of critical parts of its system, which are more than 40 years old.	• Approve a multi-year plan for system inspection.	The Commission approved Transmission Pipeline Integrity Plan expenditures for the Year 2001 and 2002 work program (Order No. C-15-01). In March 2002, the Commission accepted BC Gas' report on 2001 activities and approved additional expenditures for 2002 and 2003. The Commission reviews individual safety related incidents.
BC Hydro – Vancouver Island Supply to Vancouver Island is becoming constrained and some existing undersea cables are becoming unreliable. New resources (e.g. gas pipeline, conductors, and/or on-island generation) appear to be lagging behind load growth.	• BC Hydro has been directed to review its plans for use of the Port McNeill Keogh Plant, and report on both the status of undersea cables and the Georgia Strait natural gas line proposal.	The Georgia Strait Crossing Pipeline project is before the federal National Energy Board and the BCUC is an inactive intervenor. The report on the status of undersea cables was filed with the Commission and reviewed.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
BC Gas and West Kootenay Power Performance Measures The multi-year settlements of revenue requirements include financial incentives, which can only be earned if safety and reliability targets are met.	• Measure annually the performance of utilities against the safety and reliability targets. • Develop new safety and reliability measures with input from customers and utilities to broaden the targets when new issues are identified.	The Commission approves electric utilities' membership and agreements (e.g. Reliability System Agreement, Reliability Criteria Agreement) with the Western Systems Coordinating Council (now Western Electricity Coordinating Council), an organization responsible for coordinating and promoting electric system reliability. Specific safety and reliability targets are regularly incorporated into negotiated settlements adopting performance-based regulation. The utility's results are reviewed in annual reviews attended by Commission staff, customer groups and other interested parties.

CORE SERVICE (6): Complaints

Strategy: The Commission has a mandate to deal with customer complaints of unfair treatment by utilities. It must be respectful of complainants and seek resolution of the issues presented where they fall under the jurisdiction of the Utilities Commission Act. The Commission must continue to seek out ways to respond to and rule on complaints fairly and efficiently, while balancing the needs of the complainant, other customers, and the utility.

2001/02 Complaints Major Activities, Performance Measures, and Targets

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Complaints Handling Review The Utilities Commission Act gives the Commission considerable latitude in acting on complaints. Current procedures are articulated in its "Complaints Handling" pamphlet. As the number and complexity of complaints trends upwards, the Commission plans to review its complaint management process, including the resources it allocates to resolve complaints and the ways it communicates its decisions on complaints.	• "Complaints Management Review" Report by April 2002. • In future stakeholder assessments, improved satisfaction levels by complainants with the clarity of the Commission's explanations.	In 2001 the Commission dealt with 2,490 complaints and inquiries, a decrease of 13 percent over the previous year. The decrease is directly attributable to the commodity price decreases in natural gas that occurred after March 2001. As the commodity price declined, so did the number of customer complaints and inquiries received. In order to be responsive to customer needs, the Commission prepared, at each calendar quarter, a detailed information package that explained the commodity cost trends and reasons. The quarterly packages included a detailed letter explaining why the commodity cost of gas had changed (both increases and decreases), a Commission News Release, Backgrounder prepared by BCUC Staff and a comparative rates table for residential consumption by utility service area. The gas price information was also posted to the Commission's web site. The Commission did not complete the Complaints Management Review report in 2001/02 fiscal year due to the large number of complaints handled by staff. The Commission expects the report to be completed in the next fiscal year.

Organizational Efficiency and Effectiveness

Strategy: The Commission is a small, results oriented organization that strives for constant improvement in its work processes. This is why service delivery was maintained or improved during down-sizing in the 1980s and early 1990s. Most public utility tribunals with comparable responsibilities have significantly larger budgets and staff (e.g. in-house lawyers, communications/media relations staff, complaints investigation sections). The Commission must remain vigilant in anticipating, planning for, and managing changes to its organizational structure to meet its goals and objectives.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Performance Indicators The Commission reports annual performance indicators dating back to 1987 in its Annual Reports, including annual staffing levels, orders issued, hearing days, alternative dispute resolution days, commission expenditures, commission costs per customer, and commission costs per gigajoule of energy sold. While these individual indicators do not necessarily measure how efficiently or effectively the Commission meets its mandate, collectively they do reveal important trends.	• Maintain Commission budgets and core expenditures at current levels, adjusted for inflation, as measured by costs per utility customer and costs per unit of energy sold. • Continue to collect annual statistical indicators to discern trends.	In 2001, the cost of regulation per GJ of energy sold is 0.6 cents and the cost of regulation per customer is $0.95. The cost of regulation per customer increased in 2001 from $0.88 largely due to the increased number of hearing days. The BCUC has the lowest cost per capita among all provinces surveyed. (See table following this section.)
Document Logging and Tracking The Commission receives thousands of documents by mail, fax, courier and e-mail, ranging from complaint "form letters" to multi-volume utility applications. The current manual recording and tracking method is no longer efficient.	• Procure, install, train staff, and use a computer-based document logging, tracking and assignment system by November 2001.	In October 2001 the CLIFF database tracking software was installed and training sessions took place for nine staff members. As of March 31, 2002, over 900 document entries had been made. The current status of correspondence and applications is monitored by the Assistant Commission Secretary who brings outstanding items to the attention of staff. The new system allows staff to track items by department or by staff member, and established due dates.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Review and Revise Commission Processes and Programs Periodic reviews of Commission policies, procedures, programs, processes, and generic decisions are necessary to ensure they remain timely, effective, and efficient.	• Monitor the effectiveness of changes to the Commission's March 2001 "Negotiated Settlement Process: Policy, Procedures, and Guidelines". • Monitor Participant Assistance / Cost Award claims and approved payments for necessity and reasonableness, and amend published Guidelines as may be necessary.	Since the revisions to the NSP Guidelines, two utility applications have been resolved through negotiated settlements. No further revision is required at this time. The Participant Assistance / Cost Award guidelines were amended in February 2001. Since that time ten cost awards have been approved. No further revision is required at this time.
Review Job Descriptions and Compensation Levels With its emphasis on teamwork, complementarily among the BCUC's units, and an approach based on results, each person's responsibilities need to be clearly defined and each senior manager should have the opportunity for compensation increases based on meritorious performance.	• Review and revise each position's job description by December 2001. • Complete a compensation review for Commission administrative support, professional, and middle management staff positions.	Revised draft job descriptions were completed but have not yet been finalized, pending completion of the Core Services Review process. A compensation review was deferred to fiscal 2002 / 03 pending receipt of the new compensation mandate from the Public Sector Employers Council Secretariat / Crown Corporation Employers Association.

Major Activity	Performance Measures and Targets	Actual Results and / or Implications For the Year 2001 and Beyond
Regulatory Convergence and Cooperation Participate in provincial, national, and North American initiatives that promote information sharing, joint processes, reduced duplication, best practices, and common regulatory principles.	• Lead Canadian regulatory tribunal input into Energy Ministers' Task Force on Energy Pipeline Regulation. • Participate in Canadian Association of Members of Public Utility Tribunals ("CAMPUT"), the Committee on Regional Electric Power Cooperation, and other organizations promoting efficient and effective energy utility regulation.	The Commission chaired a group of federal and provincial energy pipeline regulators and prepared a report for the Energy Minister's Task Force for consideration at the September 2001 Energy Ministers' meeting. The report supports ways to improve the efficiency, effectiveness and jurisdictional certainty of pipeline regulation in Canada. The Commission represented BC regulatory interests at meetings of the Committee on Regional Electric Power Cooperation and the Western Electricity Coordinating Council. The Commission also organized the annual CAMPUT Education Conference at Whistler in the Spring of 2002.

Comparisons with Other Jurisdictions

The table below compares the BCUC with utility regulators in other jurisdictions, in terms of number of staff, budget and cost per capita of energy utility regulation. By these standards, the BCUC is the most efficient energy regulator in Canada, operating at costs and levels which are significantly lower than comparable tribunals.

Prior to 2001, the Ontario Energy Board regulated a similar complement of natural gas utilities and had no responsibilities to regulate Ontario Hydro. At that time they employed a staff of approximately 55. In 2001, the Ontario Energy Board doubled its staff as a result of that province's electricity restructuring. The Ontario Energy Board now has five times the staff and budget of the BCUC.

The Quebec Régie de l'énergie is comparable with the BCUC as it regulates natural gas utilities and has some responsibilities with respect to Hydro Quebec. It also monitors gasoline prices. The BCUC is one-third the size and less than half the cost of the Quebec Régie.

The Alberta Energy and Utilities Board is less comparable to the BCUC because it has a large staff involved in the upstream oil and gas activities. It has a staff complement of 32 to deal with the electric and gas utilities in Alberta. The National Energy Board regulates large natural gas and oil pipelines but has very limited responsibilities for electricity. The National Energy Board also provides forecasting and market monitoring functions.

Utility tribunals in Manitoba and the Atlantic Provinces have additional responsibilities (primarily auto insurance regulation), although with the exception of Nova Scotia, most of their resources are allocated to energy utility regulation. The Utilities and Transportation Commission in Washington state ("WUTC") also has a variety of regulatory responsibilities in addition to energy regulation, including telecommunications, household moving, private solid waste, private ferry and private bus companies. The WUTC devotes about 14 percent of its budget of $31.9 million (U.S.) to gas and electric utility regulation. The Bonneville Power Administration and several rural and municipal utilities (e.g. Seattle City Light) are outside WUTC jurisdiction.

The energy regulatory innovations implemented by the BCUC have allowed it to become dramatically more efficient and effective in delivering regulatory services in British Columbia compared to any other jurisdiction. The regulatory expertise of the small complement of ten professional staff at the Commission is highly sought after and the Commission provides regulatory staff services to Yukon and Saskatchewan on a consulting basis. This revenue is used to further reduce the cost of regulation to British Columbians. There is little duplication in skills of the Commission's professional staff. For example, there is only one electrical engineer and only one energy commodity expert.

COMPARISONS WITH OTHER JURISDICTIONS

	Members	Staff	Budget	Energy Utility Regulation: Cost per Capita[i]
BC Utilities Commission	1 full-time Chair 4 Temporary Commissioners	19	$3.3 million, fully cost recovered	$0.81
Alberta Energy and Utilities Board	8 full-time Members, including Chair	32 "utilities" staff 728 "oil and gas" staff	$94.0 million, 78% cost recovered, 22% funded by government est. $4.0 million for energy utility regulation	$1.31
Washington Utilities and Transportation Commission[ii]	1 full-time Chair 2 full-time Commissioners	169 includes 15 in Energy sector	$31.9 million fully cost recovered est. $4.3 million for energy utility regulation	$0.74 (U.S.)
The Public Utilities Board, Manitoba[iii]	1 full time Chair 7 part-time Members	6	$5.82 million fully cost recovered est. 65% for energy utility regulation	$3.29
Ontario Energy Board	8 full-time Commissioners, including Chair and 2 Vice Chairs 8 part-time Commissioners	101	$20.3 million, fully cost recovered	$1.74
Quebec Régie de l'énergie	7 full-time Commissioners, including Chair 2 part-time Commissioners	66	$7.2 million, fully cost recovered	$0.98
New Brunswick Board of Commissioners of Public Utilities[iv]	1 full time Chair 1 part-time Vice Chair 8 part time Commissioners	16	$1.27 million fully cost recovered est. 80% for energy utility regulation	$1.35

	Members	Staff	Budget	Energy Utility Regulation: Cost per Capita
Nova Scotia Utility and Review Board[v]	1 full time Chair 1 full time Vice Chair 8 full time Members	31	$3.4 million 33% cost recovered, 67% funded by government est. 24% for energy utility regulation	$0.86
Newfoundland Board of Commissioners of Public Utilities[vi]	3 full-time Commissioners, including Chair and Vice Chair 5 part-time Commissioners	10	$1.7 million, fully cost recovered est. 70% for energy utility regulation	$2.22
National Energy Board	8 full-time Members, including Chair and 2 Vice Chairs 6 part-time Members	281	$30.0 million, 90% cost recovered, 10% funded by government	Not Comparable

____

i The annual budget (BC, Ontario, Quebec), or the portion of the budget devoted to energy utility regulation (Washington, Alberta, Manitoba, New Brunswick, Nova Scotia, and Newfoundland), divided by the population of the province or state.

ii $U.S. for Washington Utilities and Transportation Commission. WUTC also regulates household movers, some telephone companies, private ferries, some bus companies, and private disposal companies. Energy utility staff and budget statistics exclude overhead, administration, and legal costs. Many Washington energy utilities are municipally or federally regulated (e.g. Bonneville Power Administration, Seattle City Light).

iii The Manitoba Public Utilities Board contracts for most legal, accounting, and engineering services. It also regulates car insurance, some water and sewer utilities, private cemeteries, and funeral home services.

iv New Brunswick Board staff has quadrupled in response to regulation of natural gas and car insurance.

v Nova Scotia Board resulted from merger of five boards with the former Public Utilities Board, now including water utilities, some buses, criminal injury compensation, assessment appeals, land-use appeals, and tax reviews.

vi Newfoundland Board also regulates car insurance.

Financial Report

Commission Recovery and Expenditure Summary

Authority for Cost Recovery

Beginning in 1988, the Commission was authorized to recover its costs from regulated utilities and pipeline companies by fixing levies according to Section 125 of the *Utilities Commission Act* and parameters set out in the Levy Regulation (BC Reg. 283/88). The Commission recovers most of its costs from a "per gigajoule" levy assessed on each utility, based on the amount of energy it sold in the previous calendar year. The Commission also bills utilities for its hearing costs that are attributed directly to those utilities. Direct recoveries have varied significantly from year to year, depending on the number and duration of regulatory hearings and inquiries. Minor revenues are also collected from intraprovincial petroleum pipeline companies and from other utility regulatory agencies that contract with the Commission for advice and assistance.

Levy 2001/02

The Commission is often able to underspend its annual budget due to the successes it has experienced in streamlining its proceedings and encouraging multi-year performance-based ratemaking through negotiated settlements. The fixed and recurring costs of the Commission are approximately $2.5 million, with added costs resulting from increased hearing loads. Additional hearing days may occur due to referrals of issues by government (e.g. Kemano Completion Project) or unusually complex regulatory issues requiring hearings (e.g. WKP's proposed sale of hydroelectric assets). Although the cost of hearings are typically recovered from applicants, the out-of-pocket costs for legal services, court reporting and consultants also show in the Commission's expenditures.

The Commission’s fiscal year runs from April 1 to March 31. The voted expenditure for the 2001/02 fiscal year was $3,294,000. Of this, $363,000 was forecasted to be recovered directly from utilities for Commission expenditures attributable to their public hearings and other proceedings under the Act. This left a net annual budget of $2,931,000 to be recovered from the levy, as identified in the formula below.

$$\frac{\text{Total Budgeted Expenditures } \textbf{minus} \text{ estimated Direct Recoveries (\$)}}{\text{Total Utility Energy Volumes sold in previous calendar year (GJ)}} = \frac{\$2{,}931{,}000}{436{,}759{,}052 \text{ GJ}} = \$0.00671079/\text{GJ}$$

The Commission’s costs were therefore expected to be recovered from a levy of $0.00671079/GJ for the fiscal year beginning April 1, 2001, payable in four quarterly installments. The levy for the last quarter of fiscal year 2000/01 (i.e., January 1 through March 31, 2001) was $0.006782/GJ.

Levy Billing Adjustments

Lower than forecasted Commission expenditures in the 2000/01 fiscal year resulted in a year-end credit from 2000/01 levy payments received of $147,485.38. This amount was credited to the utilities in their first quarter billing for 2001/02. The second, third and fourth quarter billings were at the full levy rate of $0.00671079/GJ. An actual end of fiscal year 2001/02 surplus of $711,837.82 will be credited to utilities in the first quarter levy invoices in 2002/03.

2001/02 Revenues and Expenses

Levy billed and Recoveries received in 2001/02		$3,080,914.47	
Add: Deferred Revenue from 2000/01 Levy		147,485.38	
Total Recoveries (see below)			**$3,228,399.85**
Less:	Expenditures (see below)	2,515,562.03	
	Government Voted Appropriation	1,000.00	2,516,562.03
Revenue deferred to 2002/03			**$711,837.02**

The levy amounts recovered from utilities and other revenue sources for the 2001/02 fiscal year are as follows:

Commission Revenues Recovered Through the Levy (Order No. G-48-01)	**Amounts Recovered 2001/02 Fiscal Year (Actual)**
British Columbia Hydro and Power Authority	$ 1,073,714.00
BC Gas Utility Ltd.	
- Lower Mainland Division	808,659.00
- Inland Division	390,484.00
- Columbia Division	49,664.00
- Fort Nelson Division	5,250.00
Centra Gas British Columbia Inc.	175,151.00
Centra Gas Whistler Inc.	4,342.00
Central Heat Distribution Limited	7,005.00
Corporation of the City of Nelson	1,124.00
Hemlock Valley Electrical Services Limited	24.00
Pacific Northern Gas Ltd.	183,933.00
Pacific Northern Gas (N.E.) Ltd.	
- Dawson Creek and Fort St. John	32,528.00
- Tumbler Ridge	5,136.00
Port Alice Gas Inc.	121.00
Princeton Light and Power Company, Limited	977.00
Silversmith Power & Light Corporation	0.00
Squamish Gas Co. Ltd.	3,137.00
West Kootenay Power Ltd./UtiliCorp Networks Canada (British Columbia) Ltd.	42,261.00
The Yukon Electrical Company Limited	14.00
Sun Peaks Utilities Co., Ltd.	364.00
Sun Rivers Services Corp.	12.00

Recoveries from Intra-Provincial Oil Pipeline and Other Companies

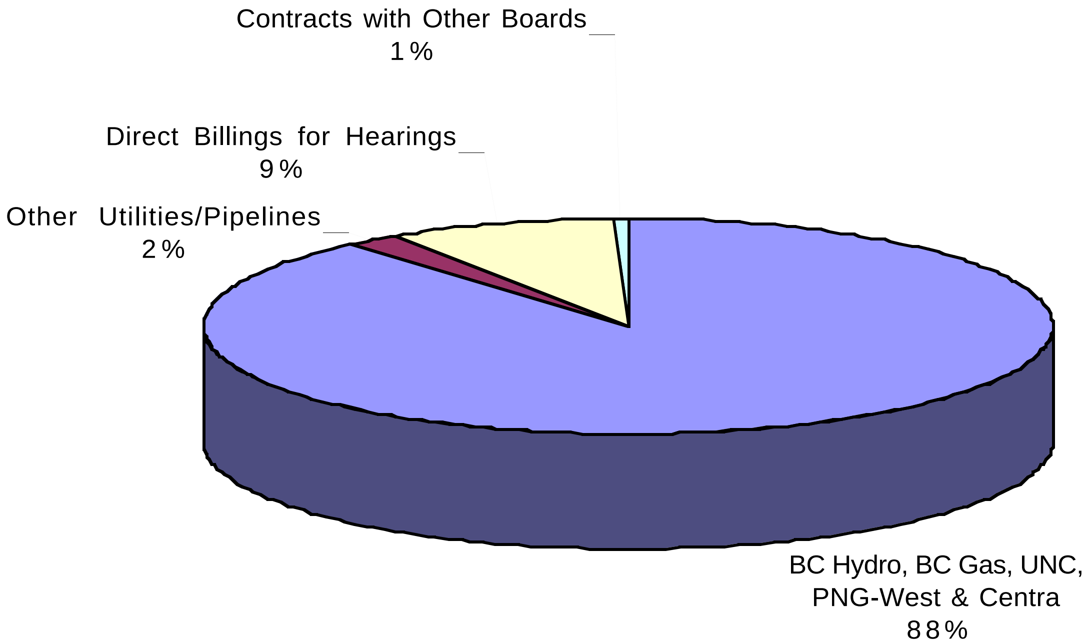
Canadian Midstream Services	1,000.00
Coastal Canada Field Services	1,000.00
EnerMark Inc. (formerly Newcal Energy Inc.)	1,000.00
JJH Equipment Trust	1,000.00
Plateau Pipe Line Ltd.	6,000.00
TransCanada Gas Pipeline Ltd. / Williams Energy Canada Ltd.	1,000.00
Trans Mountain Enterprises of British Columbia Limited	1,000.00
Westcoast Gas Services Inc.	1,000.00

Miscellaneous Revenues

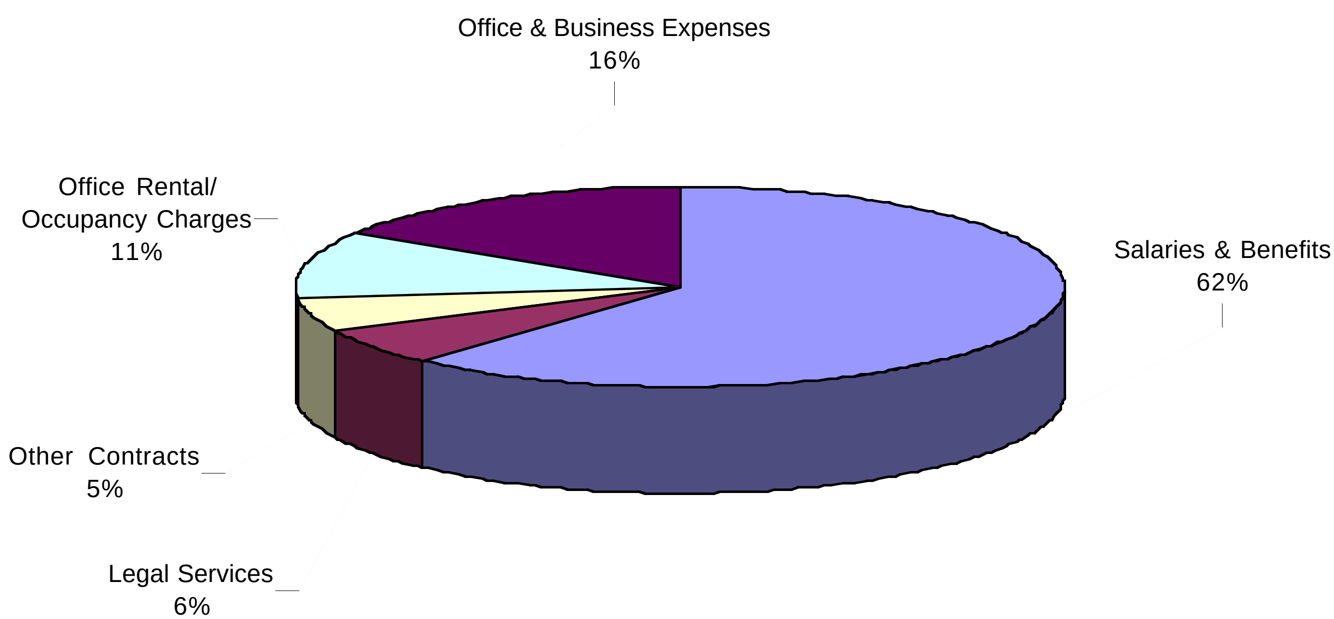
Commission Contracts with:	
- Yukon Utilities Board	3,056.00
- Government of Saskatchewan	12,798.51
Recovery of Proceeding Costs from Utilities	265,952.67
Recovery of Room Rental and Photocopying Costs	799.00
Other Recoveries	1,408.29
Deferred Revenue from 2000 / 01 (credited to utilities' first quarter billing in 2001 / 02)	147,485.38
TOTAL REVENUES	**$ 3,228,399.85**

Commission Expenditures per Expense Category	**Amounts Spent 2001/02 Fiscal Year (Actual)**
Commission and staff salaries and benefits	$ 1,551,068.44
Commission fees and expenses	137,463.92
Travel	55,226.43
Professional Services	287,887.26
Information Systems	58,222.21
Office and Business Expenses	91,717.97
Advertising and Publications	11,683.05
Materials and Supplies	1,125.22
Amortization	47,380.21
Leasehold and Occupancy Charges	273,787.32
TOTAL EXPENDITURES	**$ 2,515,562.03**

REVENUES



EXPENDITURES



Corporate Governance

The *Utilities Commission Act* provides for a Chair, one or more Deputy Chairs, up to seven Commissioners [including the Chair and Deputy Chair(s)], and temporary Commissioners. As of May 2002, there are four temporary Commissioners and the Chair. The Deputy Chair position is currently vacant. The Commission staff of 19 is made up of professional engineers, accountants, economists, and administrative staff. The Commission's annual budget ranges between $3.0 and $3.5 million, with costs being recovered through a levy on the public utilities it regulates.

Over the last decade, the Commission has successfully reorganized, downsized, and reduced its costs. Over the same period the Commission has increased the effectiveness of its regulatory methods in an increasingly competitive world.

Following are brief biographies for Commissioners and temporary Commissioners serving in 2001:

Peter Ostergaard, Chair

Queen's University, 1973 [B.A. (Honours) Geography and Economics]; University of British Columbia, 1976 (M.A.); Member, Canadian Institute of Planners; 1990-96 Assistant Deputy Minister, Energy Resources Division, Ministry of Energy, Mines and Petroleum Resources; 1996-97 Assistant Deputy Minister, Energy and Minerals Division, Ministry of Employment and Investment; January, 1998 appointed Chair of the British Columbia Utilities Commission; January 1999 reappointed Chair for a three-year term.

Kenneth L. Hall, Temporary Commissioner

University of Saskatchewan (B.E.), Professional Engineer, Trans Mountain Pipe Line Company (30 years) retired 1983 as President, C.E.O. and Chairman of the Board; Honorary Life Member Canadian Petroleum Association; appointed December, 1989.

Paul G. Bradley, Temporary Commissioner

Cornell University, 1956 (B. Chemical Engineering); Massachusetts Institute of Technology, 1966 (Ph.D. Economics); Postdoctoral Fellow, Sloan School of Management, MIT (1969-70); Visiting Scholar, Centre for Energy Policy Research, MIT (1978-79); Director, Mineral Revenues Inquiry, State of Western Australia (1984-86); Resident Consultant, Dept. of Energy, Mines & Resources, Ottawa (1987), Professor Emeritus, University of British Columbia (1965-96); appointed September, 1992.

Nadine F. Nicholls, Temporary Commissioner

University of British Columbia, 1976 (B.Sc. Mathematics); University of British Columbia, 1982 (M.Sc.); rates economist, British Columbia Hydro and Power Authority (1980-83); electricity utilities advisor, Government of the Northwest Territories (1990-92); energy policy consultant in the Northwest Territories (1993-98); appointed March 2000.

Richard (Kim) R. Deane, Temporary Commissioner

University of British Columbia (B.A. Sc. Electrical Engineering), Professional Engineer, Distribution Engineer, Wellington, New Zealand (1965), mine design and construction with M.A. Thomas & Associates (1966-68) and Placer Development (1968-72), Manager, Transmission and Distribution, West Kootenay Power Ltd. (1976-81) and Manager, Energy and Services, Cominco Trail (1982-00); appointed Temporary Commissioner in March 2001.

