IN THE MATTER OF

PLATEAU PIPE LINE LTD.

TAYLOR TO KAMLOOPS PIPELINE
APPLICATION FOR PERMANENT TOLLS

DECISION

June 26, 2001

Before:

Peter Ostergaard, Chair
Barbara L. Clemenhagen, Commissioner
Kenneth L. Hall, Commissioner

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EXECUTIVE SUMMARY

Background

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

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

The Commission approved an Incentive Tolling Agreement that was negotiated between the Western System owner and shippers for the 1995 – 1999 period. The BCUC extended the arrangement through to the end of 2000, with tolls of $\$4.16/m^3$ for deliveries to Prince George and $\$6.40/m^3$ for deliveries to Kamloops.

Pine River Spill

On July 31, 2000, the Western System pipeline ruptured at milepost 102.5. A spill of approximately 952 m^3 (6,000 barrels) resulted. Approximately 500 m^3 of oil leaked into the Pine River about 90 km upstream of the town of Chetwynd. Plateau spent in excess of $26 million in the cleanup. Public concerns remain about the long-term impacts of this spill on the quality of life and the environment in this region, as well as the possibility of another spill in future.

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

Regulatory Events

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

In response to an application from Plateau, the Commission made the current tolls interim effective September 7th, and directed Plateau to initiate discussions with its shippers and apply for permanent tolls. Plateau met with shippers in attempts to arrive at a consensus on tolls and commitments but no agreement was reached.

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

Pipeline Integrity and Upgrading

Plateau identified the pipeline upgrades and major operating expenditures that it considered necessary to fulfil its responsibility as pipeline operator. The work was estimated to cost $27.351 million over the period 2000 to 2004.

Canspec Group Inc. ("Canspec") was commissioned by Environment Canada to evaluate the failed pipe. They found the failure was due to a non-metallic inclusion that had been present from the time of manufacture and caused a "hook" crack to from. With such defects, a significant number of variables need to be present at the same time for failure to occur. Canspec agreed that the Pine River failure was a low probability event. Canspec, as well as Cimarron Engineering Ltd. and Colt Engineering Corporation, considered that a successful hydrostatic retest would prove the current integrity of the pipeline and allow Plateau time to plan and implement other pipeline integrity initiatives.

The section of line from Prince George to Kamloops remains out of service. In addition to testing and upgrading the pipeline, Plateau also wanted to be assured it would be allowed to recover all costs. The Commission is of the view that Plateau has not justified its decision to not return the southern section to service. For the purpose of setting tolls, the Commission finds that Plateau could have returned the section to service by December 1, 2000, and determines that the revenue that was lost because crude oil deliveries to Kamloops were delayed is Pembina's responsibility.

A determination by the OGC that system improvements are needed will be justification for recovering the expenditure in rates, providing the work is carried out in a prudent fashion. In the absence of an OGC determination on Plateau's upgrade program, the Commission has determined an estimate of costs to be used for calculating rates. The Commission has also approved the use of a deferral account, subject to review, for recording variances in the amount of insurance claims from the Pine River spill that are denied by the insurer.

Load Forecast

From the evidence, the Commission concludes that crude oil production delivered to Taylor can be maintained at approximately 7,200 m^3/d for at least the next five years. With the Western System in service, and with competitive tolls, most if not all of the volumes now going east are likely to be redirected to the Western system. The expected capacity of the pipeline from Taylor, after a successful retest, is at least 7,100 m^3/d. For the purpose of setting tolls, the Commission has used deemed normal deliveries to Prince George of 1,600 m^3/d commencing September 7, 2000. The Commission has also used deemed normal deliveries to Kamloops of 3,900 m^3/d for September 7, 2000 to October 31, 2001, and 5,000 m^3/d commencing November 1, 2001.

<u>Rate Base</u>

When Plateau and its shippers were unable to come to an agreement on tolling in the fall of 2000, the Commission was required to undertake for the first time a comprehensive review of an oil pipeline regulated under the Pipeline Act. Plateau requested approval of a semi-depreciated rate base methodology where the plant in service portion of rate base is calculated as the average gross plant cost less one-half of the average accumulated depreciation for the period. The Commission determines that the fully depreciated rate base methodology is appropriate for the Western System, as it properly represents the net investment that has been made by the pipeline owner. The substantial capital investments required should address concerns about a vanishing rate base. The Commission has rejected Pembina's request to revalue the pipeline.

The Commission has used September 7, 2000 opening balances of $45.512 million of Gross Plant and $45.456 million of Accumulated Depreciation in the toll calculations. The Commission considers a physical life of 20 years is appropriate and has set a depreciation rate of 5 percent straight line. The Commission also determines that major operating expenses should be amortized over a five year period commencing with the year of the expenditure. The Commission accepts Plateau's proposal that working capital be set as one-eighth of the normal operating expenses for the year.

<u>Operating and Maintenance Expense</u>

Plateau reported operating expenses for the period September 7 to December 2000 of $2.971 million, and estimated $7.448 million for 2001. These are very close to the historical amounts and are accepted by the Commission subject to adjustments to power costs. The Commission accepts the inclusion of the net costs of a nitrogen purge used for removing the oil from the idle southern section. The Commission also approves a deferral account to record any difference between the insurance premium estimate and the actual insurance premium cost. Plateau may also record future insurance deductible outlays in this deferral account.

<u>Capital Structure and Return</u>

Plateau proposed a capital structure funded by 100 percent equity and an after-tax return on equity ("ROE") of 15 percent, on the basis that this corresponded to the previous Incentive Tolling Agreement. The Commission considers it must determine a deemed capital structure which would be efficient for a stand-alone pipeline, and has used a deemed equity component of 50 percent.

The Commission considers its Generic Formula is an appropriate mechanism to determine the ROE for the Western System provided an appropriate risk premium can be established to recognize the business, financial and regulatory risk facing Pembina. The pipeline owner and shippers accepted a risk premium of 3 percent above a low risk utility's ROE at the time that the Incentive Tolling Agreement was negotiated in 1995, and the Commission is satisfied that maintaining that risk premium is a reasonable approximation of the appropriate return for Pembina. An after-tax ROE of 12.25 percent is approved for the 2000 and 2001 test periods.

The Commission considers that a short-term debt component of 10 percent is appropriate for the Western System, and determines a cost of short-term debt of 6 percent. The Commission has used a long-term debt component of 40 percent at a cost of debt of 7.5 percent for the 2000 and 2001 test periods. The Commission determines that deferred income taxes are appropriate for 2000 and 2001, and has included deferred income tax balances in the capital structure as no-cost capital, replacing short-term debt.

Tolls and Rate Design

The Commission approved a one-year extension for 2000 of the 1995 to 1999 Incentive Tolling Agreement, but this ended when tolls were made interim effective September 7, 2000. The Commission accepts the incentive toll sharing adjustment for the January 1 to September 6, 2000 period as filed and will amortize the amount of $115,000 in tolls in 2002.

For the 2000 stub year, the Commission determines a toll of $\$4.42/m^3$ to Prince George and $\$6.81/m^3$ to Kamloops. The Commission has maintained the approach of calculating tolls so that the Taylor to Prince George toll is 65 percent of the Taylor to Kamloops toll. Unrecovered toll revenue for the 2000 stub year totalling $2.355 million is transferred to the unrecovered revenue deferral account, to be amortized into tolls over three years commencing in 2001.

The Commission determines 2001 tolls of $\$4.27/m^3$ to Prince George and $\$6.56/m^3$ to Kamloops.

Competitive Tolls, Shipper Commitments and Action Plan

The Western System faces competition from the two pipeline systems that transport oil from Taylor east to Edmonton. The tolls calculated for the Western System for the 2000 stub period and for 2001 are only slightly higher than the rates that were in effect prior to the line rupture. The current effective toll to Kamloops via Edmonton and TMPL is $\$13.209/m^3$. The Commission concludes that, in the absence of unexpected changes to tolls on competing pipelines, the Western System will be competitive and financially viable for the future.

Plateau requested that shippers provide a volume commitment for a period of time at the proposed tolls. It is the view of the Commission that throughput on the Western System at the forecast volumes and at the allowed tolls will provide Plateau with a reasonable return on rate base and recovery of expenses and system upgrading expenditures. The Commission denies Plateau's request for volume commitments and its application for Suspension of Service.

The Commission has determined permanent tolls for the Western System that place the pipeline on a sound financial foundation for the future, and expects that Plateau and shippers will work together so that regulation on a reporting basis can resume. Nevertheless, the Commission considers that timely actions to re-establish full operation of the Western System are needed to preserve the pipeline as a viable entity. The Commission directs Plateau and Pembina to immediately proceed with all steps that are necessary to resume full operation. Specifically, Plateau and Pembina are to design, obtain approval for and conduct a hydrostatic test of the Prince George to Kamloops section. They are also to file a detailed action plan for returning the pipeline to full operation.

