IN THE MATTER OF

the Utilities Commission Act
R.S.B.C. 1996, Chapter 473

and

IN THE MATTER OF

CENTRA GAS BRITISH COLUMBIA INC.
2002 RATE DESIGN APPLICATION

DECISION

JUNE 5, 2003

Before:

Peter Ostergaard, Chair
Paul G. Bradley, Commissioner
Nadine F. Nicholls, Commissioner

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1.0 INTRODUCTION

This Decision responds to three applications from Centra Gas British Columbia Inc.[1] ("Centra", "Utility"):

- a September 30, 2002 Rate Design Application ("the Rate Design Application", "the Application") that proposes rate design principles for 2003 and beyond and approval of final rates for all proposed classes of customers except ACR-2 Pioneer Rate Class customers and those customers with rates determined by existing agreements;
- a December 20, 2002 application for approval of three amending agreements involving British Columbia Hydro and Power Authority ("BC Hydro"), BC Gas Utility Ltd. ("BC Gas") and Centra for natural gas service to the Island Cogeneration Plant ("ICP") at Elk Falls; and
- an application to recover Centra's costs associated with its rate design and cost of service allocation studies.

The Rate Design Application was Phase 2 of a two-phase application process, preceded by Centra's application for approval of its 1999-2001 actual revenue deficiencies and its forecast 2003 to 2005 revenue requirements ("the Revenue Requirement Application").

Centra proposed that both the Revenue Requirement and Rate Design Applications be reviewed by negotiated settlement processes. By Order No. G-71-02 the British Columbia Utilities Commission ("BCUC", "Commission") established a Workshop and Pre-hearing Conference in Nanaimo on October 22, 2002. On October 24, 2002, by Order No. G-76-02, the Commission referred both applications to negotiated settlement processes to begin on November 25 and December 3, 2002 respectively.

A proposed Settlement Agreement on the Revenue Requirement Application was issued on December 24, 2002 and subsequently approved by Order No. G-2-03. However, participants in the negotiated settlement process for the Rate Design Application were unable to reach a proposed settlement. By Order No. G-86-02 the Rate Design Application was the subject of a regulatory timetable, with an oral public hearing to begin on February 12, 2003. The start date for the hearing was later changed to February 5, 2003 by Order No. G-96-02.

Order No. G-86-02 also directed Centra to file an application for interim rates effective January 1, 2003. The Application for Interim Rate Class Segments and Rates ("the Interim Rate Application") was filed on December 10, 2002. By Order No. G-97-02 the Commission approved the Interim Rate Application and established rates for the period from January 1, 2003 until the permanent rates as determined by this Decision are approved.

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[1] On April 25, 2003, shareholders of BC Gas Inc., Centra's parent company, approved a change to its company name to Terasen Inc. Centra Gas British Columbia Inc. has been renamed Terasen Gas (Vancouver Island) Inc.

By Letter No. L-2-03 dated January 9, 2003 the Commission included Centra's December 20, 2002 application for approval of ICP transportation, capacity assignment, and peaking amending agreements as part of the public hearing process for the Rate Design Application.

The oral public hearing took place on February 5, 2003, February 7, 2003 and from March 3 through 6, 2003. Centra's Final Argument was received on March 17, 2003, Intervenor submissions were received by March 28, 2003, and Centra's Reply Submissions were received on April 7, 2003. At the close of the oral hearing Centra and Intervenors were encouraged to include in their submissions any references to the legal basis, both from an interpretive standpoint and supported by available case law, for evaluating the set of agreements that are before the Commission and for determining the appropriateness of reviewing information arising from negotiations that led to agreements (T6:881-82).

In late January and early February prior to the commencement of the oral hearing, the Vancouver Island Joint Venture ("the Joint Venture"; "VIGJV") and Centra raised issues relating to the admissibility of certain evidence, primarily on the basis that certain statements were alleged to be argument, not evidence. In addition, Centra delivered voluminous rebuttal evidence from its consultants shortly before the hearing's February 5, 2003 start date. The Joint Venture took the position that the receipt of the rebuttal evidence was prejudicial to the Joint Venture and it needed further time to review and prepare.

The issues of admissibility and prejudice were addressed by Commission counsel on the first day of the hearing (T1:6-12). On the issue of admissibility, Commission counsel noted that the Commission traditionally allowed documents as evidence that might or might not be technically admissible in a court of law, based on the wide authority granted to the Commission by subsection 78(1) of the Utilities Commission Act ("the Act", "UCA"). The Commission Panel admitted as evidence the documents for which admissibility was questioned, and stated it would consider the weight that it would attribute to these documents during its deliberations (T1:11-12). No objections were raised at the time to the Commission proceeding in this way.

On the issue of potential prejudice arising from the delivery of the Centra rebuttal evidence, counsel for the Commission, Centra, and Intervenors agreed to revise the oral hearing schedule to allow further time to review that evidence. The Commission Panel accepted the revised schedule and adjourned part of the hearing until March 3, 2003 to allow for further review (T1:11).

On April 16, 2003 the Joint Venture objected to parts of Centra's Reply. Specifically, the Joint Venture asked the Commission to strike statements on the weight to be given to evidence of a Joint Venture witness and parts of Centra's Reply that the Joint Venture alleges are not on the record and that are false and misleading speculation. The Joint Venture's letter of objection included an affidavit from Mr. Lloyd Guenther, the technical consultant who had provided both written and oral evidence on behalf of the Joint Venture. On April 22, 2002, in order to allow parties the opportunity to be heard on the Joint Venture's objections, the Commission established a timetable for submissions on these issues. No submissions were received from other Intervenors. Centra responded on April 22, 2003. The Joint Venture provided its Reply on May 9, 2002.

Commission Determinations

At the commencement of the hearing, the Commission Panel admitted certain evidence, the admissibility of which had been in issue, and stated at that time that it would consider the weight that it would attribute to the documents during its deliberations. All parties were aware that the Commission Panel was proceeding in this way and no objections were raised at the time. **The Commission Panel therefore rejects arguments that these documents should not be considered as evidence and has weighed this evidence in the context of all of the evidence adduced during the hearing.**

In its Final Submissions (p. 40), the Joint Venture states that "If the Commission is to engage in a reconsideration of the admissibility of evidence, the Joint Venture renews its objections to the expert evidence filed by Centra Gas." The Commission Panel has not reconsidered that issue and therefore it is not necessary for the Commission to consider any renewed objection by the Joint Venture on the issue of admissibility. In addition, the Commission Panel granted an adjournment of the hearing to allow Intervenors further time to review and prepare cross-examination on the rebuttal evidence of Centra. The timing of the adjournment was agreed to by all parties. Therefore the Commission Panel considers that any prejudice to other parties created by the volume and timing of Centra's rebuttal evidence was remedied by the adjournment.

With respect to the Joint Venture's objections to certain statements in Centra's Reply, the Commission Panel has not considered those statements in arriving at its Decision. Therefore it has also not considered the statements contained in the affidavit of Mr. Guenther, as nothing turns on them.

2.0 BACKGROUND

2.1 Origins and Regulation of Centra

Centra and its predecessor companies began distributing natural gas to communities on the Sunshine Coast and Vancouver Island in October 1991 when gas was first available through the Vancouver Island Natural Gas Pipeline ("the Pipeline"). The Pipeline is a high-pressure transmission system ("HPTS") from the Lower Mainland to distribution systems serving commercial and residential customers. It also transports gas for industrial and other shippers, including:

- the Joint Venture, an association of companies that operate seven pulp and paper mill complexes;
- Squamish Gas Company Ltd. ("Squamish Gas"), which distributes gas to customers in Squamish; and
- BC Hydro, for gas transportation service to ICP, since 2001.

Until 1996 the Pipeline was separately owned and operated by Pacific Coast Energy Corporation ("PCEC"), which by 1996 was a wholly-owned subsidiary of Westcoast Energy Inc. ("Westcoast"). Gas distribution rights on Vancouver Island and the Sunshine Coast were awarded in 1989 to the Vancouver Island Gas Co., a subsidiary of Inter-City Gas, which had purchased the former BC Hydro Victoria Gas Division and held the franchise for Nanaimo. By 1995 the successor distribution companies – Centra Gas British Columbia Inc., Centra Gas Victoria Inc., and Centra Gas Vancouver Island Inc. ("the Centra Companies") – were all wholly-owned Westcoast subsidiaries.

The Pipeline and distribution facilities received financial assistance from both the federal and provincial governments, and Joint Venture mills and distribution system customers were eligible for conversion grants. Under the Consolidated Rate Stabilization Agreement between Centra and the Province, gas rates to distribution customers were decoupled from the cost of providing service and were set at a discount to oil and/or electricity. The Province provided guarantees through a Rate Stabilization Facility that absorbed the shortfall between revenues from customers and the costs of the transmission and distribution facilities.

By the mid-1990s, due in part to construction cost over-runs and lower than expected price differences between natural gas and oil/electricity alternatives, it was apparent that a financial restructuring of the Pipeline and distribution facilities was needed in an effort to achieve financial viability. The Consolidated Rate Stabilization Agreement was replaced by the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") in late 1995. The Province made a $120 million lump sum payment as a contribution to capital costs with a corresponding reduction in rate base. Further provincial government assistance was and is provided in the form of gas royalty credits. On January 1, 1996 the assets of the three Centra distribution companies were transferred to PCEC and shortly thereafter PCEC changed its name to Centra Gas British Columbia Inc., making this single legal entity the owner and operator of both the transmission facilities from the Lower Mainland to and on Vancouver Island and the distribution facilities on Vancouver Island and the Sunshine Coast.

The VINGPA includes a Special Direction to the Commission issued under the Vancouver Island Natural Gas Pipeline Act by the Lieutenant Governor in Council through Order-in-Council 1510/95 (Exhibits 6, 6A). Since 1996 and prior to January 1, 2003, rates to Centra's distribution system customers were set according to the Special Direction: for most customers, formula-based rates applied until the end of 2002. The Special Direction states that beginning January 1, 2003 the Commission is to fix the rates charged by Centra for all customers except the Apartment (ACR-2) class "…so that Centra is able to recover its cost of service in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia" (Exhibit 6, Sec. 2.8, p. 16).

Service to the Joint Venture and Squamish Gas is provided under long-term transportation service agreements ("TSAs") that contain agreed upon tariffs. These expire in 2006 or later. Prior to 1996 the rates charged to pulp and paper mills for transporting gas on the Pipeline were tied to the price of heavy fuel oil. Centra and the Joint Venture are also parties to a Peaking Gas Management Agreement ("PGMA"). Service to BC Hydro is provided under a short-term TSA that expires on October 31, 2003. Centra also has a Peaking Agreement with BC Hydro ("BCH PA").

On December 6, 2001 BC Gas Inc. applied to the Commission for approval to acquire from Westcoast a reviewable interest in the shares of Centra. The Commission approved this acquisition by Order No. G-8-02, subject to the consent of the Province. By a Novation Agreement dated March 7, 2002 BC Gas Inc. assumed the benefits and obligations of Westcoast under the VINGPA. The Special Direction has been amended to reflect BC Gas Inc. ownership of Centra (Exhibit 6A).

2.2 Centra's Circumstances

Since its inception in 1988, the Vancouver Island gas pipeline project was regarded as a potentially high-risk initiative with a potentially high-cost exposure to the Province. The principal risk was the financial exposure created by the Province's obligations under the Rate Stabilization Facility in the form of an open-ended financial obligation designed to ensure that PCEC and the Centra distribution companies recovered their full costs of service. Through the cash settlement and royalty credits, VINGPA reduced significantly the Province's exposure. However, the financial risk to Centra through the deferral of costs for future recovery has remained high.

Since the 1995/96 restructuring, the integrated operation has continued to lose money. Centra admits its long-term financial sustainability is far from certain (Centra Submissions, p. 5). Centra argues that its Rate Design Application is a balanced, rational approach that responds to four objectives (T3:149):

- a safe, reliable system;
- the competitiveness of Centra's service and the value it provides;
- the opportunity for long-term growth of the utility; and
- long-term financial sustainability.

Intervenors express varying views on Centra's prospects. In the opinion of the Joint Venture, Centra faces huge and insurmountable financial challenges (Joint Venture Final Argument, p. 1). The risks to Centra, according to the Joint Venture, include higher gas prices, higher interest rates, unfunded pension obligations, refinancing of debt, inability to recover annual revenue deficiencies, reduced sales, low oil prices, transmission capacity declines and repayment of government loans (Joint Venture Final Argument, p. 32).

Others take a different perspective. The Consumers' Association of Canada (BC Branch) et al. ("CAC (BC) et al.") asserts that "if Centra fails to establish itself as a viable entity, rather than having one or the other party losing, everyone will lose" (Final Argument, p. 1). The Vancouver Island Natural Gas Public Sector Consumers Group ("Public Sector Consumers") states that Centra's objective of obtaining financial sustainability is an initiative that the Public Sector Consumers supports and that Centra's Rate Design Application does begin a balanced and responsible pathway to long-term viability and sustainability (Public Sector Consumers Submissions, p. 3).

Most of Centra's challenges are attributable to three factors.

<u>Revenue Deficiencies:</u>

As required by the Special Direction, the Commission has determined the Annual Revenue Deficiency ("ARD") and recorded it in a Revenue Deficiency Deferral Account ("RDDA").

<u>Competitive Markets:</u>

In its residential, commercial, institutional and small industrial markets, natural gas competes with other energy sources (e.g. oil, electricity, propane, wood) which Centra argues effectively limits the price it can charge for gas service. The Special Direction directs the Commission to have regard for Centra's competitive position relative to alternative energy sources [Exhibit 6, 2.10(j)].

Financial Sustainability:

Under the terms of the VINGPA, royalty revenue payments (forecast to range between $19.7 and $26.8 million annually between 2003 and 2011) cease in 2011. Core customer rates in 2012 are likely to be increased by the amount of the foregone 2011 royalty revenue credit. Centra also anticipates it will be in a position to repay loans to Canada and the Province after 2011.

3.0 2002 COST OF SERVICE FILING AND RATE DESIGN APPLICATION

3.1 Cost of Service Allocation ("COSA") Study

Centra filed its COSA study (Exhibit 1A) in support of establishing a cost-allocation methodology for evaluating rates. Centra's COSA model was developed by EES Consulting Inc. ("EES"). The result of such analysis is a revenue requirement for each customer class which, when summed for all customers classes and adjusted for offsetting revenues such as Interruptible Revenues, should equal the total revenue requirement for the Utility. By comparing the revenue forecast from each class of customer to the class' cost-based revenue requirement, a revenue to cost ratio can be determined which indicates how closely the revenues provided by a customer class match the costs they are considered to have caused.

A COSA study is a complex and highly detailed analysis, the results of which may vary significantly depending on the assumptions made and the treatment of costs in the model. The first step in the process is functionalization of costs which, as the name implies, separates costs into major functional categories such as production, transmission, distribution and general.

The next step, classification, attempts to classify costs into cost causation categories (demand, commodity or customer). For instance, transmission costs tend to be demand-related because they are associated with the size of the facilities needed to meet the maximum demand. Classification of demand-related costs may be further refined as, for example, coincident peak ("CP") or non-coincident peak ("NCP"). CP may be further refined to reflect whether the utility experiences one demand peak per year ("1 CP"), two peaks per year such as a summer peak and a winter peak in demand ("2 CP") or demand peaks each month ("12 CP"). Procuring and delivering gas supply to the utility's system tend to be classified as commodity related. Meter reading and billing costs tend to be classified as customer related.

The third step in a COSA analysis is the allocation of costs to specific customer classes based on the class characteristics and the class contribution to the classified costs. For instance, costs classified as demand are allocated to the various customer classes on the basis of the class demand characteristics (such as the class contribution to coincident or non-coincident peak).

The May 2002 COSA filing was based on the costs and data in the Revenue Requirement Application Negotiated Settlement approved by Commission Order No. G-6-00, and included 31 different scenarios (model runs) based on different sets of assumptions.