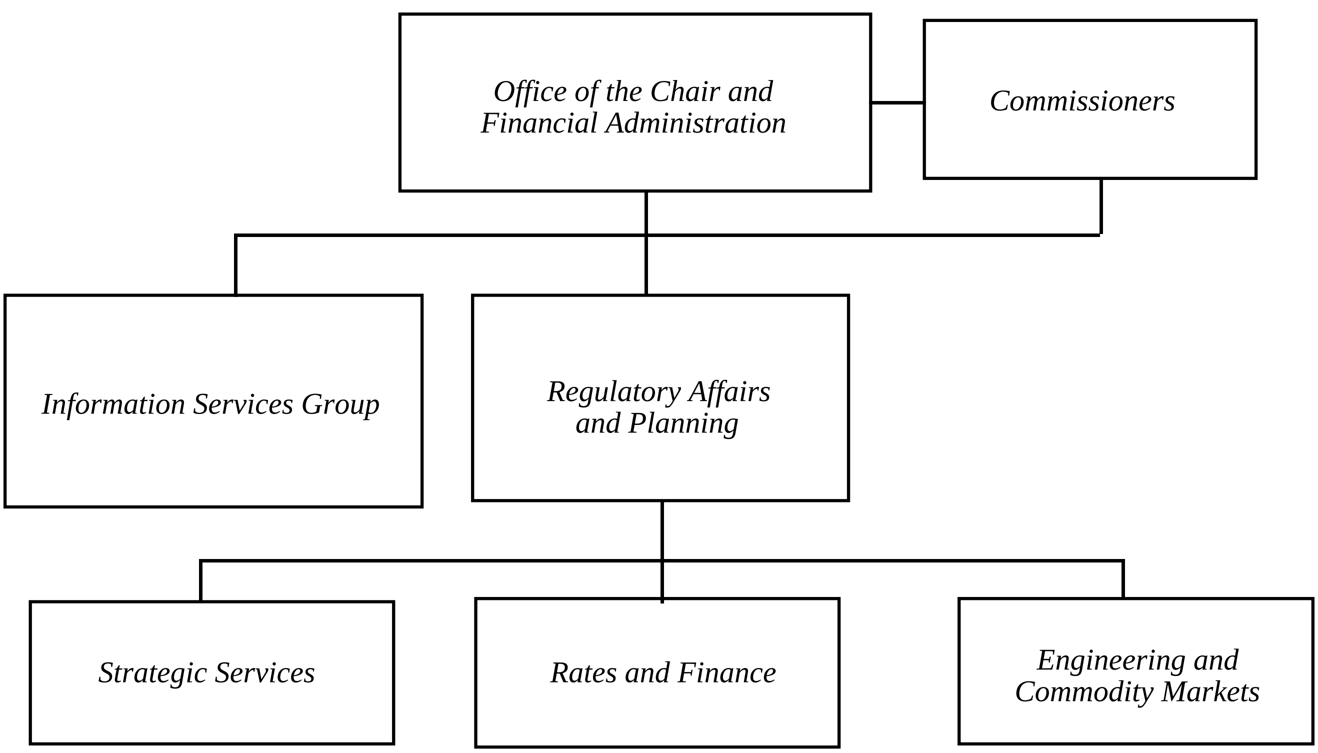
Barbara L. Clemenhagen, Temporary Commissioner

University of Victoria, 1994 (B.Com.), Principal, Koi Strategies Company; Marketing / Operations Manager and Consultant, Willis Energy Services (1996-98); Consultant, BC Hydro and Power Authority (1993-95); Vice-Chair of the Canadian Institute of Energy – Vancouver Branch; appointed March 1999. In December 2001, Ms. Clemenhagen left the Commission to join Sempra Energy in San Diego, California.

Elizabeth J. Rowbotham, Temporary Commissioner

University of Calgary (B.A. Economics), University of Saskatchewan (LL.B), University of London, UK (LL.M.); Member of the Law Societies of Alberta (1990), British Columbia (1996), and England and Wales (1994); Senior Research Associate, Centre for Social and Economic Research on the Global Environment, UK (1992-94); Consultant, OECD (1995); private legal practice (1997-01); appointed April 2001. In November 2001, Ms. Rowbotham left the Commission to join the Ministry of the Attorney General.

The organization chart below shows the reporting structure within the Commission.



The Commission staff is divided into three groups:

- **Information Services Group**

Consists of the Commission Secretary and the Information Services Group. The Commission Secretary acts as the official contact for both regulated utilities and the public. The department responds to all information requests (including Freedom of Information requests), prepares Annual Reports and quarterly Regulatory Updates, provides in-house computer services, media interaction, maintains the Commission's database of mailing lists, and library services. It also deals with utility customer complaints and operates and maintains the Commission's information resources.

- **Regulatory Affairs and Planning**

Consists of professional staff with expertise and experience in the areas of accounting, economics, ratemaking, and engineering. The regulatory affairs and planning functions of the Commission include the review of energy supply and demand, conservation, financial, accounting, social and economic impacts and the safety aspects of energy production, transmission, and distribution. In considering a matter under review by the Commission, staff have a responsibility to develop a full record of evidence. This often requires that staff be technical advisors to the Commission, and also provide external expert witnesses to testify at hearings.

- **Office of the Chairperson and Financial Administration**

Conducts background research and prepares decision support for management policies and decisions in areas such as personnel and financial management, budget preparation, internal policies, external relations with government, other agencies, utilities and the public. Also provides a range of administrative, financial and human resource services to the Commissioners and staff.

Following is a list of the Commission staff as of May 2002, their positions, and departments.

Office of the Chair and Financial Administration

Marilyn E. Donn	Assistant to the Chair and Deputy Chair / Manager, Financial Administration
Monique Oakes	Financial Assistant / Stenographer

Commission Secretary's Office and Information Services Group

Robert J. Pellatt	Commission Secretary
Constance M. Smith	Assistant Commission Secretary / Administrator, Computer Services
Alison H. Cormack	Information Services Officer
Debra L. Frank	Stenographer
Lisa D. Morris	Stenographer
Yvonne M. Lapierre	Stenographer / Receptionist

Regulatory Affairs and Planning

William J. Grant	Executive Director
Rose Tomen	Stenographer

Strategic Services

James W. Fraser	Manager
Eileen Cheng	Senior Economist
Vacant	Senior Economist

Rates and Finance

Barry McKinlay	Manager
John J. Hague	Senior Financial Analyst
Philip W. Nakoneshny	Senior Financial Analyst

Engineering and Commodity Markets

J. Brian Williston	Manager
Robert W. Rerie	Senior Electrical Engineer
Robert N. Brownell	Senior Commodities Analyst

Highlights, Accomplishments and Anticipated Events

2001 Regulatory Highlights

Regulatory proceedings before the Commission included:

- » Pacific Northern Gas Ltd. - October to December 2000 Rates and 2001 Revenue Requirements (Decision dated May 25, 2001; Order No. G-51-01)

- » British Columbia Hydro and Power Authority - Independent Power Producers Bypass Guidelines – Application by BC Hot House Growers Association (Decision dated June 1, 2001; Order No. G-52-01)

- » Plateau Pipe Line Ltd. / Pembina Pipeline Corporation
  (1) Taylor to Kamloops Permanent Tolls (Decision dated June 26, 2001; Order No. P-3-01)
  (2) Application for Reconsideration of the Commission's June 26, 2001 Decision and Order No. P-3-01 on the Taylor to Kamloops Permanent Tolls (Decision October 19, 2001; Order No. P-5-01)

- » West Kootenay Power Ltd.[1] / UtiliCorp Networks Canada (British Columbia) Ltd. - Application to Sell Hydroelectric Generation Assets (Decision dated October 26, 2001; Order No. G-112-01)

- » British Columbia Hydro and Power Authority - Access Principles for Public, Municipal and Other Utilities (Order No. G-11-01; Reasons for Decision)

- » British Columbia Hydro and Power Authority - Complaint on the Transmission Capacity to Serve the District of Fort St. James (Order No. G-60-01; Reasons for Decision)

- » British Columbia Hydro and Power Authority - Complaint by Sumas Energy 2, Inc., regarding BC Hydro's Wholesale Transmission Service Tariff (Order No. G-69-01; Reasons for Decision)

- » Pacific Northern Gas (N.E.) Ltd. - Fort St. John / Dawson Creek and Tumbler Ridge Divisions - 2001 Revenue Requirements (Order No. G-72-01; Reasons for Decision)

- » British Columbia Hydro and Power Authority - Application for a Market-Based Rate for Self-Generation Output Sold to Market under the Provisions of Order No. G-38-01 (Order G-90-01; Reasons for Decision)

- » British Columbia Hydro and Power Authority and Centra Gas British Columbia Inc.
  (1) Transportation Service Agreement and Peaking Agreement with Centra Gas British Columbia Inc. and Related Agreements (Order No. G-94-01; Reasons for Decision)
  (2) Amended and Restated Transportation Service Agreement with the Island Cogeneration Limited Partnership (Order No. G-94-01; Reasons for Decision)

- » Rate of Return on Common Equity for a Low Risk Benchmark Utility (Order No. G-109-01; Reasons for Decision)

- » BC Gas Utility Ltd. - 2001 Rate Design Application (Order No. G-116-01; Reasons for Decision)

- » BC Gas Utility Ltd. - 2002 Revenue Requirements Application (Order No. G-123-01; Reasons for Decision)

- » UtiliCorp Networks Canada (British Columbia) Ltd. - 2001 Annual Review and Incentive Mechanism Review and 2002 Revenue Requirements Application (Order No. G-133-01; Reasons for Decision)

1 On October 22, 2001 West Kootenay Power Ltd. changed its name to UtiliCorp Networks Canada (British Columbia) Ltd.

» UtiliCorp Networks Canada (British Columbia) Ltd. - Complaint by the Ootischenia Water and Land Stewardship Committee Action Group regarding the routing of the 230 kV Transmission Line through the Ootischenia Area (Letter No. L-31-01; Reasons for Decision)

» Centra Gas Whistler Inc. - 2001 Revenue Requirements Application (Order No. G-74-01; Negotiated Settlement)

» BC Gas Utility Ltd. - Gas Supply Mitigation Incentive Program for the 2001/02 Gas Contract Year (Order No. G-124-01; Reasons for Decision)

Brief summaries of the above-noted decisions may be found commencing on page 52 of this Report.

Electricity Market Developments

Over the last few years the Commission has been implementing demand response programs and competitive options into the electricity markets to enable utilities and some customers to reduce their electricity costs and to respond to opportunities for electricity trade with United States customers. BC Hydro provides wholesale transmission access, real time pricing tariffs and an opportunity for industrial customers to participate in curtailment programs to take advantage of high electricity market prices elsewhere. UNC was the first utility in Canada to offer both wholesale and retail access to large industrial and municipal customers. UNC also offers a green power rate and time-of-use rates.

Alternative Dispute Resolution/Negotiated Settlement Process

Policy, Procedures and Guidelines Review

The Commission's Negotiated Settlement Process: Policy, Procedures and Guidelines ("NSP Guidelines"), first issued in January 1996, sets the framework for utilities, intervenors, Commission staff and Commissioners in reviewing applications, attempting to achieve negotiated agreements, and the approval, amendment or rejection of a settlement agreement by a panel of Commissioners.

Since issuing its NSP Guidelines, the Commission has reviewed many settlement agreements arising out of successful negotiation processes. The Commission also established hearings to review applications or outstanding issues that were not successfully resolved through NSP.

Given the length of time since the NSP Guidelines were created, the feedback received about the NSP from participants, and the commitment made by the Commission during the West Kootenay Power Ltd. 1998 hearing, the Commission commenced a review of the NSP Guidelines in October 1999. A written review process was used and comments from interested parties were received and circulated in December 1999. Reply comments were filed in late January 2000.

Upon completion of its review of the NSP Guidelines and interested parties' comments, the Commission issued its revised NSP Guidelines in January 2001. The revised January 2001 NSP Guidelines improved upon the previous January 1996 Guidelines by:

- setting out the key considerations to be used by the Commission in determining when to refer an application to an NSP;

- making clear that participants may request the services of an external facilitator to conduct the negotiations; and

- amplifying the roles of the facilitator, Commission staff and the Commission at various stages in the process.

For a complete summary of the process and differences between the revised January 2001 NSP Guidelines and the previous January 1996 Guidelines, please refer to Letter No. L-3-01 dated January 23, 2001.

Return on Common Equity ("ROE") Mechanism

Seven years ago the Commission initiated Canada's first automatic adjustment mechanism for utility ROEs. This mechanism was revised in 1997 and again in 1999. One of the inputs into the ROE mechanism is the average spread between 10- and 30-year yields on Government of Canada bonds during the month of October. Yields on 30-year bonds have traditionally been higher than yields on 10-year bonds such that the yield spread adjustment typically increased the ROE. In October 2000 yields on 10-year Government of Canada bonds exceeded yields on 30-year bonds. Under the ROE adjustment mechanism, this resulted in a negative adjustment to the ROE.

In its Reasons for Decision (Letter No. L-61-00) responding to comments from interested parties on BC Gas' request for amendments to the calculation of the 2001 low risk benchmark ROE, the Commission stated that it would review the treatment of the yield spread when the yields on medium term bonds exceed the yields on long term bonds, and to review its practices with respect to rounding to the nearest 25 basis points (0.25 percent) within the ROE adjustment mechanism. The Commission established a written public hearing process (Order No. G-62-01) that concluded in mid-September.

By Order No. G-109-01 and attached Reasons for Decision, the Commission found that the current treatment of the yield spread between 30-year and 10-year bonds did not require adjustment at this time. The ROE for the low-risk benchmark utility, expressed as a percentage, should be rounded to two decimal points prior to adding the utility-specific risk premium.

Incentive Regulation

In past Decisions the Commission has instituted direct utility and shareholder incentives for cost efficiencies that do not negatively affect the quality of service. Incentives allow for longer periods between reviews and align the interests of shareholders and ratepayers. West Kootenay Power's 1996 three-year settlement with performance factors and utility / customer risk-sharing for each major cost and revenue category was the first of its kind in Canada. The West Kootenay Power settlement was extended to a fourth year and a new multi-year settlement was approved in 2000. BC Gas' 1998-2000 Performance-Based Rate Application was reviewed in a negotiated settlement process. It anticipates even broader proposals for performance factors and sharing mechanisms. BC Gas' Performance-Based Rate Settlement was also extended for a further year to include 2001.

British Columbia Hydro and Power Authority

Reports on Export Trade

Electricity markets have changed dramatically in recent years and BC Hydro's electricity trade activities are very important to the welfare of ratepayers. Following submissions from BC Hydro and ratepayer groups in February and March 2000, the Commission, in Letter No. L-56-00, directed BC Hydro to file quarterly reports on export trade. Although not detailed, the reports allow the Commission to undertake basic monitoring of BC Hydro's export trade activities on behalf of ratepayers.

Rate Freeze and Profit Sharing Act

On August 21, 2001, the provincial government announced the creation of an Energy Policy Task Force to develop a comprehensive, long-term energy policy for British Columbia. At the same time, government extended the BC Hydro rate freeze for up to 18 months from September 30, 2001 to March 31, 2003, to allow time to implement improvements in British Columbia's electricity industry.

The Rate Freeze and Profit Sharing Regulation (Order in Council 695/98) states that the "rates" and "fixed charge" portions of BC Hydro's rate schedules are frozen. Other terms and conditions of the tariffs can be amended, and new rates for new services not covered under tariffs in existence on December 10, 1997, can be set in accordance with established ratemaking principles. Examples include changes to the terms and conditions of the Real Time Pricing tariff, BC Hydro's Price Dispatched Curtailment Program and other demand response programs, and Bypass Rate Guidelines.

Georgia Strait Natural Gas Pipeline Crossing

BC Hydro and Williams Gas Pipeline Company propose to build a natural gas pipeline from Sumas to Cherry Point, Washington and then cross underwater to Vancouver Island ("GSX pipeline"). The pipeline would reach Vancouver Island south of Duncan and connect with the Centra Gas BC pipeline near Shawnigan Lake.

The Canadian portion of the GSX pipeline is under Federal jurisdiction and subject to the National Energy Board Act and the Canadian Environmental Assessment Act ("CEAA"). It has been referred to a Joint Review Panel for review under the CEAA. Approvals from the British Columbia Utilities Commission will be needed for Centra to connect to the GSX pipeline, for Centra rates to transport gas received from the pipeline, and for BC Hydro rates that may include expenditures related to the GSX pipeline. The National Energy Board oral public hearing was scheduled to commence June 17, 2002 but has been delayed. The National Energy Board's web site is *http://www.neb-one.gc.ca*.

BC Gas Utility Ltd.

2001 Rate Design Application

BC Gas filed its rate design application on February 5, 2001. The application sought approval of certain rate design proposals and to make permanent the interim rate increases that resulted from the allocation of the Southern Crossing Pipeline capital costs. At the request of participants the Commission hired a consultant to validate the Cost of Service Study and a copy of the Consultant's report was provided to participants for review. Information requests were submitted by participants and responded to by BC Gas. Subsequently, a negotiated settlement process commenced and culminated in a Settlement Document that was circulated to participants for final comment.

The Commission approved the Settlement Document (Order No. G-116-01), which established rates effective January 1, 2002.

Lease-In-Lease-Out Application

On May 18, 2001, BC Gas applied for approval to enter into Lease-In-Lease-Out ("LILO") arrangements with the City of Kelowna for its natural gas distribution system and to establish the mode of regulation by which BC Gas rates will reflect these arrangements.

A workshop and pre-hearing conference on July 5, 2001 addressed procedural matters including the scope of the Application, the process for reviewing the Application, and the timing of the review. The Commission issued a Regulatory Agenda for a written hearing (Order No. G-78-01) and on August 13, 2001, BC Gas filed minor amendments to some of the agreements forming part of the LILO Application. The Inspector of Municipalities approved the arrangements.

The Commission approved BC Gas' LILO Application (including the minor amendments) to enter into the proposed lease arrangements with the City of Kelowna (Order No. G-108-01).

Agent Billing and Collection for Transportation Service

Implementation of ABC-T service would provide BC Gas' residential and small commercial customers with the choice of buying gas from non-utility suppliers. BC Gas provided a status report on April 27, 2001.

On August 10, 2001, BC Gas filed its Report on the Requirements Definition Phase of the ABC-T Project. BC Gas held an information session on September 20, 2001, regarding the ABC-T business model and implementation plan. Commission staff requested comments from participants regarding their level of support for the business model and proposed November 2002 in-service date.

BC Gas provided its overall position to the next phase in the development of ABC-T service and recommended that the implementation date be deferred to November 2003 (letter dated October 9, 2001). After considering the various viewpoints, the Commission agreed with the revised implementation date and that the project should not proceed any further until licensing and enforcement mechanisms are in place. The Province is undertaking a review of energy policy and the Commission's request for legislative amendments to the *Utilities Commission Act* to permit the licensing and bonding of marketers will be assessed as part of this initiative.

Pacific Northern Gas Ltd.

Acquisition by Duke Energy Corporation of Westcoast Energy Inc. Shares in Pacific Northern Gas Ltd., Pacific Northern Gas (N.E.) Ltd., Centra Gas British Columbia Inc. and Centra Gas Whistler Inc.

On October 22, 2001, Duke Energy Corporation and named subsidiaries filed an Application for approval to acquire indirect control of Pacific Northern Gas Ltd., Pacific Northern Gas (N.E.) Ltd., Centra Gas British Columbia Inc., and Centra Gas Whistler Inc.

Westcoast Energy Inc., Centra Gas' parent company, undertook a stakeholder communication and consultation program in the service areas of the affected provincially regulated utilities. No significant concerns or issues were raised respecting the Duke Energy acquisition.

On November 14, 2001, the Commission approved the acquisition by Duke Energy of indirect control of Pacific Northern Gas Ltd., Pacific Northern Gas (N.E.) Ltd., Centra Gas British Columbia Inc., and Centra Gas Whistler Inc. (Order No. G-121-01).

Centra Gas British Columbia Inc. and Centra Gas Whistler Inc.

BC Gas Inc. – Application to Acquire Centra Gas and Centra Whistler

On December 6, 2001, BC Gas Inc. applied for approval to acquire a reviewable interest in the shares of Centra Gas British Columbia Inc., and a reviewable interest in the shares of Centra Gas Whistler Inc. from Westcoast Energy Inc. On December 7, 2001, Centra Gas and Centra Whistler applied for approval to register a transfer of shares in the capital of Centra Gas and Centra Whistler to BC Gas Inc. Westcoast Energy Inc. undertook a comprehensive stakeholder communication and consultation program in the service area.

The acquisition of a reviewable interest by BC Gas Inc. and the transfer of shares from Centra Gas and Centra Whistler to BC Gas Inc. were approved by the Commission under Orders No. G-8-02, G-9-02, and G-10-02. The Commission's approvals are subject to the consent of the Province through amendments to the Vancouver Island Natural Gas Pipeline Act.

Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Balance

In 1999 and 2000 gas prices increased dramatically prompting the Commission to approve mid-year rate changes for BC Gas. Prior to the mid-year rate change, gas cost recovery rates for BC Gas were set once per year taking effect January 1. The difference between revenue from the gas cost recovery rates and gas costs incurred accumulates in the Gas Cost Reconciliation Account ("GCRA") and is paid back to BC Gas or refunded to customers in subsequent periods. The rising gas prices resulted in gas costs that were higher than rate revenue and led to a GCRA balance estimated at around $180 million at the end of 2000.

Due to concerns about the mid-year rate increases and the large GCRA balance, the Commission asked its staff to prepare a report on the method of establishing gas cost recovery rates for BC Gas and amortizing the GCRA balance. The staff report was circulated and comments were received from BC Gas and four other parties.

Based on its review of the staff report and the submissions, the Commission requested quarterly reports from BC Gas and established "Guidelines for Setting Gas Recovery Rates and Managing the GCRA Balance" (Letter No. L-5-01 dated February 5, 2001). Although the Guidelines were developed with specific reference to BC Gas, the Commission now expects Centra Gas and PNG to file quarterly reports on expected gas costs and revenue and gas cost variance account balances and to apply for a rate change if expected gas costs and revenue differ by more than 5 percent.

Although gas commodity markets have been very volatile, the Commission has approved rate decreases as the average cost of gas has declined.

The following is a summary of the results of the reviews of BC Gas' rates that have occurred under the Guidelines. Shown are gas cost recovery rates for residential customers in the Lower Mainland and percentage changes to annual bills for typical residential customers.

BC Gas Residential Rates

Results of Quarterly Reviews of Gas Costs and Revenue

Effective Date	Gas Cost Recovery Charge[1] (Lower Mainland) Dollars per gigajoule	Typical Annual Bill[2] (Lower Mainland) Percent Change
January 1, 2001	$8.822	
April 1, 2001	8.822	0
July 1, 2001	8.822	0
October 1, 2001	7.532	–9%
January 1, 2002	6.631	–6%
April 1, 2002	6.631	0

1 Excludes basic and delivery charges

2 Includes basic and delivery charges

Assistance to Yukon Utilities Board

Under a contract, Commission staff provided professional and technical services, assisting the Yukon Utilities Board with its regulatory proceedings.

Assistance to the Government of Saskatchewan

Under a contract, Commission staff prepared an independent report on proposed natural gas rate commodity and revenue requirement increases of Sask Energy for review by a panel reporting to the Government of Saskatchewan.

Electricity Supply Contract Exemptions

Section 22 of the *Utilities Commission Act* was amended in July of 1998 to allow the Minister to exempt from the provisions of Section 71, by order, persons entering into energy supply contracts for the provision of electricity. Ministerial Orders have subsequently been issued and are set out on page 74 of this Report.

Canadian Association of Members of Public Utility TribunalsAnnual Educational Conference

The British Columbia Utilities Commission organized and hosted the CAMPUT 2002 Educational Conference in Whistler from May 5-8, 2002. Attended by over 225 delegates, the conference focussed on competition issues and the changing methods of regulation across Canada and the United States.

2002 Anticipated Events

During the 2002/03 fiscal year the Commission will be responding to the following expected major applications:

» Plateau Pipe Line Ltd. – Permanent Tolls and Suspension of Operations
Application with the BC Court of Appeal to vary an earlier Order of a Justice of the Court of Appeal

» BC Gas Utility Ltd. – Multi-Year Revenue Requirements Application

» BC Gas Utility Ltd. – Application for the Disposition of Property and Approval of Customer Care Agreements

» BC Gas Utility Ltd. – Application for Approval of a Standard Form Operating Agreement between BC Gas and Interior Municipalities

» Centra Gas Whistler Inc. – 2003 Revenue Requirement Application

» Centra Gas British Columbia Inc. – 2003 Revenue Requirement Application

» Centra Gas British Columbia Inc. – Rate Design Application

» Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. – 2002 Revenue Requirements Applications

» UtiliCorp Networks Canada (British Columbia) Ltd. – Detailed Routing of 230kV Kootenay System Development Project

» UtiliCorp Networks Canada (British Columbia) Ltd. – Multi-Year Revenue Requirements Application

» UtiliCorp Networks Canada (British Columbia) Ltd. – Okanagan Reinforcement Project

2002 Anticipated Events
(continued)

- » Princeton Light and Power Company, Limited – 2002 / 03 Revenue Requirements Application
- » BC Gas Utility Ltd. – Inland Pacific Connector Pipeline Certificate of Public Convenience and Necessity Application

Supplementary Information

Regulated Utilities

CROWN-OWNED ELECTRIC UTILITY	**SERVICE AREA**
British Columbia Hydro and Power Authority 333 Dunsmuir Street Vancouver, BC V6B 5R3	Lower Mainland, Vancouver Island, Central and Northern BC and East Kootenay Regions

INVESTOR-OWNED ELECTRIC UTILITIES	**SERVICE AREA**
Hemlock Valley Electrical Services Limited 20955 Hemlock Valley Road Agassiz, BC V0M 1A1	Hemlock Valley
Princeton Light and Power Company, Limited Box 700 Princeton, BC V0X 1W0	Princeton, Osprey Lake and Missezula Lake Areas
Silversmith Power & Light Corporation Box 369 New Denver, BC V0G 1S0	Sandon, BC
Sun Rivers Services Corp. #1002 - 1708 Dolphin Avenue Kelowna, BC V1Y 9S4	Lot 152, CLSR Plan 78619 Kamloops IR No. 1
West Kootenay Power Ltd. UtiliCorp Networks Canada (British Columbia) Ltd. P.O. Box 130 Trail, BC V1R 4L4	West Kootenay and Okanagan Regions of BC
The Yukon Electrical Company Limited Box 4190 Whitehorse, Yukon Territory Y1A 3T4	Lower Post

INVESTOR-OWNED NATURAL GAS OR PROPANE UTILITIES	**SERVICE AREA**
BC Gas Utility Ltd. 1111 West Georgia Street Vancouver, BC V6E 4M4	Lower Mainland, Fort Nelson, Central and Northern Interior, the Kootenays and the Okanagan
Centra Gas British Columbia Inc. 1675 Douglas Street, P.O. Box 3777 Victoria, BC V8W 3V3	Sunshine Coast, Powell River, and Vancouver Island north to Campbell River, west to Port Alberni, and south to Victoria
Centra Gas Whistler Inc. 1675 Douglas Street, P.O. Box 3777 Victoria, BC V8W 3V3	Whistler (Propane Grid System)

Investor-Owned Natural Gas or Propane Utilities (continued)	Service Area
Pacific Northern Gas Ltd. #1400 - 1185 West Georgia Street Vancouver, BC V6E 4E6	Summit Lake to Prince Rupert and Kitimat
Pacific Northern Gas (N.E.) Ltd. #1400 - 1185 West Georgia Street Vancouver, BC V6E 4E6	Dawson Creek, Rolla, Pouce Coupe, Tumbler Ridge, Fort St. John
Pacific Northern Gas Ltd. #1400 - 1185 West Georgia Street Vancouver, BC V6E 4E6	Granisle (Propane Grid System)
Port Alice Gas Inc. #101 - 4381 Dawson Street Burnaby, BC V5C 4B4	Port Alice (Propane Grid System)
Stargas Utilities Ltd. P.O. Box 3002 Silver Star Mountain, BC V1B 3M1	Silver Star resort community
Squamish Gas Co. Ltd. 1111 West Georgia Street Vancouver, BC V6E 4M4	Squamish (Natural Gas)
Sun Peaks Utilities Co., Ltd. 1280 Alpine Road Sun Peaks, BC V0E 1Z1	Resort area north of Kamloops
Sun Rivers Services Corp. #1002 - 1708 Dolphin Avenue Kelowna, BC V1Y 9S4	Lot 152, CLSR Plan 78619 Kamloops IR No. 1

Investor-Owned Steam Heat Utility	Service Area
Central Heat Distribution Limited 720 Beatty Street Vancouver, BC V6B 2M1	Downtown Vancouver

Municipally-Owned Electric Utilities — **Service Area**

Only service outside of the Municipal boundaries is subject to regulation by the British Columbia Utilities Commission.

