BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-113-04

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

and

An Application by Terasen Gas (Vancouver Island) Inc.
for Approval of 2003 Actual Revenue Surplus, Forecast 2005 Royalty Adjusted Cost of Gas,
Amortization of the Gas Cost Variance Account Balance
and 2005 Customer Rates

BEFORE:	R.H. Hobbs, Chair	)	
	K.L. Hall, Commissioner	)	December 14, 2004

O R D E R

WHEREAS:

A. On November 5, 2004, Terasen Gas (Vancouver Island) Inc. ("TGVI") filed its Annual Review material and an Application in accordance with the 2003-2005 Negotiated Settlement as approved by Commission Order No. G-2-03 ("the Application"). The Settlement required that an Annual Review be held in November of each year to review TGVI's performance for that year and its proposed activities for the upcoming year; and

B. On November 26, 2004 TGVI filed revised materials including proposed rates for 2005 and various other items ("the Revised Application"). The Revised Application requested approval, pursuant to Sections 23, 60 and 61 of the Utilities Commission Act ("the Act") and the Special Direction (Order in Council 1510/95) of the 2003 actual revenue surplus, a proposed operating lease arrangement to allocate 10 percent of the SAP-related costs to TGVI from Terasen Gas Inc. ("TGI"), $8.0 million in capital additions related to the Utilities Strategy Project, allocation of Shared Services costs to TGVI, 10 percent allocation of Gas Supply Core Administration costs to TGVI, 2005 Core Customer Rates, setting the Gas Cost Variance Account ("GCVA") Rate Rider D to zero, 2005 Firm Transportation and Interruptible rates, 2005 OM&A capitalization, forecast 2005 Royalty Adjusted Cost of Gas, and amortization of the forecast GCVA Balance; and

C. The 2003-2005 Negotiated Settlement did not include the incremental operating, maintenance and administrative expenses ("OM&A") of possible significant capital projects such as the Sooke main extension. That extension was filed as a Certificate of Public Convenience and Necessity ("CPCN") application and approved by Order No. C-15-02. The Revised Application includes the $22,000 incremental OM&A of the Sooke extension for 2005; and

D. Commission Order No. G-95-04 scheduled an Annual Review for November 19, 2004 and directed TGVI to file advance material by November 5, 2004 and provide a copy of the material to participants in the settlement discussions and 2004 Annual Review registered intervenors. Appendix A to Order No. G-95-04 set the Regulatory Timetable for information requests, responses and the Annual Review. At the Annual Review the participants accepted the regulatory timetable for TGVI to respond to issues raised and file the

2005 delivery rates, registered participants to provide comments, and TGVI to reply to comments received by December 3, 2004. Comments were filed by the British Columbia Public Interest Advocacy Centre representing BC Old Age Pensioners' Association Organization et al ("BCOAPO"), British Columbia Hydro and Power Authority ("BC Hydro"), Rental Owners and Managers Association of BC ("ROMA BC"), and Avista Energy; and

E. On December 11, 2004 the Province of British Columbia issued to the Commission the Vancouver Island Natural Gas Pipeline Special Direction No. 2 (Order in Council 1224/04). Special Direction No. 2 directed the Commission to approve the October 27, 2004 letter agreement ("Amending Agreement") between TGVI and the Vancouver Island Gas Joint Venture ("VIGJV") that amended and extended the Transportation Service Agreement ("JVTSA"); and

F. The Commission has considered the Revised Application and the submissions received.

NOW THEREFORE pursuant to Sections 23, 60 and 61 of the Act the Commission orders for TGVI with Reasons for Decision attached as Appendix A to this Order:

1. The Commission approves the 2003 actual revenue requirements as filed in the Revised Application and a 2003 revenue surplus of $12,622,751 with a cumulative balance in the Revenue Deficiency Deferral Account ("RDDA") of $75,287,752 at the end of 2003.

2. The Commission accepts that the 10 percent SAP Operating Lease charge from TGI to TGVI is appropriate and directs that the calculation of the lease be based on TGI's cost of service. The Commission finds that this lease charge should be part of the TGVI OM&A costs that were fixed by Commission Order No. G-2-03.

3. The Commission accepts the $8.0 million of capital additions for TGVI related to the Utilities Strategy Project.

4. The Commission approves the allocation of Shared Services costs to TGVI as proposed in the Revised Application.

5. The Commission approves the 10 percent allocation of Gas Supply Core Market Administration Expense to TGVI as proposed in the Revised Application.