The scenario put forward by Centra as the most appropriate scenario in its May 2002 COSA filing (Exhibit 1A) was based on the following parameters:

- gas supply costs split between demand and commodity using a fixed-variable approach;
- high pressure transmission costs classified on the basis of 1 CP;
- intermediate pressure transmission classified on the basis of 1 CP for core customers only;
- minimum system analysis for classifying distribution costs between NCP demand and customer-related costs;
- demand allocation of 1 CP based on the contract demands of all customers;
- add-back of grant amounts for purposes of functionalizing and classifying rate base amounts;
- direct assignment of costs where economic and efficient; and
- allocation of Administrative and General expenses using standard allocation factors rather than direct assignment (Exhibit 1A, Tab 6, p. 6.1).

3.2 September 2002 Rate Design Application

Centra's Rate Design Application was intended to provide rate design principles that would guide future rate setting at Centra and establish rates for each class of service effective January 1, 2003, based on the following rate design objectives:

- long-term financial viability;
- revenue deficiency recovery;
- rate stability and continuity;
- adherence to cost of service principles;
- avoidance of undue customer rate impacts; and
- observance of competitive forces (Exhibit 1, Tab 3, p. 3.5).

Centra is proposing a "soft-cap" rate setting mechanism under which rates would be set to be competitive with electricity and fuel oil for core market customers such as residential and commercial customers. In most cases, the retail burner tip price for any customer class would be capped at the price level of the class' applicable alternative fuel in order to maintain the competitiveness of natural gas. The proposed mechanism is a soft-cap since the burner tip rate would float as necessary to respond to changing market conditions or other market factors. The soft-cap will allow Centra to maximize its revenue from the core market customers during the early life of the Utility when large cost deferrals exist.

A major factor in considering Centra's rate design proposal is recovery of revenue deficiencies from past years that have been accumulated in the RDDA. Revenues for the sale and transportation of gas have typically resulted in annual revenue deficiencies, as the rates established under the Special Direction were insufficient to recover Centra's cost of service. Under the VINGPA, Centra funds the revenue deficiency through the issuance of preferred shares ("Class A Instruments") or promissory notes ("Class B Instruments") which Centra's parent company (BC Gas Inc.) will subscribe for and take up. The accumulated revenue deficiency at year-end 2002 (unaudited) was approximately $87.9 million (Exhibit 2A, Tab C, Tab 5, Response JV5-35; T4:438).

Centra states in its Rate Design Application that it can only meet its fundamental goal of becoming financially sustainable if a rate design framework is established that provides regulatory flexibility enabling Centra to set rates that fully recover the accumulated revenue deficiency over the shortest time period reasonably possible. Recovery of the accumulated revenue deficiency should, in Centra's view, be complete by no later than 2011 when royalty credit revenues end. Upward pressure on rates would be mitigated if the RDDA amortization can be removed before the expiry of the royalty credits (Exhibit 1, p. 1.4).

4.0 RECOVERY OF THE ACCUMULATED REVENUE DEFICIENCY

Centra's right to future recovery of the balance in the RDDA has not been contested by any party in the hearing. Nor was Centra's proposal to include RDDA costs in the rates of distribution system customers objected to by either CAC (BC) et al. or the Public Sector Consumers. The Public Sector Consumers offered the following perspective on the Centra Rate Design Application including its proposal for amortizing the RDDA:

> "The Public Sector Consumers Group recognizes that the cost recovery approach proposed by Centra at this point may in some circumstances see our members pay more than 100% of their costs of service. This is an issue we will monitor on a go forward basis. However, at this time it is also recognized that all customers on the system have to participate in a manner which ensures that the system can become viable and sustainable under a full cost of service rate design." (Public Sector Consumers Submissions, p. 3)

The Special Direction is clear that in no event, while the Special Direction is in force, shall the rates or transportation tolls that are approved for the Joint Venture or Squamish Gas include any amount for amortization or recovery of the RDDA balance (Exhibit 6, Section 3.7).

The two central, inter-related issues in the hearing regarding amortization of the RDDA in rates were:

- whether or not other customers who only transport natural gas on the HPTS should be required to contribute in rates to the amortization or recovery of the RDDA balance; and
- what approximate time period is reasonable for allowing Centra to reduce the RDDA balance to zero or near-zero.

Only four parties currently transport gas on the HPTS. Those four are Centra, on behalf of its distribution system customers, the Joint Venture, Squamish Gas and BC Hydro. The distribution system customers will collectively contribute to amortization of the RDDA in their rates. The Joint Venture and Squamish Gas, as noted above, are exempt from contributing to the RDDA. The remaining current customer on the Centra HPTS is BC Hydro. A central question before the Commission, therefore, is whether BC Hydro and any other new HPTS shippers should be required to contribute to amortization of the RDDA in the firm transportation rate.

4.1 Special Direction

The Special Direction was issued by the Province during the restructuring of agreements between the Province, PCEC, the Centra Companies and Westcoast. That financial restructuring is set out in the VINGPA (Exhibit 38). Several documents are attached as Schedules to the VINGPA including the Special Direction (Schedule B) and the Joint Venture TSA (Schedule F). The Special Direction's approval by the Lieutenant Governor in Council and that it be in full force and effect (subject to notice to the BCUC) were among the conditions for the closing of the VINGPA [Exhibit 38, Article 7.01(d)]. When the Special Direction was issued in December 1995, the Centra Companies owned and operated the distribution system, and PCEC owned the Pipeline system. In January 1996 the assets of the Centra Companies and PCEC were merged to a single company, Centra (Exhibit 34).

The Special Direction is comprised of five parts. Part 1 deals with preliminary and general matters. Part 2 relates to Centra, which is a defined term meaning the company or companies that may from time to time own and operate the Centra Distribution System ("CDS"). The Special Direction defines the Centra Distribution System to mean the gas distribution systems of Centra. Part 3 relates to PCEC, the definition of which includes such other company that may own and operate the Pipeline. Pipeline is defined to mean the Vancouver Island Natural Gas Pipeline described in the Energy Project Certificate issued to PCEC. Part 4 relates to the "Determination of Annual Revenue Deficiency, rate base, capital structure and return on equity where the Pipeline and Centra Distribution System are owned by a Single Entity." Single Entity is defined to mean a single legal entity, which owns and operates both the Centra Distribution System and the Pipeline. Part 5 is a direction respecting Squamish Gas.

Part 2 of the Special Direction explicitly allows Centra to recover RDDA in the rates to be charged to its customers. Section 2.10(j) of the Special Direction reads as follows:

> "For each year beginning January 1, 2003, the cost of service of Centra that is approved by the BCUC for the purpose of determining the rates to be charged to Centra's customers shall include an amount for the deemed redemption of Class "A" Instruments or repayment of Class "B" Instruments that the BCUC determines to be appropriate in order to amortize the balance of the Revenue Deficiency Deferral Account over the shortest period reasonably possible, having regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates."

Part 3 is silent on the issue of RDDA except in Section 3.7, which explicitly excludes the Joint Venture and Squamish Gas from paying "directly or indirectly" for any part of the RDDA.

Part 4, Section 4.1 regarding Annual Revenue Deficiencies states:

> "The BCUC shall determine Annual Revenue Deficiencies and the balance of the Revenue Deficiency Deferral Account for a Single Entity in the manner set out in Section 2.10 based upon the actual revenue and the cost of service associated with both the Centra Distribution System and the Pipeline but without taking into account any revenue or costs that relate to any other business conducted, or assets owned, by the Single Entity."

4.1.1 Centra's Position

Centra submits that there are two questions that hinge on interpretation of the Special Direction:

- Is the Commission prevented by the Special Direction from approving rates for transmission customers that allow for recovery of the RDDA? The answer in Centra's view is "no", except for the Joint Venture and Squamish Gas.
- Is the Commission required by the Special Direction to include RDDA amortization in the rates of BC Hydro and other transmission customers? The answer in Centra's view is that effective 2003 the Special Direction requires that the Commission approve rates for all customers, including transmission customers except the Joint Venture and Squamish Gas, that include an amount for RDDA recovery over the shortest time period reasonably possible.

Centra argues that its rate proposals for transmission service are not dependent on the Commission concluding that the Special Direction requires inclusion of an amount for RDDA recovery in transmission rates, but simply a conclusion that the Special Direction does not prohibit recovery of the RDDA in transmission rates. Centra submits that the inclusion of RDDA recovery in the rates of BC Hydro and other transmission customers, except the Joint Venture and Squamish Gas, is supported by the requirement in the Special Direction that effective 2003 the Commission is to approve rates that include an amount for recovery of the RDDA over the shortest time period reasonably possible (Centra Reply Submissions, p. 28). Centra submits that this requirement can only be met through approval of a rate for transmission customers, such as BC Hydro, that includes an amount for RDDA amortization (Centra Reply Submissions, pp. 31-32).

In Centra's view, the rates to be charged for firm transmission service are included in the phrase "…rates to be charged to Centra's customers" in Section 2.10(j) of the Special Direction and accordingly the Commission is required to include RDDA recovery in the cost of service used to determine those rates. Centra further argues that the definitions of "Centra" and "Single Entity" have the same meaning and, by substituting Centra's predecessor company for "Single Entity" in the wording of 2.10(j), it becomes clear that the rates of all customers of the Single Entity that owns both the transmission and distribution facilities are to include an amount for RDDA amortization.

Centra believes that such an interpretation is consistent with the wording of other sections of the Special Direction and related documents. Centra submits that the examples referenced in Section 2.10(f) and attached as Schedule E show that the calculation of the ARD applies for the Single Entity because of Section 4.1. Examples 4 and 5 of Schedule E, which apply to a post-2002 time period, show the amortization of the RDDA as part of the forecast cost of service without any differentiation in the treatment for distribution or transmission facilities.

Centra also cites the "implied exclusion" rule which, in effect, says if there is reason to believe that the legislature had meant to include a particular thing with legislation, it would have done so expressly and failure to mention that thing implies an intention to exclude that thing. Centra argues that if the intention had been to exempt customers such as BC Hydro from the RDDA once there was a single entity then it would have been stated in the Special Direction similar to the exemption of the Joint Venture and Squamish Gas in Section 3.7.

Centra further notes that the Joint Venture TSA is a schedule to the Special Direction, and Section 11.01(a) of the Joint Venture TSA contemplates that revenue deficiencies may exist and exempts the Joint Venture from any such revenue deficiencies on the PCEC (transmission) system. Section 11.01(b) does not exempt new shippers on the PCEC system from revenue deficiency recovery. Centra submits that the express exemption in 11.01(a) on the PCEC system and the lack of such an exemption in 11.01(b) implies that new customers on the transmission system would be subject to revenue deficiency recovery. It is to be noted that Section 11.01(b) refers to "any Third Party Shipper". Third Party Shipper is defined in the Joint Venture TSA to exclude members of the Joint Venture, PCEC, Centra and their successors.

Centra also argues that the definition of Royalty Revenue Payments in the Special Direction is modified when the distribution and transmission facilities are owned and operated by a single entity, and when that occurs the Royalty Revenue Payments also include Interruptible Incentive Payments. According to Centra, once the single entity operates both parts of the system, the calculation of the ARD and the RDDA includes the Interruptible Incentive Payments that relate only to the transmission facilities. Centra submits that this can only be interpreted as indicating that the transmission-related revenues and costs were not to be kept separate from the distribution-related costs and revenues for RDDA purposes.

Centra argues that the adoption of the position that BC Hydro and other future HPTS customers should not be responsible for recovery of the RDDA would mean that the RDDA balance would not be recovered by 2011 and probably not at all. This, in Centra's view, would be in direct conflict with the requirement for RDDA recovery under Section 2.10(j).

4.1.2 The Positions of CAC (BC) et al. and of the Public Sector Consumers

Both CAC (BC) et al. and the Public Sector Consumers support the Centra Application. On the issue of which parties should be exempted from contributing to recovery of the RDDA under the Special Direction, CAC (BC) et al. also looked to the "exclusio unius" or "implied exclusion" principle. CAC (BC) et al. stated its position as follows:

> "14. Is there anything in the Special Direction or elsewhere signaling the intent that the Joint Venture and Squamish be examples rather than the exhaustive list of parties that are exempted from contributing to the RDDA? No. Is there any reason why the drafters of the Special Direction could not have made a more general exclusion from responsibility for RDDA recovery for the HPTS and its users if that was their intention? No. Was it impossible for the drafters of the Special Direction to know that there might be third party shippers? No.
>
> 15. Given that, the rationale for the application of the *exclusio unius* rule is very strong in this case." [CAC (BC) et al. Final Argument, pp. 7-8]

The Public Sector Consumers note that distribution system customers invested in natural gas facilities on Vancouver Island and expected that rates set by Centra would be fair, just and reasonable. In their view, all customers should participate in RDDA recovery.

4.1.3 BC Hydro's Position

BC Hydro disputes that Section 2.10(j) applies to transmission rates. In BC Hydro's view, the legislative intent of the Special Direction is that, for cost of service and ratemaking purposes, Centra distribution system customers and HPTS shippers are to be treated separately and differently.

In BC Hydro's submission, the purpose of the VINGPA and the Special Direction is to restructure the CDS rates over time to recover current and deferred costs of service provided to distribution system customers. BC Hydro submits that the factual matrix surrounding the VINGPA demonstrates the expectation that revenue deficiencies would be incurred and that they would result from the distribution system. It argues that Centra explicitly recognized this when it said in its Revenue Requirement Application that under the Special Direction, BC Gas (Centra's parent company) funds the revenue deficiencies until such time as gas sales revenues (BC Hydro's emphasis) increase to a level sufficient to recover current and deferred cost of service.

On the Centra system, sales customers (those who purchase the gas commodity from Centra) currently take delivery of the gas from the distribution system. Transportation customers (those who purchase gas from a third-party supplier and purchase transportation service from Centra) currently take delivery of the gas from the transmission system. However, the Commission notes that the distinction between sales and transportation customers relates to the gas purchasing choice of the customer, not the distinction between a distribution system and a transmission system. On the BC Gas system many commercial and small industrial customers are transportation service customers.

BC Hydro argues that the Special Direction provides separate directions for determining rates charged to distribution system customers (Part 2) and for determining transmission tolls to be charged for transportation services provided to third-party shippers (Part 3). BC Hydro argues if it were the intent of the Special Direction to displace such provisions, clear provision could have been made in Part 3 of the Special Direction for recovery of the RDDA from HPTS shippers.

In support of its arguments, BC Hydro further states that Part 2 is clearly intended to deal with CDS rates only, hence the references to "gas distribution utilities". It notes that the time references are not fixed for establishing new transportation tolls but are fixed for CDS tolls, and that Section 2.10(i) provides for redemption of instruments associated with funding the RDDA when the revenues of the CDS (BC Hydro's emphasis) exceed the cost of service. BC Hydro also argues that Section 4.5 of the Special Direction requires the Single Entity to maintain separate records relating to the Pipeline and the distribution system (BC Hydro Argument, pp. 8-9).

BC Hydro argues that Centra focuses on the wrong word in its analysis of Section 2.10(j); the focus should be on the word "customers", not "Centra". BC Hydro submits that the Section refers to CDS customers and does not include "shippers" on the HPTS. Therefore, the issue is not whether the calculation is or isn't an aggregate calculation for a single entity, but from whom the RDDA is to be recovered. BC Hydro believes that it is appropriate to look at related agreements to interpret the meaning of the Special Direction, and that the term "Shippers" is used in the Joint Venture TSA and the PCEC Terms and Conditions. Therefore, BC Hydro submits that "customers" refers only to CDS customers.

In BC Hydro's submission, the principle of "implied exclusion" is a weak argument and does not create a positive obligation on other HPTS shippers to bear a portion of RDDA recovery when the legislation does not impose any such positive obligation elsewhere. BC Hydro argues that the express exclusion from RDDA recovery for the Joint Venture and Squamish Gas does not overcome the regulatory scheme established by the Special Direction which calls for recovery of the RDDA from CDS customers only.