City of Grand Forks Box 220 Grand Forks, BC V0H 1H0	Grand Forks

Municipally-Owned Electric Utilities (continued)	Service Area
City of Kelowna 1435 Water Street Kelowna, BC V1Y 1J4	Kelowna
City of Nelson 502 Vernon Street Nelson, BC V1L 4E8	Nelson (urban and rural areas)
City of New Westminster 511 Royal Avenue New Westminster, BC V3L 1H9	New Westminster
City of Penticton 616 Okanagan Avenue East Penticton, BC V2A 3K6	Penticton
District of Summerland Box 159 Summerland, B.C. V0H 1Z0	Summerland

Domestic Electricity Sales - 2001

	Customers #	Revenue ($000)	Sales (GW.h)
CROWN-OWNED ELECTRIC UTILITY			
British Columbia Hydro and Power Authority	1,606,599	2,299,990	46,425.86
MUNICIPALLY-OWNED ELECTRIC UTILITIES			
City of Grand Forks	1,993	2,206	32.68
City of Kelowna	12,083	15,832	278.78
City of Nelson	9,013	8,740	146.54
City of New Westminster	28,559	21,673	376.62
City of Penticton	14,747	16,580	295.83
District of Summerland	5,049	4,764	79.73
Total Municipally-Owned	71,444	69,795	1,210.18
INVESTOR-OWNED ELECTRIC UTILITIES			
Hemlock Valley Electrical Services Limited	200	154	0.96
Princeton Light and Power Company, Limited	3,014	4,059	60.12
Silversmith Light & Power Corporation	7	5	0.05
Sun Rivers Services Corp.	48	55	0.88
UtiliCorp Networks Canada (British Columbia) Ltd.	88,132	109,408	1,885.00
The Yukon Electrical Company Limited	81	122	0.75
Total Investor-Owned	91,482	113,803	1,947.76
TOTAL ALL ELECTRICAL UTILITIES	1,769,525	2,483,588	49,583.80

NOTES:

1. 1 gigawatt hour (GW.h) = 1 million kilowatt hours.

2. Figures reported are for the 2001 calendar year. Customers reported are as at December 31, 2001.

3. Revenues and sales for BC Hydro and UtiliCorp Networks Canada (British Columbia) Ltd. (formerly known as West Kootenay Power Ltd.) are net of wholesale sales to other reporting electrical utilities identified in this table.

Domestic Gas Sales - 2001

	Customers #	Revenue ($000)	Sales (GJ)(000)
INVESTOR-OWNED NATURAL GAS UTILITIES			
BC Gas Utility Ltd.			
Lower Mainland Division	534,447	1,029,140	117,148
Inland Division	206,505	307,131	53,662
Columbia Division	20,958	38,551	7,381
Fort Nelson Division	2,064	3,802	879
Squamish Gas Co. Ltd.	2,388	3,182	327
Centra Gas British Columbia Inc.			
Vancouver Island, Powell River and Sunshine Coast areas	71,218	113,118	27,075
Pacific Northern Gas (N.E.) Ltd.			
Fort St. John Inc. / Dawson Creek Division	14,900	30,271	4,238
Tumbler Ridge Division	1,141	1,614	745
Pacific Northern Gas Ltd.	23,015	80,815	26,779
Stargas Utilities Ltd.	128	423	27
Sun Peaks Utilities Co. Ltd.	391	840	48
Sun Rivers Services Corp.	43	8	1
TOTAL INVESTOR-OWNED	877,198	1,608,895	238,310
INVESTOR-OWNED PROPANE GRID SYSTEM UTILITIES			
BC Gas Utility Ltd.			
Squamish Gas	42	43	2
Revelstoke	1,443	3,243	237
Centra Gas Whistler Inc.	2,019	10,134	686
Pacific Northern Gas Ltd.			
Granisle Grid	174	276	18
Port Alice Gas Inc.	270	379	18
Total Propane Grid Systems	3,948	14,075	961
TOTAL ALL GAS UTILITIES	881,146	1,622,970	239,271

NOTES:

1. 1 gigajoule (GJ) is approximately equivalent to 0.910 mcf (mcf = one thousand cubic feet) or 0.0258 10^3m^3 of natural gas or 0.376 mcf of propane vapour in L.P. gas grid systems.

2. Figures reported are for the 2001 calendar year. Customers reported are as at December 31, 2001.

3. Sales of GJ shown include sales to end-use customers plus gas owned by customers and transported to their industrial operations by utilities.

4. Revenues reported for natural gas utilities include only transportation margins for large industrial customers who have purchased gas supplies directly from producers or aggregators.

Map to be inserted by Queen's Printer

Map to be inserted by Queen's Printer

Decisions, Reasons for Decision and Negotiated Settlements

Pacific Northern Gas Ltd.
October to December 2000 Rates and 2001 Revenue Requirements
Dated May 25, 2001; Order No. G-51-01

On September 28, 2000, PNG filed its Revenue Requirements and Rates Applications for customers in northwestern British Columbia. PNG-West is a natural gas utility serving more than 26,000 residential, commercial and industrial customers in a service territory extending along Highway 16 from Vanderhoof / Fort St. James to Prince Rupert and Kitimat.

PNG made several applications dating from October 2000 for significant rate increases to all customers, primarily as a result of liquidity problems associated with the July 2000 Methanex plant shutdown in Kitimat and higher costs of purchasing the natural gas commodity. Most increases were allowed on an interim basis, pending a public hearing. The public hearing was held in Terrace and Vancouver in March 2001.

In the same hearing, the Commission considered an application from Methanex for a long-term load retention rate that would improve the prospect that the plant would reopen in the future. The Methanex plant was constructed in 1982 and produces up to 500,000 tonnes of methanol per year from natural gas feedstock. Natural gas deliveries to Methanex are about two-thirds of the volumes transported on the PNG system and provide 45 percent of PNG's total operating margin when the plant is operating at normal levels.

The situation in the service area is complicated because the rapid escalation in natural gas commodity prices pushed consumer rates towards levels where some customers may switch from natural gas to wood, electricity, and oil.

The Commission approved the rates contained in the PNG applications, except that the proposed restructuring to commercial customers was reduced to $0.85 per GJ to be implemented July 1, 2001, and charges to industrial customers for restructuring purposes were reduced to half of that proposed by PNG. All of the additional ratepayer payments directed by the Commission were found to be appropriate for customers to contribute, since they will write down accounts, which are the responsibility of customers to fund. The Commission denied PNG's proposal for about $6 million in additional revenue from Methanex, associated with increased depreciation and unbooked income taxes. Previously unanticipated revenues of about $4 million from the operation of BC Hydro's natural gas-fired electricity generation plant in Prince Rupert were directed to help cover reduced sales to other industrial customers and write down deferral accounts.

With regard to the Methanex load retention rate application, the Commission found that the rate should be no less than $0.46 per GJ, not the $0.32 per GJ Methanex proposed. The Commission was hopeful that PNG and Methanex could agree upon a new rate for Methanex that would be beneficial to PNG, Methanex and other customers. By providing stability and certainty to PNG, a long-term load retention rate agreement should allow the utility to more easily obtain debt financing, and other customers would benefit through Methanex's continuing contributions to PNG's revenues.

British Columbia Hydro and Power Authority
Bypass Guidelines for Independent Power Producers Seeking Access to
BC Hydro's Transmission Service through BC Hydro's Distribution System
Dated June 1, 2001; Order No. G-52-01

The BC Hot House Growers' Association, in a letter dated February 27, 2001, requested that the Commission undertake a process to clarify and establish the basis for export market access through the BC Hydro system for cogeneration proposals that would involve greenhouse operations and Independent Power Producers ("IPPs").

BC Hydro filed its Application for Approval of Bypass Guidelines for Independent Power Producers Seeking Access to BC Hydro's Transmission Service Through BC Hydro's Distribution System on March 23, 2001. An oral public hearing commenced in May 2001 to examine the issue of IPP access to BC Hydro's distribution system and charges for distributed generation.

Following consideration of the Application, evidence and argument the Commission determined that a rate and conditions for access to BC Hydro's distribution system are required for Independent Power Producers who wish to obtain access through the distribution system to the transmission system.

The Commission's determinations were as follows:

- The Commission believed it is in the interest of ratepayers to establish access conditions to the distribution system. A rate of 1.0 mill / kWh was established for distributed generators connecting to BC Hydro's distribution system to transmit power to the transmission system.

- The Commission believed that fixing the distribution access rate in a contract that extends over a defined term could alleviate concerns that IPPs could invest in distributed generation based on the then current tariff, only to have a higher rate subsequently approved by the Commission.

- To assess the benefits and costs of distributed generation to BC Hydro's distribution and transmission system, BC Hydro was directed to file a report, by December 31, 2002, reviewing the use of the distribution system by Independent Power Producers, and the costs and benefits of such distributed generation to the BC Hydro distribution and transmission systems. If the evidence then warrants a change in the rate, the Commission may adjust the rate for new contracts commencing after the effective date of any rate change.

- The Commission determined that IPPs should pay the full cost of any dedicated facilities required to connect to the BC Hydro system. The Commission also found that the BC Hydro "Connection Requirements for Utility or Non-Utility Generation, 35 kV and Below" are appropriate for allocating connection costs to distributed generators. The Commission accepted BC Hydro's proposal to charge nothing and require nothing with respect to system upgrade facilities.

- The Commission determined that until there is sufficient evidence to support a charge or credit for losses on a hypothetical direct connection to the transmission system, a zero charge for losses is appropriate.

- BC Hydro was expected to work cooperatively with distributed generators, within its Wholesale Transmission Service tariffs, to facilitate their efforts to gain access to the export markets. If such cooperative efforts fail, and the Commission receives complaints that distributed generators are being effectively precluded from making export sales, the Commission may require a review of the WTS tariffs to ensure that they function equitably for all who desire transmission service.

Plateau Pipe Line Ltd.
Application for Permanent Tolls on the Taylor to Kamloops Pipeline
Dated June 26, 2001; Order No. P-3-01

Intraprovincial oil pipelines are regulated by the Oil and Gas Commission ("OGC") and the BCUC. The OGC is responsible for oil pipeline regulation from a technical and safety perspective. The BCUC must approve the tolls and conditions of service for oil pipelines that are also common carriers. The Commission also must approve the suspension of service by a common carrier pipeline. The BCUC has traditionally regulated oil pipelines on a reporting or complaint basis. Under that method of regulation, in the absence of complaints, the BCUC approves agreements on tolls and terms of service that are negotiated between the pipeline company and shippers without further review.

On July 31, 2000, Pembina Pipeline Corporation ("Pembina"), the operating company for the Pembina Pipeline Income Fund, purchased a group of seven crude oil pipelines in east-central British Columbia and northwestern Alberta. The largest of these, the former Federated Western System, connects oil field facilities at Taylor, BC to Kamloops (the "Western System"). It is now operated by a Pembina subsidiary, Plateau Pipe Line Ltd. The Western System, constructed in 1961, is a 323.9 mm (12.75 inch), 800 km (500 mile) pipeline that delivers crude to the Husky Oil Operations Ltd. refinery in Prince George, and to refineries on the west coast by way of a connection with the facilities of Trans Mountain Pipe Line Company Ltd. at Kamloops. Through subsidiary companies, Pembina now owns 14 pipelines in British Columbia and Alberta. Two of these are in competition with the Western System, in that they transport crude oil from Taylor to oil terminals in Edmonton, Alberta.

Pine River Spill

On July 31, 2000, the Western System pipeline ruptured at milepost 102.5. A spill of approximately 952 m^3 (6,000 barrels) resulted. Approximately 500 m^3 of oil leaked into the Pine River about 90 km upstream of the town of Chetwynd. Plateau spent in excess of $26 million in the cleanup.

The break was repaired and Pembina advised the OGC that it had successfully tested the pipeline section near the break. On August 23, 2000, the OGC authorized Pembina to operate the pipeline from Taylor to Kamloops, provided the maximum operating pressure was restricted to 75 percent of the certified operating pressure. Plateau elected to test the entire section of line between Taylor and Prince George before restoring any service.

Regulatory Events

Husky continued to operate its refinery following the pipeline break using on-site inventory and trucked crude, and on August 30, 2000 applied to the BCUC for an Order compelling Plateau to return the line to service. The BCUC accepted Plateau's decision to retest the line to Prince George and denied Husky's application for an emergency order. Following the successful hydrostatic test, the Taylor to Prince George segment was returned to service on September 21. Plateau applied to be relieved of its obligation to provide service to Kamloops, which the Commission refused unless the OGC agreed the segment should not be reactivated due to safety or operational concerns.

Plateau filed an application on December 29, 2000, requesting BCUC approvals for proposed tolls and shipper commitments under which they were prepared to operate the line to Prince George and reopen the line between Prince George and Kamloops, or, if shipper commitments at volumes and the tolls set by the BCUC failed to materialize, approval for the suspension of service. The oral public hearing commenced April 2, 2001 and continued for seven hearing days. Written Arguments were completed on May 10, 2001.

Following consideration of the application, submissions and evidence filed during the public hearing, the Commission made the following determinations.

- Plateau had not justified its decision to not return the southern section to service. For the purpose of setting tolls, the Commission found that Plateau could have returned the section to service by December 1, 2000, and determined that the revenue that was lost because crude oil deliveries to Kamloops were delayed is Pembina's responsibility.

- The use of a deferral account, subject to review, for recording variances in the amount of insurance claims from the Pine River spill that are denied by the insurer was approved.

- Pembina's request to revalue the pipeline was rejected.

- Plateau's proposal that working capital be set as one-eighth of the normal operating expenses for the year was approved.

- The inclusion of the net costs of a nitrogen purge used for removing the oil from the idle southern section was accepted.

- A deferral account to record any difference between the insurance premium estimate and the actual insurance premium cost was approved. Plateau may also record future insurance deductible outlays in this deferral account.

- An after-tax ROE of 12.25 percent for the 2000 and 2001 test periods was approved.

- Deferred income taxes are appropriate for 2000 and 2001, and deferred income tax balances were included in the capital structure as no-cost capital, replacing short-term debt.

- The incentive toll sharing adjustment for the January 1 to September 6, 2000 period was accepted as filed and will amortize the amount of $115,000 in tolls in 2002. For the 2000 stub year, a toll of $4.42 / m^3 to Prince George and $6.81 / m^3 to Kamloops was approved. The Commission maintained the approach of calculating tolls so that the Taylor to Prince George toll is 65 percent of the Taylor to Kamloops toll. Unrecovered toll revenue for the 2000 stub year totalling $2.355 million was transferred to the unrecovered revenue deferral account, to be amortized into tolls over three years commencing in 2001.

- 2001 tolls of $4.27 / m^3 to Prince George and $6.56 / m^3 to Kamloops were approved.

- Plateau's request for volume commitments and its application for Suspension of Service were denied.

- Plateau and Pembina were directed to immediately proceed with all steps necessary to resume full operation. Specifically, Plateau and Pembina were directed to design, obtain approval for and conduct a hydrostatic test of the Prince George to Kamloops section. They were also to file a detailed action plan for returning the pipeline to full operation.

Plateau Pipe Line Ltd.
Reconsideration of the June 26, 2001 Taylor to Kamloops Pipeline
Permanent Tolls decision and Order No. P-3-01
Dated October 19, 2001; Order No. P-5-01

On August 15, 2001, Plateau filed an Application for Review of the Decision, pursuant to Section 99 of the UCA. Plateau submitted that the Decision contained errors of fact and law, which resulted in prejudice and possible damage to Plateau and Pembina and constituted grounds for the BCUC to reverse its Decision. The errors alleged included:

1. The determination that Pembina as well as Plateau is a common carrier;

2. The setting of tolls which were not just and reasonable;

3. The determination of matters which were properly within the jurisdiction of the British Columbia Oil and Gas Commission;

4. The making of clerical errors; and

5. The direction that Pembina invest significant sums of money in the pipeline thereby indirectly resulted in cross-subsidization.

In addition, Plateau alleged:

6. New evidence had become available on the issue of financing.

Plateau also requested a stay to Order No. P-3-01 and the directions under the Decision pending the outcome of the Reconsideration Application and/or an appeal to the Court of Appeal. The Commission considered the request for a stay as a separate application (the “Application for Stay”).

A written process was established and submissions were requested by the Commission from Registered Intervenors to the Application for Permanent Tolls on the Taylor to Kamloops Pipeline. Submissions were received from Imperial Oil Resources, Husky Oil Operations Limited, Calpine Natural Gas Partnership, the Canadian Association of Petroleum Producers, and Chevron Canada Resources.

Upon consideration of Plateau’s Reconsideration Application and Application for Stay, the submissions of the registered intervenors and Plateau’s response, the Commission made the following determinations on each of the alleged errors identified in the Reconsideration Application.

1. <u>Relationship of Plateau and Pembina and Common Carrier Status</u>

Plateau submitted that the BCUC committed an error in law and exceeded its jurisdiction by treating Plateau’s parent company, Pembina, as a common carrier under the *Pipeline Act*.

The Commission considered that Pembina acquired a common carrier and has acted as a common carrier in regards to the Western System by holding itself out as willing to do business in a particular area of endeavour.

2. Setting Just and Reasonable Tolls

In the Reconsideration Application, Plateau claimed that the Commission erred in law by failing to establish tolls for the Western System that are just and reasonable, as required under Section 45 of the *Pipeline Act*. Section 45 of the *Pipeline Act* states that:

> "Equal tolls to be charged
> 45 All tolls must be just and reasonable, and must always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate."

The Commission found that Plateau had not presented a prima facie argument for reconsideration on the setting of just and reasonable tolls for September 7, 2000 to December 31, 2001.

3. Jurisdiction of the Commission relative to the Oil and Gas Commission

Plateau stated that the Commission reached conclusions concerning safety and technical matters relating to pipelines that are within the exclusive jurisdiction of the OGC.

The Commission found that the request for a reconsideration on the basis that the Commission erred in law and usurped the jurisdiction of the OGC, was not substantiated. The Commission also found that the request for reconsideration on the basis that the Commission erred when it determined that operation of the southern section could have resumed by December 1, 2000, was not substantiated.

4. Clerical Errors

Plateau submitted that the BCUC made two clerical errors in the calculation of tolls for 2000 and 2001 and in the determination of closing balances of gross plant and accumulated depreciation.

Based on the filed evidence and testimony, the Commission considered that the plant values shown in Exhibit 1C, IR1.1 were likely incomplete and no prima facie case existed to adjust the 1994 opening net plant values. If Plateau was able to provide evidence that the amounts shown in the exhibit properly reflected the 1993 closing net plant assets, the Commission would be prepared to adjust the plant values and toll calculations accordingly.

The Commission considered that Plateau's request to calculate depreciation expense from January 1, 1994 to September 6, 2000, at the rate of 5 percent per annum based on the net plant assets at historical cost, would understate the depreciation expense that had actually been charged to shippers during the incentive toll period. Plateau's request, if approved, would result in a double-charge of depreciation expense. The Commission considered that no prima facie case existed for the recalculation of depreciation expense.

5. BCUC Indirectly Ordered Cross-subsidization

Plateau claimed the BCUC erred in directing Pembina or the Pembina Pipeline Income Fund to use the assets of other pipelines to raise financing for Western System improvements.

The Commission found that Pembina had not demonstrated that the Commission was requiring any cross-subsidy from other pipelines.

6. New Evidence on Raising Capital

In support of the Reconsideration Application, Plateau filed as "new evidence" a letter from Scotia Capital dated August 14, 2001. The letter, directed to Pembina, indicated that Scotia Capital, on the basis of its current understanding of the Western System, would not be prepared to extend a credit facility to Plateau on a stand-alone basis. The letter noted the absence of shipper commitments on Plateau and other uncertainties with regard to future earnings. Plateau argued that it could only secure such evidence after receiving the complete Decision and was unable to raise the capital to carry out the investments the BCUC requires.

The Commission did not consider the Scotia Capital letter as new evidence sufficient to merit a reconsideration of the Decision as it simply reinforced the view presented by Pembina at the hearing that Plateau would obtain its financing from its parent, Pembina.

Plateau's request for reconsideration of the Decision was denied. Plateau's request for a stay of Commission Order No. P-3-01 was denied. Plateau subsequently sought Leave to Appeal the Commission decisions but was rejected by the Court of Appeal.

West Kootenay Power Ltd. now known as
UtiliCorp Networks Canada (British Columbia) Ltd.
Sale of Hydroelectric Generation Assets
Dated October 26, 2001; Order No. G-112-01

On March 22, 2001, WKP filed an Application for the sale of its generation assets, pursuant to Sections 50, 52, 54, 60, and 71 of the Act. WKP owns four hydroelectric plants on the Kootenay River with a combined rated capacity of about 214 MW. With winter peak loads approaching 700 MW, most of WKP's energy and capacity needs are met through power purchase contracts and agreements.

WKP proposed to sell its four hydroelectric plants and related facilities to a joint venture subsidiary of the Columbia Basin Trust and the Columbia Power Corporation ("Columbia Joint Venture") for a purchase price of $120 million. WKP would purchase the output of the four plants under a long-term power purchase agreement.

An oral public hearing was convened in Rossland on May 29, 2001. At the request of WKP, with the support of the Columbia Joint Venture, the hearing was adjourned, and later reconvened in Rossland on July 16, 2001 after a Technical Information Session in Kelowna.

On June 8, 2001, WKP filed updates to its Application, being an Amended and Restated Brilliant Power Purchase Agreement, an Operations Agreement, a Transitional Services Agreement, and a Transmission Maintenance Agreement, with the Commission and intervenors. WKP also requested Commission approval of a letter agreement dated June 1, 2001 regarding entitlement to benefits resulting from tailrace improvements at Brilliant.

The hearing was completed on July 25, 2001 and the filing of written argument was completed on September 7, 2001.

In its Decision dated October 26, 2001, the Commission denied the WKP Application and advised WKP that it would not approve the transfer of assets to Kootenay River Power Corporation unless the terms of the sale were restructured to provide for sharing of the proceeds on sale with customers, as determined in the Reasons for Decision. On November 16, 2001, WKP advised the Commission that it would not be proceeding with the sale.

Pacific Northern Gas Ltd.
Order No. G-1-01 dated January 2, 2001
Application by Skeena Cellulose Inc. to Modify or Set Aside Commission Order No. G-94-00 relating to PNG's Application to Increase Rates on an Interim and Final Basis, effective October 1, 2000 and January 1, 2001

On November 24, 2000, Skeena applied to the Commission, pursuant to Section 91(3) of the Act and Commission Letter No. L-51-00, to modify or set aside the interim rate increase granted in Interim Order No. G-94-00 (the "Skeena Application"). Skeena sought to have the Interim Order set aside or modified on the following grounds:

1. Skeena submitted that the Commission erred in law by approving the interim rate increase in Order No. G-94-00 in circumstances where the statutory conditions for the Commission to have jurisdiction to grant such interim relief under Section 91(1) of the Act were not satisfied; and

2. Skeena further submitted that the Commission erred in law by approving the interim rate increase without fixing its duration or setting a time limit for a hearing to be held and a final decision made, contrary to Section 91(2) of the Act; and

3. Finally, Skeena submitted that, after Order No. G-94-00 was issued by the Commission, additional information was released to the public which indicated that PNG did not make full and frank disclosure to the Commission of all facts which were relevant to its interim rate application, and this constituted a fundamental change in the circumstances or facts which were before the Commission at the time it made the Order, such that the Order should be reconsidered.

By letter dated December 6, 2000, as clarified by letter dated December 7, 2000, the Council of Forest Industries' Natural Gas Committee also requested that the Commission set aside or modify the Interim Order to disallow the interim rate increase on the basis that the Interim Order constituted an error in law since it was contrary to:

- basic principles of fairness; and
- the rate approval scheme established under the Act.

By letter dated December 7, 2000, PNG responded to the Skeena Application and, among other things, referred to the special circumstances it was relying on.

On December 8, 2000, the Commission established a Regulatory Agenda for the PNG Application. The Order provided for an oral public hearing in Terrace to commence on March 5, 2001.

By letter dated December 13, 2000, Eurocan filed submissions supporting the Skeena Application. Eurocan alleged that the Commission erred in law in granting the Interim Order on the grounds that the Interim Order established rates that are:

- unjust and unreasonable contrary to the provisions of Sections 59 and 60 of the Act;
- not supported by the evidence submitted by PNG, and
- unduly prejudicial to the interests of Eurocan and PNG's other large volume industrial transportation service customers.

By letter dated December 13, 2000, Skeena filed a Reply Submission to the PNG letter dated December 7, 2000.

The Commission dismissed Skeena's Application and denied the relief sought by Eurocan and the Council of Forest Industries' Natural Gas Committee. The Commission concluded that there was a sufficient evidentiary basis to grant the interim rate increase and found that any failure by PNG to disclose information to the Commission at the time of the Interim Order was not of such a nature that it impacted on the special circumstances that the Commission found to be the basis for the Interim Order. The Commission also noted that if the PNG Application was denied, or the Commission ordered a rate increase less than that allowed in the Interim Order, the affected ratepayers would be entitled to a refund with interest.

British Columbia Hydro and Power Authority
Access Principles for Public, Municipal and Other Utilities
Reasons for Decision - Order No. G-11-01 dated January 25, 2001

On September 29, 2001, BC Hydro filed an application for Access Principles for Public, Municipal and Other Utilities, identified as Tariff Supplement No. 55, which set out the principles that would govern the rights and obligations of access to embedded cost of service for wholesale customers. A written public hearing process was established to deal with the Application and submissions were received from the Consumers' Association of Canada (B.C. Branch) et al., the City of New Westminster, and the Joint Industry Electricity Steering Committee.

The Commission approved the Access Principles for Public, Municipal and Other Utilities as applied for on September 29, 2000. The Commission recognized BC Hydro's argument that the substance of these principles may not be appropriate for BC Hydro in the medium- or long-term, given that the policy issue of entitlement to low embedded cost electricity had yet to be resolved. The Commission expected that BC Hydro will revise its principles once this issue and others concerning further deregulation are clarified. In the interim, the Commission accepted the principles as they provide greater certainty over the rights and obligations for existing and new specified access customers to leave and return to embedded cost of service.