6. The Commission approves the permanent rates effective January 1, 2005 for RGS, AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, LCS-13, HLF, and ILF rate classes as proposed in the Revised Application, subject to TGVI filing corresponding Gas Tariff pages in a timely manner.

7. Based on the directive to the Commission in Special Direction No. 2 attached to OIC 1224/04, the Commission approves the Amending Agreement between TGVI and the VIGJV. TGVI is to provide the filing in tariff format.

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8. The Commission directs TGVI to charge interim firm and interruptible rates, effective January 1, 2005, to BC Hydro that are equal to the current rates.

9. The Commission approves the 2005 capitalization of OM&A of $4,626,494.

10. The 2005 Royalty Adjusted unit cost of gas of $4.29/GJ is accepted by the Commission based on a sales forecast of 11.9 PJ.

11. The Commission approves setting the October 1, 2004 GCVA Rate Rider D to zero effective January 1, 2005. The Commission approves the amortization of the forecast December 31, 2004 balance of the GCVA into rates.

12. The Commission approves the 2005 incremental OM&A costs of $22,000 from the Sooke extension.

13. The Commission directs that $78,500 be removed from project costs for the Sooke extension.

14. TGVI will comply with all other directions in the Reasons for Decision attached as Appendix A to this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of December 2004.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

Attachment

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

and

An Application by Terasen Gas (Vancouver Island) Inc.
for Approval of 2003 Actual Revenue Surplus, Forecast 2005 Royalty Adjusted Cost of Gas,
Amortization of Gas Cost Variance Account Balance
and 2005 Customer Rates

REASONS FOR DECISION

1.0 BACKGROUND

Commission Order No. G-2-03 approved the 2003-2005 Negotiated Settlement ("Negotiated Settlement") for Terasen Gas (Vancouver Island) Inc.'s ("TGVI") 1999-2001 Actual Revenue Requirements and Revenue Deficiencies and 2003-2005 Forecast Revenue Requirements. In accordance with the Special Direction (OIC 1510/95) to the Commission, the revenue requirements for TGVI are established on a forecast basis and are "trued-up" to actual except for the operating, maintenance and administrative expenses ("OM&A" or "O&M") to determine the annual revenue deficiency for a particular year.

Subsequent to approval of the Negotiated Settlement, the Commission issued its June 5, 2003 Decision concerning a Rate Design Application by TGVI. That Decision approved the basis for rates for Distribution system customers and Transportation (transmission system) customers.

The Negotiated Settlement required that an Annual Review be held in November of each year to review TGVI's performance for that year and its proposed activities for the upcoming year. Commission Order No. G-95-04 scheduled an Annual Review for November 19, 2004 and directed TGVI to file advance material by November 5, 2004 and provide a copy of the material to participants in the settlement discussions and 2004 Annual Review registered intervenors. On November 5, 2004, TGVI filed its Annual Review material and Application ("the Application") (Exhibit B2-1). The Regulatory Timetable in Appendix A to Order No. G-95-04 set the schedule for information requests to be issued to TGVI by November 12, 2004 and that TGVI would respond by November 17, 2004. At the Annual Review all participants accepted that by November 26, 2004 TGVI would respond to issues raised and file the 2005 delivery rates; by December 1, 2004 registered participants would provide comments on the November 26, 2004 submission; and by December 3, 2004 TGVI would reply to comments received.

On November 26, 2004 TGVI filed revised materials including proposed rates for 2005 and various other items ("the Revised Application") (Exhibit B2-8). Comments were filed by the British Columbia Public Interest Advocacy Centre representing the BC Old Age Pensioners' Organization et al ("BCOAPO"), British Columbia Hydro and Power Authority ("BC Hydro"), Rental Owners and Managers Association of BC ("ROMA BC"), and Avista Energy. On December 3, 2004 TGVI replied to the comments received (Exhibit B2-10).

2.0 ISSUES

2.1 2003 Annual Revenue Surplus ("ARS")

Commission Order No. G-2-03 approved forecast revenue requirements for 2003-2005 and the annual revenue deficiencies for 1999-2001. Commission Order No. G-81-03 approved the 2002 annual revenue deficiency. In the Annual Review material, TGVI proposes to true-up to actual the 2003 results and requests approval of the 2003 ARS and cumulative balance in the Revenue Deficiency Deferral Account ("RDDA") (Exhibit B2-1, p. 4.3; and Exhibit B2-8, Application, p. 2).