1.0 INTRODUCTION

1.1 Background to the Application

1.1.1 <u>Regulation of Oil Pipelines in British Columbia</u>

Intraprovincial oil pipelines are regulated by the Oil and Gas Commission ("OGC") and the British Columbia Utilities Commission ("BCUC", "the Commission"). The OGC is a Crown Corporation responsible for the oil pipeline regulation from a technical and safety perspective; it oversees pipeline inspection and integrity management programs to ensure B.C.'s pipelines are properly designed, constructed, operated, and maintained. The BCUC is responsible for the financial regulation of oil pipelines, including tolls and conditions of service.

Three statutes establish the regulatory framework for the OGC and the BCUC. The *Oil and Gas Commission Act* establishes and defines the powers of the OGC. Section 19 enables the OGC to declare common carrier status for a crude oil pipeline. (Prior to the OGC's establishment in 1998, this declaratory power resided with the BCUC.) Section 65 of the *Utilities Commission Act* enables the BCUC to establish conditions under which a common carrier must accept and carry crude oil. As described in Section 1.2.3, by Order No. P-7-00, the BCUC found that the Taylor to Kamloops pipeline is a common carrier.

The third statute, the *Pipeline Act*, is administered by the OGC except for Part 7. Part 7 sets out the BCUC's authority as it relates to oil pipelines located entirely within the Province of British Columbia which are also common carriers. For example:

> s. 42. Subject to exceptions or conditions the British Columbia Utilities Commission approves, a common carrier must, according to its powers, without delay and with due care and diligence, receive, transport and deliver all oil offered for transportation by means of its company pipeline.
>
> s. 43. The British Columbia Utilities Commission may require a common carrier to provide adequate and suitable facilities for receiving, transporting and delivering all oil offered for transportation by means of its company pipeline, and adequate and suitable facilities for storage of oil at the junction of its line with other pipelines.
>
> s. 44. A common carrier must not charge a toll unless it is specified in a tariff that has been filed with the British Columbia Utilities Commission and is in effect.

The BCUC has traditionally regulated oil pipelines under Part 7 of the *Pipeline Act* on a reporting or complaint basis (Exhibits 31 and 32). The pipeline companies and shippers negotiate the terms, conditions and rates for service, which are then filed with the BCUC. In the absence of a complaint from an interested party, without further review the Commission confirms that the general terms and rates in the negotiated Agreement are in compliance with the governing Acts, and approves the Agreement and resulting tolls in accordance with Section 44 of the *Pipeline Act*. Under this reporting method of regulation, the Commission has not specifically reviewed or approved the tolling methodology.

Other than Part 7, the *Pipeline Act* establishes the regulatory framework under which pipelines are applied for, approved, located, constructed, operated, and abandoned. For example, Section 9 states that a company pipeline must not be abandoned without the OGC's leave, and that the OGC may order a company abandoning the operation of a pipeline to remove structures likely to threaten public safety, create a fire hazard, or obstruct a stream.

1.1.2 Pembina/Plateau Corporate Structure

Pembina Pipeline Corporation ("Pembina") is the operating company for the Pembina Pipeline Income Fund (the "Fund"). The relationship of the Fund and related companies are set out in Figure 6-1 (Exhibit 1D, p. 1). In the hearing, it was not always clear which company was being referred to as Pembina. In this Decision, "Pembina" will refer to Pembina Pipeline Corporation. Pembina, through subsidiary companies, owns 14 pipelines, including the oil pipeline between Taylor and Kamloops, which is known as the "Western System" (Exhibit 20, p. 4). Pembina owns 100 percent of the shares of Plateau Pipe Line Ltd. ("Plateau"), which is the general partner of Pembina West Limited Partnership, the direct owner of intraprovincial oil pipelines in British Columbia. In addition to the Western System, these pipelines include the Blueberry, BC Light, and Boundary Lake systems which feed oil from gathering lines into the Taylor area, and Pembina's interest in the Taylor system (Exhibit 1D, p. 1). Figure 1-1 identifies Pembina's pipelines. The OGC has granted Pembina and Plateau various approvals to operate pipelines in British Columbia.

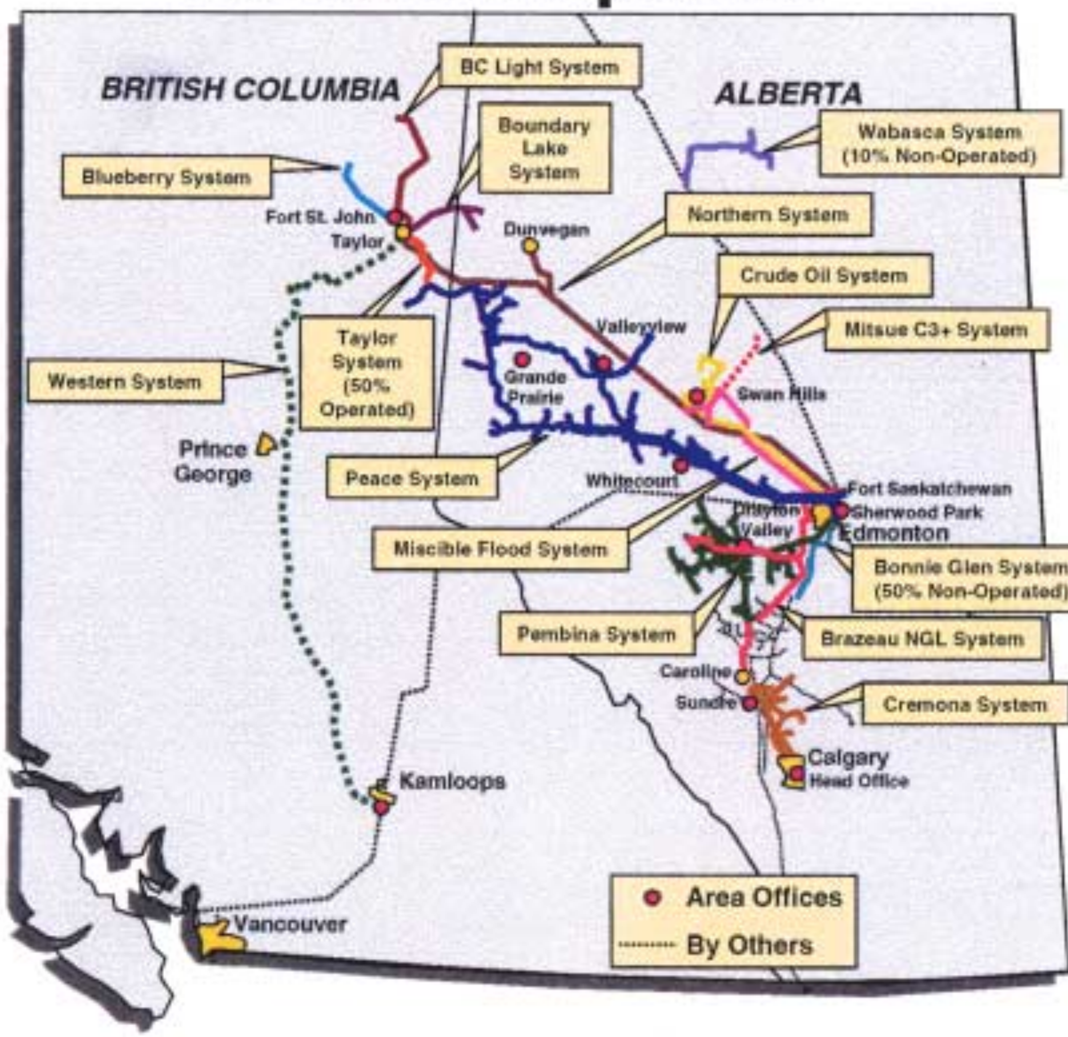
Regulation by the BCUC of common carrier pipelines under Part 7 of the *Pipeline Act* extends to tariffs and terms and conditions of service of the pipelines, which therefore includes Pembina and Plateau with respect to the Taylor to Kamloops pipeline.

1.1.3 The Western System: 1961 to July 31, 2000

In 1960, the Government of British Columbia invited proposals for a pipeline, to be constructed wholly within British Columbia, to transport crude oil and natural gas condensates from the Peace River district to the West Coast. In January, 1961, a subsidiary of Westcoast Transmission Company Ltd. (now Westcoast Energy Inc. ("Westcoast") was authorized to construct a 323.9 mm (12.75 inch), 800 km

Figure 1-1
(Reference: Exhibit 1D, p. 1, attachment)

Pembina's Pipelines



(500 mile) pipeline on the existing Westcoast right-of-way from Taylor, British Columbia to connect with the facilities of Trans Mountain Pipe Line Company Ltd. ("TMPL") at Kamloops. The Western System was owned by Westcoast Petroleum Ltd. and predecessor companies until 1993. In that year it was sold to Numac Energy Inc. Numac sold it to Federated Pipe Lines (Western) Ltd. ("Federated") in July 1994.

Federated, owned by Imperial Oil Ltd. and a subsidiary of Anderson Exploration Ltd., operated seven pipeline systems in British Columbia and Alberta. On July 31, 2000, the Federated group of companies and a related pipeline were sold to Pembina for $349 million (Exhibit 20, p. 9).