BC Hydro disputes Centra's rewording of Section 2.10(j) to replace "Centra" with "Single Entity". BC Hydro argues that there is no basis in the Special Direction to suggest that 2.10(j) directs inclusion of the RDDA in the cost of service for determining HPTS tolls. BC Hydro submits that transportation tolls are governed by Part 3, both before and after Part 4 comes into effect, and that the cost of service determined under Part 3 includes no amount for RDDA recovery. In BC Hydro's submission, the reliance by Centra on the provisions of Part 4 does not abrogate the scheme of the Special Direction. Rates to be charged to Centra's CDS customers are affected by Part 4 only to the extent that Part 4 affects the determination of the applicable cost of service. BC Hydro submits that the rates themselves are established pursuant to Section 2.8, which is not subject to Part 4.

4.1.4 The Joint Venture's Position

The Joint Venture argues, as does BC Hydro, that under the Special Direction the RDDA applies only to the CDS. The Joint Venture submits that the Commission must exercise some discretion and judgment in the interpretation of the Special Direction and accordingly it is appropriate for the Commission to consider the factual matrix in which the Special Direction was issued. The fact that PCEC purchased the assets of Centra Distribution in 1996 does not change the meaning of any of the terms of the Special Direction, PGMA, TSA, or VINGPA.

The Joint Venture submits that the RDDA was calculated and accrued based on the operations of "Centra Gas". It states that under the Special Direction, Centra Gas was and remains the CDS and is consistently treated as separate and distinct from the "Pipeline". The Joint Venture further argues that the Special Direction does not establish an RDDA account in relation to the operations of PCEC or the HPTS because all parties knew the Joint Venture was paying 100 percent of its cost of service. Squamish Gas had negotiated a distance-based toll and the only other shipper was the CDS.

The Joint Venture submits that Centra's argument that the term "Single Entity" can be substituted for "Centra" in Section 2.10(j) of the Special Direction without changing its meaning is absurd and renders Section 4.5 meaningless. Section 4.5 states that "The BCUC shall require that the Single Entity keep separate records relating to the Pipeline and the Centra Distribution System sufficient at all times to differentiate, where appropriate, between all activities related to the construction and operation of the Pipeline and the Centra Distribution System." The Joint Venture states that Centra has effectively admitted that it does not have those records.

The Joint Venture also refers to Section 10.01 of the VINGPA, which states that in relation to the reorganization of Centra Distribution and PCEC certain transactions must be reviewed by the Province to verify that the transactions will not have an adverse impact on the RDDA. The Joint Venture states that when the VINGPA was signed, Centra Distribution and PCEC were separate entities, and by definition the RDDA applied only to Centra Distribution. The Joint Venture concludes that the obvious intent of the Province was to ensure that the reorganization of Centra Distribution and PCEC would not affect responsibility for the RDDA. The Joint Venture submits that it was therefore never the intention of the Province that deficits from the operation of the HPTS would be added to the RDDA and the attempt to imply such a result is contrary to the VINGPA.

4.1.5 Centra's Reply to BC Hydro and the Joint Venture

BC Hydro witnesses gave evidence that "the unit cost of a pipeline is high when it is first installed because much of the capacity on the initial pipeline is provided by higher-cost pipe than lower-cost compression" (Exhibit 3, Confer/Optimum evidence, p. 27). Centra argues that by proposing to avoid any contribution to RDDA recovery, BC Hydro is seeking to take advantage of the lower unit costs of the system going forward, without making any contribution to the shortfall in cost recovery in the past, a shortfall that arose because of higher costs per unit of throughput in the past (Centra Reply Submissions, p. 2).

Centra submits that Section 4.1 of the Special Direction makes it "abundantly clear" that upon there being a Single Entity, the ARD and RDDA balance are determined on the basis of revenues and cost of service of both the distribution and transmission facilities (Centra Reply Submissions, p. 31). Centra also argues that its interpretation is supported by the plain and unambiguous meaning of the words "Centra's customers" in Section 2.10(j), and by the application of the "implied exclusion" rule to the exclusion of the Joint Venture and Squamish Gas from any RDDA recovery (Centra Reply Submissions, p. 42).

Centra argues that the Joint Venture and BC Hydro interpretations of the Special Direction ignore the defined meanings of Centra (the legal entity) and Centra Distribution System (the physical assets). Section 2.10(j) refers to Centra's customers, not Centra Distribution System customers (Centra Reply Submissions, pp. 30-31).

Centra disputes BC Hydro's assertion that substitution of the words "Single Entity" for "Centra" in Section 2.10(j) would change the meaning of the Section. Centra also disputes BC Hydro's focus on the word "customers" in Section 2.10(j). Centra argues that the Special Direction is unequivocal that the customers reference in Section 2.10(j) are the customers of the legal entity known as Centra Gas British Columbia Inc. Centra argues that "shippers" is not a term used in the Special Direction and therefore there is no basis for distinguishing between "shippers" and "customers". Centra also notes that the VINGPA uses the word "customers" in a way that is entirely consistent with Section 2.10(j).

In Centra's view, BC Hydro's submission that Part 4 modifies Parts 2 and 3 only to a limited extent ignores the fact that once there is a single entity there is only one public utility as defined in the Act, plus one rate base, one capital structure, one management and employee organization, and one RDDA. The inclusion of a "Single Entity" and of Part 4 demonstrates the intention of the Special Direction for integration of revenues, costs and RDDA, not separate regulation of separate legal entities that no longer exist. In response to BC Hydro's submission that the reference to Centra Distribution System revenues in Section 2.10(i) implies that the RDDA is only associated with the CDS, Centra argues that Section 2.10(i) is subject to Part 4, and the redemption of the financial instruments must be based on aggregate results.

Centra states that it has kept separate records of the Pipeline and Distribution systems as required by Section 4.5 of the Special Direction and that nothing in Section 4.5 exempts pipeline customers from RDDA recovery. Centra further argues that the precise references to "Pipeline" and "Centra Distribution System" are used when physical facilities are meant, and "Centra", "PCEC" and "Single Entity" are used when legal entities are meant. Centra submits that it is clear from the definitions that the latter three terms were intended to have the same meaning if there was a single owner. Centra also submits that BC Hydro's argument that the provisions of Part 4 have limited significance in the construction of the Special Direction ignores the definitions of "Centra", "PCEC", "Single Entity" and the impact on references in Sections 2.10(j) and 3.1 for determining cost of service.

Centra submits that its interpretation of the Special Direction provides consistency amongst the documents. Centra points out that the seventh recital in the VINGPA states that the Pipeline system and the distribution system were in financial difficulty. Centra also cites the eighth recital of the VINGPA which states that PCEC will acquire the gas distribution assets of the Centra Companies on Vancouver Island and the Sunshine Coast in order to enhance operational efficiencies. According to Centra, this is consistent with the Special Direction, which contemplates a single owner/operator of both systems.

Centra denies that the first recital on page 3 of the VINGPA suggests that it was expected that revenue deficiencies incurred by the distribution system would not add to the RDDA, as argued by BC Hydro. Centra argues based on other sections of the VINGPA that BC Hydro's inference is incorrect and that if BC Hydro was correct the VINGPA would refer to Centra Distribution System in Section 3.01 rather than "Centra".

Commission Determinations

In resolving the issue of whether or not it was the intention of the Special Direction that the RDDA be collected from HPTS customers other than the Joint Venture and Squamish Gas, the Commission has to consider the words and provisions of the Special Direction as a whole, as well as related documents such as the VINGPA and the Joint Venture TSA. In other words, the Commission must assess the factual matrix.

After reviewing and considering the evidence and the arguments, the Commission determines that the interpretations of Centra, CAC (BC) et al. and the Public Sector Consumers are more consistent with the applicable documents. The Commission finds that the Special Direction does not prohibit the Commission from allowing Centra to recover some of the RDDA in its transmission tolls from HPTS customers other than the Joint Venture and Squamish Gas, as well as in rates to distribution system customers on the CDS.

An argument advanced to support the position that tolls on the CDS and the HPTS should be treated separately, is based on the use of the word "customers" in Section 2.10(j) of the Special Direction. BC Hydro argues that this excludes parties who only transport gas on the HPTS system, since those parties are referred to as "shippers" in the Joint Venture TSA and the PCEC Terms and Conditions (Schedule H to the Special Direction). The Commission rejects that interpretation. If natural gas service were unbundled on the Centra system, then distribution system customers who chose to purchase gas from a third-party shipper would be able to avoid RDDA recovery in contrast to similar customers who continue to purchase gas from Centra. Also, as pointed out by Centra in argument, the VINGPA uses the term customers in a way that is consistent with the use of the word in Section 2.10(j) of the Special Direction (see, for example, the ninth recital of the VINGPA). Finally, if the distinction raised by BC Hydro was intended, the Commission would expect that "shippers" and "customers" would be defined terms in the Special Direction (as are many other terms), but they are not.

The Commission agrees with BC Hydro that the terms of the Special Direction only prevail over the provisions of the Act and applicable regulatory principles if they are inconsistent with the Special Direction (BC Hydro Argument, p. 20). The Commission notes that it is directed in Sections 2.8, 2.10(d) and 3.7 of the Special Direction, to apply normal regulatory principles. For reasons discussed later in this Decision, the Commission also concludes that its interpretation is consistent with normal regulatory principles, and with the requirements of the UCA.

4.2 RDDA Cost Responsibility

Cost of service analyses consider the issue of which customers caused which utility costs. This is termed the principle of cost causation. The weight to be given to cost causation as compared to several other possible rate design objectives is subject to debate.

The issue of which customers should be responsible for amortization of the RDDA balance in their rates comprises two questions. The first is whether the RDDA balance has resulted from Annual Revenue Deficiencies on the CDS or from the combined operations of the CDS and the HPTS. The second question is how much weight should be given to cost causation in setting Centra's rates, as compared to other rate design objectives.

4.2.1 RDDA Cost Causation

Centra's Position

Centra argues that the RDDA arose from the combined revenues and costs of a single entity. In Centra's submission, Section 4.1 of the Special Direction makes it clear that upon there being a Single Entity the ARD and the balance of the RDDA are to be determined on the basis of the revenues and cost of service associated with both the distribution and transmission facilities (Centra Reply Submissions, p. 31).

Centra further argues that since the restructuring in late 1995 through 2001 the integrated operations of the transmission and distribution facilities have lost money. Centra submits that it is not possible to determine where the losses have occurred. Centra acknowledged that the distribution system had contributed to the revenue deficiencies, but because its rates were established by formulas in the Special Direction (prior to

January 1, 2003), the rates were not cost-based. Centra submits that it was unable to connect revenues to any specific costs or determine whether the revenues were related to distribution costs or high pressure system costs. For that reason, it could not know how revenue deficiencies were split between the distribution and the high-pressure systems (T4:546-47).

Centra further argues that there is nothing in the Special Direction, the VINGPA, the Joint Venture TSA, or the Squamish TSA that states the negotiated rates to the Joint Venture and Squamish Gas were cost-based. Further, the Joint Venture TSA in Section 11.01(a) specifically addresses the potential for a revenue deficiency related to the transmission facilities (Centra Reply Submissions p. 40).

BC Hydro's Position

BC Hydro argues that the RDDA was accumulated from revenue deficiencies on the CDS and, based on the principle of cost causation, BC Hydro should not be responsible for repayment of the RDDA. BC Hydro supports its argument by reference to a September 17, 2001 letter from Centra (Exhibit 1A, Tab C). In that letter Centra states that within the context of the Special Direction's requirement for Centra to maintain separate records for the Pipeline and the CDS, the HPTS as a stand-alone system would generate income and be taxable. The letter also states that the CDS does not recover its cost of service and is therefore not taxable. BC Hydro quotes Centra's COSA study which states that "…the high-pressure system is considered to operate in such a manner as to recover its current cost of service for the purposes of COSA and ratemaking. Income taxes are therefore paid by the high-pressure transmission system." BC Hydro submits that the evidence shows that the HPTS was operated so as to recover its cost of service, and that the RDDA was created through revenue deficiencies from a lack of revenue from CDS customers (BC Hydro Argument, pp. 60-66).

BC Hydro also argues that Centra allocates 100 percent of the Customer Loss Carryforward arising from the RDDA to CDS and none to HPTS, which contradicts Centra's view that class responsibility for the RDDA cannot be established (Exhibit 2, Response to BCUC IR 2-5.3.1). Centra says that its allocation of the Loss Carryforward would have had no effect on its toll proposals for 2003 because the soft-cap mechanism limited distribution system rates and because the alternative allocation would have established an inappropriate cost structure for 2004 and 2005 when the Loss Carryforward would no longer exist (T3:311). BC Hydro disputes this rationale, arguing that it should not be denied a credit in one year because the credit would not be available in future years (BC Hydro Argument, p. 68).

BC Hydro submits that Centra's argument makes much of the provisions of Part 4 of the Special Direction requiring an aggregate RDDA balance and the inclusion of Interruptible Incentive Payments. However, it considers that these arguments serve merely to obscure the truth that the RDDA is the result of the under-contribution of the CDS.

BC Hydro presented Table 4 in Argument (p. 70) to show that the unit cost, based on the allocation method of Centra, would not decrease if BC Hydro was not a customer. BC Hydro argues that even using its allocation proposal, such that the unit cost of service would increase if its contract demand of 28,000 GJ/d was eliminated, the resulting average unit costs would be below the Joint Venture's toll. BC Hydro argues that this shows that the Joint Venture toll is higher than the allocated cost of service for a period where the allocated costs are available (BC Hydro Argument, pp. 69-71). BC Hydro also presented Table 5 to argue that the average Joint Venture toll has exceeded the average capacity-related HPTS cost of service.

BC Hydro submits that Squamish Gas has covered its costs, and the revenue to cost ratio that shows otherwise is wrong because the allocated costs in the COSA are wrong and there is no accounting for any payments from the Rate Stabilization Facility. BC Hydro further argues that the Joint Venture toll was cost-based and it is not plausible that the Joint Venture and Squamish Gas tolls were set below forecast costs because to do otherwise would have been to add to the RDDA from which the Joint Venture and Squamish Gas were exempted. Finally, BC Hydro points to the Joint Venture's evidence that, although the Joint Venture rate was a negotiated rate, it was cost-based. The Joint Venture's evidence also stated that it was more likely that the recovery of costs for the Joint Venture was in excess of what was forecast. BC Hydro submits that this supports the conclusion that the average Joint Venture toll has exceeded the average capacity related HPTS cost of service. BC Hydro also argues that the interruptible revenue from the Joint Venture should remove any lingering concern that the Joint Venture toll did not recover its allocated HPTS cost of service (BC Hydro Argument, pp. 73-76).

BC Hydro submits that the CDS revenue shortfall, even if allocated to the HPTS, still means the shortfall originates with the CDS. Therefore, cost causation requires that the CDS should be responsible for the RDDA. The revenue deficiency created by the CDS was supported by the CDS borrowing from Centra's shareholder and the liability therefore rests with the CDS, not other HPTS shippers (BC Hydro Argument, pp. 77-78).

BC Hydro further submits that, in spite of "overwhelming evidence to the contrary", Centra insisted that it cannot say who contributed to the RDDA since it did not allocate its revenue stream to any particular customer or shipper. BC Hydro claims that the onus is on Centra to show that a lack of HPTS revenues has contributed to the RDDA. Without such proof, its application to require BC Hydro to contribute to RDDA should be rejected (BC Hydro Argument, p. 80).

The Joint Venture's Position

The Joint Venture argues that "…there is no doubt as to which customer classes caused the RDDA to accumulate." The Joint Venture believes that the CDS is responsible for the RDDA regardless of whether one assumes the RDDA has accrued solely in relation to the CDS or whether some portion of the RDDA has accrued by reason of the CDS having failed to pay its share of the HPTS costs (Joint Venture Final Argument, p. 13).