The Commission Panel has reviewed the 2003 ARS and finds that it is consistent with the 2003-2005 Negotiated Settlement and approves a 2003 ARS in the amount of $12,622,751. The Commission Panel also approves the cumulative balance in the RDDA of $75,287,752 at the end of 2003.

2.2 10 Percent SAP Operating Lease Arrangement

The operational integration of TGVI and Terasen Gas Inc. ("TGI") began in September 2003 to harmonize the information technology platforms. The integration will facilitate a shared services approach that enables both companies to achieve economies of scale by having a single management and support structure. As part of the integration, TGVI will have use of the common SAP technology platform assets. The Revised Application proposes to allocate from TGI to TGVI a 10 percent SAP-related lease cost as if TGVI had ownership of the 10 percent portion of the SAP Assets. However, TGI will continue to own all of the previous existing SAP assets and calculate its taxes based on full ownership of the assets. The 10 percent allocation was arrived at by TGVI after consideration of the relative proportion of TGVI vs. TGI employees (11.5 percent) and TGVI vs. TGI customers (9.0 percent) (Exhibit B2-1, Sec. 9, App. J, Shared Services Management Report, p. 5).

The Revised Application calculates an operating lease payment of $574,000 for 2005 based on TGVI's cost of service. TGVI proposes to use this calculation based on a 10 percent notional ownership of the net book value of the TGI SAP assets. The lease calculation based on 10 percent of TGI's cost of service is $614,000 for 2005. TGVI states that the lease costs under both scenarios are not materially different (Exhibit B2-8, p. 9). BCOAPO in its December 1, 2004 letter are of the view that consistent TGVI or TGI factors should be used in the lease amount derivation and it submits that TGVI factors should be utilized for 2005. However, BCOAPO requests that TGVI report back in the next annual review to fully explain the impacts of this methodology on TGI (Exhibit C4-6, p. 4).

The Commission Panel notes that the lease calculation based on TGI's cost of service is simpler and more transparent than the proposed alternative. **The Commission Panel accepts that the 10 percent SAP Operating Lease charge from TGI to TGVI is appropriate and directs that the calculation of the lease be based on TGI's cost of service.**

TGVI proposes to categorize this SAP operating lease expense similar to rent for the compressor lease equipment so TGVI would not be adversely impacted by the negotiated settlement O&M mechanism (Exhibit B2-1, Sec. 9, App. J, October 20, 2004 letter).

TGVI's SAP operating lease expense is to be included as regular OM&A expense. This arrangement is similar to other shared service arrangements between companies that are under the regulation of the Commission. Accordingly the Commission Panel rejects the treatment of the SAP operating lease expense to be excluded from the negotiated settlement allowed OM&A amount.

2.3 Capital Additions

2.3.1 $8.0 million of 2004 and 2005 Capital Additions Related to the Utilities Strategy Project ("USP")

TGVI plans to spend $3.6 million in 2004 and $4.4 million in 2005 of capital additions in order to harmonize Information Technology platforms that are required to share common work processes between TGI and TGVI (Exhibit, B2-1, Sec. 9, App. J, May 31, 2004 letter; and Exhibit B2-8, p. 5). TGVI expanded on the justification of these capital additions in its November 26, 2004 Revised Application (Exhibit B2-8, pp. 5-8). TGVI submits that it would improve functionality compared to existing systems and enable best-practice business processes. Five major areas would benefit: Back-Office, Order Fulfillment and Operate and Maintain Distribution, Meter Management and Mobile Systems, AM/FM / Drafting Systems, and Infrastructure. By implementing the Utilities Strategy Project, TGVI submits that the company will achieve annualized O&M savings due to restructuring of $6.4 million in 2004 and $6.7 million in 2005 mostly from employee related savings (Exhibit B2-4, BCUC IR 1.9.9.1). TGVI submits that the Business Case is captured in the advance materials under Appendix J in the Shared Services Management Report (Exhibit B2-5, BC Hydro IR 1.21.0b).