The Western System receives crude oil from a network of three gathering systems (Blueberry, BC Light, and Boundary Lake) upstream of Taylor. Oil is also trucked into Taylor. At Taylor, the oil has historically moved west and south on the Western System. Pembina bought the three main gathering systems upstream of Taylor from the Western Facilities Fund for $38.4 million on August 28, 2000 (Exhibit 20, p. 9).

In addition to the pipeline, the Western System includes associated metering, pumping, loading, and storage facilities. The system had a sustainable capacity of at least 7,100 cubic metres per day (44,700 barrels per day) (Exhibit. 1C, p. 26). Husky Oil Operations Limited ("Husky") relies on the Western System for crude oil supply for its refinery in Prince George, 370 km downstream of Taylor. Built in 1967, the refinery takes about 1,600 m^3/d (10,000 barrels per day). Husky asserts that without the Western System, its Prince George refinery is guaranteed to close (Husky Argument, p. 53). This is disputed by Plateau, citing the lack of evidence on refinery economics (Plateau Reply Argument, p. 31).

Prior to the line rupture on July 31, 2000, approximately 5,000 m^3/d (31,400 barrels per day) of crude oil was delivered to Kamloops for interconnection with the TMPL system for delivery to the Chevron Canada Ltd. ("Chevron") refinery in Burnaby and to Puget Sound refineries. The Western System is able to segregate the BC Light crude stream, which is advantageous to both the Husky and Chevron refineries.

1.1.4 Alternatives to the Western System

Until 1998, the Western System provided the only pipeline service to deliver crude oil from the Peace River area to market. In 1998, the Northern and Peace pipeline systems were connected to Taylor and the Western System faced competition for the first time, as shippers were then also able to move crude oil southeast to Edmonton, Alberta (T2: 363). With the purchase of Federated in 2000, Pembina now owns all three pipeline systems transporting crude oil from Taylor, except for the Taylor system segment in which it has a 50 percent interest.

The Northern system from Taylor is under National Energy Board ("NEB") jurisdiction, although some evidence seems to indicate that pipeline links that complete the connection to Edmonton are under Alberta Energy and Utility Board ("AEUB") jurisdiction (T3: 433). The toll to Edmonton of $9.00/m^3 is a negotiated flat toll that is not adjusted for variations in throughput (T3: 433).

The Taylor-Peace system consists of the Taylor system from Taylor to Dawson Creek, the Pouce Coupe system from Dawson Creek to the vicinity of Gordondale, Alberta, and the Peace system from the Pouce Coupe interconnect to Edmonton. The Taylor system is under BCUC jurisdiction, the Pouce Coupe system is under NEB jurisdiction and the Peace system is under AEUB jurisdiction. The toll from Taylor to Edmonton on the Taylor–Peace system is $9.00/m^3, reducing to $7.00/m^3 for volumes greater than 5,000 m^3/month (Exhibit 1D, p. 1; T3: 424-436).

Boundary Lake crude is shipped via the Northern system (T3: 433). BC Light crude is currently blended into the Boundary Lake, Peace system sweet and Peace system sour streams (Exhibit 7B, p. 3). Due to insufficient capacity on the Taylor-Peace system, and the unwillingness of shippers to mix BC Light into Boundary Lake, Pembina is trucking 700 to 800 m^3/d of BC Light to the Peace system at La Glace, Alberta, at a cost of about $13.00/m^3. Pembina applies a surcharge of $1.60/m^3 to crude volumes received by pipeline and truck at Taylor, to cover the cost of trucking (T2: 269-271). Mr. Webb stated that Pembina could modify its delivery systems to Edmonton to accommodate a segregated stream of BC Light crude (T3: 444-447).

1.1.5 Tolls and Incentive Agreement

BCUC Order No. P-5-95 approved the incentive tolling methodology for Federated's Taylor to Kamloops pipeline from January 1, 1995 to December 31, 1999. Negotiated between Federated and its shippers, it involved a sharing of throughput variances and significant integrity expenditures, and allowed annual formula-based toll revisions, subject to review by the BCUC in the event of a complaint.

BCUC Order No. P-3-99 approved revised Rules related to Evidence of Receipts and Deliveries and to Liability of Carrier, set out in the Crude Petroleum Tariff for the Western System.

On March 13, 2000, Federated applied to the BCUC for approval to increase tolls for 2000, based on a one-year continuation of the 1995-99 incentive tolling methodology. A shippers' meeting had been held and no complaints were received by the BCUC. Order No. P-3-00, dated March 28, 2000, approved the application to:

- increase the toll from \$3.61/m^3 to \$4.16/m^3 for deliveries to Prince George;
- increase the toll from \$5.56/m^3 to \$6.40/m^3 for deliveries to Kamloops; and
- extend until December 31, 2000, the incentive tolling methodology.

No volume commitments from shippers were required under this approved tolling structure.

1.2 Pipeline Failure and Subsequent Events

1.2.1 Pipeline Failure at Pine River

Several hours after the purchase from Federated and the commencement of operations by Plateau, at about 10:30 p.m. on July 31, 2000, the Western System pipeline ruptured at milepost 102.5. For a variety of reasons the remote control centre operator did not recognize the leak situation until after 1:00 a.m. on August 1. The pipeline was shut down at 1:17 a.m. on August 1 and field personnel were notified of the emergency.

Pipeline maintenance personnel were dispatched to find the leak and close the nearest isolating valves (T1: 88). By 2:45 a.m. valves had been closed at milepost 92, 10.5 miles upstream of the leak and at milepost 106.8, 4.3 miles downstream (Exhibit 1E, p. 12). A check valve at a critical low point at milepost 112.9 prevented drain down from a section of line rising some 168 metres (550 feet) higher in elevation downstream of the leak site.

A spill of approximately 952 m^3 (6,000 barrels) resulted, of which about 300 m^3 were estimated to be drain down of oil in the pipe following shutdown of the pipeline (Exhibit 1, Tab 2, p. 3, Exhibit 1F, Tab Encal, p. 17). Approximately 500 m^3 of oil found its way into the Pine River about 90 km upstream of the town of Chetwynd (Exhibit 1E, pp. 10 and 13; T1: 16).

The submissions by the Mayor of Chetwynd, the Chair of the South Peace Health Council, and the Chetwynd Environmental Society stated that Plateau responded quickly and responsibly. As a precautionary measure, the local health authority issued a water advisory and the Chetwynd water supply intake system was shut in. Plateau expended considerable effort in cleaning up the river and oil contaminated log jams along the banks. About 29,000 cubic metres of contaminated soil were removed and replaced with clean fill. Up to 150 people were employed in the cleanup and monitoring program. Nonetheless, the immediate consequences (e.g., fish kill, water quality concerns) were major. Public concerns remain about the long-term impacts of this spill on the quality of life and the environment in this region, as well as the possibility of another spill in future.

With cleanup and restoration costs exceeding $26 million, plus several million dollars in future costs of remediation and claims settlement, Plateau stated that the Pine River spill is the most expensive oil spill in Canadian history (Plateau Argument, p. 14). Plateau also stated it believes another spill of this magnitude would be devastating, both to the environment and to Plateau's and Pembina's financial stability (Plateau Reply Argument, p. 1).

1.2.2 Oil and Gas Commission Permission to Operate

Within three weeks of the break, the pipe had been repaired and a hydrostatic pressure test completed on a 24 km section between block valves on either side of the break.

On August 23, the OGC authorized Pembina to operate the pipeline from Taylor to Kamloops under three conditions (Exhibit 10):

1. Maximum operating pressure restricted to 75 percent of the certified operating pressure; any increase must be approved by the Chief Inspecting Engineer; this restriction to be reviewed upon successful completion of a leak and strength test; the plan and schedule for testing to be submitted within 30 days from the date of commencing operations; testing to be completed within 12 months thereafter.

2. Pembina to conduct an operational analysis of the pipeline operation procedures and submit it to OGC within six months.

3. Pembina to develop an Integrity Management Plan and submit it within 12 months; once approved, it must be implemented as directed by OGC; plan to include baseline assessment, continual process of assessment and evaluation, an analysis of available information about pipeline integrity and consequences of a failure, criteria for repair actions, identification of areas of high consequence and a plan to protect these areas, methods to measure program's effectiveness, and a process for review of integrity assessment results and data analysis.

Plateau considered the OGC permission letter as approval to recommence operations of the Western System if Plateau considered it safe and prudent to do so (Exhibit 6G, p. 9, paragraph 33). Plateau was determined to satisfy itself about pipeline integrity before reopening because it was being investigated for possible offences under British Columbia and federal environmental and fisheries statutes.