The technical witness for the Joint Venture testified that the firm service toll for the Joint Venture TSA was negotiated on a full fixed-variable cost of service methodology as described in a letter dated December 13, 1995 from Leon Cender on behalf of PCEC to the Joint Venture (the "Cender letter") (Exhibit 4, Schedule 4) and based on a forecast of PCEC's rate base and cost of service. The forecast, which covered a ten-year period ending in 2005, originated with PCEC and was revised as a result of negotiations, discussions and new information (T5:753). The Joint Venture stated that the Centra COSA methodology differed from the method applied in 1995 in several respects, including the allocation of high pressure transmission capacity, some differences related to the PGMA, and the treatment of interruptible transportation ("IT") revenues (T5:755). The Joint Venture witness testified that the IT revenue in the model used to develop the Joint Venture TSA firm toll was credited back to the cost of service associated with the transmission system. The Joint Venture stated that the firm service toll had been reduced for the share of the IT revenue based on the contract demands and that, if the IT revenue had not been applied against the cost of service, the toll would have been higher (T6:836-37).

Centra's Reply Submissions

In response to the BC Hydro argument that the transmission system could only result in excess revenues, not deficiencies, Centra states that there is no evidence to suggest that the potential for revenue deficiency related to transmission was not contemplated, and argues that Section 11.01 of the Joint Venture TSA specifically contemplates a revenue deficiency on the transmission system. Section 11.01 states, in part, that:

> "11.01 Covenants. Pacific Coast covenants with and in favour of Shipper that Pacific Coast:
>
> (a) shall not at any time seek to recover from Shipper, directly or indirectly, whether in tolls or otherwise, any Revenue Deficiency incurred prior to or during the term of this Agreement, including the Renewal Period, in the operations of the Pacific Coast System or in the operations of any gas distribution utility connected to the Pacific Coast System..."

Centra argues that Tables 4 and 5 in BC Hydro's Argument incorrectly allocate transmission costs in the scenario without BC Hydro. Centra submits that, when corrected, the tables show that the Joint Venture was paying less than its cost of service.

Centra also argues that the negotiation-related evidence of Mr. Guenther relates only to the Joint Venture TSA and does not affect the appropriate rate to be paid by BC Hydro or other users of Centra's transmission facilities.

Centra further submits that its treatment of income taxes in the COSA study was based on the assumption that it was not necessary to attribute taxes to customers on the distribution system since the rates set under the soft cap would not be affected by the allocation of taxes. Centra argues this is reasonable and does not support the submissions that the RDDA is attributable only to distribution customers (T4:337).

Commission Determinations

The Commission is unable to determine from the evidence if the entire RDDA balance has arisen solely as a result of costs exceeding revenues on the distribution system. Even if, as Centra testified, it has kept separate records of the costs of the distribution and the transmission systems, accounting records are only a first step in functionalizing and allocating common costs, such as HPTS capacity or overhead, to one system or another. To properly allocate such common costs one would require a COSA analysis for the period 1996 to 2002.

The difficulty of determining whether the CDS system is solely responsible for the RDDA balance is further illustrated by the Joint Venture evidence which stated that the IT revenue in the model used to develop the Joint Venture TSA firm toll was credited back to the cost of service associated with the transmission system. The Joint Venture technical witness stated that the firm service toll had been reduced for the share of the IT revenue based on the contract demands and that, if the IT revenue had not been applied against the cost of service, the toll would have been higher (T6:836-37). The evidence remains unclear whether the Joint Venture toll would have been considered to cover its full cost of service if the IT revenues were allocated to the CDS customers.

4.2.2 RDDA Cost Recovery

Centra believes that established rate design principles prescribe that rate setting, when properly done, should consider a broad range of factors or criteria including, but not limited to, cost causation. Centra considered various non-cost factors in developing its rate design proposal and submits that its Rate Design Application (Exhibit 1, Tab 3, pp. 3.8-3.9) permits it to achieve many of its cost and non-cost related objectives, including those which:

- stabilize rates to end-use customers;
- provide flexibility to manage impacts;
- respect competitive conditions;
- support revenue deficiency recovery;
- observe cost of service and rate equity principles; and
- meet Special Direction mandates.

Centra further holds that the Act does not require that rates be established only by costs and points to subsection 60(1) which says that the Commission must consider all matters that it considers proper and relevant affecting the rate.

BC Hydro argues that lack of revenue from CDS customers caused the RDDA and it should be recovered from CDS customers. BC Hydro submits that this is consistent with its interpretation of the Special Direction.

The Joint Venture states that Section 11.01(b) of the Joint Venture TSA requires that Centra not seek rates other than those determined on a "full fixed variable cost of service methodology…determined on a rolled-in basis as opposed to an incremental basis." The Joint Venture comments that Centra's witnesses agreed that the Cender letter properly described this methodology (T4:436). The Joint Venture submits that the Cender letter is an unambiguous statement of the methodology required by the Joint Venture TSA for the determination of rates for third-party shippers. The Centra Rate Design Application, in the submission of the Joint Venture, does not propose rates consistent with the requirements of Section 11.01(b) of the Joint Venture TSA.

The Joint Venture further submits that no one disputes that the Commission has "…the discretion to depart <u>when appropriate</u> from rates that are strictly cost-based" (Joint Venture Final Argument, p. 17, emphasis in original). The Joint Venture argues that such divergence of rates from costs for transmission service typically does not exist and therefore, there is no justification for a divergence of rates from costs for transmission service on the Centra system.

Centra's position is that it is now "…an integrated distribution and transmission system owned and operated by a single legal entity and regulated by the Commission on an integrated basis including determination of the Annual Revenue Deficiencies for the integrated system as required by the Special Direction" (Centra Reply Submissions, p. 5). All customers should be responsible for RDDA recovery (Centra Reply Submissions, p. 11).

Commission Determinations

The Commission determined in Section 4.2.1 that it is unable to conclude from the evidence whether the RDDA balance results solely from the operation of the distribution system or whether some of the accumulated revenue deficiency was contributed by the operation of the Pipeline. The Commission agrees with Centra's submission that it is now an integrated distribution and transmission system owned and operated by a single legal entity and regulated by the Commission on an integrated basis (Centra Reply Submissions, p. 5). The Pipeline would not have been viable without the combined loads and the government support provided to deliver gas to Vancouver Island (Exhibit 38, pp. 2-3).

The Commission further recognizes that the rate design process has several objectives, as described by Centra, and that for an immature system, cost causation, which is often expressed as a revenue to cost ratio, is a less dominant objective than it would be for a mature system (T3:273). In a mature system the other objectives can typically be met, leaving room to establish rates reflecting revenue to cost considerations. In an immature system, the priorities are to provide for fair treatment to all customers and the financial viability of the system for the continued service to all customers.

Further, the Commission has no doubt that the RDDA balance established by the Special Direction is a legitimate cost of service of the Utility. To not allow the Utility a reasonable opportunity to amortize the RDDA balance over time would have the same effect as disallowing any other legitimate cost of a utility, thereby removing the opportunity for it to earn its approved rate of return.

BC Hydro and the Joint Venture acknowledge the duty of the Commission under the UCA to approve rates that will provide Centra with the opportunity to earn a fair return. BC Hydro argues that the obligation to approve rates that allow the Utility to earn a fair return is not an issue in this case, since the revenue requirements settlement negotiation established a fair and reasonable return for Centra. Previous court decisions [i.e., Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission) (1992)

66 B.C.L.R. (2d) 1 (BCCA)] have indicated that once a fair return on a utility's investment has been established, the Commission must allow the utility a reasonable opportunity to recover it. As the Court stated in that Judgement "…the Commission has no discretion to fix rates which do not permit recovery of that return" (p. 21). The establishment of the appropriate return Centra should be allowed to collect on its investment was one outcome of the Phase 1 negotiated settlement agreement. The Commission believes that setting rates for Centra that will give it a reasonable opportunity to earn its allowed return is consistent with the requirements of the Act and the Special Direction.

Secondly, the Commission notes that no party in the proceeding has suggested that there is room, given the prices of alternative fuels, to increase rates to distribution customers above those proposed by Centra. Centra's proposed distribution rates, having regard to the price of competitive fuels, are consistent with Section 2.10(j) of the Special Direction.

Given that Centra is to be allowed an opportunity to amortize the RDDA balance over the shortest period reasonably possible as required by the Special Direction, and recognizing competitive fuel prices, equity issues and other non-cost factors, the Commission determines that all customers - other than the Joint Venture and Squamish Gas - must contribute to the recovery of the RDDA. The issue of what constitutes a reasonable timeframe is considered in the following section.

4.3 Financial Constraints/Timeline

Centra's Application seeks approval to recover the balance of the RDDA as at December 31, 2002 over the shortest period reasonably possible and no later than 2011 (Exhibit 1, Tab Application, Section 9). Centra also states that in order to amortize the balance of the RDDA by 2011, it must reduce the RDDA by $13.3 million each year, and to achieve this it requires $21.3 million of pre-tax revenue dedicated to RDDA amortization (Exhibit 1, Executive Summary, p. 2).

Under the VINGPA, the Province pays Centra an annual Royalty Revenue payment that is based on the wellhead price of gas. Centra will continue to receive this payment until December 31, 2011. The Royalty Revenue is currently about $25 million and is expected to range from approximately $20 million to $27 million between now and 2011 (Exhibit 1F, Appendix D, p. 1). Centra expects to be required to begin payment of a $75 million Federal/Provincial refundable contribution in 2012. Both the expiry of the Royalty Revenue and the beginning of repayment of the refundable contribution will create upward pressure on rates. In Centra's view it is imperative that the RDDA balance be eliminated by 2011 in order to help offset the impact of the other two expected events (Exhibit 1F, p. 1.2; T3:181-82).

Although a Centra witness agreed that an extension of the Royalty Revenue credit was conceivable, the witness stated that he had no reason to believe that it would be extended and that "… if I was a betting man I would bet that they would pass legislation to shorten it rather than lengthen it" (T4:407). Centra argues that extending the amortization period for the RDDA past 2011 would be irresponsible to ratepayers, to the Province and to the Special Direction and VINGPA (Centra Reply Submissions, p. 12).

Centra argues that the Commission has a statutory obligation to approve rates that will produce a fair and reasonable return. The Special Direction requires that Centra's rates are to include an amount for amortizing the RDDA over the shortest period reasonably possible. Centra submits that setting rates that do not allow Centra an opportunity to recover the RDDA by 2011 is contrary to the Act since there would be no reasonable opportunity to recover RDDA after 2011 (Centra Submissions, p. 15).

BC Hydro argues that there is nothing in Centra's long term view of the world that might not turn out better than foreseen. In its view, the Confer/Optimum evidence indicates that a significant contribution can be made to RDDA recovery by the CDS alone. BC Hydro argues that the Centra proposal contains no limit to the liability of HPTS shippers (BC Hydro Argument, p. 86).

The Joint Venture submits that Centra's Application is founded on false assumptions, namely that: the Special Direction expires in 2011; requires that the RDDA must be recovered by that time; and provides an unconditional right to recover the RDDA. It argues that the Special Direction imposes no deadline for recovery of the RDDA (Joint Venture Final Argument, p. 15).

In its Reply Submissions, Centra argues that the contrasting views of BC Hydro and the Joint Venture as to Centra's possible future business risks highlight the significant risk to Centra's ability to amortize the RDDA. Moreover, Centra argues that modeling the BC Hydro proposed rate in Exhibit 1F provided a forecast RDDA balance of $53 million in 2011 (Centra Reply Submissions, p. 13).

Commission Determinations

Section 2.10(j) of the Special Direction directs the BCUC to include an amount in rates that it determines to be appropriate in order to amortize the balance of the RDDA over the shortest period reasonably possible, having regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates.

In the Commission's view, the implications of the repayment of the Federal/Provincial refundable contribution and the end of royalty relief in 2011 are relevant factors to be considered in determining the timeline for recovery of the RDDA, as are other factors to ensure that the resulting rates are fair, just, reasonable and competitive with other energy options.

Subsection 59(5) of the UCA establishes that a rate is "unjust" or "unreasonable" if it is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Paragraph 59(4)(a) states that it is a question of fact, of which the Commission is the sole judge, whether a rate is unjust or unreasonable.

In the Commission's view, to refuse Centra a reasonable opportunity to amortize the RDDA balance by 2011 would place Centra in jeopardy of being unable to recover the amount remaining beyond that date because of the upward pressure on rates expected due to the end of the royalty relief and the expected repayment of the Federal/Provincial refundable contribution. The Commission does not consider it a realistic possibility that the government would extend the annual Royalty Revenue payment beyond its expiry in 2011.

However, it is important to recognize that the conditions underpinning various Centra costs and revenues may change several times between now and 2011. By allowing Centra the opportunity to recover the RDDA by 2011, the Commission is not guaranteeing that Centra will be able to meet that date, nor is it inviting Centra to collect all of the RDDA balance from HPTS customers, should competitive conditions for CDS customers significantly reduce the amount of RDDA recoverable from them. The Commission will evaluate the rates of Centra during the period to 2011 and will have to balance the interests of the Utility and its customers, having regard to the Special Direction and the Act.

5.0 COSA AND RATE DESIGN

5.1 Core Customer Class Segmentation

Consultants for Centra assessed historical billing data and conducted a load factor analysis to determine appropriate customer groupings for Centra's rate design. One notable outcome of the segmentation analysis is Centra's proposal to offer a single class of service for Residential customers.

The methodology of the segmentation analysis and the proposed customer segments have not been challenged by the Intervenors. No argument has been made for consideration of an alternative methodology or grouping of customers.

The Commission accepts the core customer class segmentation proposed by Centra.

5.2 Soft-Cap Mechanism

Centra proposes a soft-cap pricing mechanism to set core service rates relative to competing fuel alternatives. Centra intends to use this mechanism to amortize a portion of the RDDA by 2011 while managing core service rates with regard to changing competitive forces, short-term cost variability, and long-term financial sustainability. The mechanism is designed to allow Centra to evaluate and respond to factors affecting rate stability and the Utility's competitive position with regard to the alternative energy sources available to its customers. The "basis of the soft-cap is that to the extent cost of service inputs change over time, Centra will be allowed to hold rates relatively constant by adjusting the amount of revenue deficiency recovered" (Exhibit 1, p. 1.3).

As part of the soft-cap analysis of competitive fuel alternatives, Centra has studied the energy market for electricity and fuel oil. For each customer segment in the CDS customer class, Centra estimated an applicable BC Hydro electricity tariff. Centra has also analyzed the market for fuel oil in order to estimate retail fuel oil prices for each customer segment in the CDS. The results of this study are summarized in Tabs 4 and 5 and Appendix I of the Application (Exhibit 1). Table 5.1 below shows the proposed rates from the Application relative to the price of alternative energy sources (Exhibit 1, Table 5.2). The table highlights that rates are constrained overall by the competitive pressures of the marketplace. In particular, Centra notes that residential rates are constrained by the price of electricity, after accounting for the lower efficiency of natural gas furnaces and water heaters.

Table 5.1: Centra's Competitive Position vs. Alternative Energy Sources

Proposed Rates		Electricity Rates		No. 2 Fuel Oil Rates	
Class	$/GJ	$/GJ	% difference from proposed	$/GJ	% difference from proposed
RGS-1	$14.43	$16.03	-10%	$15.24	-5%
SCS-1	$15.25	$18.61	-18%	$15.24	0%
SCS-2	$13.57	$18.61	-27%	$13.56	0%
LCS-1	$10.52	$12.67	-17%	$10.51	0%
LCS-2	$9.91	$12.67	-22%	$9.90	0%
LCS-3	$9.30	$12.67	-27%	$9.29	0%
HLF	$8.96	$12.67	-29%	$9.29	-4%
ILF	$6.65	$12.67	-48%	$9.29	-28%

Centra emphasizes in its argument that the rates proposed for residential and commercial customers are priced relative to their alternate energy sources; cost is a secondary factor in establishing the level of those rates.