BCOAPO in its December 1, 2004 letter submits that none of the $8 million in capital additions be allowed in the 2005 revenue requirement because of insufficient opportunity to review these capital projects (Exhibit C4-6, p. 3). TGVI submits there has been adequate opportunity to review the capital expenditures (Exhibit B2-10 p. 2). Additionally, TGVI has submitted the USP Program Charter under confidential cover to the Commission (Exhibit B2-9).

The Commission Panel accepts that TGVI has provided a financial justification for the $8.0 million of capital additions related to the Utilities Strategy Project. **In order to harmonize Information Technology platforms and processes and to achieve cost and operational efficiencies, the Commission Panel accepts that the $8.0 million of capital additions is required for TGVI.**

2.3.2 Gross Plant in Service

Major projects planned but deferred in 2003 include the compressor oil seal retrofit work which a preliminary investigation estimated would cost $825,000/unit. A subsequent examination revealed that the entire compressor assemblies would require replacement and costs escalated to about $2,200,000 per unit. This work will be deferred until TGVI identifies less expensive methods to address the hydraulic inefficiencies (Exhibit B2-1, p. 4.8; and Exhibit B2-4, BCUC IR 1.24.1).

The Coquitlam Dam crossing that was to be undertaken in 2003 at a cost of $1.0 million has been deferred to 2005 (Exhibit B2-1, p. 4.8).

2.3.3 Sooke Mains Extension

The project was approved with Order No. C-15-02 based on an estimate of $4,261,811. The final actual adjusted cost was $4,970,000 or about 16.6 percent over the original estimate. TGVI's April 16, 2004 letter addressed reasons why the cost of the transmission pipeline segment of the Sooke Project increased from $1,960,364 (as estimated in the Certificate of Public Convenience and Necessity Application) compared to the actual cost of $2,606,627 (Exhibit B2-4, BCUC IR 1.27.3).

One contributor to the cost over-run was the necessity to install rock shield in 2.8 km. of pipeline. The cost that was incurred by having to uncover the pipe, inspect the coating, repair and rebury this section of pipe line amounted to $78,500. The Commission Panel considers that a detailed geotechnical inspection of soils along the route would have identified the requirement for a rock shield along this section. A study should have been conducted given that this was an unusual situation that required high compaction in conjunction with the shallow depth of the pipeline installation.

The Commission Panel directs that $78,500 be removed from the project costs.

2.3.4 Main Extensions – 2004 Main Extension Report

In the Negotiated Settlement approved by and attached to Order No. G-2-03, TGVI agreed to review its main extension test with Commission staff and participants to the negotiated settlement to determine if the test is providing appropriate results such that the utility is investing capital for new main extensions and customer additions that are beneficial to existing customers. As part of the review, TGVI agreed to provide evidence on the appropriateness of including an allowance for future capacity expansion, and the appropriate amount of that allowance.

TGVI filed its main extension report on July 22, 2004. The Commission, in its letter of September 14, 2004, directed the utility to include the report in the materials to be discussed in its 2004 Annual Review.
In addition to the main extension report, TGVI included in the Annual Review materials its 2004 Annual Report on the Sooke Pipeline Project. Information included in the Sooke Pipeline Project report indicated that the number of customers added to the Sooke main extension in the first year and the volumes delivered are significantly below forecast levels.

During the review, Commission staff requested further information on how the actual results of other past main extensions had compared to the forecast results for the extensions. TGVI, in its letter dated November 26, 2004, committed to filing a report to the Commission by the first quarter of 2005 comparing actual results to budget for capital costs, customer additions, sales volume and sales revenue for all main extensions that are five years old or less as at 2004.

The Commission Panel accepts TGVI's proposal to file a report by the first quarter of 2005.

2.4 Allocation of Shared Services Costs to TGVI

The Shared Services Management Agreement proposes an allocation approach to be used for Shared Services costs (Exhibit B2-1, Sec. 9, App. J). Shared Services costs charged to TGVI from TGI would compose of both direct and allocated costs. The direct costs include Other Post Employment Benefits (OPEB) costs which are directly attributable to TGVI staff and direct charges via timesheets from TGI employees, consistent with the Transfer Pricing policy. The Shared Services allocated costs would be based on two cost drivers: number of customers and number of employees. For 2004 TGVI comprised 9 percent of the customers and 11.5 percent of the employees for the total combined TGVI and TGI entities (Exhibit B2-1, Sec. 9, App. J, Shared Services Management Report, p. 11). Each cost driver would be applied to the relevant functional shared service cost. The calculated amount will be subject to true up at year end when actual shared costs are known.