1.2.3 Failed Negotiations and Regulatory Events: August to December 2000

For the month of August 2000, Husky continued to operate its refinery at reduced levels, using on-site inventory and trucked crude. On August 30, 2000, Husky applied to the BCUC for an Order under the *Utilities Commission Act* compelling compliance with Part 7 of the *Pipeline Act*, especially Sections 42 and 44. Husky had asked Plateau to resume service, with Plateau taking the position that it would not resume service immediately, but would proceed with a hydrotest before making a decision. Husky claimed that Plateau had offered to resume service if Husky paid for the hydrotesting costs and provided additional indemnities beyond those contained in the tariff. On August 31st, the BCUC requested Plateau's response to Husky's August 30th application.

Meanwhile, on August 31st Plateau applied to have the $4.16/m^3 toll made interim effective September 1st, pending a new revised permanent toll application upon successful completion of negotiations with Husky. Plateau expected the toll to rise to reflect lower volumes, higher costs and the costs of the hydrostatic test. This test began on August 31st, and Husky began receiving the oil that was displaced by the water. The BCUC, by Order No. P-6-00 on September 7th, ordered that the tolls be made interim effective September 7th, that Plateau initiate discussions with its shippers, and that Plateau apply for permanent tolls for Taylor to Prince George by October 31st addressing tolls for Taylor to Kamloops as well.

Plateau's September 6th response to the Husky application asserted:

- it was not a common carrier;
- even if it was, the order sought could not be granted; and
- any jurisdiction related to authorizing continued operations rests with the OGC, not the BCUC.

Plateau stated it did not intend to resume shipments until it could be satisfied it was safe and prudent to do so. Husky replied to Pembina's response on September 11th, requesting an expedited decision.

The BCUC's Decision on Husky's application was provided in Order No. P-7-00 on September 14, 2000, followed by Reasons on September 21st. The Order:

- found that the Taylor to Kamloops pipeline is a common carrier for the purposes of Part 7 of the *Pipeline Act*, based on Pembina holding itself out to be a common carrier through submissions under Part 7, the functions that Pembina performs are consistent with those of common carriers and 1961 agreements that reference the proposed pipeline as such;

- denied Husky's application for an emergency order, accepting that Plateau's hydrostatic testing is prudent;

- directed Plateau to report the hydrostatic test results to the BCUC and the OGC;

- directed Plateau to apply for permanent tolls for Taylor to Prince George if this segment is returned to service; and

- required Plateau to provide written confirmation from the OGC that the line was unsafe or unreliable to operate if this segment was not returned to service.

In its Reasons, the BCUC concluded it had jurisdiction under Section 42 of the *Pipeline Act* to determine whether suspension of service was in the public interest. The Commission agreed with Plateau that hydrostatic testing between Taylor and Prince George was a prudent exception under Section 42 prior to recommencing operations and, once a successful test was completed, expected normal service to resume "… unless there are safety or other operational impediments which the OGC identifies." The Commission also stated:

> "Recognizing the impact on customer tolls, the Commission expects that Pembina will reopen service on the entire pipeline as soon as it is considered safe to do so. A successful hydrotest of the pipeline between Taylor and Prince George may be adequate information for Pembina to reopen the pipeline from Prince George to Kamloops at 75 percent of the certified operating pressure until a pressure test of that section of pipeline can be scheduled … "

Following the successful hydrotest, Plateau advised shippers that the Taylor to Prince George segment was returned to service on September 21st. Plateau also noted in its memorandum to shippers that it planned to empty the oil from the Prince George to Kamloops section.

On October 17th, Plateau applied for an Order from the BCUC relieving Plateau, for the time being, of its obligations under Section 42 for the Prince George to Kamloops segment. The BCUC in Letter No. L-50-00, replied on October 19th:

> "If Plateau obtains the concurrence of the OGC that the Prince George to Kamloops segment should not be reactivated due to safety or operational concerns, the Commission would be prepared to grant the suspension of service request as an exception under Section 42 of the Pipeline Act." (Exhibit 3D)

Plateau subsequently advised the BCUC it was attempting to arrange a procedure with the OGC to secure such concurrence.

On October 30th, Plateau requested a one-month postponement of the filing date for the Taylor to Prince George permanent toll application to November 30th. It also suggested a meeting of shippers, Plateau, BCUC, and OGC staff. On November 2nd by Order No. P-9-00, the BCUC approved the one-month extension, directed Pembina to provide a report, and instructed BCUC staff to meet as suggested by Plateau.

The meeting was held in Calgary on November 23 and 24, 2000. On November 30th Plateau asked for a further one-month postponement for its toll application filing, stating it would meet with shippers in early December to try to arrive at a consensus on tolls and commitments. If there was no consensus, Plateau advised that it intended to apply for deactivation/suspension of the pipeline. Plateau held meetings with individual shippers and producers where possible tariff calculations were presented, comments solicited, and commitments sought.

On December 15, 2000, by Order No. P-10-00 the BCUC:

- extended the filing date to December 29th, and set out what the toll application was to include;
- if there was a deactivation/suspension application, expected Plateau to demonstrate that it was appropriate based on safety concerns supported by the OGC; and
- established the Regulatory Agenda for an oral public hearing beginning on February 13, 2001.

The Application was submitted on December 29, 2000. In response to a January 16, 2001 request from Plateau, Order No. P-1-01 amended the regulatory timetable, culminating in a hearing starting April 2, 2001. After seven hearing days, the evidentiary portion concluded on April 10, 2001. Written Arguments were received in four stages ending May 10, 2001.

1.3 Plateau Application

Plateau's Tolling and Suspension of Service Application included proposed rate base calculations, recommended upgrades, deferral accounts, tariff calculations, proposals for shipper commitments, and conditions for suspension of pipeline operations (Exhibit 1). Amendments in the form of toll revisions were submitted on March 23, 2001 as a consequence of the availability of updated information and the information request/response process. Information on adjustments to the year 2000 incentive toll to September 6, 2000 was provided on January 11, 2001 (Exhibit 1A).

In summary, Plateau's application requested BCUC approvals under three mutually exclusive scenarios:

1. If the entire pipeline between Taylor and Kamloops is to open, tolls would be $12.50/m^3 from September 7, 2000 to December 31, 2000 and for 2001, and shippers would collectively commit to 5,500 m^3/d for ten years; or
2. If the pipeline is only to stay open as far as Prince George, tolls would be $18.64/m^3 from September 7, 2000 to December 31, 2000 and $15.39/m^3 for 2001, Husky would commit to 1,600 m^3/d for five years, and the system south of Prince George would be suspended; or
3. Suspension of service of the entire pipeline, if shipper commitments at volumes and the tolls set by the BCUC fail to materialize (Exhibit 1, Tab 2, pp. 3-4; Tab 8, p. 1).

Plateau asked the BCUC to allow a period of 45 days after the decision for shippers to commit to the use of the Western System; if the commitment volumes were not met a suspension order could be issued without a further hearing (Plateau Reply Argument, p. 28). Plateau was not interested in operating the

Western System unless significant improvements were made and it received a reasonable return on its investment. Otherwise, it would examine its options, including selling the Western System (Plateau Reply Argument, p. 14).

2.0 PIPELINE INTEGRITY AND UPGRADING

Plateau agreed that it is the responsibility of the pipeline operator under the *Pipeline Act* and Regulations to operate safely and prevent spillage (T1: 75). Section 38 of the *Pipeline Act* requires a pipeline company to "make every reasonable effort to prevent spillage" and, if a spillage occurs, to promptly remedy the cause, contain the spillage and restore the site.

Plateau identified the pipeline upgrades and major operating expenditures that it considered necessary to meet these responsibilities (Exhibit 1F, Tab Encal, pp. 18 and 19). Including pipe break repair and testing at Pine River, the work was estimated to cost $27.351 million. In this Chapter, the Commission will review the expenditures proposed by Plateau, and will also assess whether Plateau could have returned the southern section of the pipeline to full service at an earlier date.

2.1 Pipeline Integrity

2.1.1 Design of the Pipeline

The route of the 323.9 mm (12.75 inch) Western System pipeline runs through terrain with considerable changes in elevation. This results in substantial changes in operating pressure within the pipe. Accordingly, to make more economic use of steel, the pipeline was "telescoped". That is, pipe of heavier wall thickness was used only in sections of low elevation or in close proximity to the discharge side of pump stations. Although the line was described as having a nominal wall thickness of one-quarter inch, in actuality five wall thicknesses were used, ranging from three-sixteenths of an inch (4.78 mm) to five-sixteenths of an inch (7.92 mm) increasing in increments of one-thirty-second of an inch (Exhibit 1F, Tab Encal, p.1).

The pipe was manufactured at the Page Hersey Mill in Welland, Ontario by the electric resistance weld process to a specification of API 5LX Grade 46. Grade 46 indicates that, following welding and normalizing, the pipe strength was increased by cold-expanding to the design diameter, raising the specified minimum yield strength ("SMYS") to at least 46,000 pounds per square inch ("psi"). A burst test on a section of the failed joint of pipe from milepost 102.5 gave results that substantiated the SMYS of 46,000 psi (317,000 kPa) (Exhibit 1K, pp. 58 and 64). The code in effect in 1961 permitted field hydrostatic testing of the pipeline, after assembly, to 90 percent of the SMYS. Approval could then be given for a Maximum Operating Pressure ("MOP") of 80 percent of the proven test pressure. The current code, CSA Z662, permits testing with a liquid medium to 110 percent of the SMYS. CSA Z662 permits operating the pipeline section up to 80 percent of the lesser of the proven test pressure or the line pressure that corresponds to the SMYS (Exhibit 47).