Centra states that if a significant and prolonged increase in the commodity cost of gas exceeds the soft-cap it may request a rate for certain customer segments higher than the price of the competitive alternative.

The Joint Venture and BC Hydro do not oppose determining rates with the soft-cap mechanism. They do not challenge the rationale or the methodology of the mechanism. A BC Hydro witness agreed that setting residential and commercial rates relative to the price of oil and electricity was not unreasonable in Centra's circumstances (T5:622-23). CAC (BC) et al. submits that the soft-cap mechanism is appropriate and represents progress insofar as the proposed rates will recover the current cost of service and begin to pay down the RDDA. CAC (BC) et al. is concerned that residential customers could easily and perhaps permanently switch to wood, fuel oil or electricity if natural gas prices were to increase steeply.

Centra proposes to adopt a quarterly review mechanism to administer the proposed rates and to account for future changes to the conditions addressed by the soft-cap mechanism. Centra proposes to submit a quarterly report to the Commission until the third quarter of 2005. The report would detail Centra's total cost of service (including RDDA amortization) and revenues on a year-to-date and outlook basis, describe market conditions, and provide the rationale for any recommended rate changes.

Commission Determinations

The Commission accepts the rationale and methodology of the soft-cap mechanism as appropriate to Centra's circumstances at this time. The methodology is consistent with a principle of supporting a utility in its early years as it matures. In light of the RDDA balance and the Special Direction, this principle supports setting rates that recover the maximum that core customers can be expected to pay given the price of alternative fuels. The Commission agrees that the mechanism offers an effective means to meet the objective of rate stability with respect to short-term variability in the commodity cost of gas and the price of alternative energy sources.

The soft-cap mechanism does not fully mitigate uncertainty associated with the ability of customers to temporarily or permanently switch energy sources. The Commission is also concerned about the degree to which the amount of RDDA recovery could be impacted by short- or long-term changes in the commodity cost of gas and the price of alternative fuels. **The Commission accepts Centra's proposed quarterly review mechanism and directs Centra to work with Commission staff to develop the exact required elements of the quarterly report.**

5.3 Core Customer Revenue to Cost Ratios

Centra's proposed core service rates and allocated cost of service result in revenue to cost ratios for core customers that vary between 0.84 and 1.42, assuming BC Hydro contract demand equals 38 TJ/day. The average revenue to cost ratio for the entire core market class equals 0.98 (Exhibit 30, Proposed Rate Revenues). The Residential revenue to cost ratio is less than 1.0 because the rate is constrained by fixed electricity rates. For most other core customers proposed revenue levels exceed the allocated cost of service. Centra argues that the proposed core customer rates are consistent with the UCA.

Neither the Joint Venture nor BC Hydro take issue with the revenue to cost ratios derived from the proposed revenues and allocated cost of service of the respective CDS customer segments. As noted in Section 5.2, the Intervenors do not oppose the rationale and methodology of the soft-cap mechanism for determining core service rates, the key driver of revenue to cost ratios that differ from 1.0 in this class.

Accordingly, the Commission accepts that the revenue to cost ratios for the core customer class, as reported in Exhibit 30, are reasonable under the unusual circumstances faced by Centra. Therefore, the Commission approves the core customer rates proposed by Centra, effective January 1, 2003.

5.4 Firm Transportation Rate

Centra proposes a Firm Transportation ("FT") rate of to $1.13/GJ. BC Hydro and the Joint Venture propose an FT rate of $0.597/GJ for 2003. The current rate for FT service under the Joint Venture TSA is $0.890/GJ. This toll was approved as the interim rate for BC Hydro (see Chapter 6).

Centra determines its proposed rate based on cost and non-cost factors, as well as the need to recover the RDDA balance. In particular, "value of service" was a consideration in determining the FT rate. Centra regards value of service as a concept that includes analysis of avoided cost and ability to pay[2] (in addition to cost allocation) as a means to assess the competitive alternatives for firm transportation customers.

Following general cost-causation principles for functionalizing, classifying and allocating costs, Centra computes a fully allocated cost of service ("FACOS") for FT service equal to $0.859/GJ, assuming BC Hydro demand equals 38,000 GJ/day. Under Centra's proposal, total average FT unit cost of service is comprised of commodity-related costs, demand-related costs, customer-related costs, direct assignment costs and RDDA recovery. Centra computes an avoided cost of $2.01/GJ based on a detailed analysis of the costs of the Georgia Strait Crossing ("GSX") project and gas transportation to the point of delivery at Elk Falls (Exhibit 1F, pp. 1.5-1.6). The proposed rate of $1.13/GJ falls within the lower half of the range bounded by the FACOS and its calculation of avoided cost.

BC Hydro calculates its proposed rate of $0.597/GJ for 2003 based on: allocating transmission capacity using the design day peak demand of the CDS; recovering the balance of the RDDA from the CDS only; setting rates based on the transmission cost of service for third-party shippers (i.e., a revenue to cost ratio equal to 1.0 for third-party shippers and no reliance on an avoided cost or ability to pay methodology); and crediting interruptible revenues to the HPTS cost of service.

5.4.1 Firm Transmission Allocated Cost of Service

5.4.1.1 Transmission Capacity Cost Allocation

Centra allocates transmission capacity costs using a one coincident peak methodology. Centra defines this method as the allocation of demand (transmission capacity) costs on the basis of a single demand value for each class at the time of the transmission system peak demand. Specifically, Centra proposes to allocate transmission capacity costs based on the firm contract demands of customers and the physical design capacity of the system. Centra allocates transmission capacity for the CDS as the residual of total system

[2] Centra uses the term "ability to pay" to mean "willingness to pay" relative to the price of competitive fuels.

capacity less the contract demands of the Joint Venture, BC Hydro and Squamish Gas. When the capacity of the system was increased by more than 10,000 GJ/day (accomplished by the addition of the V4 compressor on Texada Island) to accommodate a BC Hydro demand increase of 10,000 GJ/day, Centra determined that the residual would stay the same by arguing that the needed capacity had only increased by 10,000 GJ/day.

BC Hydro's position is that the Commission should approve the non-coincident peak methodology used by BC Hydro. Under BC Hydro's terminology and recommendation, transmission capacity peak day allocation is the sum of the temperature sensitive design peak day requirement of the CDS plus the firm contract demands for small and large industrial shippers. BC Hydro submits that this is the same methodology approved by the Commission in its Decision respecting the 1998 Pacific Northern Gas Ltd. ("PNG") Cost of Service/Rate Design Study (Exhibit 25) and PNG's 2003 Revenue Requirements Application (Exhibit 14, p. 3, column 4).

BC Hydro states that "the use of the full firm industrial contract demands, including those portions that are curtailable on a design peak day, does not result in any matching reduction to other rate classes' peak day requirements to equal the physical capacity of the system for the purposes of cost allocation" (BC Hydro Argument, p. 37). BC Hydro submits that this was clearly recognized as inappropriate in the case of PNG and is also inappropriate in the case of Centra.

Centra argues that PNG's circumstances are substantially different from Centra's. Referring to the 1998 PNG Decision, Centra highlights that PNG cannot accurately determine peak day demand on its transmission system. Moreover, Centra notes that PNG's choice of methodology has an immaterial impact on the cost allocation to its core customers, which is not the case under alternative allocation methodologies for Centra's core customers.

Concerning Centra's proposal to use the coincident peak methodology in combination with the physical capacity limit of the HPTS, BC Hydro submits that a correct application of the method would clearly result in BC Hydro being allocated no HPTS capacity costs (see Exhibit 3, p. 13, Table 5). However, BC Hydro submits that this result is inconsistent with commitments made by Centra to provide firm service on the HPTS.

BC Hydro proposes that HPTS costs be allocated based on the design peak day demand for the CDS and the aggregate contract demands of the other shippers. The total of these demand values (166 TJ/d) is greater than the physical capacity of the HPTS. BC Hydro asserts that the peaking arrangements provide

Centra with the ability to have a total of 166 TJ/d of peak day commitments. BC Hydro terms its proposal a non-coincident peak methodology.

Centra points out that the rationale for BC Hydro's use of the term "non-coincident peak" arises from the fact that the peak demand of each shipper does not necessarily occur at the same time. BC Hydro agrees that a NCP methodology, as typically defined, is not being proposed by any party for cost allocation on the HPTS. Under an NCP methodology, transmission capacity costs are allocated to each class of service based on the highest NCP demand of each class (including interruptible demand), regardless of the time of occurrence.

Centra agrees that based on the design day requirements of the CDS there is insufficient capacity to serve the full CDS load at the same time as the full contract demands of the Joint Venture and BC Hydro, but that if a design day were to occur the CDS will be making use of capacity provided via Centra's peaking arrangements with the Joint Venture and BC Hydro. Centra contends that given the low frequency of reaching design day loads (a one in 25-year event) and the ability of the Joint Venture and BC Hydro to curtail, the peaking arrangements with these shippers were in the interests of all customers when compared to the costs of expanding HPTS capacity. Centra notes that both the Joint Venture and BC Hydro are compensated in the event Centra curtails them and that both the Joint Venture and BC Hydro benefit from the peaking agreements because the overall costs of the transmission facilities are lower (Centra Reply Submissions, p. 50).

Centra submits that its treatment of on-system peaking arrangements is the same as if design day peak requirements were contracted from a third-party such as a Liquefied Natural Gas ("LNG") supplier. BC Hydro responds that the peaking arrangements are not analogous to a contract with an LNG supplier. With an LNG plant on the distribution system, only 65 TJ/d would be flowing to the CDS on a peak day. Without an LNG plant, but with peaking arrangements, the physical reality is that 95 TJ/d will flow to the CDS.

The Joint Venture notes that in contrast to BC Hydro's Peaking Agreement with Centra, its PGMA with Centra provides it with no demand charge credit or other compensation for curtailment of HPTS capacity; it is only compensated with respect to the commodity cost of gas. Centra argues that this assertion is incorrect because the PGMA is intended as an agreement for capacity as well as commodity. Centra notes that the Joint Venture is paid the index price of gas plus an adder of $5.26/GJ. Centra submits that even though the adder is not specified as a transmission capacity charge, the actual existence of the adder indicates that the Joint Venture is being compensated for more than just the cost of gas. Centra adds that other arrangements with the Joint Venture factor into a determination of whether the Joint Venture is adequately compensated. Centra argues that the Joint Venture's firm transmission rate; its exclusion from RDDA recovery; its ability to bank excess capacity for use as interruptible service at a later time (Interruptible Offset Gas); the adder paid under the PGMA; and the low expectation of interruption all indicate that the Joint Venture is adequately compensated. Centra asserts that to provide the Joint Venture with a demand charge credit for HPTS capacity would amount to compensating it twice for the same peaking arrangements.

5.4.1.2 Allocation of Interruptible Transmission Revenues

Centra proposes that interruptible transmission ("IT") revenues be credited to the overall cost of service and allocated against the RDDA. Centra notes that most of the capacity used for interruptible service is from capacity required for CDS customers, resulting from their lower load factor. Centra asserts that crediting IT revenues to the cost of service effectively increases RDDA amortization and benefits all customers by reducing a long-term obligation.

The Joint Venture submits that the practice of crediting IT revenues to the total transmission cost of service is appropriate and consistent with standard utility practice for transmission service. The Joint Venture asserts that this was the agreed to principle between PCEC and the Joint Venture in 1995 when determining Joint Venture TSA tolls (Exhibit 4, p. 4, paragraph 3).

BC Hydro's position is that all IT revenue from the HPTS should be credited to the cost of service of the HPTS. BC Hydro notes that under its recommended cost allocation, almost 60 percent of the benefit of the IT credit flows to the CDS (BC Hydro Argument, p. 108; T5:590-91). BC Hydro argues that streaming the IT revenues to low load factor customers is not standard Canadian utility practice and is wrong as it infers property rights that do not exist without some form of capacity release protocol. BC Hydro states that the difference in the surplus available for RDDA recovery is similar under both the BC Hydro and Centra proposals. The reason for this is because a lower cost of HPTS service under the BC Hydro proposal does not flow through to the rates of the CDS or to the tolls of the Joint Venture and Squamish Gas.

Centra asserts that since BC Hydro uses its firm service at nearly 100 percent load factor it contributes little capacity for IT service. Therefore, Centra submits that BC Hydro should not receive a share of the revenue credit disproportionate to its contribution. Centra recognizes that capacity above 145 TJ/day is provided by the V4 compressor which BC Hydro paid for. Centra, therefore, recommends that BC Hydro receive a direct credit for the IT revenues associated with the additional provision of IT capacity above the level of 145 TJ/day.

CAC (BC) et al. submits that Centra's original proposal to allocate IT revenues entirely to the CDS is the correct treatment. The underlying rationale was that the IT capacity was being made available by the low load factor of the CDS customers and therefore the CDS should receive the benefit of this capacity on the principle that they created it. Centra's rationale for changing the allocation of IT revenues under its proposal is that it believes that conceivably some of the benefit could come from BC Hydro and Joint Venture capacity. CAC (BC) et al. considers that the current proposal for the allocation of IT revenues is a compromise of sorts. CAC (BC) et al. submits that a benefit causality principle favours allocation of IT revenues to the CDS. However, it submits an alternative proposal to recognize Centra's concern that some of the benefit could come from BC Hydro and Joint Venture capacity. Under its alternative, CAC (BC) et al. would find it acceptable to allocate IT revenues to all shippers on the basis of the difference between the Demand allocator (GJ/day) used to allocate HPTS costs to each shipper and each shipper's average firm load (i.e., the difference is intended to estimate the benefit each shipper creates).

Commission Determinations

The Commission accepts $0.859/GJ as the FACOS for FT service. The Commission notes that the FACOS for FT service includes an amount of RDDA amortization equal to $0.110/GJ. This is consistent with the Commission's determination in Section 4.0 of this Decision.

The Commission accepts Centra's proposal to allocate transmission capacity costs based on the coincident peak of the system with the CDS portion determined on the basis of the residual capacity of the HPTS.

The Commission finds that Centra's circumstances are unlike those faced by PNG in 1998. The Commission stated in the 1998 PNG Decision that "PNG testified that the non-coincident peak is used instead of the coincident peak because PNG could not measure the coincident peak with 100 percent accuracy for core market customers and because the use of the non-coincident peak is expected to have little impact on the results of the allocation" (Exhibit 25, p. 21). The Commission finds that Centra is able to measure allocation factors under its coincident peak methodology. Moreover, the Commission finds that the relative allocation of transmission costs is materially impacted by the choice of allocation methodology in Centra's case. The Commission endorsed as appropriate the estimates obtained by the methodology used by PNG given its circumstances at the time. However, in its determination the Commission did not explicitly approve the non-coincident peak methodology as a generally applicable and appropriate mechanism by which to allocate transmission costs among customer classes.

The Commission finds that Centra's negotiated peaking arrangements are appropriate to provide capacity in situations where the physical capacity of the transmission system is constrained by core market demand that approaches or equals the design day peak of the CDS. Such situations are anticipated to be limited to a one in 25-year event. The Commission accepts that Centra's comparison of its treatment of peaking arrangements to an option to contract for peaking from an LNG supplier is a useful illustration of the logic in its approach (Centra Submissions, p. 28). The Commission further finds that the peaking arrangements provide compensation to BC Hydro and the Joint Venture for any associated curtailments.

The Commission concludes that a number of factors indicate that the Joint Venture is compensated for the provision of peaking gas. These factors include: the Joint Venture's firm transmission rate; its ability to bank excess capacity for use as interruptible service at a later time; the adder paid under the PGMA; the low expectation of interruption; and the language of the PGMA regarding delivery to the CDS for commodity and capacity. This is consistent with the Joint Venture's references to the fact that the Joint Venture's agreements with Centra were negotiated as part of a package. It is also consistent with the Joint Venture's argument that the factual matrix must be considered to gain a clear picture of the intent and broad agreement among the parties at the time.