British Columbia Hydro and Power Authority
Surcharge to Customers in the Community of Meziadin Lake, BC
Reasons for Decision - Order No. G-50-01 dated May 16, 2001

In 1999 BC Hydro applied to extend service to Meziadin Lake, BC and to finance the customers' capital contribution by way of a surcharge estimated to be 15.6 cents/kWh. On January 17, 2000, BC Hydro advised that the line to Meziadin Lake was complete and the Commission approved the collection of the interim surcharge from customers served off the Meziadin Lake extension effective January 12, 2000 (Order No. G-10-00). The financing alternative allowed customers to become connected to the BC Hydro grid at costs less than their current self-generation and to receive rates equal to other integrated customers once the financing was paid off.

On February 15, 2001, BC Hydro applied for approval of Tariff Supplement No. 47, which reflected a final surcharge rate of 15.6 cents/kWh for customers served off the Meziadin Lake extension and a 12-year period over which the surcharge would apply. Copies of BC Hydro's application were provided to the Meziadin Lake Fellowship Association and other customers served by the extension. Nine responses were received. Rebuttal comments were subsequently received from BC Hydro.

Following a review of comments received from customers and other interested parties, the Commission approved a modified surcharge rate of 14.5 cents/kWh, to be collected over a ten year period. The effective date of the surcharge is the date of energization of the Meziadin Lake extension and the surcharge is to remain in effect until the balance of the loan is paid off.

British Columbia Hydro and Power Authority
Application for Reconsideration of Commission Order No. G-50-01 by Rose Smith, Meziadin Residents' Association regarding the Surcharge to Customers in the Community of Meziadin Lake, BC
Reasons for Decision - Order No. G-92-01 dated September 20, 2001

On August 1, 2001, Ms. Smith, on behalf of the residents and businesses of Meziadin Lake, applied for a reconsideration of the May 16, 2001 Decision pursuant to Section 99 of the Utilities Commission Act. The application for reconsideration alleged that the Commission made errors in fact and further alleged that basic principles, although raised, were not addressed by the Commission.

Before accepting an application for reconsideration, an applicant must first establish a prima facie case sufficient to warrant full consideration by the Commission. The Commission generally applies the following criteria to determine whether or not a reasonable basis exists for allowing a reconsideration:

1. The Commission has made an error in fact or law;
2. There has been a fundamental change in circumstances since the Decision;
3. A basic principle was not raised at the original proceeding; or
4. A new principle has arisen as a result of the Decision.

There were nine allegations made, six of which fell under the first criterion and three under the third criterion. The Commission denied, with reasons, the Reconsideration Application as the applicant had failed to meet the prima facie test for a reconsideration.

British Columbia Hydro and Power Authority
Complaint on the Transmission Capacity within the District of Fort St. James
Reasons for Decision - Order No. G-60-01 dated July 4, 2001

On September 8, 2000, Apollo Forest Products Ltd. proposed to construct a 69 / 25 kV substation to expand its sawmill facilities in the Fort St. James area and reduce its power costs by taking service from the transmission system. During the Commission's review of Apollo's application, the District of Fort St. James submitted a complaint about the adequacy of the transmission system to meet potential new load. Other parties expressed similar concerns. The District of Fort St. James and Apollo also expressed a concern with BC Hydro's determination of Apollo's share of the cost of a new transmission line between Vanderhoof and Fort St. James that would be needed to serve the existing load and Apollo's new load.

The Commission concluded that the potential load growth would generate sufficient revenue to offset the cost of line modifications and directed BC Hydro to reinforce the transmission line at its own expense once it confirmed that the new load will exceed the capacity of the existing line. Modifications required to the Fort St. James substation and facilities downstream of that point were to be carried out with customer contributions calculated in accordance with BC Hydro's standard policies and tariffs.

By letters dated December 21, 2001 and January 17, 2002, Apollo indicated that it anticipated lower initial load growth and did not intend to build its substation before 2004.

BC Gas Utility Ltd.
Market-Based Commodity Rates for Rate Schedules 7, 10 and 14 and
Changes to Notice Periods for Rate Schedules 5, 7 and 14 for the 2001/02 Gas Contract Year
Reasons for Decision - Order No. G-67-01

On May 10, 2001, BC Gas requested approval of market-based gas commodity rates, effective November 1, 2001, for Rate Schedules 10 and 14. On May 31, 2001, BC Gas requested approval of market-based gas commodity rates, effective November 1, 2001, for Rate Schedule 7, and requested changes to the notice periods under Rate Schedule 5 – General Firm Sales and Rate Schedule 7.

Commission staff requested interested parties to file comments on the Application and comments were received from Enbridge Business Services, Consumers' Association of Canada (B.C. Branch) et al., Weyerhaeuser Company Limited, and Lower Mainland Large Volume Gas Users Association, which included a letter of comment from Canadian Forest Products Ltd. A reply to these submissions was subsequently filed by BC Gas.

The Commission considered the Application and the submissions and approved the following:

- Rate Schedule 7 tariff, except that a requirement for the Gas Cost Recovery Account rider to apply for longer than the 2001/02 gas contract was not approved, with commodity pricing as follows:

Daily Index Option:	Daily Index price, plus $0.15/GJ.
Fixed Price Option:	Rate Schedule 5 Gas Cost Recovery Charge plus Rate Schedule 5 Gas Cost Reconciliation Account rider.

- Rate Schedule 10 tariff with the commodity pricing as follows:

Daily Index Option:	Daily Index price.
Monthly Index Option:	Monthly Index price, including a 3 percent discount during November through March, and a commitment by the customer to purchase a daily Contract Demand quantity when gas is available.

- Rate Schedule 14 tariff for firm term and spot sales with commodity pricing as follows:

Daily Index Option:	Daily Index price, plus a Market Factor of not less than $0.15/GJ.
Fixed Price Option:	Annualized price based on the Sumas monthly forward prices for physical purchases that BC Gas fixes at approximately the time when the customer commits to the Fixed Price option for 2001/02 plus a Swing Premium of $1.50/GJ for November through March and $0.90/GJ for April through October.
Spot Gas:	Daily Index plus $0.02/GJ to $0.05/GJ, and not less than cost.

BC Gas will offer a Monthly Index Option under Rate Schedule 14 that is similar to the Monthly Index Option under Rate Schedule 10, including a daily Contract Demand quantity commitment, except that the price will include the appropriate Market Factor(s) for firm one-year gas bought on a Monthly Index, and will not include a winter discount. BC Gas specified the Market Factor(s) when it filed the tariff.

The Gas Management fee under Rate Schedule 14 will be maintained at $0.02 / GJ to $0.08 / GJ.

Customers migrating to or from Rate Schedules 7 and 14, and from Rate Schedule 25 to Rate Schedule 5, will give at least 60 days notice, to be effective November 1, 2001.

Within 30 days of the end of each month BC Gas will file a report summarizing gas purchase and sale quantities, and cost and revenue for each price option for the month for Rate Schedule 14 transactions. A report will be submitted on a quarterly basis within 60 days from the end of the contract year quarter of all Rate Schedule 14 transactions.

British Columbia Hydro and Power Authority
A Complaint by Sumas Energy 2, Inc. regarding BC Hydro's Wholesale Transmission Service Tariff
Reasons for Decision - Order No. G-69-01 dated June 28, 2001

On October 23, 2000, Sumas Energy filed a complaint alleging that BC Hydro's Wholesale Transmission Service Tariff Supplement No. 30 ("WTS Tariff") and associated rate schedules are unreasonable for its particular circumstances and that BC Hydro's application of the WTS Tariff in the terms and conditions of the proposed Service Agreement is unreasonable. Sumas Energy requested that the Commission set a process for the resolution of its complaint.

Following a review of the submissions, the Commission issued Order No. G-121-00 directing BC Hydro to reinstate Sumas Energy in the appropriate reservations queue for services as of October 23, 2000, and to discuss with Sumas Energy the appropriate rates and terms for location specific point to point transmission services. The Order also directed BC Hydro either to submit an agreed upon rate and terms of service to the Commission by March 30, 2001, or BC Hydro and Sumas Energy could make submissions to the Commission on the form of rate and terms of service they deemed to be appropriate.

On March 30, 2001, BC Hydro and Sumas Energy filed separate reports pursuant to Order No. G-121-00, and BC Hydro requested approval to remove Sumas Energy's Open Access Same Time Information System ("OASIS") Request No. 343571 from the reservation priority queue. Comments were again received from both parties.

Upon consideration of the evidence and information submitted, the Commission dismissed the Sumas Energy complaint and directed BC Hydro to provide 30 days notice to Sumas Energy prior to removing Sumas Energy's OASIS Request from the reservation priority queue.

Pacific Northern Gas (N.E.) Ltd.
Fort St. John / Dawson Creek and Tumbler Ridge Divisions
2001 Revenue Requirements Application
Reasons for Decision - Order No. G-72-01 dated July 5, 2001

In a 2001 Revenue Requirements Application dated December 1, 2000 and revised December 18, 2000, PNG (N.E.) applied to increase its rates on an interim and final basis, effective January 1, 2001, pursuant to Sections 91 and 58 of the UCA. Interim rate increases were approved and a written public hearing process was established to review the 2001 Revenue Requirements for the Fort St. John / Dawson Creek and Tumbler Ridge Divisions (Order No. G-129-00).

Interventions were received and, after a series of Information Requests and Responses and the filing of Final Arguments, the Commission issued Order No. G-72-01 with Reasons for Decision reducing the revenue deficiency to $5,000 for the Fort St. John / Dawson Creek Division and to $122,000 for the Tumbler Ridge Division. The Commission approved as final the Gas Supply Charges for Fort. St. John / Dawson Creek and the proposed new main extension test, subject to review of the actual tariff when filed. As the approved rates were less than the interim rates, an amended Summary of Rates and Bill Comparison schedule along with a method for refunding excess payments back to customers was filed with the Commission.

British Columbia Hydro and Power Authority
Application for a Market-Based Rate for Self-Generation Output
Sold to Market under the Provisions of Order No. G-38-01
Reasons for Decision - Order No. G-90-01 dated August 9, 2001

On April 6, 2001 the Commission issued Order No. G-38-01 regarding BC Hydro's obligation to serve Rate Schedule 1821 customers with self-generation capability. In that Order, the Commission directed BC Hydro to allow Rate Schedule 1821 customers with idle self-generation capability to sell excess self-generated electricity provided the self-generating customers do not arbitrage between embedded cost utility service and market prices.

Pacifica Power Co. Ltd., a wholly-owned subsidiary of Pacifica Papers Inc., sold its hydroelectric generation and transmission facilities on Powell River and at Lois Lake British Columbia (the "Power Facilities") to Powell River Energy Inc. ("PREI") early in 2001. Pacifica currently owns approximately 50 percent of PREI. The Power Facilities are used to generate electricity for use by Pacifica in its pulp and paper mill at Powell River, BC, which had a combined installed nominal capacity of 82 MW and produced an average of 540,000 MW.h of electricity per year for use at Pacifica's mill. Pacifica purchased additional electricity required for the mill from BC Hydro under Rate Schedule 1821.

Minister's Order No. M-22-0101 exempts PREI from Part 3 and Section 71 of the Utilities Commission Act with respect to electricity generated by PREI and sold to Pacifica for use at the mill. The Minister's Order also exempts PREI with respect to the sale of surplus power to public utilities or wholesale customers.

On June 8, 2001, BC Hydro applied to the Commission for approval to establish a market-based rate for re-supply of self-generation output sold to market in violation of the provisions of Commission Order No. G-38-01. BC Hydro proposed to set the market-based rate by applying the Dow-Jones Mid-Columbia Firm Electricity Price Index for High Load Hours and Low Load Hours to the export schedule during the shutdown and dividing by total energy exported. This rate would apply to the energy taken from BC Hydro by the mill, upon restart, up to the total amount of energy exported.

Upon consideration of the comments, information requests and submissions received from the parties involved, the Commission concluded that the sale of electricity by PREI during the Pacifica mill shutdown met the definition of surplus power under the Minister's Order and that Pacifica should not be charged a market-based rate.

British Columbia Hydro and Power Authority
Centra Gas British Columbia Inc.

- Transportation Service Agreement ("TSA") and Peaking Agreement ("PA") with Centra Gas British Columbia Inc. and Related Agreements
- Amended and Restated Transportation Service Agreement with the Island Cogeneration Limited Partnership ("ICLP")

Reasons for Decision - Order No. G-94-01 dated August 30, 2001

On March 12, 2001, Centra Gas applied for approval of an Amended and Restated Transportation Service Agreement ("ARTSA") with ICLP. This would replace the ICLP TSA and would provide interruptible transmission service to the ICLP Plant. The ARTSA was to become effective April 1, 2001 and to expire on the earlier of the Commercial Operation Date as specified in a notice from ICLP, or July 1, 2002.

On April 6, 2001, BC Hydro applied for approval of a Transportation Service Agreement ("BCH TSA") and Peaking Agreement ("BCH PA"). The BCH TSA would provide firm and interruptible transportation service over the Centra Gas system to the ICLP Plant until the proposed Georgia Strait Crossing Pipeline is completed. The BCH PA would provide system peaking capacity and gas commodity to Centra Gas by means of reducing transportation supply to the ICLP Plant. BC Hydro applied to the Commission on May 4, 2001 for approval of the Capacity Assignment Agreement ("CAA") between BC Hydro, Centra Gas and BC Gas dated March 7, 2001.

On April 10, 2001, the Joint Venture of seven mills along the Centra system provided comments on BC Hydro's application and suggested that Commission staff convene a meeting of interested parties. Centra Gas provided material in support of the application on May 7, 2001 and stated that, aside from the issue related to potential overlapping service under the ARTSA and the BCH TSA, " … the BCH TSA and the BCH PA represent fair and reasonable contracts that enable the maximum firm demand commitment to the ICP while respecting Centra Gas' other system commitments, including the VIGJV contract for firm service."

In order to provide increased transmission capacity to the ICLP Plant, Centra Gas applied on June 11, 2001 to the Commission for a Certificate of Public Convenience and Necessity ("CPCN") to build and operate a natural gas compressor on Texada Island. After reviewing costs, timing and justification, the Commission approved the CPCN with Order No. C-6-01 dated July 25, 2001. The compressor provides an additional 21 TJ/d of natural gas throughput capacity. Order No. C-6-01 also approved the Compressor Facility Agreement ("CFA") between BC Hydro and Centra Gas. Under the CFA, BC Hydro is responsible for the capital cost of the new compressor facility and must issue an authorization notice before Centra Gas can operate the new compressor.

On May 24, 2001, the Commission convened a written public hearing (Order No. G-53-01) to review the applications relating to ARTSA, the BCH TSA, the BCH PA, and the CAA. The issues to be considered included:

1. The capacity of the Centra Gas system and possible increases resulting from additional compression;
2. The impact of Centra Gas contracting additional firm service to BC Hydro on the rights of the Joint Venture; and
3. Whether the Joint Venture has preferential rights to interruptible service.

The Commission made the following determinations in its Decision:

- That Centra Gas has sufficient firm capacity to contract 28 TJ/d with BC Hydro under the terms of the Agreement Package and, with the Texada Island compressor in operation, will be able to contract 38 TJ/d. The Commission determined that any approvals of the ARTSA and the BCH TSA must be subject to the conditions that service under the agreements will only be provided if the firm demand of the Joint Venture is being met and Centra Gas is not requesting peaking gas.

- That the Joint Venture's rights to interruptible service will not be impacted by approval of the BCH TSA, and that the terms of the Special Direction with respect to Interruptible Offset Gas will not be breached by approval of the agreement.

- Except for the determination of the Commercial Operation Date and subject to changes identified in its Decision, the Commission found the terms and conditions of service of the ARTSA were acceptable. The rate was to be equal to the interruptible rate in the Joint Venture TSA.

- Except for the determination of the Commercial Operation Date and subject to changes identified in its Decision, the Commission found the rates and terms and conditions of service of the BCH TSA, BCH PA and CAA to be acceptable.

- The ARTSA was approved, subject to the agreement being amended to provide for a term commencing September 1, 2001 and ending on the day prior to the COD as defined under the EPA, or such other date as BC Hydro and ICLP agreed upon. Service under the ARTSA would only be provided if the firm demand of the Joint Venture is being met, and Centra Gas is not requesting peaking gas. The rate would be equal to the interruptible rate in the Joint Venture TSA.

- The BCH TSA was approved, subject to the agreement being amended so that it went into effect on the COD as defined under the EPA, or such other date as BC Hydro and ICLP agreed upon. Service under the BCH TSA would only be provided if the firm demand of the Joint Venture is being met, and Centra Gas is not requesting peaking gas under the PGMA. The Commission approved the BCH PA.

- The CAA was approved, subject to amendment of the agreement to provide BC Hydro with an option to place the agreement into effect prior to the commencement of service under the BCH TSA, on the basis that no charges would be payable by Centra Gas under the CAA prior to the commencement of service under the BCH TSA.

Rate of Return on Common Equity for a Benchmark Utility
Reasons for Decision - Order No. G-109-01 dated October 10, 2001

In its Reasons for Decision attached to Letter No. L-61-00, the Commission stated that it intended to review further the treatment of the yield spread when the yields on medium-term bonds exceed the yields on long-term bonds, and to review its current practices with respect to rounding to the nearest 25 basis points (0.25 percent) within the ROE adjustment mechanism. The Commission established a written public hearing process, which concluded in mid-September.

Submissions were made by BC Gas, Pacific Northern Gas Ltd., Centra Gas British Columbia Inc., West Kootenay Power Ltd., the Consumers' Association of Canada (B.C. Branch) et al., and a group of large industrial gas customers.

The Commission Decision found that the treatment of the yield spread between 30-year and 10-year bonds did not require adjustment at that time. The Commission directed that the ROE mechanism would remain as set out in Order No. G-80-99 except that the ROE for the low-risk benchmark utility, expressed as a percentage, should be rounded to two decimal points prior to adding the utility-specific risk premium.

BC Gas Utility Ltd.
2001 Rate Design Application
Reasons for Decision - Order No. G-116-01 dated November 7, 2001

On February 5, 2001, BC Gas filed with the Commission an application for approval to implement certain rate design changes ("the Application") in its service areas.

A workshop and pre-hearing conference were established (Order No. G-21-01) for participants to discuss the issues in the Application and methods of proceeding with a Commission review. At the request of the participants, the Commission hired an independent rate design consultant to validate the BC Gas Cost of Service study. A copy of the consultant's report was circulated on June 1, 2001.

Following a round of information requests, responses and submissions a negotiated settlement process commenced in September 2001, culminating in a proposed Settlement Document, which was circulated to BC Gas, Intervenors and Interested Parties.

After considering the proposed Settlement Document, the Application, the letters of comment, and other submissions related to the Application, the Commission approved the Settlement Document. The principal terms of the Settlement reached during those negotiations are set out below.

1. The Large Volume Transportation (Rate Schedule 22) interruptible delivery charge would be reduced by $0.046 / GJ to $0.62 / GJ from the current $0.666 / GJ. This would reduce total Rate 22 delivery margin revenue by approximately $707,000 per year.

2. The decrease in delivery margin arising from the reduction of the Large Volume Transportation (Rate 22) interruptible delivery charge would be recovered through an increase in the Residential (Rate Schedule 1) delivery margin. This increase in the residential delivery margin was estimated to be $0.009 / GJ.

3. The Residential (Rate Schedule 1) Basic Charge, exclusive of any riders, would increase by $1.34 per month from the current $8.66 per month to $10.00 per month. The increase in the Residential Basic Charge would be offset by a decrease in the delivery margin, so that the increase in the Residential Basic Charge would be revenue neutral. This decrease in the residential delivery margin was estimated to be $0.139 / GJ.

4. In order to achieve an economic breakpoint between Small Commercial Service (Rate Schedule 2) and Large Commercial Service (Rate Schedules 3 / 23) that approaches 2,000 GJ per year, Rate Schedules 2 and 3 / 23 would be revised as proposed by BC Gas.

5. All of the revisions to rates listed above would be implemented effective January 1, 2002.

BC Gas Utility Ltd.
2002 Revenue Requirements Application
Reasons for Decision - Order No. G-123-01 dated November 20, 2001

On August 24, 2001, BC Gas applied for approval to increase rates for customers in the Lower Mainland, Inland and Columbia service areas, effective January 1, 2002, to recover increased revenue requirements of approximately $32 million associated with delivering natural gas. An increase of about 7 percent would apply to rates for transportation service and to the distribution portion (excluding the commodity cost of gas) of rates for customers to whom BC Gas supplies the natural gas commodity. Expressed on a burnertip basis (including the current commodity cost of gas) the increase being sought was about 2 percent.

A workshop and pre-hearing conference were held in September 2001 (Order No. G-98-01) and a Negotiated Settlement Process was established for November.

On November 1, 2001, BC Gas filed notice that it was withdrawing its Application. BC Gas explained that the withdrawal of the Application was due to a number of factors including the recently announced acquisition of Centra Gas British Columbia Inc. and Centra Gas Whistler Inc. by BC Gas Inc. BC Gas clarified the effect of its withdrawal by identifying the proposed treatment of identified revenue and cost items. The utility stated that in all other respects BC Gas would operate with the revenues that are generated by the current base rates. The utility considered that there would be cost pressures for 2002 which BC Gas would absorb and equally any benefits arising in 2002 which enhance the BC Gas' return would be retained by the utility. BC Gas included letters of support to its withdrawal from three registered intervenors.

The Commission approved the BC Gas withdrawal of its 2002 Revenue Requirements Application. BC Gas was directed to file its Revenue Requirements Application for 2003 by May 31, 2002, and to address in that application the matters that were raised in the Commission's Reasons for Decision.

UtiliCorp Networks Canada (British Columbia) Ltd.
2001 Annual Review and Incentive Mechanism Review Application
and 2002 Revenue Requirements Application
Reasons for Decision - Order No. G-133-01 dated December 20, 2001

Commission Order No. G-134-99 approved the November 22, 1999 Settlement Agreement, setting up an amended rate adjustment mechanism for the period beginning January 1, 2000 and ending December 31, 2002, whereby UNC is required to file annually with the Commission materials for a rate change, if any, effective January 1 of the next year. The terms of the Settlement Agreement require that an Annual Review process be instituted, whereby the public will be invited to examine the filed material, submit other issues for determination by the Commission, and meet to review all issues prior to the final rate application being made.

An Annual Review was held and UNC's performance in 2001 was also reviewed against each of the standards agreed to in the 1998 Settlement Agreement, as amended in the 1999 and 2000-2002 Settlement Agreements, in order to determine whether UNC had earned its incentive adjustments.

On December 12, 2001, UNC filed its Application for a general rate increase of 4.5 percent for all customer classes effective January 1, 2002. The Application included a preliminary incentive variance of $931,000 to be shared 50/50 between UNC and its customers.

After reviewing the material filed, the Commission approved a general rate increase of 4.5 percent for all customer classes effective January 1, 2002. The Commission also determined that UNC had met its performance standards in accordance with the Incentive Sharing Mechanism and had earned its portion of the preliminary sharing adjustment for 2001.

UtiliCorp Networks Canada (British Columbia) Ltd.
Ootischenia Water and Land Stewardship Committee Action Group Complaint
Routing of the Kootenay 230 kV Transmission Line through the Ootischenia Area
Reasons for Decision - Letter No. L-31-01 dated October 25, 2001

On May 7, 2001, the Ootischenia Water and Land Stewardship Committee Action Group ("the Committee"), on behalf of the residents of Ootischenia, filed a complaint regarding the proposed siting of West Kootenay Power Ltd.'s 230 kV transmission line through the Ootischenia area. The Committee requested the Commission order WKP to cease and desist the work of the 230 kV transmission line through the residential area of Ootischenia until the concerns of the residents and landowners are addressed. They further stated that, based on the body of research and existing evidence regarding adverse health effects from high voltage lines, they were opposed to the routing of the 230 kV transmission line through the residential area of Ootischenia. They cited concerns for the health of the residents by being exposed to elevated levels of aerosol pollutants and radon decay products as a result of corona ions being produced by the 230 kV transmission line. Their submission also identified general concerns regarding the effect of power frequency electromagnetic fields on the production of cancer in humans. A petition was signed by many area residents. Scientific papers postulated that corona ions created by high voltage transmission lines attract pollutant aerosols and deposit them on humans in the vicinity. Other attachments included papers describing the production of ions in electric fields and the deposition of charged particles in human airways.

A written process was established that provided the complainant, WKP and other interested parties with opportunities to file submissions and reply submissions regarding the complaint with the Commission.

Upon review of the submissions and supporting documentation, the Commission denied the Committee's complaint and its request for a cease and desist order, noting that there is insufficient evidence to conclude that corona ions from high voltage lines, and in particular from the 230 kV transmission line through Ootischenia, will cause elevated risks of adverse health effects.

While the complaint of the Committee focused on health risks from extremely low frequency electromagnetic fields and corona ions, the Commission recognized that the Committee's objective is to see the power lines removed from Ootischenia for many reasons, including aesthetics and land use.

However, the Commission intended that no community be disadvantaged by the new transmission line compared to the existing lines, unless there are no practical, cost-effective ways to avoid or mitigate the disadvantage. The Commission, therefore, expected WKP to respond to the Commission's Decision when it files its recommended final line alignment. The filing should include specific routing options through Ootischenia, the costs, and an evaluation of their impacts on the residents, including electromagnetic field values at the right-of-way edge and at residences.

Centra Gas Whistler Inc.
2001 Revenue Requirements Negotiated Settlement
Order No. G-74-01 dated July 5, 2001

On January 4, 2001, Centra Whistler applied for approval to set the current rates on its propane distribution system as interim effective January 1, 2001. Interim rates were approved by Order No. G-7-01.

On April 30, 2001, Centra Whistler filed an application to increase its basic charge from $5.00 to $7.50 per month and its commodity charge by 19.07 percent, on a permanent basis, effective January 1, 2001, and requested that the Application be dealt with through the Commission's Negotiated Settlement Process. A workshop and pre-hearing conference were held and a negotiated settlement process was established for June 2001 (Order No. G-55-01).

A proposed settlement agreement was distributed among Centra Whistler, Intervenors and Commission staff and, on July 3, 2001, the Commission was informed that a proposed settlement agreement had been reached. The Commission approved the Settlement Agreement, which included a 2001 revenue deficiency of $345,233. The $7.50 per month basic charge was approved along with an increase in commodity charges of 11.1 percent effective July 1, 2001.

BC Gas Utility Ltd.
Gas Supply Mitigation Incentive Program for the 2001/02 Gas Contract Year
Reasons for Decision - Order No. G-124-01 dated November 15, 2001

A series of negotiating meetings concerning a gas supply mitigation incentive plan for the 2001/02 gas contract year was held, and the parties reached agreement on the methodology, terms and conditions. The Commission distributed a copy of the Gas Supply Mitigation Incentive Program 2001/02 Settlement to all participants in the revenue requirements proceeding and requested their comments. No additional comments were received.

The Commission approved the Gas Supply Mitigation Incentive Program 2001/02, for the gas contract year from November 1, 2001 through October 31, 2002.

Exemptions

There are two types of exemptions from the provisions of the *Utilities Commission Act:* Section 22 Ministerial exemptions and Section 88 Commission exemptions.

Section 22-Ministerial Exemptions

Section 22 of the Act was amended in July of 1998 to allow the Minister to exempt from the provisions of Section 71, by order, persons entering into energy supply contracts for the provision of electricity. A number of Ministerial Orders (described below) have subsequently been issued for the exemption of electricity contracts and facilities:

- **M-22-9801** (M297, dated August 28, 1998) exempts from Commission review, contracts entered into by BC Hydro or Powerex for electricity before March 31, 2000. It also exempts the projects supplying the electricity from regulation as public utilities (Part 3 of the Act).