A pipeline of this design and installed at various ground elevations requires greater segmentation for hydrostatic testing. The highest operating pressures are experienced on the discharge side of pump stations and in critical points of low elevation, and the heavier wall thickness at these locations permits the pipe to be qualified for the higher pressures. This requires the pipeline to be tested in sections isolated by valves. In the original hydrostatic test following construction, the section between Taylor and Prince George (the "northern section") was tested in 14 segments. The section between Prince George and Kamloops (the "southern section") was tested in 24 segments.

2.1.2 Canspec and Colt Engineering Reports

Canspec Group Inc. ("Canspec") was commissioned by Environment Canada to evaluate the failed pipe. A copy of the report was filed with the BCUC. Dr. Hamre of Canspec appeared as a witness in the hearing (Exhibit 1K). The Canspec investigation found that the pipe failed due to a defect that had been present from the time of manufacture. A non-metallic inclusion in the steel was present near one edge of the steel plate that had been used to manufacture the pipe. When the electric resistance weld was made, the inclusion turned toward the inside surface of the pipe causing a large hook crack to form. Canspec estimated that, as manufactured, the flaw was approximately 2.1 mm deep (approximately 40 percent of the wall thickness) and 135 mm long. This grew by fatigue cracking until the pipe could no longer retain the operating pressure. From a review of the operating logs it was estimated that the pipe failed at a pressure of 6,676 kPa (968 psi). Calculations based on the dimensions and properties of the failed section indicated that the pipe containing the hook crack was capable initially of withstanding the test pressure of 9,310 kPa (1,350 psi).

The Canspec report stated that fatigue crack growth rate depends primarily on the change in stress at the tip of the growing crack. For the failed section of the pipe the stress range would occur between operating and shutdown conditions. A crack would propagate more rapidly where there are large pressure differentials between static and operating conditions. With a discharge pressure of 8,000 kPa (1,160 psi) at the Willow Flats pump station the pressure in the pipe at milepost 102.5 would be 5,971 kPa (866 psi). Under static conditions the pressure due to elevation differences would be 1,538 kPa (223 psi), a difference of 4,433 kPa (643 psi) between operating and shutdown conditions. Plateau reported that after starting up the northern section in September 2000, the pipeline was operated intermittently with frequent shutdowns. This practice has since been discontinued and the pipeline is now operated on a continuous basis (Exhibit 1B, p. 76).

In evidence presented at the hearing, Dr. Hamre acknowledged an error in the Canspec report in the calculation of the number of cycles required for failure to occur through fatigue crack growth. The analysis in the report had indicated that failure could occur in as few as ten cycles (Exhibit 1K, p. 70). Correcting the coefficients used in the formula changed the results by a factor of about ten. Dr. Hamre stated that he had not had sufficient time since discovering the error to go through all the calculations, but agreed that the required number of cycles to failure would be in excess of 100 (T6: 910). He also agreed in cross-examination that predicting the number of cycles to failure is quite inexact (T6: 927).

Canspec reported that visual inspection of the external surface of the pipe found no evidence of corrosion or mechanical damage. Chemical and mechanical testing of the section of failed pipe found that it met all requirements for the API 5LX specifications in place at the time of manufacture.

Canspec concluded that the pipe failed as a result of the steel defect present at the time of pipe manufacture. For failure to occur it was necessary that a significant number of variables be present at the same time. First, it was necessary that a relatively large non-metallic inclusion be present in the steel plate used to make the pipe. Second, this inclusion had to be near the edge of the plate after trimming so that it formed a hook crack during electric resistance welding of the pipe seam. Third, the inclusion had to be near the centre of the plate thickness for the resulting hook crack to have a significant through-thickness component. Fourth, the inclusion had to be significant but not large enough to be detected by a test in the mill. Fifth, the piece of pipe containing the flaw had to be installed at a location of high cyclic loading (T6: 918).

With respect to the presence of further hook cracks in other parts of the pipeline, the Canspec report stated, "it is relatively unlikely that similar hook cracks of comparable magnitude are present in the remaining pipe" (Exhibit 1K, p. 3). Dr. Hamre agreed that from this statement it could be inferred that the Pine River failure was a low probability event (T6: 914).

Husky retained Colt Engineering Corporation ("Colt Engineering") to provide independent engineering advice and analysis with respect to the Plateau pipeline. Mr. Spencer prepared a report for Colt Engineering entitled "Fatigue Crack Growth and Remaining Life Estimates for the Taylor to Kamloops Pipeline" which was attached to the evidence filed by Husky (Exhibit 5, Tab D, Attachment 3).

Colt Engineering was of the opinion that the original Canspec analysis was overly conservative. Like Canspec, Colt Engineering admitted in cross-examination to certain errors in its original report. Both consultants focused their analyses on the pipe in the vicinity of the line break. In the end result, there was little difference in the Canspec and Colt Engineering estimates of time to failure of the pipeline assuming the presence of further flaws in the pipe. Mr. Spencer did not consider the pipeline to be in imminent risk of failure if hydrostatically tested and operated in a prudent fashion (T6: 1059).

2.1.3 Hydrostatic Testing

Until the fall of 2000 no sections of the pipeline had been hydrostatically retested to verify the strength of the pipeline for continued operation. Hydrostatic testing is currently used to verify the integrity of operating crude oil pipelines, as well as newly constructed pipelines. Internal inspection tools in common use are not capable of detecting hook cracks and subsequent crack propagation, nor do they detect some other types of defects associated with the horizontal seam of the pipe. Pressure testing has been the surest way of detecting fatigue-crack growth caused by pressure cycling which may cause the pipe to fail at pressures below the approved Maximum Operating Pressure. An on-going hydrostatic test program, testing a few sections each year, enables the pipeline operator to verify the integrity of the entire pipeline on a ten to fifteen year cycle. Within the industry this is generally accepted as prudent practice. Pembina has carried out hydrostatic retesting on other pipelines in their system (Exhibit 1C, p. 72).

Mr. Burdylo of Cimarron Engineering Ltd. ("Cimarron") provided Plateau with a report and recommendations (Exhibit 1J). Cimarron examined four things: additional line isolation, integrity enhancements, pipeline re-routes around three towns, and the elimination of the slack flow situation affecting the last 40 miles of the pipeline (T1: 117). With regard to integrity enhancement, Cimarron recommended hydrostatic retesting as an immediate solution for three reasons:

- Larger defects will fail and the pipe can be repaired as necessary;
- The size and time to failure of any remaining defects can be determined; and
- Retest intervals can be calculated.

An immediate hydrostatic retest would prove the current integrity of the pipeline and allow Plateau time to plan and implement other pipeline integrity initiatives (Exhibit 1H, p. 2; T2: 231). Dr. Hamre and Mr. Spencer expressed similar views (T6: 945; T6: 1059).

Following replacement of the ruptured section of pipe, the 24 km (15-mile) section of pipeline between valves at milepost 92 and milepost 106.8 was subjected to a hydrostatic test to ensure the repair was satisfactory. The actual cost to repair and test the failed section of pipe was $1,058,000. The entire northern section was successfully tested in three sections in September 2000 at a cost of $777,000 (Exhibit 1A, Tab 4, revised March 23, 2001). Plateau then resumed delivery of oil from Taylor to Prince George.

The southern section has not yet been retested, and remains shut down. The estimated cost of a retest on the southern section was $1,200,000. Husky's position was that a hydrostatic test program would establish the integrity of the Western System. Encal Energy Ltd. ("Encal") and Imperial Oil Resources ("Imperial Oil") supported a hydrostatic test for the southern portion of the pipeline before it is returned to service (Encal Argument, p. 9; Imperial Oil Argument, p. 5).

The Commission accepts that it is a first priority for Plateau to hydrostatically retest the southern section of the pipeline prior to returning it to service.

2.2 Reactivation of Pipeline to Kamloops

Pembina completed hydrostatic testing of the Taylor to Prince George section of the pipeline on September 16, 2000 and commenced oil deliveries to Prince George on September 21, 2000 (Exhibit 3, pp. 1 and 2; Exhibit 10A; T2: 210). Plateau provided the following reasons why it did not proceed to put the Prince George to Kamloops section of the line back into service (Exhibit 1C, p. 35):

- the consequences of a spill in the Prince George to Kamloops section could be higher than in the northern section;
- uncertainty that shippers would use the pipeline if tolls were increased;
- Plateau did not believe it was possible to obtain acceptable leak detection on the section with slack flow north of the Thompson River;
- further evaluation of the southern portion of the pipeline was needed due to the elevation changes; and
- other pipeline options to transport British Columbia crude oil to Kamloops make it unnecessary to assume additional risks.