The Commission believes that peaking arrangements must reflect the realities of the HPTS. The Commission finds that the peaking arrangements are in the interests of all customers when compared to the costs of expanding HPTS capacity. Centra has tried to balance the interests of the large industrial customers with the needs of the core customers. The outcome is not dissimilar to curtailment rights on the BC Gas system and is appropriate at this time.

In certain situations IT revenues may be credited to the customer cost of service, but due to the added ratemaking complexity under Centra's circumstances, the Commission finds that a different approach is appropriate. While recognizing that interruptible transmission capacity is often available because of the lower load factor of the CDS, the Commission finds that it is acceptable to credit the interruptible revenue to the RDDA balance at this time. The reduction to the RDDA balance will substantially benefit the CDS and other HPTS customers over time. Further, the Commission determines that BC Hydro should receive a direct credit for the IT revenues associated with the additional provision of IT capacity above the level of 145 TJ/day. Also recognizing that circumstances change, the Commission directs Centra to review the allocation mechanism in its next Rate Design Application.

5.4.2 Avoided Cost and Other Non-FACOS Factors

Centra submits that avoided cost is a valid and widely used benchmark in utility rate setting. Thus it contends that a customer's ability to pay relative to competing alternatives is a valid consideration. It argues that the rate proposed for BC Hydro does not approach the maximum level permitted by consideration of the avoided cost of competing alternatives for BC Hydro. Centra notes that BC Hydro's costs under the proposed rate are significantly less than what BC Hydro is prepared to incur on the GSX project. Centra also notes that BC Hydro currently receives service from BC Gas for its Burrard Thermal Plant at a rate that is set on an avoided cost basis.

Centra cites various examples where utility circumstances require consideration of non-FACOS factors in rate setting. It claims that bypass rates illustrate the use of avoided cost rather than cost of service as a factor in rate setting. Centra also cites a BC Gas calculation of a 0.6 revenue to cost ratio for the Centra wheeling rate across BC Gas Coastal transmission facilities (Centra Submissions, p. 15). Centra submits that PNG's load-retention rate for Methanex is a further example of utility circumstances requiring the consideration of non-FACOS factors in rate setting.

BC Hydro maintains that the current situation is not comparable to bypass tolls, in which a shipper is threatening to leave the system unless it gets a reduced rate. BC Hydro argues that Centra is exploiting BC Hydro's "captive state"; BC Hydro has no bypass alternative. BC Hydro also submits that because one toll is set below cost to meet a competitive alternative and provide bypass service is not, in and of itself, a reason to set another toll above cost.

BC Hydro contends that Centra proposes that it must set firm transmission rates relative to the price of competitive alternatives simply because it uses such a rate design for its CDS customers (BC Hydro Argument, pp. 100-04). BC Hydro submits that the use of a competitive alternative for one toll does not justify the use of such a toll design mechanism for other customers.

The Joint Venture argues that bypass rates and load retention rates cannot be used as a comparison to the current cost allocations because contrary to the principles of such rates, the proposed rates make BC Hydro and the Joint Venture substantially worse off.

Centra considers the use of avoided cost and other non-FACOS factors to be consistent with the use of the soft-cap mechanism. Centra submits that when the Joint Venture and BC Hydro object to the use of avoided cost and other non-FACOS factors, they are only objecting to the use of these factors in determining transmission rates, not CDS customer rates.

BC Hydro argues that the HPTS is a separate function within Centra, with separate and identifiable costs that do not include recovery of RDDA, and that therefore it must be treated accordingly for toll design purposes. BC Hydro states that there are no non-FACOS factors affecting the HPTS and generally applied regulatory principles must be used to ensure HPTS tolls are cost-based.

The Joint Venture argues that avoided cost, value of service and ability to pay are not appropriate as overriding principles in rate design. They submit that there are no precedents for application of these methodologies in British Columbia. On the basis of Section 11.01(b) of the Joint Venture TSA as well as the Cender letter, the Joint Venture argues that full-fixed variable cost of service methodology, determined on a rolled-in as opposed to incremental basis, is required to set transmission service rates for the HPTS. The Joint Venture regards the Cender letter as an unambiguous statement of the methodology for full-fixed variable cost of service determined on a rolled-in as opposed to an incremental basis, as required by the Joint Venture TSA in Section 11.01(b). Moreover, the Joint Venture states that if avoided costs were appropriate, they should be applied to the CDS, because to do otherwise is discriminatory and unfair.

The Joint Venture submits that Centra proposes to deviate from cost, not to retain load for the benefit of all customers, but solely for the purpose of exploiting the vulnerability of BC Hydro, thereby depriving the Joint Venture of its contractual bargain and forcing the Joint Venture to indirectly pay for the RDDA.

The Joint Venture notes that the Special Direction allows the Commission to have regard to competitive markets in setting rates for Centra Distribution, but submits that it is not a direction to the Commission to utilize non-FACOS considerations as justification for excessive rates for HPTS shippers.

Commission Determinations

The Commission must be cognizant of all factors in designing rates that are in the public interest. Avoided cost is a relevant piece of information to consider, but it is only one decision variable for determining rates that meet rate design objectives. **The Commission uses Centra's calculation of avoided cost only as a useful check and upper bound against which to compare the level of FT rates computed at different revenue to cost ratios.**

The Commission recognizes that Centra's use of avoided cost as one consideration for setting FT rates may be regarded by some as increasing the risk associated with contracting for FT service. The Commission notes that Centra is only using avoided cost for comparative purposes and is not proposing to set FT rates near avoided cost levels. The Commission is cognizant both of

fairness considerations and the possible disincentives to potential new transmission customers. Therefore, it intends to monitor Centra's rates for both distribution and transmission service to ensure that no undue burden is placed on any one customer class.

5.5 Transmission Customer Revenue to Cost Ratios

Centra maintains that establishing rates on the basis of utility circumstances which result in revenue to cost ratios other than 1.0 is accepted practice in British Columbia. The Commission has already determined that the unit cost of FT service under Centra's proposal equals $0.859/GJ. At this toll, the revenue to cost ratio for BC Hydro would equal 1.0, including an amount of $0.110/GJ for RDDA recovery (Section 5.4.1). Centra proposes an FT rate of $1.13/GJ to assist in RDDA recovery. At this proposed toll, the revenue to cost ratio for BC Hydro equals 1.31.

Referring to the circumstances of PNG, BC Hydro submits that for pipelines regulated by the Commission, revenue to cost ratios different than 1.0 are considered by the Commission to be a "problem", and they arise in extenuating circumstances (BC Hydro Argument, p. 105). BC Hydro notes that Centra's COSA witness stated that cost allocation principles are the same for stand-alone transmission systems or the transmission portion of an integrated utility and that, therefore, revenue to cost ratios are unnecessary because revenue equals cost. However, CAC (BC) et al. highlights that Centra's COSA witness also testified that in a situation where a utility is fairly new and where cost of service has not been an issue, it would be fairly drastic for a regulator to put limits on the extent to which revenue to cost ratios differ from 1.0 (CAC (BC) et al. Final Argument, p. 14).

The Joint Venture does not suggest that the Commission has no discretion to depart from cost-based rates when appropriate. The Joint Venture notes that the Commission has established ranges for revenue to cost ratios to account for the complexities of distribution service in different communities and across customer classes. The Joint Venture argues that this complexity does not exist for transmission service customers who receive the same service from the same facilities and therefore there is no justification for deviation from cost for these customers.

<u>Commission Determinations</u>

For a financially healthy and mature utility, the Commission would expect the range of revenue to cost ratios across customer classes to tend toward 0.9 to 1.1, all other objectives being satisfied. The Commission finds that in the circumstances of an immature utility it would be unreasonable to limit revenue to cost ratios within a narrow range and thereby limit the

consideration of other circumstances in the design of rates which meet the public interest. The Commission views Centra as an immature utility under its current circumstances.

The Commission must be cognizant of relative revenue to cost impacts across customer classes. In the Commission's judgment, respecting all determinations above, the rate for FT service should be set such that the revenue to cost ratio for FT service equals 1.25. Accordingly, the Commission approves a rate for FT service equal to $1.074/GJ, effective January 1, 2003. For the interim period between the Commercial Operation Date ("COD") of April 12, 2002 and December 31, 2002, the Commission approves the interim rate as permanent.

5.6 Interruptible Transportation ("IT") Rates

The Joint Venture interruptible toll for 2002 and 2003 equals $0.701/GJ under the Joint Venture TSA. BC Hydro is currently paying an interim toll that is the same as the Joint Venture toll. As a permanent toll for BC Hydro and other HPTS customers other than the Joint Venture, Centra is proposing a seasonally priced IT rate: a summer rate of $1.13/GJ (equal to Centra's proposed FT toll) and a winter rate of $1.57/GJ (equal to Centra's proposed FT toll at 72 percent load factor). The Centra proposal is designed to discourage customers with firm service requirements from otherwise contracting for interruptible service and avoiding firm service demand charges. Centra submits that its proposal creates incentives for shippers to utilize interruptible service appropriately and to contract for firm service when required. Centra notes that with the V4 compressor in place interruptible customers could receive nearly firm service.

BC Hydro and the Joint Venture submit that Centra cannot cite any evidence of a shipper reducing its firm contract demand to migrate to IT service. Centra argues that BC Hydro made a conscious decision to delay its commitment to increase its TSA from 28,000 to 38,000 GJ/day because of the availability of interruptible gas (T5:605-07). Centra claims that the actions of BC Hydro from April 2002 to November 2002 constitute a case where a shipper relied on IT when it needed firm service. BC Hydro claims that the circumstances, including the late COD of ICP, low summer electricity demand and favourable hydro generation conditions, show it acted appropriately. Centra maintains that customers will act in their own self interest and without the proposed price signals, firm customers will be motivated to contract for interruptible service because under current conditions they can anticipate few, if any, interruptions.

BC Hydro recommends that the Joint Venture IT toll be adopted as BC Hydro's IT toll. As the basis for this recommendation, BC Hydro reasons that:

- Centra's gas tariff provides for the allocation of daily IT availability to shippers pro rata on the basis of the quantities of IT service requested by such shippers for that day (i.e., the tariff does not prioritize IT service allocation according to which shipper is paying the higher toll);

- there is no evidence of shippers reducing their firm contract demand to continue to serve firm load with IT service at a lower IT toll and there is also no evidence that Centra's proposed IT toll will maximize HPTS efficiency and load factor;

- using the Joint Venture IT toll eliminates any incentive to favour the IT nomination of the shipper with the higher toll (and the Joint Venture toll is fixed as a contract toll and therefore cannot be increased to Centra's proposed BC Hydro IT toll to achieve the same incentive effect); and

- using the Joint Venture IT toll removes any appearance that Centra's proposed IT tolls are examples of monopoly pricing.

Commission Determinations

The Commission is guided by general principles to maximize IT revenue that can then be credited back to the customers that create the available capacity and to discourage customers requiring firm service from taking advantage of lower IT rates and ample capacity in order to avoid paying their appropriate cost of service. Accordingly, the Commission approves a summer IT rate of $1.074/GJ, equal to the approved FT rate (see Section 5.4). The Commission approves a winter IT rate of $1.492/GJ, equal to the approved FT rate at a 72 percent load factor.

The Commission approves the interim ICP toll as permanent for the period prior to January 1, 2003. Although the parties had agreed to retroactively adjust the interim toll to the final rates approved by the Commission in this Decision, the Commission believes it is more reasonable to avoid the retroactive adjustment.

6.0 APPLICATION FOR APPROVAL OF AMENDING AGREEMENTS

On December 20, 2002, Centra applied pursuant to Section 61(2) of the Utilities Commission Act for approval of three amending agreements for natural gas service to ICP at Elk Falls:

- Amending Agreement to the Transportation Service Agreement ("TSA-02") dated October 17, 2002.

- Amending Agreement to the Peaking Agreement ("PA-02") dated October 17, 2002.

- Amending Agreement to the Capacity Assignment Agreement ("CAA-02") dated October 17, 2002.

In order to assess the impact of these arrangements on Centra's proposed 2003 rates and cost of service, and enable the Joint Venture to articulate its objections to these amending agreements, the Commission decided to review these amending agreements as part of the Phase 2 Rate Design Hearing.

6.1 Background

On April 6, 2001 BC Hydro applied to the Commission for approval of a transportation service agreement ("BCH TSA") and a peaking agreement ("BCH PA") both dated March 7, 2001. The BCH TSA would provide firm and interruptible transportation service over the Centra system to ICP at Elk Falls. The BCH PA allowed Centra to access system peaking capacity and gas commodity from BC Hydro when required. BC Hydro also applied to the Commission on May 4, 2001 for approval of a Capacity Assignment Agreement ("CAA") dated March 7, 2001 between BC Hydro, Centra and BC Gas. This contract allowed capacity controlled by BC Hydro on the BC Gas system to be assigned to Centra.

The BCH PA was approved by Order No. G-94-01. The CAA and BCH TSA were accepted subject to conditions for commencement of service. The BCH TSA approval was contingent on an operational constraint and was only to be provided:

> "…if the firm demand of the Joint Venture is being met, and Centra Gas is not requesting peaking gas under the Peaking Gas Management Agreement" (Order No. G-94-01, page 3, article 3).

The following Amending Agreements dated September 1, 2001 were then submitted to the Commission to comply with Order No. G-94-01:

- Amending Agreement to the Transportation Service Agreement ("TSA-01") between BC Hydro and Centra dated September 1, 2001.
- Amending Agreement to the Capacity Assignment Agreement ("CAA-01") between BC Hydro, Centra and BC Gas dated September 1, 2001.

6.2 Other Agreements that Affect the Application

6.2.1 <u>Compressor Facility Agreement ("CFA")</u>

On June 11, 2001, Centra applied for a Certificate of Public Convenience and Necessity ("CPCN") to construct and operate a compressor on Texada Island. It increased the capacity of the HPTS from 134.2 TJ/day to 155.1 TJ/day, or about 21 TJ/day.

In conjunction with the CPCN application, Centra and BC Hydro entered into a CFA whereby BC Hydro would provide a contribution in aid of construction for the full cost of constructing the Texada Island compressor. Commission Order No. C-6-01 approved the Application for the CPCN and the CFA.

6.2.2 Side Letter

The Side Letter dated June 11, 2001 provided a framework for further negotiations between BC Hydro and Centra for the BCH TSA, BCH PA and the CAA. The justification for the Texada Island Compressor was based on BC Hydro's intention to increase the BCH TSA from 28,000 GJ/day to 38,000 GJ/day in order to provide service to ICP. In addition, BC Hydro intended to negotiate in good faith to increase the quantity of gas in the BCH PA from 280,000 GJ to 380,000 GJ over one year. The CAA was also to be increased from 30,000 to 45,000 GJ/day.

6.3 Current Agreements in Place

The following agreements are currently in place:

- Amending Agreement to the Transportation Service Agreement ("TSA-01") between BC Hydro and Centra dated September 1, 2001.
- BCH PA between BC Hydro and Centra dated March 7, 2001.
- Amending Agreement to the Capacity Assignment Agreement ("CAA-01") between BC Hydro, Centra and BC Gas dated September 1, 2001.

6.3.1 Amending Agreement to the Transportation Service Agreement ("TSA-01") dated September 1, 2001

Centra and BC Hydro entered into the BCH TSA on March 7, 2001 and amended it with the TSA-01 on September 1, 2001. It provides firm transportation service of 28,000 GJ/day on the HPTS to ICP.

The term of the TSA-01 ends on the earlier of October 31, 2003 or the date Centra and BC Hydro enter into a long-term transportation service agreement. It includes Article 4.5, "Limitations on Firm Service" that complies with Order No. G-94-01 which states:

> "Notwithstanding the provisions of the General Terms and Conditions for the Gas Transportation Service, Centra shall not provide Firm Transportation Service hereunder:
>
> 1. to the extent that providing such service on any Day would render Centra unable to provide the Firm Transportation Service nominated for any such Day by the Joint Venture pursuant to the Joint Venture Transportation Service Agreement; or

2. at any time when Centra is taking delivery of peaking gas from the Joint Venture pursuant to the Peaking Gas Management Agreement."