The Commission Panel approves of the allocation of Shared Services costs to TGVI as proposed in the Revised Application. These Shared Services costs would form part of the fixed OM&A under the negotiated settlement and Order No. G-2-03.

2.5 Core Market Administration Expense Allocation

The basis for the allocation of Core Market Administration Expense is to be consistent with the Shared Services Agreement. The allocation is to be made on the basis of the number of customers. As a result, 10 percent of the total of the net Core Market Administration Expense will be allocated to TGVI, 1 percent to Terasen Gas (Whistler) Inc. ("TGW") and the remaining 89 percent allocated to TGI (Exhibit B2-8, p. 5).

The Commission Panel approves the allocation of Core Market Administration Expense as determined in the TGI Reasons for Decision.

2.6 2005 Volume and Revenue Forecasts

2.6.1 Core Market Forecast

TGVI is forecasting 11,964.8 TJ of energy sales for 2005 from 83,133 residential, commercial and large commercial customers from customers at year-end (Exhibit B2-1, p. 6.8). The volume forecast is the product of the forecast average number of customers in each class for the test year and the forecast use per account for each customer, by class. TGVI is forecasting approximately 3,100 customer additions for 2005 which is slightly less than 3,500 projected for 2004 but greater than the 2,562 actual number of customer additions in 2003 (Exhibit B2-4, BCUC IR 1.10.1). The use per account for current customer classes is forecast in most cases to be approximately the same as the projected 2004 normalized values, which in turn was close to the 2003 normalized value except for the High Load Factor customer class. The High Load Factor customers showed a significant increase in the use per account between the 2003 actual and the 2004 projected value (Exhibit B2-4, BCUC IR 1.11.3).

The BCOAPO submits, in a letter dated December 1, 2004 (Exhibit C4-6, p. 2), that the 3,013 residential customer attachments forecast for 2005 is likely unreasonably high given the high price of natural gas relative to electricity and the significantly lower number of actual attachments in 2003. TGVI, in its reply dated December 3, 2004, submits that the forecast number of residential attachments for 2005 is reasonable and points to its projection of 3,257 residential attachments for 2004. TGVI notes that its projection for 2004 is based in part on recorded additions to the end of September 2004 (Exhibit B2-10, p. 6).

The Commission Panel accepts TGVI's forecast of core market customers and volumes for 2005.

2.6.2 Transportation Forecast

TGVI currently serves two large transportation customers, the Vancouver Island Gas Joint Venture ("VIGJV") and BC Hydro. TGVI is forecasting $23.6 million of transportation revenue for 2005 which is $1.2 million more than forecast for 2005 in the 2003/2005 Revenue Requirements Application (Exhibit B2-8, Table 6.1 - Revised). No Interruptible Transportation volumes are forecast for 2005.

<u>Vancouver Island Gas Joint Venture</u>

TGVI currently serves the VIGJV under a Transportation Service Agreement ("JVTSA"). The JVTSA was approved under a Special Direction issued pursuant to Order in Council 1510 dated December 13, 1995 that was formulated in connection with the Vancouver Island Natural Gas Pipeline Act ("Special Direction").

In October 2004, TGVI and the VIGJV entered into an arm's-length commercial agreement ("Amending Agreement") that would amend the JVTSA and the Peaking Gas Management Agreement ("PGMA") that are currently in place between the two parties. The Special Direction does not allow the Commission to amend or vary the JVTSA as is contemplated in the Amending Agreement. The JVTSA is subject to expiry at the end of 2005 and the amendments which would be effective January 1, 2005 will reduce the contractual obligations of the VIGJV for 2005 in exchange for an 8 year firm commitment and revenue stream (Exhibit B2-1, pp. 7.2-7.3).

Under the Amending Agreement, the 2005 contract demand for the VIGJV will decrease to 20 TJ/d for 2005 (Exhibit B2-1, p. 7.3) and firm revenue from the VIGJV will be $6.5 million (Exhibit B2-4, BCUC IR 1.28.5). The firm transportation rate to the VIGJV will be based on the current firm demand formula escalating at one-half the Consumer Price Index. The Interruptible rate is based on a three-tier formula depending on the quantity of interruptible gas taken. The VIGJV will provide up to 10 TJ/d of peaking gas under the amended Peaking Gas Management Agreement between TGVI and the VIGJV (Exhibit B2-1, p. 7.3).