Plateau's unwillingness to resume operation of the southern section was discussed at length in the hearing (T2: 210–225). Plateau decided that the risk associated with resuming operation of the section to Prince George was acceptable, as the line had just been hydrostatically tested, it was only operating during daylight hours and was running at 75 percent of maximum operating pressure.

Plateau viewed operation of the Prince George to Kamloops section quite differently. This section had not been hydrostatically tested in nearly 40 years, and Plateau felt it would have to operate above 75 percent of licensed operating pressure. Also, slack flow was a larger problem in the southern section and the line would exceed maximum operating pressure if valves at Kamloops were closed (T2: 218).

In addition to a hydrostatic retest, Plateau considered that a problem related to the potential for exceeding the maximum certified operating pressure and the slack line flow problem must be eliminated before the southern section of the pipeline is reopened (Plateau Argument, pp. 20 and 25). An over-riding concern was that there would be no merit in starting the upgrade or carrying out some upgrades unless Plateau was assured it would recover the costs of the upgrade (Plateau Argument, p. 14).

Husky's position was that a hydrostatic retest could have been carried out in the fall of 2000. Husky relied on the approval set out in the OGC's August 23, 2000 letter that the pipeline could have been operated at reduced pressures pending a hydrostatic test within one year. Husky also noted that the pipeline rupture had little direct connection with the majority of proposed pipeline upgrades and maintenance expenditures, which had generally been identified during Pembina's due diligence examination prior to buying the pipeline (Husky Argument, pp. 46-48).

2.2.1 OGC Approvals and BCUC Directives

The OGC's August 23, 2000 letter authorized Pembina to operate the pipeline subject to restricting the operating pressure to 75 percent of the certified operating pressure and undertaking a leak and strength test of the pipeline within 12 months (Exhibit 10). On February 1 and March 2, 2001, Plateau wrote to the OGC, stating that the Canspec report raised questions concerning the integrity of the Western System and the advisability of operating it as approved by the August 23, 2000 letter, and requested further direction (Exhibit 1K, 10B). The Commission is unaware of any response.

In Order No. P-7-00 and related Reasons for Decision, the Commission accepted that it was a prudent action for Pembina to hydrostatically test the section of the pipeline between Taylor and Prince George, and stated that it expected Plateau to reopen service on the entire pipeline as soon as it was considered safe to do so.

2.2.2 Operating Pressures in Excess of Certified Maximums

Plateau's concern about operating in excess of 75 percent of licensed maximum operating pressure relates to high line pressures due to low elevations in the Bonaparte River and Loon Lake areas, at approximately mileposts 444 and 450 (T2: 243). The pipe in the section from milepost 415.5 to milepost 504.3 is reported to have a wall thickness of 0.188 inches (4.78 mm), although there is evidence that the Bonaparte River area may have about one mile (1.6 km) of pipe with heavier wall thickness of 0.219 inches (5.56 mm) (T2: 243 and 244; Exhibit 15). Plateau agreed that pipe of 4.78 millimetre wall thickness could be tested to about 8841 kPa. Testing to at least 8,422 kPa should permit a maximum operating pressure of approximately 6730 kPa. Plateau agreed that retesting to this higher pressure would remove concerns about operating within the certified pressure limit (T2: 234-249).

Mr. Spencer of Colt Engineering agreed that retesting to a higher pressure should permit an increase in the operating pressure in this section (T7: 1211-1214). Colt Engineering filed material showing that, for 0.219 inches (5.56 mm) wall thickness pipe, CSA Z662 would permit a maximum design pressure of 8,769 kPa, and testing up to 12,058 kPa (Exhibit 47). The corresponding CSA Z662 limits for 4.78 mm pipe are estimated at a maximum design pressure of about 7,400 kPa and a maximum test pressure of approximately 10,000 kPa.

Based on the evidence, the Commission finds that a properly designed hydrostatic test would have resolved concerns about operating pressures in excess of certified maximums, and that Plateau's concern did not justify its decision to keep the southern section of the pipeline out of service.

2.2.3 Slack Line Flow Conditions

The ground elevation of the last 64 km (40 miles) of the pipeline decreases to a low point where the line crosses the Thompson River near Savona, B.C. The significant elevation drop creates a "slack line" flow condition where the pipeline is not always full of oil below the highest point. As a result of this slack line condition, crude oil volume balances for the pipeline and leak detection can be compromised.

Plateau's due diligence investigation did not identify that slack line flow conditions existed in either the northern or southern section of the pipeline (Exhibit 1D, p. 61; T2: 218-220). In the northern section of the line, Plateau identified a slack line condition in late September 2000, and in late October 2000 decided that a back pressure valve would resolve the problem. The valve was installed in December 2000 (T2: 215-217).

Plateau recognized that slack flow conditions existed in the Prince George to Kamloops section of the pipeline in the September to October 2000 period. Plateau's October 6, 2000 letter to shippers identified a cost of $8.6 million to replace 40 km of line with heavier wall thickness pipe (Exhibit 3, Table 1; T2: 214-215). By mid-November 2000, Cimarron had provided its recommendation that the slack line flow could be eliminated by the installation of two back pressure regulator stations on the down slope to eliminate the slack line operation, at a cost of $930,000 (Exhibit 1J, p. 4; T2: 303-304).

Mr. Burdylo was aware of at least one other pipeline system that operated with slack line flow but he had made only a casual enquiry of how the Supervisory Control and Data Acquisition ("SCADA") and leak detection systems accommodated this condition (T2: 302). Plateau agreed that with pressure regulating valves there could still be flow and pressure problems during startup and shutdown and to accommodate the passage of maintenance scrapers (T2: 305).

It is not clear whether Plateau was aware of the slack line flow in mid-September when it made the decision to not proceed with testing the southern section. In any case, it is apparent that Plateau was prepared to continue to operate the northern section of the pipeline for a period with a slack line flow condition.

This portion of the line has operated in a slack line flow condition since it first went into service almost 40 years ago. **The Commission agrees with installation of back pressure regulator stations to eliminate the slack line flow condition, but considers that the presence of slack line flow is of insufficient concern to justify Plateau's decision not to proceed with a hydrostatic test and resume operation of the southern section of the pipeline.**

2.2.4 Ability to Recover Cost of Resuming Operation

The Application considers the Western System as separate from other Pembina pipelines, and so it is appropriate to focus on the Western System in isolation when considering Plateau's concern about the recovery of the costs to resume operation of the southern section. Costs associated with the Pine River spill, like earlier investments in the pipeline, are committed expenditures that Plateau can only recover from tolls collected for delivering crude oil. In the short-term, many operating expenses continue, and can also only be recovered through tolls.

The immediate expenditure to resume operations would have been $1.2 million for a hydrostatic test (Exhibit 1A, p. 3). At the current interim rates and deliveries of 3,900 m^3/d, this represents less than two month's revenue. Plateau chose to focus on tolls that would recover its incremental costs in addition to current tolls, notwithstanding the lack of revenue when the pipeline is out of service. Plateau did not show that tolls at the current interim levels would have failed to recover the cost of future upgrading and maintenance, or that such tolls would discourage shippers from using the pipeline.

The Commission considers that Plateau's concern about its ability to recover the expenditures required to return the pipeline to service are unsubstantiated and do not justify its failure to meet the obligations of Section 42 of the *Pipeline Act*.

2.2.5 Time Required to Hydrostatically Test the Southern Section

At the beginning of September 2000 Plateau initiated the test on the northern section. Plateau completed the test (in three segments) on September 16 and resumed crude oil deliveries on September 21, 2000.

Plateau has not designed a plan for a test of the southern section, but expected that it could be tested in 24 segments or less (T2: 226 and 306). The time to test a section varies widely, depending on the amount of work that needs to be done, such as installing test heads. A typical allowance appears to be 2-4 days per section (T2: 226-230). This implies that it would take approximately 3 x 24 = 72 days, or less, to complete the test. This is consistent with the estimate by Mr. Spencer of Colt Engineering that a 20 segment test for the southern section would take about 60 days (T2: 140).

The hydrostatic test of the northern section of the pipeline did not identify any additional problems with the pipeline, and there is no reason to expect that the results of testing the southern section will be materially different. The Commission considers that, if a hydrostatic test of the southern section had commenced immediately after the test to Prince George was completed, the pipeline would have been available for crude oil service by about the end of November 2000. If the pipeline had been put back into service at the completion of the test, the crude oil would have displaced the test water from the pipeline.

The Commission concludes that Plateau has not adequately justified its decision not to proceed with testing the southern section of the pipeline and returning it to service, given the determinations of the Commission and the OGC that were current at the time. Plateau has not met its responsibility under Section 42 of the *Pipeline Act* to maintain service to its shippers. The Commission determines that the revenue that was lost because crude oil deliveries to Kamloops were delayed beyond November 30, 2000, will be Pembina's responsibility.