TSA-01 Terms and Conditions of Service

Firm Contract Demand	28,000 GJ/d
Receipt point	Huntingdon Receipt Point into the BC Gas System
Delivery point	Island Cogeneration Plant at Elk Falls
Alternate Delivery Point	Any Delivery Point on the Centra system under conditions of a Forced Outage, Planned Outage or Maintenance Outage
Interim Tolls	Same as the Joint Venture Firm and Interruptible Tolls
Term Start	Commercial Operation Date of April 12, 2002
Term End	The earlier of the start date for a long term TSA or October 31, 2003

6.3.2 Peaking Agreement ("BCH PA") dated March 7, 2001

Centra and BC Hydro entered into a BCH PA on March 7, 2001 to allow Centra to manage the system capacity and gas supply requirements of the core customers of the CDS in the event of a peak day weather occurrence. The term of the BCH PA is coincident with the term of the TSA-01 and provides Centra with up to 28,000 GJ/day of gas supply for a maximum of ten days in a 12-month period.

BCH PA Terms and Conditions of Service

Term		Coincident with TSA-01.
Contract Amount		Maximum of 280,000 GJ in any 12-month period.
Peaking Rights	Level 1	4,700 GJ/d of capacity at Centra Toll. 4,700 GJ/d of supply at Sumas Daily Index.
	Level 2	23,300 GJ/d of supply and capacity at the Centra Toll plus the higher of the combined monthly gas price paid by BC Hydro and Powerex at Sumas or the price of Distillate.
Put Rights		BC Hydro will have the right to put an amount of capacity and supply to Centra equal to the difference between 28,000 GJ/d and any amount called upon by Centra if Centra utilizes peaking rights in excess of 4,700 GJ/d but less than 28,000 GJ/d.
Put Capacity Right		50 percent of any positive difference between Distillate less the Sumas Monthly Index on days ICP is not fuel switched.
Put Commodity Right		The lesser of the Sumas Monthly Index price and the Distillate price on days ICP is fuel switched. The Sumas Daily Index price on days ICP is not fuel switched.

6.3.3 Amending Agreement to the Capacity Assignment Agreement ("CAA-01") dated September 1, 2001

The CAA (dated March 7, 2001) is between Centra, BC Hydro and BC Gas to provide the required capacity on the BC Gas system for the wheeling of gas to the Centra HPTS. It provides for the assignment to Centra of 30,000 GJ/day of firm capacity that had been held by BC Hydro on the BC Gas system.

The CAA-01 dated September 1, 2001 has the term of the agreement coincident with the term of the TSA-01.

CAA-01 Terms and Conditions of Service

Service	Firm Transportation Service on the BC Gas system
Term Start	Coincident with the TSA-01
Term End	Date of termination of the BTA[3] by BC Hydro or October 31, 2003
Assigned Capacity	30,000 GJ/d
Monthly Demand Toll	$15,786/month

6.4 Applied-for Amending Agreements

6.4.1 Amending Agreement to the Transportation Service Agreement ("TSA-02") dated October 17, 2002

Centra and BC Hydro entered into a BCH TSA dated March 7, 2001 and later amended it September 1, 2001 (TSA-01). A second amending agreement was agreed to and dated October 17, 2002 (TSA-02).

The TSA-02 is consistent with the terms of the Side Letter and was contemplated in the Reasons for Decision attached to Order No. G-94-01. It requests that Firm Contract Demand increase from 28,000 GJ/day to 38,000 GJ/day. The amendment in Article 4.5 shown below, allows Centra to provide firm transportation service to ICP to a maximum amount of 10,000 GJ/day even though the Joint Venture may be curtailed under the PGMA.

Article 4.5, "Limitations on Firm Service" has been changed as shown underlined in the following text:

> "Notwithstanding the provisions of the General Terms and Conditions for the Gas Transportation Service in excess of 10,000 GJ/day, Centra shall not provide FT Service in excess of 10,000 GJ/day hereunder:
>
> 1. to the extent that providing such service on any Day would render Centra unable to provide the Firm Transportation Service nominated in excess for any such Day by

3 Bypass Transportation Agreement for 275 TJ/d of non-recallable firm transportation service by BC Gas to BC Hydro. Delivery is made at Burrard or Centra interconnect at Coquitlam.

the Joint Venture pursuant to the Joint Venture Transportation Service Agreement; or

2. at any time when Centra is taking delivery of peaking gas from the Joint Venture pursuant to the Peaking Gas Management Agreement."

TSA-02 Terms and Conditions of Service

Firm Contract Demand	38,000 GJ/d
Limitation on Firm Service	No firm transportation service in excess of 10,000 GJ/d if VIGJV not receiving nomination or Centra taking peaking gas from VIGJV
Receipt Point	Huntingdon Receipt Point in the BC Gas System
Delivery Point	Island Cogeneration Plant at Elk Falls
Alternate Delivery Point	Any Delivery Point on the Centra system under conditions of a Forced Outage, Planned Outage or maintenance
Term End	The earliest of i) the last date before the start date of the long term TSA (contract not yet completed), ii) October 31, 2003, or iii) upon termination or expiry of the Compressor Facility Agreement.

6.4.2 Amending Agreement to the Peaking Agreement ("PA-02") dated October 17, 2002

Centra and BC Hydro entered into a BCH PA dated March 7, 2001 and reached an amending agreement, PA-02 dated October 17, 2002 that maintains the amount of peaking resources available to Centra at 28,000 GJ/day. The Side Letter proposed an increase in the firm contract demand under the BCH TSA with a corresponding increase of 10,000 GJ/day in the BCH PA. However, Centra submits that it has sufficient capacity to meet the terms of the BCH TSA without a corresponding increase to the PA-02.

PA-02 Terms and Conditions of Service

Term		Coincident with TSA-02
Contract Amount		Maximum of 280,000 GJ in a 12 month period
Peak Shaving Rights	Level 1	Capacity Right - Use all or part of the 4,700 GJ/d firm capacity at the Centra demand toll
		Commodity Right – An amount of gas equivalent to Capacity Right for that day at the Sumas Daily Index
	Level 2	Centra additional right:
		Up to 23,300 GJ/d of supply and capacity at the Centra Toll plus the higher of the combined monthly gas price paid by BC Hydro and Powerex at Sumas or the price of Distillate
Put Rights		BC Hydro will have the right to put an amount of capacity and supply to Centra equal to the difference between 28,000 GJ and any amount called upon by Centra if Centra utilizes peaking rights in excess of 4,700 GJ but less than 28,000 GJ
Put Capacity Right		50 percent of any positive difference between Distillate less Sumas Monthly Index on days ICP is not fuel switched.
Put Commodity Right		The lesser of the Sumas Monthly Index price and the Distillate price on days ICP is fuel switched. The Sumas Daily Index price on days ICP is not fuel switched

6.4.3 Amending Agreement to the Capacity Assignment Agreement (“CAA-02”) dated October 17, 2002

The CAA-02 between BC Gas, BC Hydro and Centra provides the necessary capacity on the BC Gas system to satisfy terms of the TSA-02. The agreement increases the amount of the capacity assignment from BC Hydro to Centra from 30 TJ/day to 45 TJ/day of daily firm service.

CAA-02 Terms and Conditions of Service

Service	Firm Transportation on the BC Gas system
Term	Same as CAA-01
Assigned Capacity	45,000 GJ/d
Monthly Demand Charge	$23,679/month

Centra currently holds about 119.5 TJ/day of capacity under the BC Gas Wheeling Agreement. The addition of 45 TJ/day would bring the capacity to approximately 164.5 TJ/day. The difference between that amount and the delivery capacity of 155.1 TJ/day provides an allowance of approximately 5.7 percent for system and fuel gas use (Exhibit 2, BCUC 2-3.2, p. 1).

6.5 System Capacity and Peaking Contracts

With the addition of the Texada Island compressor (approved by Commission Order No. C-6-01), the overall system delivery capacity has been increased by 20.9 TJ/day from 134.2 TJ/day to 155.1 TJ/day. The TSA-02 increases firm contract demand by only 10 TJ/day leaving an additional 10.9 TJ/day of interruptible capacity as a result of the added facilities. Centra is able to provide firm service to the Joint Venture and at the same time access only 18 TJ/day of the available 28 TJ/day under the PA-02 as shown in the table below. Gas under the PGMA is not required to meet the 2002/03 design day.

2002/03 Design Day Firm Capacity and Loads

	2002/03 TJ/day
HPTS Delivery Capacity	155.1
VIGJV Load	37.6
Squamish Gas Load	4.5
Centra CDS	93.0
TSA-02 Load	38.0
BCH PA-02	-18.0
VIGJV PGMA	0.0
Deficiency	0.0

However, for the 2003/04 contract year, the HPTS capacity will be reduced by 5.1 TJ/day. This decrease is caused by lower contract suction pressure at the Coquitlam compressor station (Response to Information Request to Centra at T1:56). In this same period, the load growth on the CDS is expected to increase to 96 TJ/day (T1:34). A future review of a long-term or short-term agreement by the Commission would take these factors into account.

There is the possibility that operational problems such as a breakdown of the V4 compressor may cause firm service to be curtailed below design capacity (Exhibit 2, BCUC 2-1.1, pp. 1-2, T1:24-25). However, a disruption of this type would only impact the Joint Venture if the CDS load exceeded 82.9 TJ/day. In a typical design year this event is expected to occur only four times. As the TSA-2 and the PA-2 are set to expire on October 31, 2003, the likelihood of this occurrence taking place because of cold weather is very remote (T1:25).

The Joint Venture argues that Centra is providing interruptible service that is characterized as firm due to the PGMA. The Commission addressed this issue in its Reasons for Decision, page 7 of Appendix A to Order No. G-94-01:

> "The Commission accepts that the purchase of on-system gas to reduce the requirement of the CDS for the HPTS capacity is a cost effective and appropriate means to reduce costs and increase system utilization. Therefore, the Commission does not accept the Joint Venture's position that Centra Gas is reclassifying interruptible service as firm."

The preceding table indicates that Centra has sufficient capacity on its system until October 31, 2003. **Therefore the Commission finds that the Centra HPTS has adequate capacity to meet the design day load for 2002/03.**

The Joint Venture also contends that there is insufficient capacity on the HPTS to provide service to ICP. This argument can only be accepted if the Joint Venture and BC Hydro are not obligated to provide peaking gas from their facilities under the peaking agreements. However, the PA-02 and the PGMA allow for this action to take place.

The PA-02 provides for 28,000 GJ/day of peaking supply for Centra, which then allows for 10,000 GJ/day of residual supply from the transportation service agreement to maintain partial output of ICP. Although the Joint Venture mills have dual fuel capability, ICP does not yet have this option and without gas supply to operate, electricity output would be curtailed to zero (T1:38). The result would be less reliable electricity supply for the Joint Venture as well as other customers (Exhibit 2, BCUC 2-1.3, p. 1).

The first tranche of peaking gas would be called from BC Hydro under the PA-2 to a maximum of 28,000 GJ/day. The subsequent call on additional peaking, to a maximum of 18,800 GJ/day would be taken from the Joint Venture under the PGMA. Centra would then allocate additional peaking supply pro rata, based on the maximum amounts available of 18,800 GJ/day (65.3 percent) from the Joint Venture and 10,000 GJ/day (34.7 percent) from BC Hydro (T1:76). **The Commission finds that both BC Hydro and the Joint Venture are treated equally if further resources are required after each party fulfills its commitments under the respective peaking agreements.**

The Commission approves the following agreements:

- **Amending Agreement to the Transportation Service Agreement dated October 17, 2002.**
- **Amending Agreement to the Capacity Assignment Agreement dated October 17, 2002.**
- **Amending Agreement to the Peaking Agreement dated October 17, 2002.**

7.0 OTHER ISSUES

7.1 Recovery of COSA and Rate Design Study Costs

The Settlement Agreement with respect to the Revenue Requirement Application, approved by Commission Order No. G-2-03, left the question of recovery of the costs of the rate design and COSA analyses to the Phase 2 process. The Settlement Agreement states:

> "25. Rate Design Deferral Accounts
>
> Centra Gas will provide Commission Staff and the participants with the details of COSA and Rate Design deferral accounts including activities performed, results provided and the level of expenditures incurred.
>
> Centra Gas has incurred approximately $775,000 of consulting costs over the past three years to prepare its cost of service studies and Rate Design Application and anticipates this amount to be $850,000 in the event of a hearing. The prudency of these expenditures are [sic] to be reviewed in the Phase 2 proceeding."

Centra filed evidence in the Rate Design hearing to explain and justify its expenditures on the COSA study and rate design. Centra stated that it had established a working group of stakeholders including BC Hydro, the Joint Venture, and the CAC (BC) et al. (Exhibit 1F, Appendix E). The group also included Centra, BC Gas and EES Consulting Inc. Five working group meetings were held between May 2000 and the May 2002 filing of the COSA study.

Centra stated that issues raised by the working group in June 2000 had to be resolved prior to the working group accepting the results. The analyses necessary to resolve those issues required additional model development beyond that anticipated in the scope of work for EES, and resulted in additional modeling, analyses, reporting and meetings of the working group. Centra estimated that this increased the costs of the analysis from the initial estimate of $75,000 to approximately $200,000. Extensions to the COSA model included “toggle switch” programming that allowed the model to switch efficiently between key sensitivity issues and enabled Centra to report on the results of various combinations of sensitivities. In addition to the work on the COSA model, Centra states that it also had to include in its analyses the impact of BC Hydro’s proposed GSX and the cost implications for Centra of transportation by others on the GSX. In the subsequent period leading up to the May 2002 COSA filing, further sensitivity analyses were undertaken as part of the working group consultation.

Stone & Webster Management Consultants, Inc. (“Stone & Webster”) assisted Centra with the rate design analysis. The work undertaken by Stone & Webster included development of rate design principles, customer segmentation and load factor analysis, strategy development, modeling, the revenue proof to ensure that the appropriate level of revenue would be recovered in the proposed rates, bill impact analyses, rate tariffs, “cross-over” curves and competitive fuel analyses.

Exhibit 1F estimates that the cost to achieve a final rate design resulting from the hearing process will be $950,000 including forecast Commission and legal costs. Centra has requested that it be allowed to amortize this amount over three years beginning in 2003. During the hearing Centra stated that the work provided by the consultants will provide ongoing benefit to Centra as it has full rights to use the EES and Stone & Webster models and Centra staff have been trained in and have become proficient at using the models. Therefore, Centra has gained the ability to carry out further rate design and cost of service allocation studies with much greater reliance on Centra personnel and less reliance on third-party assistance (T4:533-35; Exhibit 1F, Appendix E).

BC Hydro takes no position on Centra’s COSA and rate design costs (BC Hydro Argument, p. 124), and neither CAC (BC) et al. nor the Public Sector Consumers comment on the issue. The Joint Venture argues that Centra’s costs are excessive and suggests that a minimum of 50 percent of the costs should be disallowed. The Joint Venture argues that most of the activities and related costs of the studies were for customers on the CDS and accordingly the costs should be allocated primarily to those customers.

Commission Determinations

After reviewing the evidence and submissions of Centra and the arguments of the Joint Venture, the Commission has concluded that the costs are excessive, but that the majority of the costs were required to establish an initial rate design framework for Centra. The Commission has also considered that Centra now has the rights and the staff to undertake such analyses with much less outside help in the future. **Therefore, the Commission determines that it will allow Centra to recover $700,000 of its COSA and rate design costs, to be allocated as a general cost in rates and amortized over three years beginning in 2003.**

7.2 Abrogation of Existing Contracts

The Joint Venture submits that the Centra proposal will, if accepted, be in breach of existing agreements. It argues that the Commission should not, when a proposal by a regulated utility is in breach of a filed tariff, approve a new tariff that will facilitate the breach of an existing contract. The Joint Venture further argues that the Special Direction requires the Joint Venture TSA to be approved by the Commission and that the Joint Venture TSA is part of the Special Direction. The Joint Venture submits that the Province expected that the Joint Venture TSA and the Special Direction would be read and consistently interpreted together, and it is not open for the Commission to fix rates that are in breach of the requirements of the Joint Venture TSA.