- **M-22-9801-A1** (dated March 30, 2000) – extends M-22-9801 to September 30, 2001.

- **M-22-9802** (M374, dated November 18, 1998) exempts Island Cogeneration Limited Partnership, Fletcher Challenge Canada Limited (and its subsidiaries Fletcher Challenge Canada Pulp Operations Ltd. and Elk Falls Forest Industries Limited), their successors and assigns, as well as any equipment, facility, plant, project or system of such persons from all provisions of Part 3 of the Act solely for the purposes of the September 29, 1998 Agreement.

- **M-22-9803** (M376, dated November 25, 1998) exempts from Commission review, various contracts and projects in the Columbia Basin, including the Waneta upgrade, the Purcell project and the Keenleyside project, Cominco, the Columbia Power Corporation (“CPC”), the Columbia Basin Trust (“CBT”) and joint ventures with CPC and CBT for purchases and sale of electricity and coordination.

- **M-22-0001** (M337, dated October 3, 2000) rescinds M-22-9803 above, and exempts CPC and CBT, the Brilliant Project, the Brilliant Expansion Project and the Waneta Expansion Project from Part 3 and Section 71 of the Act in respect of the sale, purchase or production of power. Also exempted persons, other than CPC / CBT and Cominco, from Section 71 of the Act in respect of Energy Supply Contracts for the purchase of CPC / CBT Power Service and the production and sale of Waneta Upgrade Power Service.

- **M-22-0002** (dated December 18, 2000) exempts the Port Alberni Generation Plant, its developers, related facilities and energy supply contracts from regulation by the Commission under Part 3 and Sections 45, 46, 47 and 71 of the Act.

- **M-22-0002-A** (M28, dated January 24, 2001) exempts BC Hydro from Sections 45, 46 and 47 of the Act for the purposes of constructing, owning and operating the fourth unit at the Seven Mile hydroelectric generating station on the Pend d'Oreille River, including any equipment, appliances, safety devices, facilities, plant system or system extensions BC Hydro may construct, own or operate in connection with the Project.

- **M-22-0101** (M26, dated January 30, 2001) Pacifica Power Co. Ltd. - exempts Powell River Energy Inc., Maclaren Energy Management Services Inc. and Pacifica's Power Facilities from Part 3 of the Act in respect of the production and sale of: (i) the power service to any of Pacifica and Pacifica Papers Co. Limited Partnership, and their affiliates, successors or assigns that acquire a controlling interest in the Mill, for use in the Mill; (ii) surplus power to public utilities and Wholesale Customers; and (iii) surplus power to the Partnership for marketing and sale to public utilities and to Wholesale Customers.

Section 88 – Commission Exemptions

Commission exemptions may exempt a utility from any provision of the Act, apart from Section 22. The Commission has developed a specific practice to issue Section 88 exemptions. First, the utility applies to the Commission for an exemption from regulation with respect to a particular activity, project, or agreement. The Commission staff then assesses the application and makes a recommendation to the Commission. If the Commission agrees with the application in principle and decides that an exemption will not jeopardize the public interest, it requests approval from cabinet. By order of the Lieutenant Governor in Council, Cabinet formally approves the exemption. Finally, the Commission issues its own order granting an exemption under Section 88(3).

The following Commission exemptions from regulation were granted under Section 88(3) of the Act in 2001.

» WILLIAMS ENERGY (CANADA) INC.
Order No. G-13-01 / Order in Council No. 16, 2001

Approved an exemption from Part 3, other than Sections 24 and 25, of the West Stoddart facilities which Williams Canada uses to transport or process natural gas for others.

» NOVAGAS CANADA LTD.
Order No. G-36-01; Order No. G-77-98 / Order in Council No. 831, 1997

Rescinded Order No. G-77-98 granting an exemption from Part 3, other than Sections 24 and 25, of the West Stoddart facilities as the Novagas facilities were sold to Williams Energy (Canada) Inc.

» RFP POWER LTD.
Order No. G-91-01 / Order in Council No. 739, 2001

Approved, effective August 9, 2001, an exemption from the provisions of the Act, other than Part 2 and Section 99, in respect of the production, delivery and sale of steam to Riverside Forest Products Limited.

» RIVERSIDE FOREST PRODUCTS LIMITED
Order No. G-113-01 / Order in Council No. 919, 2001

Exempts Riverside from the provisions of the Act, other than Part 2 and Section 99, in respect of the production and sale of Incremental Power to:

- Brokers or others for export outside of the Province;
- The City of Kelowna or to Powerex Corporation, BC Hydro or WKP; and
- For use outside of the City of Kelowna's electrical service area.

Exempts the purchaser of the Incremental Power (the "Purchaser") from Section 71 of the Act in respect of the purchase of the Incremental Power if the Purchaser is not a public utility under the Act.

Exempts Riverside from the provisions of the Act, other than Part 2 and Section 99, in respect of the production and sale to the City of Kelowna of that portion of the Power Plant's initial 2 MW of generation each hour that is not required by the facilities.

» CLEAN POWER OPERATING TRUST
Order No. G-120-01

Orders the following pursuant to the authority under the Act and Ministerial Order No. 1-M-51:

- The amalgamation of Regional Power Inc. with its two wholly-owned subsidiaries;

- The sale of the Sechelt Creek hydroelectric generating facility by Regional Power Inc. to Clean Power Operating Trust; and

- The ongoing operations of the Sechelt Creek hydroelectric generating facility and the sale of power by Clean Power Operating Trust to BC Hydro are exempt from the Act, other than Part 2 and Sections 99 and 100, pursuant to the authority under the Act and given by Ministerial Order No. 1-M-51, and the assignment of the Electricity Purchase Agreement to the Trust.

Performance Indicators

Proceeding Days Summary (Calendar 2001)

Applicant	Application	Pre-hearing Conference	Workshop	ADR	Oral Public Hearings	Total Days
BC Gas	Rate Design	1	1	3		5
PNG	Revenue Requirements				6	6
PNG (N.E.)	Revenue Requirements		Written Hearing Process			-
Pembina Pipeline / Plateau Pipe Line	Permanent Tolls on the Taylor to Kamloops Pipeline				7	7
BC Hot House Grower's Association	Bypass Guidelines for IPPs Seeking Access to BC Hydro's Transmission Service through BC Hydro's Distribution System				3	3
WKP / UNC*	Sale of Generation Assets		1		7	8
PLP	Revenue Requirements		Written Hearing Process			-
Centra Gas BC	Peaking & Transportation Service Agreement with BC Hydro and Transportation Service Agreement with Island Cogeneration Limited Partnership		Written Hearing Process			-
Centra Whistler	Revenue Requirements	.5	.5	1		2
BC Gas	Lease-In / Lease-Out Arrangements with the City of Kelowna	1	Written Hearing Process			1
BC Gas, WKP / UNC* PNG, PNG(N.E.), Centra Gas BC	Rate of Return on Common Equity		Written Hearing process			-
BC Gas	Revenue Requirements Application (withdrawn)	1	1			2
UNC	2001 Annual Review and 2002 Revenue Requirements	.5	.5			1
TOTAL DAYS		**4**	**4**	**4**	**23**	**35**

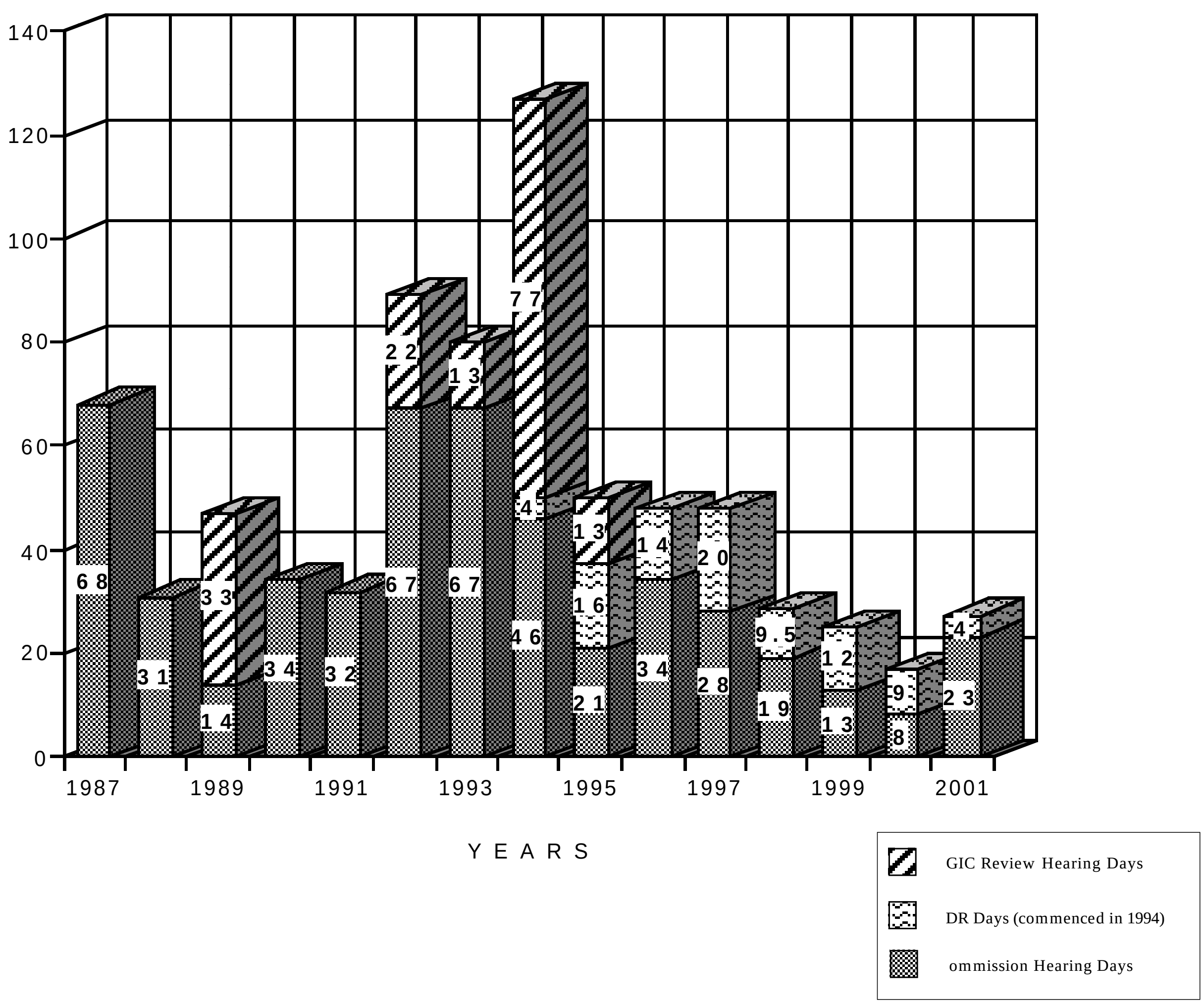
* West Kootenay Power Ltd. changed its name to UtiliCorp Networks Canada (British Columbia) Ltd. on October 22, 2001.

Hearing and Alternative Dispute Resolution Days (Calendar 2001)

The Negotiated Settlement Process is part of the Commission's efforts to improve the quality and efficiency of its regulatory process. Use of the Negotiated Settlement Process, which is also referred to as Alternative Dispute Resolution, requires considerable staff work before, during and after the negotiations. Updated "Negotiated Settlement Process: Policy, Procedures and Guidelines" were issued on January 23, 2001 (Letter No. L-3-01).

During 2001 a total of 23 hearing days were spent reviewing PNG's 2002 revenue requirements application, UNC's application to sell its hydroelectric generation assets, the BC Hot House Growers' Association application for bypass guidelines for Independent Power Producers seeking access to BC Hydro's transmission service through BC Hydro's distribution system, and the Plateau / Pembina application for tolls on its oil pipeline from Taylor to Kamloops.

Alternative Dispute Resolution, the use of formulas for setting ROEs, and multi-year performance based rate setting have all contributed to the decline in the number of hearing days (see chart). Matters referred to the Commission by the Lieutenant Governor in Council can have a dramatic affect on the number of hearing days; for example, in 1994 the Kemano Completion Project was reviewed over 77 hearing days.



Customer Complaints and Inquiries (Calendar 2001)

Inquiries from Utility Customers concerning Terms and Conditions of Utility Service, Quality of Service, Rate Increases, Billing and Payment Requirements, Disconnections, etc.

An important aspect of the Commission’s mandate is to apply regulation in a manner that reflects fair, consistent and clearly enunciated standards. Commission staff are available to assist the public in dealing with regulated utilities so that problems and inquiries are handled in a prompt, helpful and efficient manner.

Most complaints and inquiries are resolved through discussions between the customer and the utility concerned. Unresolved issues are referred to the Commission. To facilitate communication between the Commission and the customers of regulated utilities wishing to file complaints or have points clarified, toll-free calling from anywhere in the Province is available. The number of complaints and inquiries in 2001 decreased to 2,490 from 2,848 in 2000. Of the total number of complaints received, 2,329 complaints were associated with the fluctuation in the commodity cost of natural gas.

For each natural gas utility shown in the following summary, the number of cost of gas complaints and inquiries to the Commission remained high. To respond to the numerous customer calls, letters and inquiries, the Commission prepared a detailed information package that helped explain why commodity charges for gas had increased to unprecedented levels. The package included a detailed letter explaining why the commodity cost of gas had not kept pace with decreases in the market price, a Commission News Release, a Backgrounder prepared by staff, and a comparative rates table for residential consumption.

The response to the information package has been quite favourable and has allowed the Commission's staff to deal with other formal complaints in an efficient manner. The information packages were also posted on the Commission's web site.

During 2001, three requests for information were made under the Freedom of Information and Protection of Privacy Act.

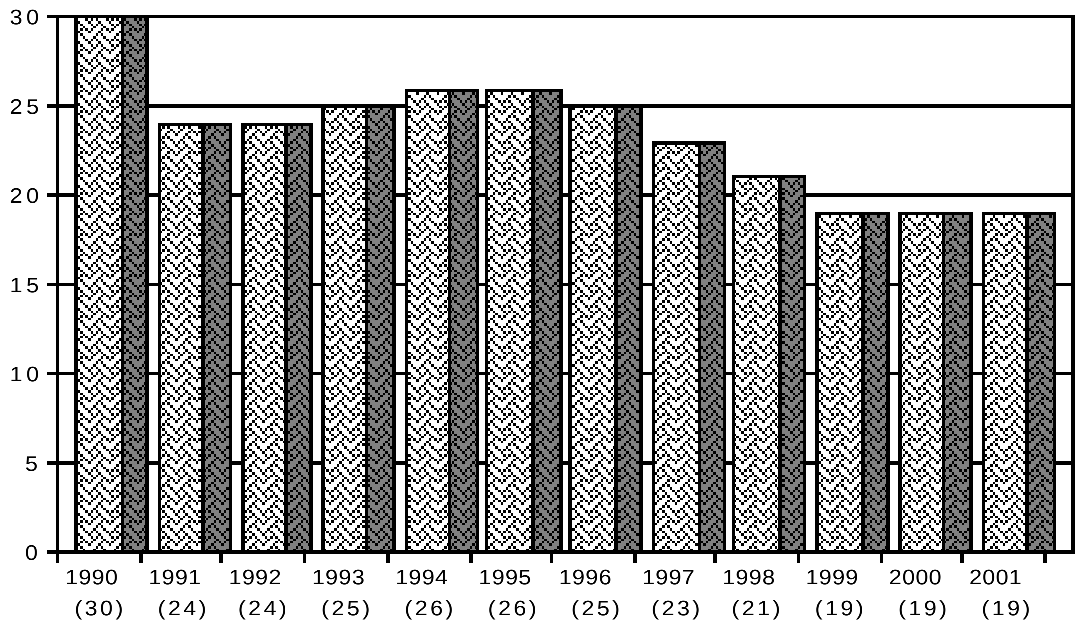
Summary of 2001 Customer Complaints and Inquiries

Gas Utilities		Total
BC Gas Utility Ltd.		
General Complaints	43	
Cost of Gas Complaints:		
~ January 1, 2001		
• Customers	1,845	
• Municipalities	12	
• District of Hope Petition	*	
~ July 1, 2001	90	
~ October 1, 2001	163	2,153
Pacific Northern Gas (N.E.) Ltd.		
General Complaints	8	
Estimated Meter Reading / Call Centre Problems	19	
Cost of Gas Complaints:		
~ January 1, 2001	146	
~ July 1, 2001	4	
~ October 1, 2001	9	186
Pacific Northern Gas Ltd.		
General Complaints	14	
Estimated Meter Reading / Call Centre Problems	7	
Cost of Gas Complaints:		
~ January 1, 2001	22	
• Petition (covering Prince Rupert, Terrace, etc.)	*	
~ July 1, 2001	13	
~ October 1, 2001	19	75
Centra Gas British Columbia Inc.		
General Complaints	5	
Cost of Gas Complaints:		
~ July 1, 2001	4	
~ October 1, 2001	2	11
Squamish Gas Co. Ltd.		1
Electric Utilities		
British Columbia Hydro and Power Authority		33
BC Hydro / BC Gas Utility Ltd. (combined)		2
UtiliCorp Networks Canada (British Columbia) Ltd. (previously known as West Kootenay Power Ltd.)		24
Hemlock Valley Electrical Services Limited		3
Princeton Light and Power Company, Limited		1
Silversmith Power & Light Corporation		1
Total 2001 Complaints / Inquiries		2,490

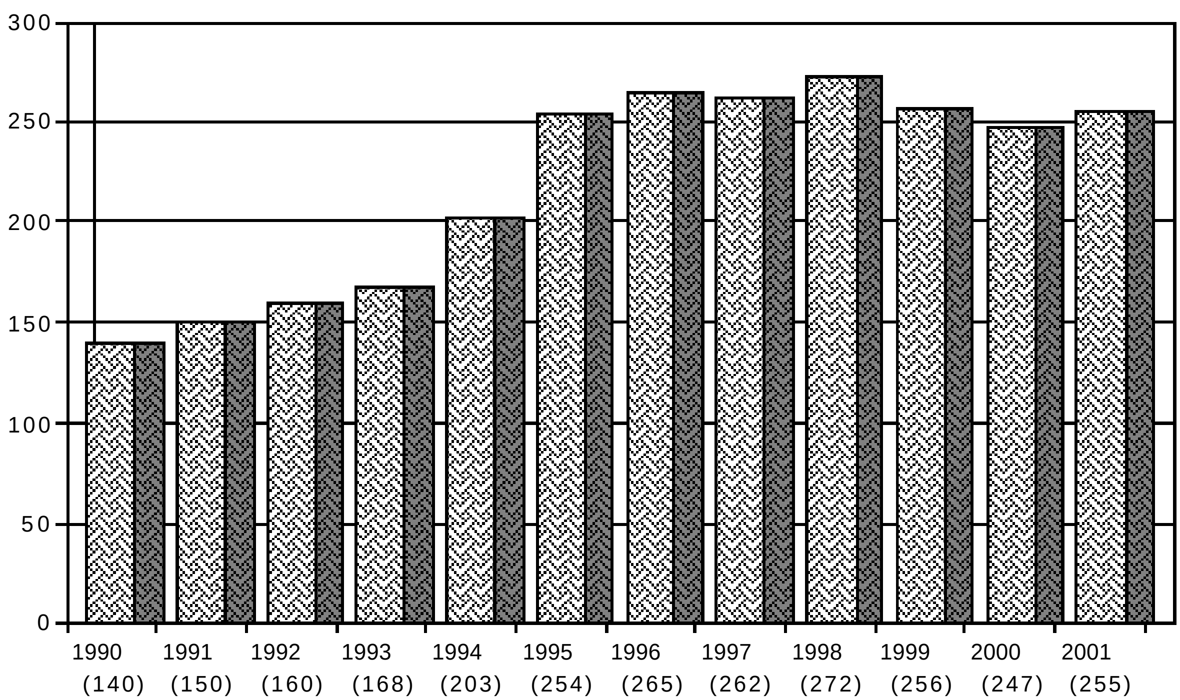
* The BCUC received signed petitions from 994 customers from the District of Hope (BC Gas service area) and 2,923 customers in Pacific Northern Gas' service area complaining about natural gas rates. These numbers are not included in the totals reflected above.

Staffing Levels

For over two decades Commission staffing levels have decreased while the number of Directives issued (i.e. Orders and Letters of Direction) continued to rise.

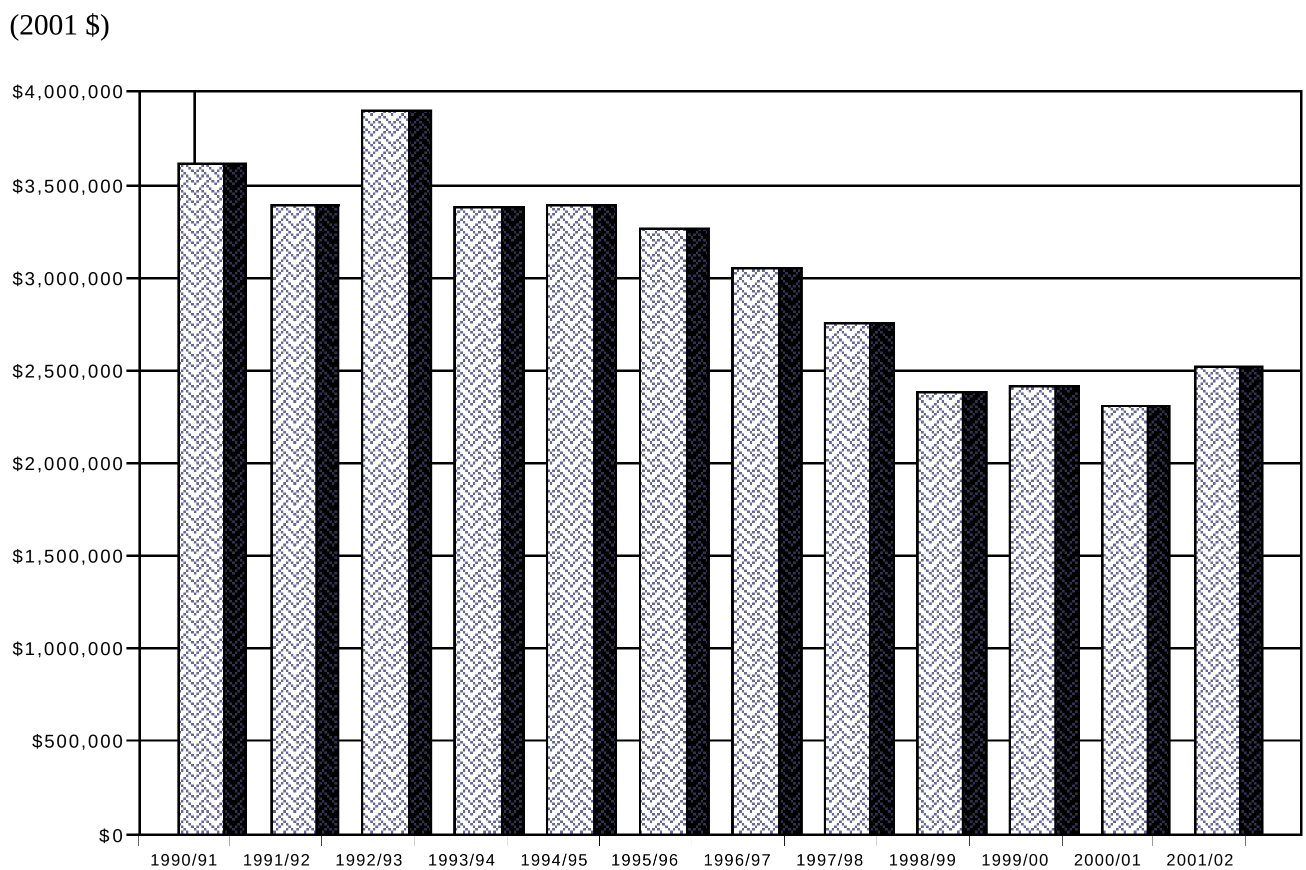


Directives Issued



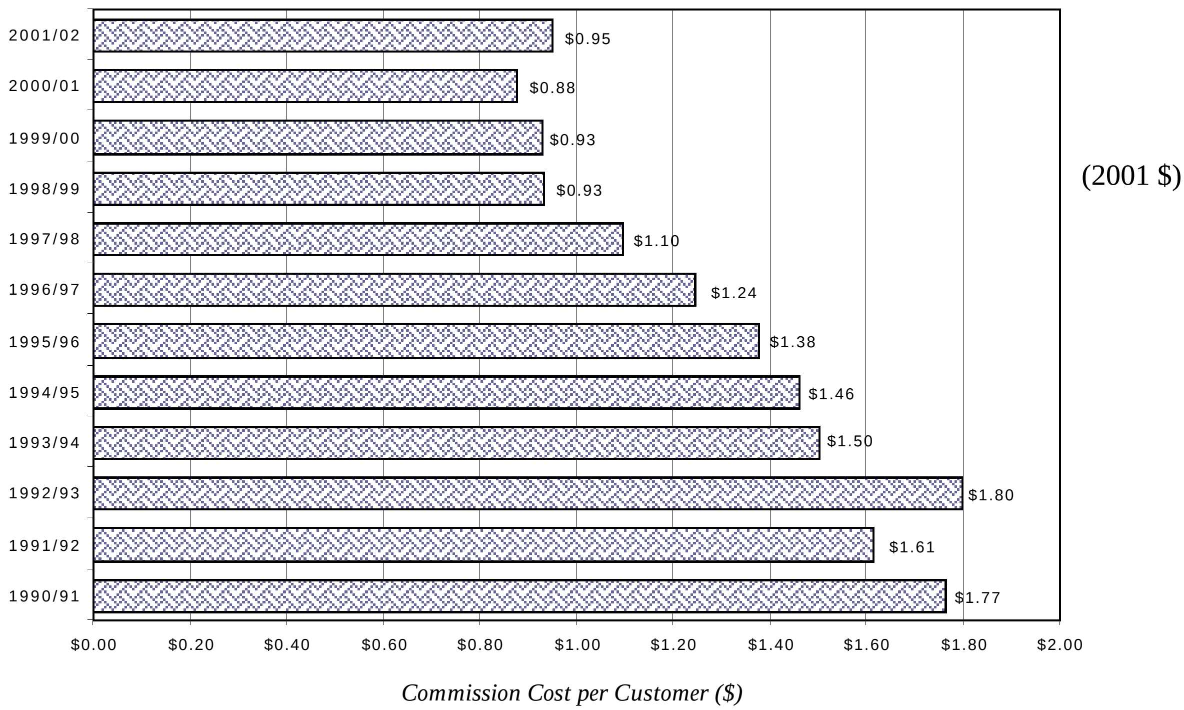
Commission Expenditures

For the past ten years, the Commission's budget has trended downward in real terms. Expenditure reductions are associated with reduced fees for legal counsel, consultants, temporary Commissioners, and court reporters. The Commission's actual expenditures for fiscal year 2001/02 (unaudited) were $2,515,362.03. A summary of revenues and expenditures may be found on pages 28 to 31.