2.3 Pipeline Maintenance and Upgrades

2.3.1 Internal Inspections

In the Application, Plateau listed the elements to be included in good pipeline operating practices, and among them identified internal inspection and repair of observed anomalies (Exhibit 1, Tab 4). The pipeline had been inspected internally by a magnetic flux inline inspection tool on a five-year frequency to detect anomalies in pipe wall thickness. The southern section was last inspected in 1996 and the northern section in 1999. The more serious anomalies were excavated for inspection and any necessary repairs made. In 1998 the operator recorded $218,000 in expenses for a pipeline repair program and a further $380,000 on other elements of pipeline maintenance (Exhibit 26). In 1999, $442,000 was recorded as the cost of internal inspection and $193,000 for other major operating expenses (T4: 616 and 617).

From the 1999 inspection of the northern section Plateau plans 14 excavations because of strength calculations, 11 excavations because of corrosion greater than 40 percent of pipe wall thickness and 30 excavations because of metal loss with lengths greater than 4 inches. Nine excavations are planned on the southern section for work still incomplete from the 1996 inspection. Cost estimates for line repairs in 2001 are estimated at $1.1 million for the northern section and $180,000 for the southern section. Plateau plans an internal inspection of the southern section in 2001 at a cost of $660,000, and is forecasting repair costs of $1.1 million for 2002. The northern section is scheduled for an internal inspection in 2004 at a cost of $540,000 (Exhibit 1, Tab 4, p. 4).

2.3.2 River Crossings and Right-of-Way Maintenance

Plateau incurred a $13,000 major operating expense in 2000 for assessment of the Fraser River aerial crossing. The previous owner had commissioned a feasibility study of replacement using a drilled crossing to avoid annual maintenance costs of $50,000 and major overhaul costs of $700,000. This is still under review by Plateau (Exhibit 1, Tab 4, p. 8).

In 2001, Plateau expects to spend $500,000 on a capital project to repair the exposed crossing in the Deadman River (milepost 465). It also forecasts $200,000 per year of major Operating Expenses for maintenance of the Fraser River and Peace River aerial crossings, other river crossings and right-of-way brushing. Plateau budgeted a further $200,000 per year for normal operating expenses for right-of-way maintenance. Regular right-of-way inspection and maintenance is carried out under contract by Westcoast crews and the Western System is billed annually for its share of the expense (T1: 94). The work scheduled for Westcoast crews for 2001 is budgeted at $268,000 (Exhibit 27). **The Commission accepts the river crossings and right-of-way maintenance cost estimates.**

2.3.3 Tank Cleaning

There is no record that any of the eight tanks in the system have been cleaned and inspected for possible damage or repair in the 39 years of use. Plateau recognized the oversight of previous owners in failing to clean tanks periodically. It plans to clean, internally inspect and repair as necessary, two tanks per year over a four-year period. The expense of cleaning and inspecting was estimated to average $300,000 per tank. Capital costs for repairs have been estimated to average $860,000 per tank (Exhibit 1, Tab 4, p. 4). The eventual cost of tank repairs, replacement or abandonment will not be known with certainty until inspections have been completed.

Plateau supported its cost estimate for repair and upgrading by referring to estimates of $528,000 and $597,000 it prepared for repairing and upgrading two tanks at Taylor, based on its experience with similar tanks in Alberta. Alternatively, Plateau estimated the cost of cleaning, dismantling and reclaiming a large crude oil tank at $320,000 to $880,000 (Exhibit 1B, pp. 47-49). The Commission acknowledges that the cost to repair or dismantle a tank is highly dependent on the condition of the tank and underlying tank base. **The Commission determines that the evidence at this time supports an estimate of $600,000 for the capital cost to repair and upgrade each tank and $300,000 to clean and inspect each tank, for the purpose of calculating tolls.**

In response to Encal, Plateau acknowledged that there may be opportunities to rationalize the tank farm at Taylor, by reducing the number of tanks and sharing the costs of the tank farm between the Western System and the upstream gathering system. This may reduce the rate base and the major operating expenses allocated to the Western System (T3: 592 and 593). **In its next revenue requirements application (or rate proposal to shippers), Plateau is directed to provide a plan for rationalizing the tank farm at Taylor, and identify the portions of rate base and expenses for the tank farm that relate to the Western System.**

2.3.4 Block and Check Valves

Cimarron reviewed the placement of block and check valves and recommended additional valves and valve actuators to minimize the consequences in the event of a leak. The cost of valve upgrading was estimated at $6,041,000 (Exhibit 1H). In making its recommendations, Cimarron took into consideration the distances between existing block valves, the location of water crossings and the presence of ground slopes. On the Western System there are 219 water crossings made up of 29 river crossings, 91 named creeks and 99 unnamed creeks. From a study of the hydraulic gradient and additional technical information provided by

Plateau, Cimarron recommended the addition of 14 new remote-operated valves, 11 new check valves and the addition of remote operators on 7 existing valves. In the existing system there are 30 manual block valves, 23 check valves and 24 remote-operated valves, with some locations having both a check valve and a manual block valve (T1: 107).

Mr. Burdylo described the analysis done to date as a desktop study and not as a program for installation or construction. Cimarron had been supplied with hydraulic and elevation profile drawings for the pipeline route, alignment sheets and a list of the water-crossings by milepost. Cimarron had not evaluated the placement of valves based on a field study. Mr. Burdylo agreed that it was possible that additional work could affect the number and type of valves and the estimated cost (T1: 132). The potential size of spills that Cimarron estimated could occur were considered to be a maximum based on the ground profile. Plateau described the Cimarron recommendations as its current estimate of valve requirements (T1: 129). Plateau accepted this as a starting point and agreed that, depending on the degree of slope and the exact nature of undulations in the terrain, the actual number of valves could be substantially less.

In the Colt Engineering information filed by Husky, the consultant expressed the opinion that a number of the valves proposed by Cimarron were not required (Exhibit 5, Tab D, p. 1). From its review of the elevation profile, in Colt Engineering's opinion adequate improved sectionalizing could be obtained with fewer valves, although the consultant recommended that a more rigorous valve spacing and spill analysis be performed before any capital expenditures were considered. Colt Engineering also questioned the necessity of placing a check valve immediately next to a remote-operated valve as had been recommended in certain cases.

Colt Engineering also prepared a report entitled "Valve Cost Revision Estimates". This included a summary of the unit and total costs of the valve upgrades it believed to be reasonable relative to the total costs proposed by Plateau. The Colt Engineering analysis estimated that the Plateau capital cost estimates were substantially overstated. Some of the differences were resolved during cross-examination of the witnesses, but Mr. Spencer still recommended a significantly lower cost for valve upgrading. In argument, Husky proposed that the location and number of valves is a matter to be determined by the OGC, with the program designed to ensure the best results for the most economic costs (Husky Argument, pp. 48-50).

Pembina also retained TERA Environmental Consultants (Alta.) Ltd. ("TERA") to conduct a preliminary Environmental and Socio-Economic Sensitivity Overview of the pipeline (Exhibit 1I). The main objective of the overview was to identify and locate areas along the pipeline where a rupture could result in an environmental impact of high consequence. No attempt was made to assess the nature or likelihood of a particular release beyond estimating the volume of line segments, evaluating the terrain and making some initial predictions of the potential release. For the purpose of the assessment, it was assumed that a substantial volume would be released which would result in off right-of-way contamination and surface or subsurface movement of spilled oil. The assessment also assumed that all segments of the pipeline had the same likelihood of failure (Exhibit 1I, pp. 1 and 2).

The summary of the TERA report indicated that the primary concern was the 251 watercourses crossed by the pipeline. From a socio-economic standpoint, the report noted that the pipeline traverses several communities and their sources of water supply. More than 1,000 licensed points of water diversion are located within the zone of impact of the pipeline system. TERA's observations were based on one over-flight of the pipeline and a review of the hydraulic gradient. Volumes of oil considered were obtained from the volume contained in the segments between installed block valves or check valves.

There is uncertainty about the number, location and cost of valve additions that are needed. The Commission expects that Plateau's Integrity Management Plan and other analyses will enable the OGC to specify the additions that are necessary. **Until a more refined scope of this project is known, the Commission determines that an estimate of $4,000,000 for valve upgrading should be included in the calculation of tolls for 2001.**

2.3.5 Communications and Control Upgrading

In the Application, Plateau stated that the SCADA system and leak detection software were modern, "top of the line" systems. Nevertheless, Plateau recognized that performance could be enhanced to improve the control centre operator's ability to recognize a leak situation by:

- Removal of unimportant information;
- Improving scan time;
- Removal of the filtering of leak alarms;
- Adding periodic re-alarm if an alarm threshold is exceeded;
- Providing a separate alarm queue for leak alarms; and
- Improving the alarm annunciation and acknowledgment.

Plateau was dissatisfied with the current communications system and proposed that five satellite telephones be purchased. It planned to complete an overview study of communications requirements in 2001. After the Pine River failure, Plateau moved the control centre for the Western System from Calgary to the Edmonton Pembina control centre where there is a shift supervisor available around the clock. Along with the relocation, Plateau revised the alarm system to reduce the number of alarms to those that were of greater significance to the pipeline operator.