On December 11, 2004, the Commission received from the Province the Vancouver Island Natural Gas Pipeline Special Direction No. 2 ("VINGP SD No. 2"), which directed the Commission to approve the Amending Agreement.

Pursuant to VINGP SD No. 2, the Commission Panel approves the Amending Agreement between TGVI and the VIGJV.

<u>BC Hydro</u>

The volumes to be transported in 2005 for BC Hydro for use in the Island Cogeneration Project ("ICP") are uncertain as TGVI is currently delivering gas for BC Hydro under amended transportation, peaking and related agreements that expire on December 31, 2004. No new agreements have been reached for gas transportation service to the ICP for 2005. TGVI states that for the purposes of the 2005 forecast it has assumed a firm contract demand of 40 TJ/day and that 17 TJ/day of peaking gas will be available from BC Hydro (Exhibit B2-8, Tab 1, pp. 12-13). As discussed in a subsequent section, BC Hydro disputes the allocation method employed by TGVI to calculate the firm transportation rate.

The Commission Panel notes that firm transportation volumes and revenues related to transportation service for BC Hydro will remain uncertain until the Commission has approved a firm transportation agreement.

2.7 2005 Rates

2.7.1 2005 Core Customer Rates

The burner tip rates approved by Commission Order G-87-04 (effective October 1, 2004) are to remain unchanged for January 1, 2005. In consideration of the revenue to cost ratios for each class, the fluctuation in the cost of gas, competitive energy alternatives and the objective of rate stability TGVI proposes to maintain the current rate levels for the core market rate classes (RGS, AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, LCS-13, HLF and ILF) (Exhibit B2-8, p. 14 and Application p. 1).

The Commission Panel approves the 2005 Core Customer Rates as proposed in the Revised Application as permanent, effective January 1, 2005.

2.7.2 Rate Design - Transportation Rate

TGVI is proposing a firm transportation rate of $1.117/GJ, based on Cost of Service Allocation ("COSA") results filed by TGVI in its November 26, 2004 Revised Application. The November 26, 2004 COSA is based on distribution system customer demand of 72.6 TJ/day, BC Hydro contract demand of 40.0 TJ/day, Terasen Gas (Squamish) demand of 4.7 TJ/d and VIGJV contract demand of 20.0 TJ/day as per the proposed amendments to the JVTSA. These revisions lead to a total demand for allocation purposes on the TGVI High Pressure Transmission System ("HPTS") of 137.4 TJ/day (Exhibit B2-8, App. K, Table 1). TGVI submits that the COSA results for 2005 have been determined on a basis consistent with TGVI's 2002 Rate Design application (Exhibit B2-1, p. 7.4).

BC Hydro submits that the firm rate should be reduced by approximately $0.10/GJ to approximately $1.01/GJ (Exhibit C7-4, p. 1). BC Hydro's submission is based on alternative allocation and capacity assumptions than those used by TGVI and depends to some extent on the outcome of the proposed amendments to the agreements between TGVI and the VIGJV. BC Hydro submits that the HPTS could have a capacity of 155 TJ/day and that TGVI has unnecessarily limited system capacity. BC Hydro also submits that if the HPTS capacity was 155 TJ/day and the VIGJV volumes were those established by the proposed amendment to the JVTSA, TGVI would require no peaking gas to satisfy the core market peak demand and the BC Hydro rate would be reduced by approximately $0.10/GJ. BC Hydro also claims that TGVI's peak day demand is being reduced below what is necessary to meet system capacity through the quantity of peaking service TGVI suggests is required from BC Hydro (Exhibit C7-4, p. 5). BC Hydro suggests that TGVI and BC Hydro are continuing to negotiate, and states that the BC Hydro Transportation Service Agreement and Peaking Agreement quantities could be determined based on the JVTSA and PGMA values. BC Hydro asked that the Commission Panel delay setting the BC Hydro rate for 2005 until at least after December 10, 2004 when the decision of the Province concerning the Amending Agreement between TGVI and the VIGJV would be known (Exhibit C7-4, p. 2).