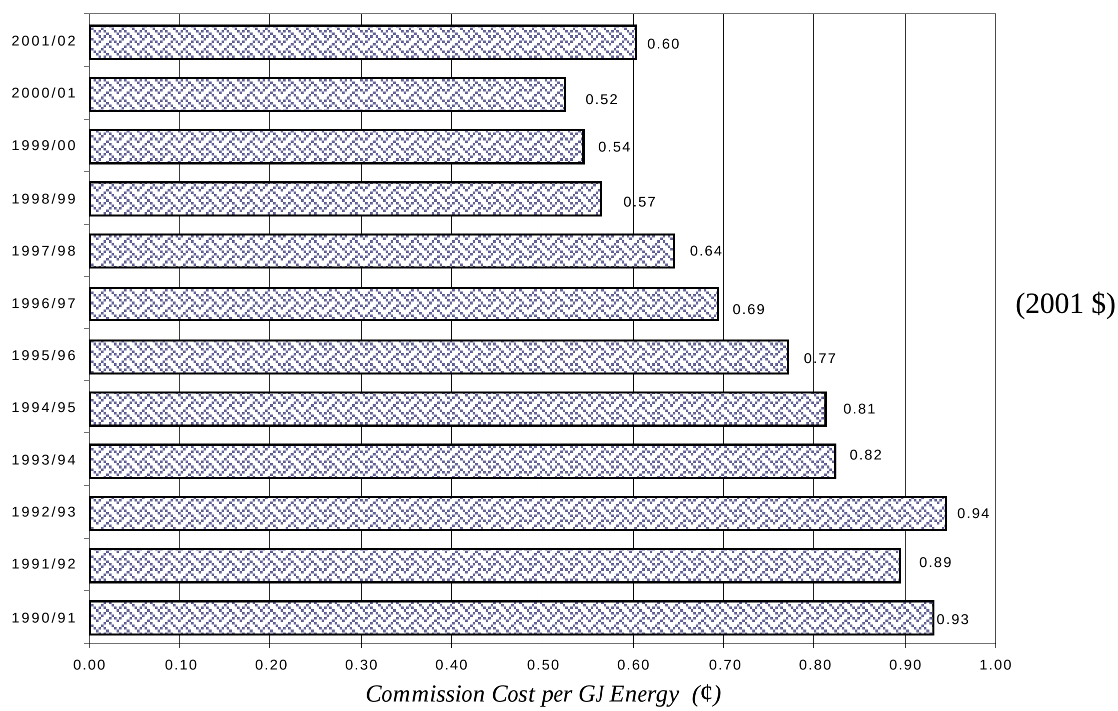


Cost of Regulation per Customer

Commission expenditures, and consequently the cost of regulation per customer, increased in 2001/02 primarily due to the higher number of hearing days. This added costs for outside legal counsel, court reporting services, temporary Commissioners, and travel for hearings outside of Vancouver. An additional increase, unrelated to the number of hearing days, resulted from increased charges for employee benefits.



Cost of Regulation per GJ of Energy Sold (cents)



G-1-01 PNG

Dismissed Skeena Cellulose Inc.'s application to modify or set aside Commission Order No. G-94-00, which approved interim rates for PNG, and denied the relief sought by Eurocan Pulp and Paper Co. and the Council of Forest Industries' Natural Gas Committee. Reasons for Decision were attached.

The Commission concluded that there was a sufficient evidentiary basis to grant the interim rate increase and found that any failure by PNG to disclose information to the Commission at the time of its making of the Interim Order was not of such a nature that it impacted on the special circumstances that the Commission found to be the basis for the Interim Order.

G-2-01 WKP

Approved the issuance of 200,000 authorized $100 par value common shares to UtiliCorp British Columbia Ltd. for a total consideration of $20 million.

G-3-01 Centra Gas

Approved an increase in rates to the Pioneer Large General Service LGS-1 to LGS-3 customers of between 2.34 and 4.49 percent and a decrease in rates to the ACR-1 customers of between 2.05 to 2.21 percent, effective February 1, 2001.

G-4-01 Stargas

Approved, pursuant to Section 61(4) of the Act, an addition to permanent rates of $2.554 / GJ for Residential and Commercial customers, effective January 1, 2001. The change comprised an increase to the BC Gas Utility Ltd. Charge of $2.432 / GJ and Stargas' Lost and Unaccounted for Gas of $0.122 / GJ.

G-5-01 Sun Peaks

Approved, pursuant to Sections 59, 60 and 61 of the Act, the Gas Tariff, General Terms and Conditions, and Rates for Gas Service as permanent, effective March 1, 1997.

G-6-01 Sun Peaks

Approved the following pursuant to Section 61(4) of the Act:

- an increase in the Gas Commodity Charge-Propane from $6.00 / GJ to $11.56 / GJ, effective December 15, 2000.
- the movement of the $0.7695 / GJ Sun Peaks Charge from the Gas Commodity Charge to the Delivery Charge, effective December 15, 2000.

- a Propane Cost Reconciliation Account to record the cost of propane purchases and transportation, the cost of vaporizer fuel and lost and unaccounted for propane, revenue from the Gas Commodity Charge-Propane, and interest on the account balance.

The Propane Cost Reconciliation Account is deemed to have a debit balance of $56,291 as of the end of March 2000. Within three months of the end of each fiscal year, Sun Peaks is to file a statement summarizing the transactions in the Propane Cost Reconciliation Account over the previous year, and identifying the account balance at year-end.

Accepted for filing, pursuant to Section 71 of the Act, the Link Propane Supply Contracts and the AutoGas Propane Supply Contract, subject to Sun Peaks filing a fully executed copy of the AutoGas document.

G-7-01 Centra Whistler

Approved the current customer rates as interim, effective with consumption on and after January 1, 2001, subject to a review of the utility's 2001 Revenue Requirements Application to be filed in late January 2001.

G-8-01 BC Hydro and WKP

Approved the following for BC Hydro and WKP effective November 1, 2000:

- First Amendment to the Reliability Management System Agreement with the Western Systems Coordinating Council, and

- Second Amendment to the Reliability Criteria Agreement with the Western Systems Coordinating Council.

G-9-01 Squamish Gas

Approved an increase in rates to the General Service LGS-1 to LGS-13 customers of between 2.34 and 4.49 percent and a decrease in the ACR-1 rates of 2.05 percent, effective February 1, 2001.

G-10-01 PLP

Approved the application to alter the Monthly Adjustment in the energy charge for Time-of-Use Rate Schedules AX, CX1-CX4, CXM, JX, EX and FX, to pass-through differences in power purchase costs due to the Time-of-Use program, effective January 31, 2001.

G-11-01 BC Hydro

Approved Tariff Supplement No. 55, Access Principles for Public, Municipal and Other Utilities and issued Reasons for Decision.

G-12-01 BC Hydro

Approved Rate Schedule 1853 - Transmission Service, Station Service for Maintenance and Black-Starts, effective January 25, 2001. Rate Schedule 1853 service is to be addressed in BC Hydro's next comprehensive rate design application.

G-13-01 Williams Energy (Canada) Inc.

Approved, pursuant to Section 88(3) of the Act and Order in Council No. 16, 2001, the exemption from Part 3 of the Act, other than Sections 24 and 25, of the West Stoddart facilities, which are used to transport or process natural gas for others, effective January 25, 2001.

G-14-01 PNG

Approved an interim increase of $1.068/GJ to the gas supply deferral account rates for Rate Schedules 1, 2, 4, 5, 6, and 7, effective February 1, 2001. Corresponding increases to minimum monthly charges for Rate Schedules 4, 5, and 6 that include a quantity of gas commodity were also approved as interim effective February 1, 2001.

Denied PNG's request to increase the Gas Supply Charge.

Interim rates are subject to refund with interest pending the outcome of the March 5, 2001 public hearing on PNG's revenue requirements.

G-15-01 WKP

Approved the December 20, 2000 Electricity Supply Brokerage Agreement and Curtailment Agreement with KPMG Inc. (Celgar Pulp), effective November 1, 2000.

Approved the Curtailment Agreements with Atco Lumber Ltd. at Park Siding and Fruitvale, BC, for curtailment of load from January 2 to February 2, 2001.

G-16-01 BC Gas

Approved the Natural Gas Vehicle Service Agreement, Tariff Supplement No. C-1 with Beach Place Ventures Ltd. for the period December 16, 1999 to December 15, 2001.

G-17-01 BC Gas

Approved amendments to the Gas Tariff effective January 1, 2001, to reflect similar tariff changes approved for BC Hydro's Lower Mainland customers by Order No. G-81-00, which amended the General Terms and Conditions of Service, Billing Plan Name changes and the treatment of customers in its service areas.

G-18-01 Squamish Gas

Approved an increase in the propane rates of $1.610/Ccf, and an increase in the Propane Cost Deferral Account Reference Price from $0.2095 to $0.3595/litre, effective February 1, 2001. The difference between the actual cost of propane and the cost recovered in rates will be recorded in the Propane Cost Deferral Account.

G-19-01 Centra Gas

Approved the following decreases in rates effective March 1, 2001:

- Pioneer Large General Service LGS-1 to LGS-3 customers of between 2.66 and 2.67 percent.
- ACR-1 customers of between 5.31 to 6.88 percent for customers in the Capital Regional District.
- ACR-1 customers of between 2.05 to 6.65 percent for customers in Other Communities.

G-20-01 Squamish Gas

Approved a decrease in rates for LGS-1 to LGS-13 customers of between 2.66 to 2.67 percent and a decrease in rates for the ACR-1 rate schedule of between 2.05 to 6.65 percent, effective March 1, 2001.

G-21-01 BC GAS

Established a workshop and pre-hearing conference for the 2001 Rate Design Application.

G-22-01 PORT ALICE GAS

Approved the Schedule of Rates as permanent and the proposed methodology for calculating the cost of propane for billing purposes and recovery of the 2001 fiscal year revenue deficiency identified in the Application, effective December 1, 2000. The Commodity Fee will be billed at the higher of the $13.4574 / GJ December 1, 2000 rate or the actual cost of propane for the month as calculated in accordance with the approved Propane Tariff.

G-23-01 REVISED GUIDELINES PARTICIPANT ASSISTANCE/COST AWARDS

Issued amended Participant Assistance / Cost Award Guidelines by revising Section 4(d) Consultants' Costs, effective February 22, 2001.

G-24-01 CITY OF NELSON

Approved and accepted for filing Electrical Utility Amendment By-Law No. 2909, 2001 and corrected rate schedules incorporating a 2 percent rate increase to reflect increased power purchase costs from its supplier, WKP, effective February 1, 2001.

G-25-01 CENTRA GAS

Approved amended Competitive Range Rate Schedules for the Empress Hotel and Sunwing Greenhouses Ltd., effective April 1, 1994.

G-26-01 BC HOT HOUSE GROWERS' ASSOCIATION AND BC HYDRO

Established a public hearing to consider the conditions of access by distributed generation including cogenerators to the BC Hydro transmission and distribution system and the charges, if any, for the transport of power.

G-27-01 BC HYDRO

Established a workshop and regulatory timetable regarding BC Hydro's obligation to serve industrial customers with self-generating capability served under Rate Schedule 1821 Transmission Service, who wish to take their self-generation output to the market.

G-28-01 SUN RIVERS

Approved an increase in natural gas rates for Rate Schedule 1 - Residential Service and Rate Schedule 2 - Small Commercial Service customers, effective February 1, 2001.

G-29-01 CENTRA GAS

Approved a cost of gas pass-through to the second block of the Competitive Range Rate E-Plus Rate Schedule from 2.060 cents to 2.383 cents, effective March 1, 2001.

G-30-01 CENTRA GAS

Approved a decrease in rates of between 3.07 to 3.16 percent for Pioneer LGS-1 to LGS-3 customers; a rate increase of between 2.27 to 2.41 percent for ACR-1 customers in the Capital Regional District; and a rate increase of between 2.11 to 2.34 percent for ACR-1 customers in Other Communities, all effective April 1, 2001.

G-31-01 SQUAMISH GAS

Approved a rate decrease of between 3.07 to 3.16 percent for the LGS-1 to LGS-13 customers and a rate increase of between 2.11 to 2.34 percent for the ACR-1 rate schedule, all effective April 1, 2001.

G-32-01 BC GAS

Directed Commission staff to hire an independent rate design consultant to review the 2001 Rate Design Application in accordance with the Terms of Reference drafted by Commission staff, and to report the consultant's findings to Registered Intervenors and Participants.

G-33-01 WKP

Established a public hearing in Rossland to review the sale of its Kootenay River hydroelectric generation plants and related facilities to subsidiaries / joint venture companies held by Columbia Basin Trust and the Columbia Power Corporation for $120 million.

G-34-01 CENTRA GAS AND ISLAND COGENERATION LIMITED PARTNERSHIP

Approved an extension to the term of the Second Amending Transportation Service Agreement with Island Cogeneration Limited Partnership by one month to April 30, 2001.

G-35-01 BC Hot House Growers' Association and BC Hydro

Delayed the commencement of the public hearing and issued an amended regulatory timetable to allow additional time for information requests.

G-36-01 TransCanada Midstream

Rescinded Order No. G-77-98, effective April 5, 2001, as the West Stoddart gas processing plant and associated pipelines had been sold to Williams Energy (Canada) Inc.

G-37-01 PLP

Approved the recovery of the forecast 2002 fiscal year revenue deficiency on an interim basis, effective April 1, 2001, subject to refund with interest after a written public hearing. The interim increase is to be applied across all rate classes and access as well as service charges and is to be no greater than 1.85 percent of its total cost of service including energy.

G-38-01 BC Hydro

Directed BC Hydro to allow Rate Schedule 1821 customers with idle self-generation capability to sell excess self-generated electricity, provided the self-generating customers do not arbitrage between embedded cost utility service and market prices. This means that BC Hydro is not required to supply any increased embedded cost of service to a Rate Schedule 1821 customer selling its self-generation output to market. Directed the utility to file a full report on the program with the Commission by March 31, 2002.

G-39-01 Centra Gas

- Approved a decrease in rates for Pioneer LGS-1 to LGS-3 customers of between 4.35 and 4.37 percent, effective May 1, 2001.
- Approved a decrease in rates to ACR-1 customers of between 4.44 and 4.78 percent in the Capital Regional District, and between 4.19 and 4.61 percent in Other Communities, effective May 1, 2001.

G-40-01 Squamish Gas

Approved a decrease in rates to General Service customers of between 4.35 and 4.37 percent for the LGS-1 to LGS-13 customers and a decrease to the ACR-1 rate schedule of between 4.19 and 4.61 percent, all effective May 1, 2001.

G-41-01 BC Gas

Approved the amendment to Order No. G-119-99 and authority to issue up to $800 million Medium Term Note Debentures from time-to-time, effective from April 12, 2001 until the end of November 2001. BC Gas shall continue to file, within one week of issue, a pricing supplement for each Medium Term Note Debenture issued.

G-42-01 BC Gas

Approved a Rate Schedule 5-Large Commercial Service Tariff Supplement with I.G. Machine & Fibers Ltd. dated January 25, 2001, for the period commencing July 1, 2001.

G-43-01 Centra Gas and Island Cogeneration Limited Partnership

Approved, effective April 30, 2001, an extension to the term of the Second Amending Transportation Service Agreement between Centra Gas and the ICLP to the earlier of June 30, 2001 or the date that gas deliveries commence, under a contract with a firm service component between Centra Gas and BC Hydro, which has been ratified and approved by the Commission.

G-44-01 Centra Whistler

Established a workshop and pre-hearing conference on the utility's 2001 Revenue Requirements Application.

See Order No. G-55-01 that outlines the review process.

G-45-01 WKP

Accepted for filing the following Agreements for the supply of electricity service between WKP and:

- The City of Penticton, dated February 1, 2001 for a five-year term from January 1, 2001 to December 31, 2005.
- The District of Summerland, dated February 1, 2001 for a five-year term from January 1, 2001 to December 31, 2005.
- The City of Kelowna, dated February 1, 2001 for a five-year term from November 1, 1999 to October 31, 2004.
- The City of Grand Forks, dated February 1, 2001 for a five-year term from January 1, 2001 to December 31, 2005.
- The City of Nelson, dated February 1, 2001 for a five-year term from November 1, 1999 to October 31, 2004.

- Princeton Light and Power Company, Limited, dated December 1, 2000 for a five-year term from November 1, 2000 to October 31, 2005.

G-46-01 BC GAS

Approved a deferral account to record external information technology consulting services costs for the Requirement Definition Phase of the ABC-T project up to $335,000.

G-47-01 BC GAS

Approved the Puget Sound Energy, Inc., Reliant Energy Services and Mirant Americas Energy Marketing Agreements as Rate Schedule 30 Tariff Supplements, subject to BC Gas filing the Agreements with the Commission in Tariff Supplement format by June 15, 2001. BC Gas is to identify any contracts to purchase gas, pursuant to the Agreements, in its monthly spot gas report.

G-48-01 BCUC

Public utilities are ordered to pay a fixed levy of $0.00671079 per GJ equivalent to energy sold for the calendar year 2000, commencing April 1, 2001. Also, pursuant to Levy Regulation 283/88 and Letter No. L-39-96, upstream natural gas processors and intraprovincial oil pipelines are each ordered to pay $1,000 for the fiscal year commencing April 1, 2001.

G-49-01 SQUAMISH GAS

Approved amendments to Gas Tariff, General Terms, Conditions and Regulations affecting Equal Payment Plan eligibility and late payment charges for customers in the SGS-11 rate class, effective April 1, 2001.

G-50-01 BC HYDRO

Reduced the calculation of surcharge charged to customers served from the Meziadin Lake extension. The capital costs to be collected through the surcharge will be adjusted to $1,331,100 at an interest rate of 6 percent on the outstanding balance and amortized over ten years. Customers are to be refunded the difference between the interim and final surcharge at an interest rate of 6 percent per annum.

G-51-01 PNG

- Confirmed as permanent the interim rates approved by Order No. G-94-00 for the period October 1, 2000 to December 31, 2000.
- Confirmed as permanent the rates as applied for on the "Summary of Rates Schedule Effective January 1, 2001" on pages 2 and 3 of Exhibit 1B, effective January 1, 2001, except that the Industrial and Rate Schedule 3 restructuring charges are reduced by 50 percent retroactive to January 1, 2001, and the restructuring charge for Commercial Rate Schedule 2 rates is set at zero for the period January 1, 2001 to June 30, 2001 and set at $0.85/GJ effective July 1, 2001.
- Confirmed as permanent, the Gas Supply Charges as applied for on the "Summary of Rates Schedule Effective February 1, 2001" on page 5 of Exhibit 1B, effective February 1, 2001.
- Denied the Methanex Application and directed PNG to advise the Commission by June 15, 2001 on the status of negotiations with Methanex towards establishing a long-term load retention rate based on the findings in the Commission's Decision on the October to December 2000 Rates and 2001 Revenue Requirements Applications and the application by Methanex Corporation.

G-52-01 BC HYDRO

Approved rates and conditions for access to the distribution system by IPPs as set out in the Commission Decision dated June 1, 2001. A report reviewing the use of the distribution system by IPPs, and the cost and benefits of the distributed generation to the transmission systems is to be filed by December 31, 2002.

G-53-01 CENTRA GAS AND BC HYDRO

Convened a written hearing into the applications for the Amended and Restated Transportation Service Agreement, BC Hydro Transmission Service Agreement, Peaking Agreement and the Capacity Assignment Agreement.

Centra Gas' application for the approval and recovery of costs related to serving cogeneration loads on Vancouver Island will be considered in the next Centra Gas Revenue Requirements and Revenue Deficiencies review.

G-54-01 CENTRA GAS

Approved the fixing of $65 million of floating rate debt, on or before May 31, 2001, in an all-in cost rate not to exceed 6.85 percent. The approved final terms of the interest rate swaps are to be provided to the Commission.

G-55-01 CENTRA WHISTLER

Scheduled a negotiated settlement process proceeding in Whistler, BC to review the 2001 Revenue Requirements Application.

G-56-01 CENTRA GAS

Approved an increase in rates to ACR-1 customers of between 2.35 to 2.50 percent in the Capital Regional District, and between 2.28 and 2.42 percent in Other Communities, effective July 1, 2001.

G-57-01 BC HYDRO

Approved Tariff Supplement No. 56 for the sale of steam from the Burrard Thermal Generating Station to Imperial Oil's IOCO terminal facility in Port Moody, BC, commencing November 1, 2001.

G-58-01 PLP

Confirmed rates for Services Charges and the 2.871 percent increase to the Access Charges rate, effective April 1, 2001.

G-59-01 BC GAS

Established a workshop and pre-hearing conference in Kelowna to discuss the Lease-in-Lease-out ("LILO") Application. (See Order No. G-78-01 for further review process.)

G-60-01 BC HYDRO / DISTRICT OF FORT ST. JAMES

Ordered BC Hydro to construct at its own cost, the necessary transmission line modifications between Vanderhoof and Fort St. James. Modifications to the Fort St. James substation and facilities downstream of that point will be carried out with customer contributions, where required, in accordance with BC Hydro's standard policies and tariffs. Reasons for Decision were attached.

G-61-01 WKP

Reconvened the public hearing in Rossland to hear the Application to Sell its Hydroelectric Generation Assets and the request for approval of the Letter Agreement regarding the unresolved Brilliant tailrace issue.

G-62-01 RETURN ON COMMON EQUITY

Established a written public hearing regarding the automatic adjustment formula for setting the ROE for a low-risk benchmark utility, limited to (1) the treatment when the yields on 10-year Government of Canada bonds exceed the yields on 30-year Government of Canada bonds and (2) whether to continue to round the nearest 25 basis points and, if so, if the rounding should apply to the low-risk benchmark ROE or the utility-specific ROE.

G-63-01 BC HYDRO

Approved the May 24, 2001 Special Electric Service Agreement, Tariff Supplement No. 58 with Richmond Plywood Corporation Limited for a bypass rate at the equivalent of Rate Schedule 1821 plus a monthly rider of $6,472.50 for a period of 20 years, effective July 1, 2001.

G-64-01 BC GAS

Ordered a change to the Propane Reference Price, effective July 1, 2001, to a level that will ensure that the Deferral Account balance will be zero as at June 30, 2002.

G-65-01 BC HYDRO

Approved the following:

- Power Smart Industrial Rate Schedule 1854 as a pilot program, effective July 1, 2001 to July 31, 2002.
- Tariff Supplement No. 59 - Power Smart Industrial Rate Pilot Program Agreement, effective July 1, 2000 to July 31, 2002.
- Amendments to the Electric Tariff Index Pages v and vi and revisions to Rate Schedule 1880 - Transmission Service - Emergency, Maintenance and Special Supply were approved effective July 1, 2001.

A report evaluating the Power Smart Industrial Rate Pilot Program is to be filed by September 30, 2002.

G-66-01 PNG AND PNG (N.E.)

Approved the following:

- An increase in the PNG-West Company Use Gas Charge of $0.138 / GJ to $0.244 / GJ, effective July 1, 2001.
- A decrease in the PNG-West GCVA Rider of $0.494 / GJ to $0.874 / GJ, effective July 1, 2001.
- The recording, by PNG-West, of up to $632,000 of specified incremental operating and maintenance expenses associated with Methanex's July 1, 2001 startup in the Industrial Customer Deliveries Deferral Account, with prudency and disposition of the amount to be determined by the Commission at a future date, effective July 1, 2001.

G-67-01 BC GAS

Approved the Rate Schedule 7 tariff, but denied the request for the Gas Cost Recovery Account rider to apply for longer than the 2001/02 gas contract, with commodity pricing as follows:

Daily Index Option:
Daily Index price, plus $0.15/GJ.
Fixed Price Option:
Rate Schedule 5 Gas Cost Recovery Charge plus Rate Schedule 5 Gas Cost Reconciliation Account rider.

Approved the Rate Schedule 10 tariff with the commodity pricing as follows:

Daily Index Option:
Daily Index price.
Monthly Index Option:
Monthly Index price, including a 3 percent discount during November through March, and a commitment by the customer to purchase a daily Contract Demand quantity when gas is available.

Approved the Rate Schedule 14 tariff for firm term and spot sales with commodity pricing as follows:

Daily Index Option:
Daily Index price, plus a Market Factor of not less than $0.15/GJ.
Fixed Price Option:
Annualized price based on the Sumas monthly forward prices for physical purchases that BC Gas fixes at approximately the time when the customer commits to the Fixed Price option for 2001/02 plus a Swing Premium of $1.50/GJ for November through March and $0.90/GJ for April through October.

Spot Gas:
Daily Index plus $0.02/GJ to $0.05/GJ, and not less than cost.

A report will be submitted within 30 days of the end of each month summarizing gas purchase and sale quantities, and cost and revenue for each price option for the month for Rate Schedule 14 transactions.

A report will be submitted on a quarterly basis within 60 days from the end of the contract year quarter of all Rate Schedule 14 transactions.

G-68-01 PORT ALICE GAS

Approved the application to revise the Gas Tariff to adjust the rates by the actual change in propane prices once the delivered cost of propane declines below $294.429/$m^3$ pursuant to methodology for calculating the cost of propane for billing purposes and recovery of the 2001 fiscal year revenue deficiency approved by Order No.G-22-01.

G-69-01 SUMAS ENERGY 2, INC.

Dismissed complaint regarding the rates and terms and conditions of the BC Hydro Wholesale Transmission Service Tariff Supplement and associated rate schedules. BC Hydro is to provide 30 days notice to Sumas Energy prior to removing Sumas Energy's Open Access Same Time Information System Request No. 343571 from the reservation priority queue.

G-70-01 CENTRA GAS

Approved an increase in ACR-1 rates of between 2.26 to 2.43 percent for customers in the Capital Regional District, and between 2.09 and 2.34 percent for customers in Other Communities, effective August 1, 2001.

G-71-01 CENTRA GAS AND ISLAND COGENERATION LIMITED PARTNERSHIP

Approved an extension to the term of the Second Amending Transportation Agreement to the Island Cogeneration Limited Partnership to July 13, 2001.

G-72-01 PNG (N.E.)

Approved the following with respect to the 2001 Revenue Requirements Application:

- A reduction in the revenue deficiency to $5,000 for the Fort St. John/Dawson Creek Division;
- A reduction in the revenue deficiency to $122,000 for the Tumbler Ridge Division;
- The Gas Supply Charges for the Fort. St. John/Dawson Creek Division; and
- The proposed new main extension test, subject to review of the actual tariff, when it is filed.

G-73-01 SQUAMISH GAS

Approved an increase to the ACR-1 rate schedule of between 2.24 and 2.40 percent, effective July 1, 2001.

G-74-01 Centra Whistler

Approved the Settlement Agreement which includes a 2001 revenue deficiency of $345,233 resulting in an increased energy charge for all customers of $0.994 per gigajoule, and Gas Cost Deferral Account Rider of $0.595 per gigajoule, effective July 1, 2001.

G-75-01 Centra Gas and BC Hydro

Issued an amended regulatory agenda and timetable extending the date for filing intervenor evidence by one week to July 13, 2001, with respect to the Transportation Service Agreements for the transportation of natural gas to the Island Cogeneration Plant located at Elk Falls, BC.

G-76-01 Squamish Gas

Approved an increase to the ACR-1 rate schedule of between 2.09 and 2.34 percent, effective August 1, 2001.

G-77-01 Centra Gas and Island Cogeneration Limited Partnership

Approved a further extension to August 31, 2001 of the Second Amending Transportation Service Agreement.