Section 11.01(a) of the Joint Venture TSA states that Centra "shall not at any time seek to recover from Shipper, directly or indirectly, whether in tolls or otherwise, any revenue deficiency incurred prior to or during the term of this Agreement..." The Joint Venture says that BC Hydro will pass its cost of gas transportation through to its customers in its electricity rates and that the Joint Venture is BC Hydro's largest Vancouver Island customer. Consequently, if Centra recovers some RDDA amortization in the rate it charges BC Hydro, and BC Hydro passes that cost through in its electricity rates to the Joint Venture, then Centra would be indirectly recovering some of its revenue deficiency from the Joint Venture.

Section 11.01(b) of the Joint Venture TSA requires that Centra utilize the full fixed variable cost of service methodology to determine tolls of third-party shippers. In its filed evidence (Exhibit 4), the Joint Venture provided a copy of the Cender letter describing PCEC's understanding of the "full-fixed variable methodology" and how it would apply that methodology. Centra indicated that it did not disagree with the description of the methodology in the Cender letter (T4:436). The Joint Venture submits that Centra's Rate Design Application is in breach of the Joint Venture TSA with respect to the FT rate, insofar as Centra includes additional non-cost factors such as value of service, ability to pay and avoided cost.

Section 11.01(c) of the Joint Venture TSA states that PCEC will operate its HPTS on a non-discriminatory basis in respect to gas to be transported and delivered to the shipper. The Joint Venture argues that Centra's Rate Design Application will violate Section 11.01(c) by perpetuating and expanding discriminatory contracting practices by Centra. It argues that firm service to a sawmill is "super firm" with no provision for interruption, while the firm service to BC Hydro and the Joint Venture is curtailable. The Joint Venture also states that Centra proposes to continue to provide 10 TJ/d of firm service to BC Hydro while potentially curtailing the Joint Venture's firm service under the PGMA (Joint Venture Final Argument, p. 27).

The Joint Venture submits that Centra's contracting practices, by failing to include curtailment rights in its contracts with other industrial customers such as sawmills, contravene the sections of the PGMA and the Joint Venture TSA requiring it to carry out its contracting practices in good faith (Joint Venture Final Argument, p. 28). The Joint Venture also argues that Centra is frustrating the intent of the Joint Venture TSA and acting in bad faith by failing to establish a rate structure for HPTS shippers, but instead designing a toll specifically tailored to and justified by the circumstances applicable to BC Hydro.

Centra responds that it is not abrogating any regulatory principles or contractual obligations or representations, and argues that the Joint Venture consistently fails to acknowledge key terms within the agreements as well as other evidence. Centra states that the Joint Venture toll is not open to change in 2003 and is fixed until the end of 2005 at least. It says that if the Joint Venture does not accept Centra's rate design for 2006 it can extend its contractual rate until 2011 and that the Joint Venture can assume that, all else being equal, its allocated cost of service in 2006 will be lower than its contractual rate (Centra Reply Submissions, p. 18).

Concerning the Joint Venture allegation that Centra would breach Section 11.01(a) of the Joint Venture TSA in recovering RDDA from BC Hydro, Centra states that the submission is without merit and is analogous to Centra recovering RDDA from a municipality that would seek to recover the RDDA in taxes on a Joint Venture mill.

Centra argues that it is not in breach of Section 11.01(b) of the Joint Venture TSA, as its cost of service allocation methodology is a full-fixed variable methodology and that was agreed to by BC Hydro and the Joint Venture witnesses. Centra further argues that the Joint Venture's evidence seeks to add to or vary what was in the letter.

Centra also argues that it is not in breach of Section 11.01(c) which states that Centra will provide firm and interruptible transportation service on a non-discriminatory basis. It states that the Joint Venture fails to distinguish between peaking agreements and transportation agreements and fails to recognize that the Joint Venture has 18.8 TJ/d of transmission service that Centra cannot call upon under the PGMA. Centra argues that it has a legitimate right to call on gas under the PGMA (Centra Reply Submissions, p. 57).

Centra also denies the Joint Venture's submission that Centra has not acted in good faith by requiring other industrial customers to have back-up energy supply. Centra submits that the Joint Venture's "fair reading" of the PGMA suggesting that the parties anticipated that Centra would require such contractual rights is without foundation.

Centra states that the Joint Venture, at page 29 of its Final Argument, appears to be claiming a breach of contract related to Sections 3.2 and 7.16 of the PGMA relating to Centra's gas contracting practices. Centra states that its practice of including Standard Curtailments in its gas supply portfolio is not restricted by the sections of these provisions, and that its gas supply portfolio is approved annually by the Commission.

Concerning the Joint Venture's submission that, under Section 3.3(1) of the PGMA, gas is provided to Centra and Squamish Gas at Huntingdon, Centra responds that this ignores subsections (b) to (d) which mainly direct PCEC to deliver the gas to the CDS in priority to the Joint Venture's deliveries.

Finally, Centra agrees with the Joint Venture that issues of breach of contract are normally outside the jurisdiction of the Commission.

<u>Commission Determinations</u>

The Commission does not expect that the rates which it approves in this Decision will lead to the breach of any contracts. The Commission finds that the Joint Venture's objection to including an amount for RDDA recovery in the rates to be charged to other HPTS customers such as BC Hydro is based on an unrealistically broad interpretation of Section 11.01(a) of the Joint Venture TSA. The Joint Venture's concerns about potential breach of Section 11.01(b) seem to hinge on the collection of RDDA in the rates of other HPTS shippers. That has been dealt with elsewhere in the context of the Special Direction. With respect to Section 11.01(c) of the Joint Venture TSA, the Joint Venture's objection appears to be based on a narrow interpretation of that Section and of the Cender letter. The Commission also agrees with Centra that the Joint Venture concerns about other instances of breach of contract have not considered the existence of other specific contracts that lead to different levels of available capacity or curtailment.

In summary, the Commission has considered the issues of potential breach of contract by the Joint Venture and is not persuaded that any of the rates or orders approved in this Decision will result in any breach of the Joint Venture TSA. The Commission has always been loath to abrogate approved contracts. While the Commission can interpret and give proper effect to relevant contractual provisions affecting a utility in the course of carrying out its ordinary regulatory functions, matters of breach of contract which would result in damages are more properly within the jurisdiction of the courts.

8.0 CONCLUDING COMMENTS

The Special Direction instructs the Commission in Section 1.4: "The BCUC shall regulate the Utilities and fix the rates charged by the Utilities in accordance with the requirements of this Special Direction, and in accordance with the requirements of the Utilities Commission Act and such regulatory principles that are otherwise applicable to the Utilities from time to time that are not inconsistent with this Special Direction." This general instruction can be summarized as requiring the Commission to follow regulatory practice as it has been applied to other utilities within its jurisdiction, but subject to the constraints specified in the Special Direction.

Standard regulatory practice involves two determinations: first, the revenue requirement, which was established for Centra by a negotiated settlement process; and second, the design of appropriate rates for different customer classes to recover the approved revenue requirement, which is the task of this proceeding. Central to this task are the COSA study and other rate design criteria.

As stated in the evidence of Centra's expert witness (Exhibit 1F, p. 2), "Centra's proposed rates were designed with a cost of service base and a set of non-cost considerations, or overlays, that were essential to address Centra's unique transition." Foremost among these were two imperatives from the Special Direction. Section 2.10(j) directs the Commission to include in the cost of service to Centra's customers an amount "…that the BCUC determines to be appropriate in order to amortize the balance of the Revenue Deficiency Deferral Account over the shortest period reasonably possible, having regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates." Section 3.7 states: "In no event whatsoever shall the rates or transportation tolls that are approved for the Joint Venture or Squamish Gas pursuant to this Section 3.7 include any amount for the recovery in whole or in part, directly or indirectly, of dividends or interest as described in paragraph 2.10(h), or for the amortization, reduction, or recovery of the Revenue Deficiency Deferral Account balance".

The Commission agrees with Centra that "the transmission facilities would not have been constructed if the expectation had been to only serve large volume customers taking transmission service" (Centra Reply Submissions, p. 11). Likewise the facilities would not have been built to serve only the customers on the CDS. A further consequence of economies of scale is that capacity will typically be more costly and often exceed demand in the early, or immature, years of operation. Only as demand grows does the project achieve economic viability.

In this Decision the Commission is mindful of the Special Direction's instruction to have "regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates" [Section 2.10(j)]. Accordingly, it has accepted the principle of "soft-cap" rates for distribution customers. Recognizing the uncertainty over future competitive conditions, the Commission has established a review and adjustment mechanism. In setting the firm transportation rate the Commission has sought to balance its mandate to provide the Utility with an opportunity to earn a fair and reasonable return while also providing a fair and reasonable rate to current and prospective shippers. The new rate was determined with reference to both an appropriate cost allocation and a reasonable RDDA contribution.

In this Decision, the Commission has balanced the requirements of the Special Direction and the UCA. It has sought to put in place procedures that will ensure the flexibility necessitated by the numerous uncertainties confronting the regional energy market.

Dated at the City of Vancouver, in the Province of British Columbia, this 5th day of June, 2003.

_________*Original signed by* ____________________
Peter Ostergaard
Chair

_________*Original signed by* ____________________
Nadine F. Nicholls
Commissioner

_________*Original signed by* ____________________
Paul G. Bradley
Commissioner

APPEARANCES

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K.E. GUSTAFSON, Q.C.	Vancouver Island Gas Joint Venture
M. DOHERTY R.J. GATHERCOLE	Consumers' Association of Canada (B.C. Branch), B.C. Old Age Pensioners' Organization, Council of Senior Citizens' Organizations, Senior Citizens Association of British Columbia, Tenants Rights Action Coalition
C. WEAFER PENNY COCHRANE	Vancouver Island Public Sector Natural Gas Consumers Group
STIRLING BATES	Ministry of Energy and Mines

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CENTRA PANEL	G. Higgins I.D. Anderson T.W. Jennings
VANCOUVER ISLAND GAS JOINT VENTURE CEO PANEL	R. Horner R.R. Fulton D.A. Ingram C.D. Eamer
CENTRA RATE DESIGN PANEL	I.D. Anderson G. Higgins T.W. Jennings G. Saleba D. DesLauriers
BC HYDRO PANEL	G. Engbloom G. Newcombe G. Simpson
VANCOUVER ISLAND GAS JOINT VENTURE PANEL	L.G. Guenther

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-42-03

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Centra Gas British Columbia Inc.
(now Terasen Gas (Vancouver Island) Inc.)
2002 Cost of Service Allocation Study,
2002 Rate Design Application and
Application for Approval of Amending Agreements

BEFORE:	P. Ostergaard, Chair)	
	P.G Bradley, Commissioner)	June 5, 2003
	N.F. Nicholls, Commissioner)	

O R D E R

WHEREAS:

A. The December 1995 Special Direction to the Commission, attached to Order in Council 1510, directed the Commission to fix rates for the period beginning January 1, 2003 for all customer classes except the Apartment Customer Rates ("ACR") ACR-2 class so that Centra Gas British Columbia Inc. ("Centra") is able to recover its cost of service in accordance with the requirements of the Special Direction and such regulatory principles that are otherwise applicable that are not inconsistent with the Special Direction; and

B. On May 3, 2002, Centra filed a Cost of Service Allocation ("COSA") study to support a determination of future rates. On July 31, 2002, Centra applied, pursuant to Section 23 of the Utilities Commission Act ("the Act") and the Special Direction (Order in Council 1510, 1995), for approval of its 1999 to 2001 actual revenue deficiencies and its forecast 2003 to 2005 revenue requirements as Phase 1 of a two phase process ("the Phase 1 Application") for its Vancouver Island and Sunshine Coast service areas. Centra proposed that the Phase 1 Application be reviewed through a Negotiated Settlement Process; and

C. On September 30, 2002, Centra Gas filed its Phase 2 Rate Design Application, pursuant to Sections 60 and 61 of the Act, to determine rates effective January 1, 2003 that are appropriate for the recovery of both the current cost of service and amortization of accumulated revenue deficiencies. The Phase 2 Application was also made pursuant to Sections 2.8 and 2.10(j) of the Special Direction. Centra proposed that the Phase 2 Application be reviewed through a Negotiated Settlement Process; and

D. On October 22, 2002, participants at the Pre-hearing Conference, established by Order No. G-71-02, were advised of the regulatory review options and did not oppose the establishment of Negotiated Settlement Processes for both the Phase 1 and Phase 2 Applications; and

E. By Order No. G-76-02, the Commission determined that the Applications should proceed to Negotiated Settlement Processes and established a regulatory timetable for those processes; and

F. Participants in the Negotiated Settlement Process with respect to the Phase 1 Application met on November 25 and 26, 2002 and reached a tentative settlement agreement; and

G. Participants in the Negotiated Settlement Process with respect to the Phase 2 Application met on December 3, 2002, but were unable to reach a settlement agreement; and

H. On December 10, 2002, Centra filed an Application for Interim Rate Class Segments and Rates ("Interim Rate Application"); and

I. By Order No. G-97-02 dated December 17, 2002, the Commission approved the rate class segments and interim rates applied for by Centra in its Interim Rate Application.

J. On December 20, 2002, Centra applied for approval of three amending agreements (the "Amending Agreements") involving Centra, British Columbia Hydro and Power Authority, and BC Gas Utility Ltd.; and

K. By Letter No. L-2-03 dated January 9, 2003, the Commission determined that it would conduct its review of the Amending Agreements as part of the Phase 2 Rate Design oral public hearing; and

L. In accordance with Commission Orders No. G-86-02 and G-96-02, an oral public hearing was conducted on February 5, February 7 and from March 3 to March 6, 2003. Written submissions were received from Centra on March 17, 2003, from Intervenors by March 28, 2003, and Centra's Reply Submissions were received on April 7, 2003; and

M. Following the filing of Argument and Reply, Counsel for the Vancouver Island Joint Venture ("Joint Venture") objected to certain of the submissions made by Centra in its Reply Submissions. By letter dated April 22, 2003, the Commission established a timetable for responses to the Joint Venture objection. The only party to reply was Centra, which responded on April 22, 2003. The Joint Venture replied on May 9, 2003.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves as permanent the core customer class segmentation and core customer rates proposed by Centra in its September 2002 Rate Design Application, effective January 1, 2003.

2. The Commission approves a permanent rate for Firm Transportation ("FT") service of $1.074/GJ, effective January 1, 2003. For the interim period between the Island Cogeneration Plant's ("ICP") Commercial Operation Date of April 12, 2002 and December 31, 2002, the Commission approves the interim ICP FT rate as permanent.

3. The Commission approves a permanent summer Interruptible Transportation ("IT") rate of $1.074/GJ, equal to the approved FT rate, effective January 1, 2003. The Commission approves a permanent winter IT rate of $1.492/GJ, equal to the approved FT rate at a 72 percent load factor, effective January 1, 2003. The Commission approves the interim ICP IT rate as permanent for the period prior to January 1, 2003.

4. The Commission approves the Amending Agreements.

5, The Commission determines that it will allow Centra to recover $700,000 of its COSA and rate design costs, to be allocated as a general cost in rates, amortized over 3 years beginning in 2003.

6. Centra is to abide by all Commission directions and determinations in the Decision which accompanies this Order.

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7. Centra is to inform all affected customers of the permanent rates by way of a bill insert or customer notice, to be submitted to the Commission in draft form prior to its release.

8. The Commission will accept, subject to timely filing, amended Gas Tariff rate schedules in accordance with the terms of this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of June 2003.

BY ORDER

Original signed by:

Peter Ostergaard
Chair