TGVI replies that TGVI currently has no contractual or other basis to increase the inlet pressure to the HPTS and increase the capacity to 155 TJ/day, and submits that increasing the pressure would increase the costs to its other customers. TGVI further submits that, in determining the amount of peaking gas required from BC Hydro, it is limited by BC Hydro's firm contract demand and "...the fact that TGVI can not use available supply from the VIGJV to provide service at ICP" (Ex. B2-10, p. 5). TGVI states that BC Hydro is proposing a method of calculating the amount of peaking gas required in a manner that is inconsistent with the current TSA and the approved rate design methodology. TGVI agrees that it has used a total billing determinant that is less than the HPTS capacity, and states that the allocation of transmission capacity costs is based on the Core Market's secondary peak plus the firm demand of transport customers, which TGVI states is consistent with the currently approved rate design for TGVI. TGVI requests that the Firm and Interruptible rates included in its proposal be approved (Exhibit B2-10, pp. 4-5).

The Commission Panel notes that the assumptions TGVI has used in its COSA analysis for the VIGJV volumes are consistent with the Amending Agreement. The decision of the Province with respect to the Amending Agreement between TGVI and the VIGJV has just been released, and negotiations between BC Hydro and TGVI may need to consider the impact of approval of the Amending Agreement on the transportation service and related agreements for BC Hydro. Therefore, the Commission Panel directs that the TGVI should charge interim firm and interruptible rates, effective January 1, 2005, to BC Hydro that are equal to the current rates, thus affording all parties the time and opportunity to conclude transportation service arrangements for BC Hydro.

2.8 2004 OM&A Capitalization

In the Negotiated Settlement (page 29) the forecast capitalized overhead for 2005 was $5,274,680 or 16.18 percent. The Negotiated Settlement required TGVI to continue to apply its overhead capitalization policy and to request Commission approval of each year's capitalized OM&A commencing in 2004. The Revised Application states that the utility has applied its policy and is requesting approval of 2005 OM&A capitalization of $4,626,294 or 14.2 percent, which is less than the settlement forecast (Exhibit B2-1, p. 6.10; and Exhibit B2-8, Application, p. 2). TGVI submits that the decrease is primarily due to a lower OM&A base as a result of the integration of operations with TGI. In the December 3, 2004 letter TGVI confirms there has been no change to the normal company's overhead capitalization policy.

The Commission Panel approves the 2005 capitalized overhead in the amount of $4,626,294.

When the 2003-2005 Revenue Requirements Application was filed, page 8.2 of that application stated that the capital and operating costs of some projects, such as the Sooke extension, were excluded. The Negotiated Settlement set the gross OM&A at $31.7 million for 2003, $32.5 million for 2004 and $32.6 million for 2005. The Certificate of Public Convenience and Necessity ("CPCN") Application for the Sooke extension identified incremental OM&A costs for this excluded project. The Sooke CPCN extension was approved by Order No. C-15-02 and TGVI's Annual Review material increased the Negotiated Settlement gross OM&A for 2005 by $22,000 to include the Sooke incremental OM&A (Exhibit B2-4, BCUC IR 1.4.1).

The Commission Panel approves the $22,000 incremental OM&A costs of the Sooke extension as forecast in the Sooke CPCN Application.

2.9 2005 Royalty Adjusted Cost of Gas

Total gas costs based on the November 19, 2004 forward price information are estimated to be $11.96 million. The total Royalty Revenue is forecast to be $40.40 million. Therefore the Royalty Adjusted Cost of Gas (based on sales of 11.9 PJ) results in $51.37 million or $4.29/GJ (Exhibit B2-8, App. G).

The Commission Panel accepts the forecast and sets the benchmark 2005 Royalty Adjusted Cost of Gas at $4.29/GJ.

2.10 GCVA Rate Rider D set to Zero effective January 1, 2005 and Amortization of GCVA Balance of $122,092

The Gas Cost Variance Account ("GCVA") balance on a before-tax basis before credits from Rate Rider D recoveries is $3.49 million. On a before-tax basis with Rider D recoveries of approximately $3.3 million, the projected GCVA at year-end will be $186,400. The after-tax amount in the GCVA at year end that is forecast to be amortized into core customer rates is $122,092 (Exhibit B2-8, Sch. 11).

The Commission Panel approves setting the GCVA Rate Rider D to zero effective January 1, 2005.

The proposal for the amortization of the GCVA balance is consistent with the treatment of the 2003 GCVA surplus balance in setting the 2004 core customer rates.

The Commission Panel approves the GCVA balance net of taxes of $122,092 for amortization into core customer rates in 2005.