G-78-01 BC Gas

Referred the Lease-In / Lease-Out arrangements with the City of Kelowna to a written public hearing and set out a regulatory agenda. (See Order No. G-108-01 for Commission decision.)

G-79-01 BC Gas

Approved the cancellation of Rate Schedule 31 and the revision of Rate Schedule 30 to the new GasEDI format. All existing contracts under previous Rate Schedules 30 and 31 are grandparented until such time as they have been converted to the new Rate Schedule 30 GasEDI format. Gas purchases made under the Rate Schedule 30 GasEDI contract as part of its monthly spot gas purchases is to be reported to the Commission.

G-80-01 BC Hydro

Approved the Customer Baseline Load calculations for Quesnel River Pulp and Sterling Pulp Chemicals Ltd. under Rate Schedule 1854 and Tariff Supplement No. 59, as filed on July 11, 2001.

G-81-01 BC Hydro

Approved the Customer Baseline Load calculations for Nexen Chemicals under Rate Schedule 1854 and Tariff Supplement No. 59, as filed on July 17, 2001.

G-82-01 BC Gas

Established a workshop and negotiated settlement process to review the 2001 Rate Design Application.

G-83-01 PLP

Approved amendments to the credit facilities with the Canadian Imperial Bank of Commerce in accordance with the July 3, 2001 Business Credit Agreement, pursuant to Sections 49 and 50 of the Act.

G-84-01 WKP

Approved an extension by 364 days from May 30, 2001 the Revolving Loan Agreement with the Bank of Montreal, pursuant to Section 50 of the Act.

G-85-01 BC Hydro

Approved the adjusted Customer Baseline Load calculations for the Annacis Island Sewage Treatment Facility under Rate Schedule 1854 and Tariff Supplement No. 59.

G-86-01 BC Hydro

Approved the adjusted Customer Baseline Load calculations for BC Chemicals Ltd. under Rate Schedule 1854 and Tariff Supplement No. 59.

G-87-01 BC Hydro

Approved the adjusted Customer Baseline Load calculations for Canadian Forest Products Ltd. Prince George Pulp Operations under Rate Schedule 1854 and Tariff Supplement No. 59.

G-88-01 BC Hydro

Approved the adjusted Customer Baseline Load calculations for Norske Skog, Elk Falls under Rate Schedule 1854 and Tariff Supplement No. 59.

G-89-01 Centra Gas

Approved decreases in the Pioneer LGS-1 to LGS-3 customer rates of between 3.02 and 3.09 percent, between 8.06 to 8.55 percent for ACR-1 customer rates, and between 7.79 to 8.25 percent in Other Communities, all effective September 1, 2001.

G-90-01 BC Hydro

Concluded that the sale of electricity by Powell River Energy Inc. during Pacifica Paper Inc.'s mill shutdown met the definition of Surplus Power under Minister's Order No. M-22-0101 and that Pacifica should not be charged a market based rate. BC Hydro is not required to pay the costs of Pacifica Paper Inc., Powell River Energy Inc., and Maclaren Energy Management Services Inc. with respect to the application.

G-91-01 RFP Power Ltd.

Approved an exemption from the provisions of the Act, other than Part 2 and Section 99, in respect of the production, delivery and sale of steam to Riverside Forest Products Limited effective August 9, 2001, pursuant to Order in Council No. 739, 2001. The Commission may, pursuant to Section 99 of the Act, reconsider, vary or rescind an Order made by it.

G-92-01 BC Hydro

Denied the application for reconsideration of the Commission's Decision and Order No. G-50-01 by Ms. Rose Smith of the Meziadin Residents' Association.

G-94-01 BC Hydro and Centra Gas and Island Cogeneration Limited Partnership

Approved the following:

- Amended and Restated Transportation Service Agreement commencing September 1, 2001 between Centra Gas and ICLP.
- BC Hydro Transportation Service Agreement and the BC Hydro Peaking Agreement.
- Capacity Assignment Agreement between BC Hydro, Centra Gas and BC Gas.

G-95-01 Squamish Gas

Approved a decrease in rates for LGS-1 to LGS-13 customers of between 3.02 and 3.09 percent and between 9.68 and 10.35 percent for ACR-1 rate customers, effective September 1, 2001.

G-96-01 Centra Gas

Approved an increase in the ACR-1 rates of between 2.57 and 2.66 percent for customers in the Capital Regional District and between 2.47 and 2.55 percent for customers in Other Communities, effective October 1, 2001.

G-97-01 BC Gas

Approved an increase in the deferral account to record an additional $83,000 of external information technology consulting services costs for the Requirements Definition Phase of the ABC-T project. A report on final accounting of costs for deferral treatment following the completion of the project is to be provided.

G-98-01 BC Gas

Established a workshop and pre-hearing conference to discuss the 2002 Revenue Requirements Application.

G-99-01 Squamish Gas

Approved an increase to the ACR-1 rate schedule of between 2.47 and 2.55 percent, effective October 1, 2001.

G-100-01 BC Gas

- Approved for the Lower Mainland, Inland and Columbia Divisions, changes to Gas Cost Recovery Charges and GCRA Riders, effective October 1, 2001
- Denied request to change the income tax refund rate rider (Rider 2).
- Approved for the Fort Nelson Division, a gas cost rate reduction of $0.62 / GJ, effective October 1, 2001.

G-101-01 Centra Gas

Approved a Rider C of $1.705 / GJ for New Customer rate classes, effective October 1, 2001.

G-102-01 PNG and PNG (N.E.)

Approved, as a result of the current and projected balances in the Gas Cost Variance Account, rate reductions that are 150 percent of the requested rate decreases, effective October 1, 2001. An update on Gas Cost Variance Account balances and expected gas costs and revenues for 2002 is to be reported by December 7, 2001. Rate changes should be requested if forecasted gas costs and revenues differ by more than 5 percent as set out in Letter No. L-5-01.

G-103-01 BC Gas

Established a negotiated settlement process to review the 2002 Revenue Requirements Application.

G-104-01 BC Gas

Approved for the 2001/02 gas contract year, a market factor equal to the greater of $0.05 Cdn per gigajoule or cost, to be included in the Daily Index Option rate under Rate Schedule 7 and the Daily Index Option and Monthly Index Option rates under Rate Schedule 14.

G-105-01 Stargas

Approved a reduction of $1.327/GJ in rates for Residential and Commercial customers, effective October 1, 2001.

G-106-01 Centra Gas

Approved the following rate increases, effective November 1, 2001:

- Pioneer LGS customers of between 3.61 and 3.72 percent.
- ACR-1 customers in the Capital Regional District of between 3.65 to 3.94 percent.
- Other ACR-1 customers of between 3.52 to 3.79 percent.

G-107-01 Squamish Gas

Approved the following rate increases, effective November 1, 2001:

- LGS customers of between 3.61 and 3.72 percent.
- ACR-1 customers of between 3.52 and 3.79 percent.

G-108-01 BC Gas

Approved the Lease-In/Lease-Out arrangements with the City of Kelowna (including the minor amendments to the agreements dated August 13, 2001).

G-109-01 Return on Common Equity

Directed that the ROE mechanism would remain as set out in Order No. G-80-99 except that the ROE for the low-risk benchmark utility, expressed as a percentage, would be rounded to two decimal points prior to adding the utility-specific risk premium. Reasons for Decision were issued (see page 68 for a summary of this Decision).

G-110-01 Sun Rivers

Approved decreases in natural gas rates, effective October 1, 2001, as set out in Sun Rivers' October 5, 2001 application for Rate Schedule 1 - Residential Service and Rate Schedule 2 - Small Commercial Service customers.

G-111-01 BC Hydro

Approved Rate Schedule 1253 - Distribution Service - Station Service for Maintenance and Black-Starts for Independent Power Producers, effective October 18, 2001.

G-112-01 WKP/UNC

Denied WKP's application to sell its hydroelectric generation assets situated on the Kootenay River to a joint venture subsidiary of the Columbia Basin Trust and the Columbia Power Corporation. Reasons for Decision were issued.

G-113-01 Riverside Forest Products Limited

Pursuant to Order in Council No. 919, 2001 and Section 88(3) of the Act, the Commission exempted Riverside from the provisions of the Act, other than Part 2 and Section 99, in respect of the production and sale of the Incremental Power to:

- Brokers or others for export outside of the Province; or
- The City of Kelowna or to Powerex Corporation, BC Hydro or WKP; or
- For use outside of the City of Kelowna's electrical service area.

Approved an exemption under Section 88(3) for the Purchaser of the Incremental Power from Section 71 of the Act in respect of the purchase of the Incremental Power if the purchaser is not a public utility under the Act.

Exempted Riverside from the provisions of the Act, other than Part 2 and Section 99, in respect of the production and sale to the City of Kelowna of that portion of the Power Plant's initial 2 MW of generation each hour that is not required by the facilities.

G-114-01 UNC

Established an Annual Review process for the Preliminary 2002 Revenue Requirements and Incentive Mechanism Application to take place in Kelowna

G-115-01 1198184 Ontario Limited

Approved the following:

- The proposed amalgamation of 1198184 Ontario Limited and its parent corporation Manucab Ltd.;
- The transfer of the Hluey Lakes hydroelectric generating facility to Clean Power Operating Trust; and
- The transfer of the rights, benefits and interests granted by Orders No. G-46-94, E-10-94, G-62-96 and G-54-99 from 1198184 Ontario Limited to Clean Power Operating Trust.

The Commission confirmed that Clean Power Operating Trust and the sale of power generated by Clean Power Operating Trust from the Hluey Lakes hydroelectric generating facility shall be exempt from the Act, other than Part 2 and Sections 99 and 100, and approved the Assignment, Assumption and Consent Agreement effective on the Closing Date.

G-116-01 BC Gas

Approved the 2001 Rate Design Settlement Document dated October 3, 2001.

G-117-01 Centra Gas

Approved the following decreases, effective December 1, 2001:

- Pioneer LGS customers of between 3.00 and 3.07 percent;
- ACR-1 customers of between 8.25 to 8.87 percent for customers in the Capital Regional District; and
- ACR-1 customers of between 7.97 to 8.55 percent in Other Communities.

G-118-01 Squamish Gas

Approved, effective December 1, 2001, a decrease in rates to the Large General Service customers of between 3.00 and 3.07 percent, and a decrease in rates to the ACR-1 rate schedule of between 7.97 to 8.55 percent.

G-119-01 BC Hydro

Approved the Third Amendment to the Reliability Agreement with the Western Systems Coordinating Council, effective June 1, 2001, pursuant to Sections 23 and 28 of the Act.

G-120-01 Clean Power Operating Trust

Approved the following pursuant to Section 88(3) of the Act:

- The amalgamation of Regional Power Inc. with its two wholly-owned subsidiaries, La Regionale Power Port-Cartier Inc., Société Hydroelectrique La Regionale Port-Cartier Inc. and La Regionale Power Angliers Inc., Société Hydroelectrique La Regionale Angliers Inc., which will continue under the name Regional Power Inc.;
- The sale of the Sechelt Creek hydroelectric generating facility by Regional Power Inc. to Clean Power Operating Trust; and
- The ongoing operations of the Sechelt Creek hydroelectric generating facility and the sale of power by Clean Power Operating Trust to BC Hydro is exempt from the Act, other than Part 2 and Sections 99 and 100, pursuant to the authority under the Act and given by Ministerial Order No. 1-M-51, and the assignment of the Electricity Purchase Agreement to the Trust.

G-121-01 Duke Energy Corporation et al.

Approved the acquisition of indirect control of Pacific Northern Gas Ltd., Pacific Northern Gas (N.E.) Ltd., Centra Gas British Columbia Inc., and Centra Gas Whistler Inc., by each of the following Duke Energy Companies: Duke Energy Corporation, Duke Capital Corporation, 3059703 Nova Scotia Company, 3058368 Nova Scotia Company, and 3946509 Canada Inc., pursuant to Section 54 of the Act.

G-122-01 PNG

Approved the issuance of $12 million of secured debentures, as described in the RoyNat Inc. Offer of Finance, pursuant to Sections 50 and 52 of the Act.

Approved the creation of a deferral account to record the redemption premium and other associated expenses, net of any interest saving, and a deferral account to record the variance between the floating rate and that assumed in future rate applications. The disposition of the deferral accounts will be determined in future proceedings and will be subject to a prudency review of the expenditures.

G-123-01 BC Gas

Approved the withdrawal of the 2002 Revenue Requirements Application. BC Gas is to file its Revenue Requirements Application for 2003 by May 31, 2002 and to address in that application the matters raised in the Commission's Reasons for Decision.

G-124-01 BC Gas

Approved the Gas Supply Mitigation Incentive Program 2001 / 02 for the gas contract year from November 1, 2001 through October 31, 2002.

G-125-01 BC Gas

Authorized the issuance of up to $500 million Medium Term Note Debentures from time-to-time, effective from the date of this Order until the end of November 2003, pursuant to Section 50(2) of the Act.

G-126-01 Centra Whistler

Established a workshop and pre-hearing conference for the 2002 / 03 Revenue Requirements Application to address procedural matters.

G-127-01 Methanex Corporation

Directed that Methanex's Load Retention Rate Application would be reviewed with the PNG 2002 Revenue Requirements Application. PNG's rates to Methanex were made interim effective October 1, 2001, pending the outcome of the review process.

G-128-01 BC Hydro

Approved the following amendments for Rate Schedule 1852 - Transmission Service – Modified Demand:

- An expanded definition of the low-load hours, a reduction in the time required between demand reduction events;
- Inclusion of a clause allowing BC Hydro to transfer unused demand reduction energy and events to the next contract; and
- A change in the method of calculating damages if the customer fails to curtail during a demand reduction event.

Approved changes for Rate Schedule 1880 - Transmission Service – Emergency, Maintenance and Special Supply that would make Rate Schedule 1880 available to Rate Schedule 1852 customers.

G-129-01 Sun Peaks

Accepted for filing the August 31, 2001 MP Energy Partnership and BC Gas Services Ltd. contract for the supply of liquid propane to Sun Peak's underground grid system for the period September 1, 2001 to August 31, 2003.

Approved the amortization of the Gas Cost Reconciliation Account balance over two years.

Approved a Propane Commodity Charge of $8.53 / GJ and a Gas Cost Reconciliation Account Commodity Charge of $0.83 / GJ, effective January 2, 2002. The Storage Commodity Charge of $1.1905 / GJ and the BC Gas Services Ltd. Charge of $0.60 / GJ will remain unchanged.

G-130-01 BC Gas

Approved the following amendments for customer rates, effective January 1, 2002, pursuant to Section 61(4) of the Act:

- A decrease of $1.410 / GJ in Revelstoke customer rates;
- A decrease in the reference price applicable to the Revelstoke Propane Cost Deferral Account from $0.2517 / litre to $0.2168 / litre; and
- A change in the amortization period for the Propane Surcharge Rider from June 30, 2002 to December 31, 2002.

BC Gas is to provide a report on the balance in the Revelstoke Propane Cost Deferral Account by June 1, 2002.

G-131-01 BC Gas

Approved an extension to the expiry date of the NGV Service Agreement, Tariff Supplement No. C-1 - Beach Place Ventures Ltd., to February 15, 2002.

G-132-01 PNG and PNG (N.E.)

Established a pre-hearing conference via videoconference to address procedural matters relating to the utilities' 2002 Revenue Requirement Applications.

G-133-01 UNC

Approved a general rate increase of 4.5 percent for all customer classes, effective January 1, 2002, and determined that UNC had earned its portion of the preliminary sharing adjustment for 2001 in accordance with the Incentive Sharing Mechanism.

G-134-01 BC GAS

Approved a reduction to the Gas Cost Recovery Charges for the Lower Mainland, Inland and Columbia Divisions, effective January 1, 2002.

Approved changes to the GCRA Riders so as to recover in 2002 the debit balance that accumulated in the GCRA in 2001 plus one-half of the $93 million end-of-2000 GCRA debit balance that is forecast to remain at the end of 2001, effective January 1, 2002.

G-135-01 BC GAS - FORT NELSON DIVISION

Approved a reduction in the Fort Nelson customer rates of $0.375 / GJ, effective January 1, 2002. BC Gas is to file quarterly reports on the GCRA balances and expected gas costs and revenues in accordance with guidelines outlined in Commission Letter No. L-5-01.

G-136-01 PNG

Approved changes to the Gas Supply Charges and GCVA riders, effective January 1, 2002, except that the GCVA rider for Granisle propane customers shall be $0.65 / GJ. PNG is to file, by 15 business days prior to the start of each calendar quarter, an update on GCVA balances and expected gas costs and revenue for the following 12 months for each service area. PNG is to apply for rate changes where forecast costs (including the GCVA balance at the start of the period) and revenue differ by more than 5 percent in accordance with Letter No. L-5-01.

G-137-01 PNG (N.E.)

Approved the Gas Supply Charges and GCVA riders, effective January 1, 2002, as set out in the December 17, 2002 Revised Applications. PNG (N.E.) is to file, by 15 business days prior to the start of each calendar quarter, an update on GCVA balances and expected gas costs and revenue for the following 12 months for each service area. PNG (N.E.) is to request rate changes where forecast gas costs (including the GCVA balance at the start of the period) and revenue differ by more than 5 percent in accordance with Letter No. L-5-01.

G-138-01 CENTRA GAS

Approved New Customer Basic Monthly Charges and Energy Charges and the continuation of the current cost of gas pass-through Rider C of $1.705 / GJ on sales to all New Customers, effective January 1, 2002. The approved New Customer rates are as follows:

	Basic Monthly Charge $/Month	Energy Charge $/GJ	Rider C $/GJ
SGS-11	9.45	9.631	1.705
SGS-12	12.10	9.476	1.705
LGS-11	112.06	6.584	1.705
LGS-12	175.30	6.317	1.705
LGS-13	181.74	6.308	1.705

Centra Gas is to file, by 15 business day prior to the start of each calendar quarter, an update on NCRBA balances and expected gas costs and revenue for the following 12 months. Centra Gas should request rate changes where forecast gas costs (including the NCRBA balance at the start of the period) and revenue differ by more than five percent in accordance with Letter No. L-5-01.

G-139-01 CENTRA GAS

Directed that the Pioneer rates for SGS, LGS and ACR-1 customers are to be set at the lower of a competitive fuel oil price with a zero percent discount or the New Customer rate as determined under Section 2.7 of the Special Direction, effective January 1, 2002.

Approved the following, effective January 1, 2002:

- An increase in rates to Pioneer SGS customers of between 9.12 and 20.67 percent;
- An increase in rates to Pioneer LGS customers of between 7.40 and 8.30 percent; and
- A decrease in rates to ACR-1 customers consuming a minimum annual volume of 6,000 GJs of 3.44 percent in the Capital Regional District and 7.30 percent in the Other Communities.

G-140-01 BC HYDRO

Approved, subject to amendment, Rate Schedule 1268 - Distribution Access Rate for Independent Power Producers and Customers with Self-Generation, effective December 19, 2001. Changes to the Electric Tariff Index were also approved.

G-141-01 BC HYDRO

Approved the November 23, 2001 Special Electric Service Agreement (Tariff Supplement No. 60) with Canadian Forest Products Ltd. Upper Fraser Division for a Bypass Rate at the equivalent of Rate Schedule 1821 plus a monthly rider of $5,777.25 for a period of 20 years, effective June 1, 2002.

G-142-01 UNC

Approved the issuance of up to 150,000 authorized and unissued $100 par value common shares to UtiliCorp British Columbia Ltd. for a total consideration of up to $15,000,000. The common share equity component of UNC's capital structure will remain deemed at a level of 40 percent.

G-143-01 BC Hydro

Approved and accepted for filing amendments to Rate Schedule 1854 - Power Smart Industrial Rate to amend the pricing to incorporate a 25 percent winter peak premium and a 35 percent firm premium relative to the non-firm low load hour base price, effective December 19, 2001.

G-144-01 BC Gas

Approved amendments to Rate Riders 2 (Income Tax Refund), 3 (Earnings Sharing Mechanism), and 5 (Revenue Stabilization Adjustment Mechanism) for the Lower Mainland, Inland and Columbia service areas to comply with previous Commission Orders, effective January 1, 2002.

G-145-01 Centra Whistler

Established a negotiated settlement process to review the 2002/2003 with respect to the Revenue Requirements Application.

Directed that:

- The utility's commodity charge will be reduced from the existing level of $15.314/GJ to $11.613/GJ, effective January 1, 2002 on an interim basis, subject to refund with interest, and

- Rate Rider A will be increased from the existing level of $0.595/GJ to $0.987/GJ, effective January 1, 2002 on an interim basis, subject to adjustment after the negotiated settlement process.

G-146-01 PNG (N.E.)

Approved the provision of a guarantee to the Royal Bank of Canada and to provide security for the guarantee, pursuant to Sections 50 and 52 of the Act.

G-148-01 PLP

Approved a 4.5 percent increase to the energy component of rates for all customers resulting from an increase in power purchase costs from UNC, pursuant to Sections 60 and 61 of the Act.

G-149-01 PNG and PNG (N.E.)

Approved interim rate increases in the delivery charge for all classes of customers based on the 2002 Revenue Requirement, except for the revenue requirement resulting from requested increases in the common equity component and increases in risk premium in the rate of return on common equity. The interim increases are subject to refund with interest at the average prime rate of PNG's principal bank as determined by a public hearing in 2002 for PNG and the written regulatory process for PNG (N.E.).

C-1-01 WKP

Approved the rebuild of the Unit No. 3 Head Gate at the Corra Linn hydroelectric plant at an estimated cost of $860,000. A final report and cost summary on the project is to be filed within three months of its completion.

C-2-01 WKP

Approved the Life Extension and Upgrade to Unit No. 5 at the Upper Bonnington Hydroelectric Generating Plant at an estimated cost of $14,606,000. A final report and cost summary on the project is to be filed within three months of its completion.

C-3-01 WKP

Approved the upgrade of the Powerhouse Crane at the Upper Bonnington hydroelectric generating station at an estimated cost of $430,000. A final report and cost summary is to be filed on completion of the project.

C-4-01 Centra Gas

Approved the construction and operation of a Light Industrial Complex at 2577 Mission Road in Courtenay. Construction expenditures are to be within 110 percent of $714,000 before Allowance for Funds Used During Construction. Centra Gas is to file a final report and cost summary on the project within six months of its completion.

C-5-01 BC Gas

Approved a one-year extension to CPCN No. C-20-80, which approved a 21-year Operating Agreement between Inland Natural Gas Co. Ltd. and the District of Chetwynd and the continuation of the payment of the franchise fee to the District of Chetwynd to June 30, 2002.

C-6-01 Centra Gas

Approved the construction and operation of the Texada Island natural gas compressor and an interest bearing deferral account to record incremental operating expenses. An amortization period for the BC Hydro contribution in aid of construction under the Compressor Facility Agreement that is equal to the depreciation period for the Texada Compressor was approved. A monthly report on project costs and schedule is to be provided followed by a full Final Report upon completion.

C-7-01 BC Hydro

Approved the operation of the Fort Nelson Electrical Generating Project.

C-8-01 WKP

Issued a CPCN for the Consolidated Operations at the Benvoulin Road location in Kelowna, BC estimated to cost $3,458,450. A final report and summary of actual costs are to be provided within six months of its completion.

C-9-01 WKP

Approved the rebuild of the electrical distribution system in the Village of Warfield estimated to cost $650,000. A final report and summary of actual costs are to be provided upon completion.

C-10-01 WKP

Approved the rebuild of the electrical distribution system of the City of Rossland and Red Mountain estimated to cost $1,700,000. A final report and summary of actual costs are to be provided upon completion.

C-11-01 BC Gas

Approved a one year extension to CPCN No. C-21-80 extending the expiry date of the Operating Agreement with the District of Hudson’s Hope to June 30, 2002, or 60 days after approval of a new operating agreement with the District of Hudson’s Hope.

C-12-01 WKP/UNC

Approved the installation of a 40 MVA shunt capacitor at the BC Hydro Vernon Substation at an estimated cost of $1,640,000 with an expected in-service date of December 2001.

C-13-01 WKP/UNC

Approved the construction of a new substation on a new site in the Village of Slocan. The Project is estimated to cost $1,130,000 with an in-service date of December 31, 2001. A final report and summary of actual costs is to be filed with the Commission upon completion of the project.

C-14-01 BC GAS

Approved a further one-year extension to October 31, 2002 of the Gas Franchise Agreement with the City of Prince George.

C-15-01 BC GAS

Approved Transmission Pipeline Integrity Plan expenditures for the 2001 work program (estimated cost of $9.692 million) and the 2002 work program, except for rehabilitation costs (estimated cost of $5.397 million.)

Approved the recording of an Allowance for Funds Used During Construction on those cost items that are approved as capital expenditures until such time as the capital costs are added to utility rate base.

Within 60 days of the end of each calendar year, BC Gas will file a Report on the Transmission Pipeline Integrity Plan activities.

C-16-01 CAL-GAS INC.

Approved the construction and operation of two underground propane grid systems at the Whispering Pines and Purcell Woods developments at the Kicking Horse Mountain Resort.

C-17-01 WKP/UNC

Approved the Intergraph Automated Mapping/Facilities Management system upgrade project. A final project and cost report is to be filed on completion of the project.

C-18-01 SYNEX ENERGY RESOURCES LTD.

Approved the construction and operation of a single phase 14.4 kV distribution line from BC Hydro's grid at Oclucje to Kyuquot to serve customers at Fair Harbour, Chamiss Bay, Houpsitas, Kyuquot and Walters Cove. The CPCN is subject to the following conditions:

- Construction of the Project must start within two years of the date of this Order;
- Synex or a company formed for the purposes of being a public utility, must maintain separate accounts and must file annual reports which summarize the results of utility operations;
- Synex or a company formed for the purposes of being a public utility, must file for Commission approval proposed rates and terms and conditions of service upon completion of the Project; and
- Synex or a company formed for the purposes of being a public utility, must provide a copy of this Order to each new customer and it must maintain a copy of the approved Rate Schedules and Terms and Conditions of Service to be available for inspection by customers.

Other Orders

ENERGY SUPPLY CONTRACTS

E-1-01	WKP	Power Purchase Contracts with Powerex Corp.
E-2-01	CENTRA WHISTLER	2001 to 2004 Propane Supply Contract Terms with Link Petroleum Services Ltd.
E-3-01	BC GAS	Natural Gas Storage Agreements
E-4-01	CENTRA GAS	Renewal of Westcoast Energy Inc. Transportation South and Transportation North Service
E-5-01	PORT ALICE GAS	Amendments to its Propane Gas Supply Contract
E-6-01	CENTRA GAS	Amendment to Westcoast Energy's Inc.'s Transportation-South Capacity Agreement
E-7-01	CENTRA GAS	Natural Gas Supply Agreements for the 2001/02 Gas Contract Year
E-8-01	BC GAS	Propane Gas Supply Contract
E-9-01	PNG	2001/02 Seasonal and Peaking Gas Supply Contract
E-10-01	CENTRA GAS	Pricing Amendment to a Baseload Gas Purchase Agreement
E-11-01	PNG	2001/02 Gas Supply Contract with CanWest Gas Supply Inc.
E-12-01	PNG (N.E.)	2001/02 Gas Supply Contract with CanWest Gas Supply Inc. (Tumbler Ridge service area)
E-13-01	CENTRA GAS	Baseload Natural Gas Supply contract for the 2001/02 Gas Contract Year with Petro-Canada Oil and Gas
E-14-01	CENTRA GAS	Baseload Natural Gas Supply contract for the 2001/02 Gas Contract Year with Coral Energy Canada Inc.
E-15-01	CENTRA GAS	Assignment of T-North Transportation Capacity for the 2001/02 Gas Contract Year to Engage Energy Canada L.P.
E-16-01	WKP/UNC	Power Purchase Agreement with Aquila Power Corporation
E-17-01	WKP/UNC	Letter Agreement for the Tailrace Upgrades to Amend the Brilliant Power Purchase Agreements
E-18-01	BC GAS	Letter Agreements with Aquila Canada Corp. for the 2000/01 and 2001/02 Gas Contract Years
E-19-01	BC GAS	Natural Gas Supply Contracts and Amendments for the 2001/02 Gas Contract Year with Six Suppliers
E-20-01	CENTRA GAS	Two-Year Renewal of Westcoast Energy Inc. Transportation South Capacity
E-21-01	CENTRA GAS	Natural Gas Storage Agreement for the 2001/02 Gas Contract Year with Northwest Natural Gas Company

Participant Assistance/Cost Awards

F-1-01	WKP	2001 Preliminary Revenue Requirements Application and 2000 Annual Review - $813.44
F-2-01	BC Gas	2000 Annual Review of 2001 Revenue Requirements - $7,657.53
F-3-01	WKP	2001 Preliminary Revenue Requirements and 2000 Annual Review - $9,199.16
F-4-01	PNG	October to December 2000 Rates and 2001 Revenue Requirements Applications - $37,305.76
F-5-01	BC Hydro	Bypass Guidelines for Independent Power Producers - $7,919.63
F-6-01	BC Hydro	Bypass Guidelines for Independent Power Producers - $14,275.94
F-7-01	PNG (N.E.)	2001 Revenue Requirements - $5,854.53
F-8-01	WKP / UNC	Application to Sell its Hydroelectric Generation Assets - $570.95
F-9-01	WKP / UNC	Application to Sell its Hydroelectric Generation Assets - $18,106.36
F-10-01	WKP / UNC	Application to Sell its Hydroelectric Generation Assets - $585.60
F-11-01	WKP / UNC	Application to Sell its Hydroelectric Generation Assets - $47,736.49
F-12-01	BC Gas	2002 Revenue Requirements - $9,252.60

Petroleum

P-1-01	Plateau	Application for permanent tolls on the Taylor to Prince George and Prince George to Kamloops pipeline - Revised Public Hearing Date
P-2-01	TME	2001 Jet Fuel Pipeline Tolls
P-3-01	Plateau	2000 and 2001 Tolls and Suspension of Service on the Taylor to Kamloops Oil Pipeline Decision
P-4-01	Plateau	Sunset Prairie Crude Oil Pipeline Tolls effective July 1, 2001
P-5-01	Plateau	Application for Reconsideration of Commission Decision on Tolls, Shipper Commitments, and Suspension of Service on the Taylor to Kamloops Oil Pipeline

L-1-01 BC GAS

Accepted BC Gas' Internal Audit Services report on services provided and related cross-charges between the utility and DESCO Distributed Energy Services Co. Ltd., and the Auditor's finding that utility staff are acting in compliance with the Transfer Pricing Policy and Code of Conduct for BC Gas, pursuant to the Commission's request outlined in Letter No. L-37-00.

L-2-01 WKP

Approved the subcontractor agreement with UtiliCorp British Columbia Ltd. for the supply of services to the City of Kelowna by WKP at the direction of UtiliCorp British Columbia Ltd. These services, including operation and maintenance of the electrical distribution system, capital planning and construction, metering, and administrative support, were previously undertaken by the City.

L-3-01 REVISED NSP GUIDELINES

Issued revised "Negotiated Settlement Process: Policy, Procedure and Guidelines" dated January 2001.

L-4-01 BC HYDRO

Accepted the first quarterly report on the utility's export trade activities for the period ending September 30, 2000.

L-5-01 BC GAS/OTHER REGULATED GAS UTILITIES

Established Guidelines for the setting of gas cost recovery rates and the management of the Gas Cost Reconciliation Account balance.

L-6-01 PNG

Approved a delay in the filing of the Storage Analysis Report until Engage Energy Canada Ltd. completes PNG's 2001/02 gas contracting and price risk management plans, but no later than March 16, 2001.

L-7-01 BC GAS

Letter to BC Gas advising that, in the absence of any legal requirement, the Commission could not direct BC Gas to make payments to the City of Rossland under the expired Franchise Agreement while negotiations for a new Operating Agreement with the City continued.

L-8-01 BC HYDRO

Directed BC Hydro to implement the recommendations contained in its Internal Audit Report of the Energy Performance Contracting Program. A further report is to be filed by September 1, 2001 reporting its progress in implementing the recommendations.

L-9-01 WKP

In response to a customer complaint regarding the interpretation of Tariff Sections 3.3 and 7.2, the Commission directed WKP to correct a customer billing so that the utility would only recover the appropriate costs of the connection. WKP is to complete a review of its files to determine if other customers have been incorrectly billed since the policy change and to provide the appropriate credits to those customers. WKP is required to report the results of the review by March 30, 2001.

L-10-01 METHANEX CORPORATION

Declined Methanex's request for an Order directing PNG to produce further information on its cash-flow projections with respect to PNG's October to December 2000 Rates and 2001 Revenue Requirements Application.

L-11-01 PNG

Approved the extension of filing dates for Intervenor submissions and PNG (N.E.)'s reply regarding the 2001 Revenue Requirements Application.

L-12-01 BC HYDRO

Requested that a summary or plan of the System Optimization Model be provided, which could be made available to the general public. Also requested a detailed confidential report be filed discussing the utility's operating strategies under a number of assumptions of market, reservoir inflow conditions, and risk management decisions. The plan should be updated as part of BC Hydro's quarterly reports on export trade.

L-13-01 BC GAS

Letter investigating the factors impacting the price and the validity of the Sumas Index as a price setting mechanism. The Commission requested information from Utilities and Producers regarding the current natural gas market environment and summaries of the information under the following six headings: Sumas Market and

Indices; Station 2 Market and Indices; California Situation and the Effect on Pacific Northwest Market; Pacific Northwest Resource Balance; Need for, and Viability of, Major Resource Additions; and Need for High Level Integrated Resource Planning Initiative. The Commission directed BC Gas to undertake discussions on Regional Resource Planning according to a fixed "Scope of Discussions" with a full representation of stakeholders. The report is to be submitted to the Commission by June 29, 2001.

L-14-01 BC GAS

Letter regarding the Westcoast Energy Inc. Transportation-south capacity from Kingsvale to Huntingdon and the National Energy Board Decision that a future expansion of 100 MMcfd or 400 MMcfd may require reexamination of Westcoast tolling. The Commission expects BC Gas to actively and aggressively pursue both the expansion and tolling to assure that it is in the best interest of BC consumers and to make representations to the National Energy Board as needed.

L-15-01 BC GAS

Accepted the 2001/02 Gas Supply Annual Contract Plan with a peak day demand of 1,312 TJ/day and the contracting decisions for the period November 1, 2001 to October 31, 2002 subject to additional information being provided. The Gas Price Management Strategy is accepted for the period April 1, 2001 to October 31, 2003 subject to several provisions.

L-16-01 PNG

Accepted, with one exception, the Gas Contracting Plan and Gas Supply Price Management Plan (GSPMP) for the 2001/02 period on the understanding that all individual gas supply contracts and amendments will continue to be filed in a timely fashion, pursuant to Section 71 of the Act. The Cost Management Program as it is presently structured is not to be part of the GSPMP. A report is to be filed by September 15, 2001 on the costs and benefits of establishing a GSPMP for the 2002/03 gas year.

PNG is to justify the use of Sumas prices for the winter period when it files contracts that rely on Sumas Pricing. When filing contracts using AECO pricing, PNG is expected to justify the pricing in terms of market premiums for physical gas at Station #2 and AECO, and the basis differential between the two points. PNG is to advise the Commission immediately if its call option purchases exceed 7 TJ/day.

L-17-01 CENTRA GAS

Accepted the 2001/02 Gas Contracting Plan and 2001/02 Gas Supply Price Management Program for the period November 1, 2001 to October 31, 2002. Accepted proposal to increase the firm peak day supply to 92,300 GJ/d. The Commission agreed that an additional 5,000 GJ/day of baseload and 2,000 GJ/day of three-month seasonal should be acquired and will need to justify any premiums in pricing under its seasonal, peaking, storage, and baseload contracts for 2001/02 avoiding pricing purchases using the Sumas Index.

L-18-01 BC HYDRO

Dismissed the Kemess Mine Ltd. complaint, pursuant to Section 83 of the Act. Kemess asked that the owner's property taxes and maintenance be subtracted from Rate Schedule 1821.

L-19-01 PNG (N.E.)

Acknowledged report on gas supply for Tumbler Ridge filed on May 31, 2001.

L-20-01 BC GAS

Accepted the Second Quarter Report on Gas Cost Flow-through, Gas Cost Reconciliation and the proposal that gas rates not change July 1, 2001. The 2001 Third Quarter Report is to include a pro-forma estimate of gas costs and revenues for a second 12-month period commencing October 1, 2002.

L-21-01 CENTRA GAS

Accepted the Report on New Customer Rate Balancing Account and New Customer Rates (NCRBA) effective July 1, 2001. A report on forecast gas cost and gas revenues, along with actual NCRBA balances for the 12 months commencing October 1, 2001 is to be filed by September 10, 2001.

L-24-01 CHETWYND ENVIRONMENTAL SOCIETY

Denied the Participant Assistance Cost Award Application for the Society's participation in the oral public hearing for Plateau Pipe Line Ltd.'s December 29, 2000 toll application.

L-22-01 Centra Gas

Letter holding shareholders responsible for losses incurred with regard to the 1995 revenue deficiency of Pacific Coast Energy Corporation.

L-23-01 BC Hydro

Requested the Meziadin Resident's Association to file information to support their request for reconsideration of Commission Order No. G-50-01 and Reasons for Decision in accordance with BCUC reconsideration criteria.

L-25-01 BC Hydro

Approved and accepted the Diesel Generation Costs covering the period July 1, 2001 to June 30, 2002. Electric Tariff Supplement No. 7 - Interruptible Electricity Agreement with Central Coast Power Corporation was adjusted to an energy charge of 21.38 cents per kWh and Electric Tariff Supplement No. 8 - Interruptible Electricity Agreement with Queen Charlotte Power Corporation was adjusted to an energy charge of 21.38 cents per kWh.

L-26-01 Plateau

Letter to Registered Intervenors inviting comments on Plateau's Application for Reconsideration of the Commission's June 26, 2001 Decision.

L-27-01 PNG and PNG (N.E.)

Letter requiring the utilities to file, on a monthly basis, information on the number of complaints received in the preceding month, type of complaint, the number of disconnection notices, and the number of actual disconnections. A bill message explaining the computer estimating problems and its correction, the hiring of additional staff and the location of district offices with payment drop boxes is to be included in the next billing to residential customers.

L-28-01 Centra Gas

Reviewed the 2001 forecast of operating and maintenance expense capitalization and accepted the forecast expenses of $6,999,600.

L-29-01 M.V.P. Veneer Inc.

As a result of Section 14.1 of BC Gas' Rate Schedule 5, the Commission takes no position on the meaning and application of the Force Majeure provisions and refers MVP Veneer and BC Gas to the dispute resolution procedures contained Rate Schedule 5. Upon resolution of the Force Majeure issue the Commission will be prepared to accept submissions on the discrimination issue.

L-30-01 WKP/UNC

Letter advising that the Commission is not convinced that changes to the harmonization clause are warranted at this time. WKP may reapply for changes to its harmonization clause if, after gaining some experience, it finds that IPPs impose significant ongoing administrative costs.

L-31-01 WKP/UNC

Denied the Ootischenia Water and Land Stewardship Committee Action Group complaint and request for an order directing WKP (UNC) to cease and desist the work of the 230 kV System Development through the residential area of Ootischenia until the residents' and landowners' concerns regarding the adverse effects from high voltage transmission lines on human health were addressed. Reasons for Decision were issued.

L-32-01 PNG

Approved the creation of a Refinancing Costs Deferral Account to record the costs described in the September 26, 2001 letter and attachment. The disposition of the deferral account will be determined after PNG completes its refinancing, and will be subject to a review of the prudency of the expenditures.

L-33-01 PNG (N.E.)

Approved the creation of a 2001 Dawson Creek Industrial Customer Deliveries Deferral Account.

L-34-01 WKP/UNC

Acknowledged the October 2, 2001 notice regarding the proposed name change to UtiliCorp Networks Canada (British Columbia) Ltd., effective October 22, 2001.

L-35-01 BC Hydro

Requested amendments to the proposed Rate Schedule 1268 - General Service - Distribution Transportation Access Rate for IPPs and other requested information.

L-36-01 BC Gas

Deferred implementation date of the ABC-T project to November 2003. A reassessment of the ABC-T service timetable will be made in the second quarter of 2002.

L-37-01 BC Hydro

Declined BC Hydro's request that the Commission direct WKP (UNC) not to exceed the 200 MW customer demand limit of Rate Schedule 3808 and for WKP to enter into negotiations for supply on market based prices if it foresaw a need for supply in excess of the 200 MW limit.

L-38-01 PNG

Approved an increase to $749,000 in the limit on the amount of incremental operating and maintenance expenses associated with Methanex Corporation's July 1, 2001 startup that can be recorded in the Industrial Customer Deliveries Deferral Account. The prudency of the incremental expenditures recorded and the disposition of that amount, will be dealt with in the context of the 2002 Revenue Requirement Application.

L-39-01 BC Hydro

Denied the Joint Industry Electricity Steering Committee's complaint regarding Rate Schedule 1854: Power Smart Industrial Rate Pilot Program and BC Hydro's failure to offer prices for non-firm low load hour and high load hour energy for the three-month pricing period starting in November 2001.

See also Letter No. L-40-01 regarding this issue.

L-40-01 BC Hydro

Letter to BC Hydro regarding the Joint Industry Electricity Steering Committee's complaint (see L-39-01) on Rate Schedule 1854: Power Smart Industrial Rate Pilot Program and BC Hydro's failure to offer prices for non-firm low load hour and high load hour energy for the three-month pricing period starting in November 2001.

The Commission requested that BC Hydro waive the "no-return" feature on this occasion only as it believes that Rate Schedule 1854 participants who did not accept an offer for the period starting in November 2001 should not be excluded from future participation in the program since the uncertainty surrounding the exclusion of the six-month firm and three-month non-firm options may have affected participants' decisions not to accept BC Hydro's offer.

Specifically, the Commission requested that BC Hydro allow the customers that participated from August to October, but did not accept an offer for the period starting in November, to return to Rate Schedule 1854 for the period starting in February 2002 unless BC Hydro would have otherwise terminated the contracts at that point.

L-41-01 Silversmith

Letter to complainant dismissing a complaint regarding the quality of service to residents at Sandon, BC. The Commission, upon review of information provided by Silversmith, accepted the utility's position that the system is being operated with a reasonable level of reliability.

L-42-01 BC Hydro

Letter advising BC Hydro and Apollo Forest Products Ltd. that should Apollo construct the proposed 69/25 kV substation on its property located near Fort St. James, BC Hydro should provide service under Rate Schedule 1821.

See also Order No. G-60-01 regarding the electricity supply to Fort St. James area.

L-43-01 Return on Common Equity

Determined that 9.13 percent is the appropriate ROE for a low-risk benchmark utility in the year 2002, pursuant to Order No. G-80-99, as amended by Order No. G-109-01.

L-44-01 Union of British Columbia Municipalities

Letter responding to the UBCM's Resolution A4 that "...the UBCM strongly urge the BC Utilities Commission to direct that natural gas and electrical delivery companies ensure that resources exist so that an emergency response can be provided to the community within 30 minutes". The Commission advised that it would continue to consider concerns about the safe delivery of gas and electricity on a situation-specific basis.

L-45-01 All Electrical Utilities

Denied an application for reconsideration of the Commission's October 31, 2001 decision regarding a request that all electrical utilities be required to delete references, in their approved Electric Tariffs and Terms and Conditions of Service, to the presence or absence of electric heat.

L-46-01 BC HYDRO

Letter to Mr. M.J. Wheatley responding to his request for BC Hydro to provide net metering to residential customers. BC Hydro requested that the Commission defer its inquires as net metering is being considered by the Energy Policy Task Force helping to develop the province's energy policy. Mr. Wheatley was requested to reapply for a change to BC Hydro's standard metering practices after the release of the comprehensive energy policy for British Columbia.

L-47-01 BC HYDRO

Approved the extension of three Rate Schedule 1854 customer contracts to January 31, 2002. Contract extension would be at the customer's option and on existing terms and conditions. Should any of the three customers not agree to the extension of the current term, BC Hydro will offer pricing options, if any, based on the current terms and conditions of Rate Schedule 1854.

L-48-01 UNC

Letter to the Coalition to Reduce Electro-pollution responding to an information request regarding Commission Letter No. L-31-01 and Reasons for Decision on the Ootischenia Water and Land Stewardship Committee Action Group's complaint on the routing of UNC's 230 kV Transmission lines through the Ootischenia area.

L-49-01 UNC

Letter to Ms. M. Kanigan advising that the Commission did not have the 0.5 milligauss EMF profiles for the proposed UNC 230 kV transmission line, but that UNC has been directed to file EMF profiles for its final line proposal to the edge of the right-of-way and at the nearest residences.

L-50-01 PORT ALICE GAS

Approved the extension of the Autogas Propane Ltd. liquid propane supply agreement for one year to March 31, 2003.

L-51-01 PNG (N.E.)

Referred the December 12, 2001 application to obtain a long-term loan of $4.5 million from PNG to the proceeding on the PNG (N.E.) 2002 Rate Application established by Order No. G-132-01.

L-52-01 BC HYDRO

Requested the utility to file a detailed assessment report on the power outages of December 13, 14 and 15, 2001 that occurred in the Lower Mainland and on Vancouver Island.

Publications

Copies of the following publications are available upon request or from the Commission's web site at *http://www.bcuc.com* :

- Utilities Commission Act, R.S.B.C. 1996, Ch. 473
- Introduction to the BC Utilities Commission - what it is, what it does, and why (pamphlet)
- Public Hearing Process - why we have public hearings and how to participate (pamphlet)
- Complaint Handling Procedures (pamphlet)
- Understanding Utility Regulation: A Participants' Guide to the British Columbia Utilities Commission
- Retail Markets Downstream of the Utility Meter Guidelines
- Integrated Resource Planning Guidelines
- Negotiated Settlement Procedures (revised January 2001)
- Certificate of Public Convenience and Necessity Filing Requirements
- Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Balance Guidelines

Copies of the following documents issued by the Commission are also available upon request or from the Commission's web site:

- Orders
- Decisions
- Regulatory Agendas
- Annual Reports
- Participant Assistance Cost Award Guidelines - Revised
- Service Plans
- Return on Common Equity

Commission Contacts

For further information about these items or the Commission's activities, please contact the Information Services Group at:

Telephone:	(604) 660-4700
BC Toll Free:	1-800-663-1385
Facsimile:	(604) 660-1102
Email:	commission.secretary@bcuc.com

Web Site

Internet users are invited to visit the Commission's web site at *http://www.bcuc.com*.

Glossary of Terms

allowance for funds used during construction (AFUDC)	The amount a regulated entity is allowed to earn to recover its cost of financing assets under construction. AFUDC is equal to the average cost of the construction work in process, times a financing rate which is usually equal to the entity's cost of capital rate. AFUDC is not recovered immediately through rates; it is included in the cost of the related assets and recovered in future periods through the depreciation charge.
allowed rate of return	The rate of return a regulated entity is allowed the opportunity to earn. When applied to the rate base, the allowed rate of return provides an amount equal to the cost of financing the investment required for regulated operations. The financing costs include both the cost of debt and the cost of equity.
alternative dispute resolution (ADR)	See "negotiated settlement process".
application for reconsideration	An application to have the Commission reconsider, vary, or rescind a decision or order previously issued.
burnertip rate	The rate charged for gas at the customer's meter, including the delivery charge, fixed monthly charge and gas commodity charge. It is usually calculated as an annual average rate based on typical annual consumption for the customer class.
capital cost	The fixed costs associated with the construction of an energy facility, including land and siting costs, material and labour costs, allowance for funds used during construction, and other applicable overhead charges.
cogeneration	The generation of electric power in conjunction with the use of steam in an industrial or space heating process, using waste heat from one process to drive the other. Cogeneration is more efficient compared to traditional thermal generating plants.
common carrier(s)	An energy transportation provider, typically a crude oil or natural gas pipeline which provides service on a non-discriminatory basis to all potential shippers.
cost of service	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes and cost of capital. The cost of service is also known as "revenue requirements".
cost of service study	A study to determine the cost of service by class of service and/or customer. These studies are used to help determine how the revenue requirements are to be allocated among the rates for the various services/customers.
cross subsidization	Increasing the rates for one service or class of customers so the rates of another service or class of customers can be reduced below cost.

debt-equity ratio	The ratio of money borrowed by the utility to money invested in the utility by shareholders. There is a theoretical optimum for this for each utility.
deferral account	An account that records the deferral of a cost or revenue until a future date. A deferred asset account records a cost that would normally be expensed and recovered in the current period, but which is to be expensed or recovered in a future period. A deferred liability account records an amount recovered in the current period, to cover costs of providing service in a future period.
demand-side management (DSM)	Efforts to modify customer demand patterns by either increasing end-use energy efficiency or reducing fluctuations in energy demand.
distributed generation	Generation that is relatively small scale and located close to the final customer.
distribution system	The portion of an electric or natural gas transportation infrastructure that connects end-users to bulk production or transportation facilities.
energy losses	Energy lost during transportation from suppliers to end-users. Energy losses on a typical natural gas system are around 1 to 3 percent. Energy losses on a large electric system are around 5 to 8 percent.
export sales	Bulk sales of electricity or natural gas outside of British Columbia.
firm capacity	The amount of instantaneous energy production or transportation capacity that is available at a defined time.
firm energy	The amount of energy that is available over a defined period of time.
fixed cost	Costs associated with an energy production or transportation facility which must be paid whether the plant operates or not. Fixed costs generally include capital costs, contract demand charges and operating costs which are committed or unaffected by production levels.
gas cost reconciliation account (GCRA) **gas cost variance account (GCVA)**	A deferral account which accumulates the variance in actual gas costs from the actual gas revenue recovered in customer rates.
green power rates	Rates changed for electricity service from generators which do not pollute or damage the environment. Different groups define “green” power with various levels of restriction. For example, a run of the river hydro plant may be included while a new dam and reservoir may be excluded.
hydroelectric energy, hydroelectricity	Electric energy produced by water falling through a turbine generator. In British Columbia, hydroelectricity is the dominant form of electric energy production.

incentive regulation	Regulation which rewards utilities for cost savings or other actions which are desired by ratepayers.
independent power producers (IPPs)	Non-utility electric energy generators. Until the early 1970s, independent power producers were rare. With recent changes in utility technology and economics, they have become more common. Many issues relating to restructuring of the utility industry involve the role of independent power producers in a deregulated energy market.
information requests	Questions posed to the providers of evidence pertaining to the evidence they have filed for a hearing. Information requests and their responses are made prior to the hearing, in writing, and become evidence in the hearing. Information requests are also referred to as “interrogatories”.
interim rate	A rate which is put in place until the regulator can determine the final rates. If the final rates are lower than the interim rates, customers are generally refunded their over contributions with interest for the period of time the interim rates existed.
interruptible energy, **interruptible service**	Energy flow which can be reduced or cut off on relatively short notice when needed by other customers. Generally, interruptible energy is sold by contract at a reduced price or without fixed charges to end-users, with specific terms and conditions governing interruptibility rights.
investor-owned utility	An electric or gas utility that is owned by private shareholders.
joule	A measure of energy or work done equal to a force of 1 newton applied through a distance of 1 metre. One gigajoule (one billion joules) is roughly equal to energy from 915 cubic feet of natural gas, 29 litres of gasoline, or 278 kWh of electricity.
kilowatt-hour	1,000 watt-hours.
load	The amount of energy required by end-users on a given portion of the system at a given time. Load originates primarily at customers’ energy-consuming equipment.
load growth	Increase in the demand for energy.
load-resource balance	The point at which demand for energy exactly equals energy production.

local distribution company (LDC)	A utility (natural monopoly) that owns and operates the local delivery network for commodities such as electricity, natural gas and water. In a vertically integrated utility, local delivery is just one of several functions (e.g. B.C. Hydro). Thus, a LDC only exists when the delivery function has been vertically de-integrated (e.g. BC Gas).
market-based rates	Prices set freely in a competitive market, rather than prices based on costs of production.
megawatt (MW)	1,000 kilowatts, or 1,000,000 watts.
natural monopoly	An industry whose market output is produced at the lowest cost when production is concentrated in the hands of a single firm. The term utility is sometimes applied synonymously with natural monopoly.
negotiated settlement process (NSP)	A less formal process where the applicant, interested parties and Commission staff meet to review and attempt to negotiate a settlement on some or all aspects of an application. NSP is used to complement or as an alternative to the traditional regulatory process (e.g. oral public or written hearings) in an effort to save time and reduce the cost of utility regulation while achieving sound regulatory outcomes.
peaking gas	Gas which is stored or purchased under contracts which will allow delivery during the periods of highest demand.
performance-based rates	See “incentive regulation”.
petajoule (PJ)	10^{15} or one quadrillion joules.
quasi-judicial	The powers and processes of a regulator which are similar to the courts.
rate base	The amount of investment in regulated operations on which a regulated entity is allowed to earn a return. It usually consists of the depreciated value of the plant in service required for regulated operations plus an allowance for working capital and deferred assets.
rate design	The methodology for apportioning the revenue requirement to the various class of utility customers.
rate rider	A specific charge on a customer’s bill to recover a specific cost over a fixed period of time.
ratepayers	The customers of a utility.
rates	The prices at which regulated services are provided.

real time pricing (RTP)	Variable pricing of electricity in which the price depends on the cost or market value of providing electricity during each time segment. Applying RTP to electricity service results in customer rates that vary according to the specific utility costs at various times.
retail competition	Permitting end-use electricity customers to contract directly with electricity suppliers for their electricity commodity, while continuing to deal with transmission and distribution utilities for the commodity delivery. The energy commodity is generally sourced in a competitive marketplace.
return on equity (ROE)	The percentage return allowed for the invested equity of utility shareholders.
revenue requirements	See “cost of service”.
self-generation	Generation of electricity by a customer for part or all of its own load requirements.
spot market	A real-time commodity market for immediate sale and delivery of energy products.
time-of-use rates	A rate structure that prices electricity at different rates, reflecting the changes in the utility’s costs of providing electricity at different times of the day or year.
transmission grid, transportation grid, transmission system	An interconnected system of high voltage energy transportation lines and associated facilities used for bulk transfers of electricity. A high-pressure pipeline used for bulk transfers of natural gas is also referred to as a transmission system.
watt	The power required to do work at the rate of one joule per second.
watt-hour	One watt-hour is equal to 3,600 joules of energy.
wheeling	The service of delivering electricity across a transmission system for a third party.
wholesale markets	Wholesale electricity markets are comprised of transactions between buyers and sellers of bulk power at points on a high voltage transmission system.
wholesale rates	The unit prices charged for bulk energy services.