Also, the elimination of a slack line flow situation in the northern section between Taylor and Prince George improved the leak detection sensitivity (T1: 92). To test operator response to the revised arrangement, Plateau introduced the practice of blind leak tests that are used on other parts of the Pembina system. About once per month, and without the operator's knowledge, a certain volume of crude oil is withdrawn from the line and a check is made of the operator response to the simulated leak. This is a test not only of the operator but also of the leak detection system (T1: 161).

The Commission considers that the planned upgrading of the communications, data gathering and control system is needed to provide accurate and timely data on pipeline pressure and flow conditions to the control centre. The usefulness of remote-operated valves to reduce the volume of oil spilled in the event of a pipe rupture is only as effective as the control centre's knowledge of when to shut down the pipeline and actuate the valves.

2.3.6 Pipeline Upgrading Summary

Husky considered that the pipeline upgrades and major operating expenditures proposed by Plateau were accepted by shippers without debate, except for the valve additions program. Husky and the Canadian Association of Petroleum Producers ("CAPP") noted that Plateau was aware that repairs and upgrades were needed when it bought the pipeline. CAPP felt that Plateau assumed the risk of a spill when it purchased the pipeline, and should not be allowed to pass any non-insured spill costs to shippers (CAPP Argument, pp. 2-4).

Encal submitted that only those system integrity and upgrade costs determined to be necessary for the safe operation of the Western System by the OGC should be added to the rate base of the pipeline (Encal Argument, p. 9). Imperial Oil also felt that the OGC's input would be vital to determine the upgrades that are needed, and that the cost of improvements that are required by the Commission or the OGC as a result of the spill, should be recoverable by Plateau. This would be consistent with the way that the incentive toll settlements for Enbridge and TMPL treat expenditures required by regulators (Imperial Oil Argument, pp. 3 and 4).

Any OGC determination that a pipeline must be shut down or restricted in its operations, takes precedence over the obligation of a common carrier pipeline to provide service. Similarly, a determination by the OGC that a system upgrade or other improvement is needed will be

justification for recovering the expenditure in rates, provided the work is carried out in a responsible and prudent fashion.

For an upgrade that is not required by the OGC for safety or reliability purposes, Plateau will be required to demonstrate that it is in the best interests of the pipeline and shippers before the Commission grants approval for the recovery of the cost in rates.

The Commission accepts the need for improvements to the Western System, and considers that Plateau's proposed capital and major operating expenditures, in general, are required in keeping with good pipeline operating practices. Actual costs where available will be used for future toll determinations, subject to review that the scope of work was necessary and that the amount of the expenditures was prudent and reasonable. Normally, when the scope of a project is well defined, the Commission expects actual costs will be within 10 percent of estimated costs.

The costs in the Application included $1,000,000 for insurance claims related to the Pine River spill that may not be recoverable, and Plateau requested a deferral account for additional amounts that may be denied by the insurer. Most of the cleanup costs for the Pine River spill were covered by insurance, but there is uncertainty regarding some of the claims. **The Commission approves the Pine River spill deferral account for recording variances from $1,000,000 in the amount of insurance claims that are denied by the insurer, but notes that recording an amount does not imply approval to recover it in rates. In its next revenue requirements application (or rate proposal to shippers), Plateau is directed to provide evidence of why any insurance claims that are denied are properly the responsibility of shippers.**

The Commission accepts the necessity for the system upgrades, and determines that the cost estimates identified in Tables 2-1 and 2-2 will be used to calculate tolls for 2000 and 2001. The approved amount of capital expenditures and major operating expenses for toll calculations for 2000 through 2004 is $23.23 million, $4.121 million less than the estimate in the Application.

Table 2-1

Capital Upgrade Projects
($'000)

Plant Additions	**2000**	**2001**	**2002**	**2003**	**2004**
Tank Repair	0	1,200	1,200	1,200	1,200
Pressure Reduction & Metering	0	930	0	0	0
SCADA & Leak Detection	0	100	0	0	0
Communication Upgrades	0	20	0	0	0
Containment Equipment	0	500	0	0	0
Alignment Sheets	0	302	0	0	0
Valves	0	4,000	0	0	0
River Crossings	0	500	700	0	0
Total	**0**	**7,552**	**1,900**	**1,200**	**1,200**

Table 2-2

Major Operating Expense Projects
($'000)

	2000	**2001**	**2002**	**2003**	**2004**
Line Break Repair and Test	1,058	0	0	0	0
Insurance Deductible	100	0	0	0	0
Uninsured Costs	1,000	0	0	0	0
Hydrostatic Test	777	1,200	0	0	0
Tank Cleaning and Inspection	0	600	600	600	600
Internal Line Inspection	0	660	0	0	540
Line Repairs	0	1,280	1,100	0	0
Turbine Repair	0	125	125	0	0
ROW, River Crossings	13	200	200	200	200
Risk Assessment and Integrity Mgmt	50	150	0	0	0
Total	**2,998**	**4,215**	**2,025**	**800**	**1,340**

3.0 LOAD FORECAST

3.1 Available Crude Oil Supply

Historical crude oil shipments from Taylor for 1995 through 1999 and for January to July 2000 were provided by Plateau, and show that production has been relatively stable (Exhibit 1, Tab 6, p. 7; Exhibit 1C, p. 83). This information is summarized in Table 3-1.

Table 3-1
Actual Delivery Volumes from Taylor, m^3/d

Delivery Point	1995	1996	1997	1998	1999	Jan-July 2000	Weighted Average
Prince George	1,552	1,577	1,635	1,561	1,617	1,469	1,576
Kamloops	4,035	4,732	5,505	6,053	5,137	5,100	5,093
Total Western System	5,587	6,309	7,140	7,614	6,754	6,569	6,669
Edmonton	0	0	0	28	84	397	62
Total Shipments	5,587	6,309	7,140	7,642	6,838	6,966	6,731

With respect to the short-term supply outlook for crude oil in the Taylor area, Plateau expected the area will be subject to active exploration and development activity, although recent drilling activity has been focused on natural gas (T2: 355 and 356). Some discussions have taken place with producers about connecting new production to the gathering pipelines (T4: 722).

Plateau indicated that it had not prepared a long-term supply forecast of B.C. crude production. It had reviewed government publications on reserve statistics, and was not concerned about any decline in the production of B.C. crude over the next five years (T4: 720 and 722). Plateau stated that it has been in the pipeline business a long time and that there continues to be production from old reservoirs. Reserves are generally being replenished year by year (T3: 514).

Husky anticipated that given the record land sales in B.C. there would be additional reserves of crude oil established in the near future (T6: 1017). Husky also indicated that CAPP statistics show that over the past 15 years exploration and development activity has maintained a reserves to production ratio of approximately 9.5 years (Exhibit 5, p. 13). Husky commented that this was a conservative number which only considers proven reserves plus half of the probable reserves (T6: 985).

The Commission did not receive a detailed forecast on the expected supply of crude that would be delivered to Taylor over the next several years. However, the statistical evidence provided by Husky indicates that reserves have continued to be replenished by ongoing exploration and development. Plateau also expected that new reserves would permit production levels to be maintained. Crude oil shipments from Taylor averaged 7,167 m^3/d over 1997 to July 2000, and the current higher levels of well drilling activity is expected to at least maintain this level of oil production. **The Commission concludes that crude oil production delivered to Taylor will be maintained at approximately 7,200 m^3/d for at least the next five years, and expects that any declines after that will be quite gradual.**

3.2 Capacity of the Western System

There is evidence that the design capacity of the pipeline was calculated to be 12,400 m^3/d (78,000 barrels per day) from Taylor to Prince George, and 11,400 m^3/d (72,000 barrels per day) for the Prince George to Kamloops portion, with 12 pump stations in service. Only six pump stations were constructed, providing a design capacity of approximately 7,680 m^3/d (48,300 barrels per day) from Taylor to Kamloops (Exhibit 1C, p. 26).

Prior to the Pine River spill, the maximum delivery capacity to Kamloops of 7,680 m^3/d assumed there were no deliveries to Prince George, and 100 percent equipment availability. With deliveries of 1,600 m^3/d to Prince George, Plateau indicated that the maximum delivery rate to Kamloops seemed to occur when there was slip streaming to Prince George for part of the day. With 100 percent availability, deliveries to Kamloops would be 6,300 m^3/d, for a total system delivery of 7,900 m^3/d. Plateau indicated that over a month the system should be able to sustain 90 per cent of that amount, calculating a sustainable delivery capacity from Taylor of approximately 7,100 m^3/d (44,700 barrels per day).

Plateau stated that, based on hydraulic modeling, it was no longer convinced this rate could be achieved without exceeding the certified operating pressure (Exhibit 1C, p. 26). During the hearing, Plateau acknowledged that the section of pipeline that was of concern could be retested to qualify it for a higher maximum operating pressure, as discussed in Section 2.2.2. Plateau provided an estimate of the capacity of the northern and southern sections of the line with the OGC's 75 percent limitation on maximum operating pressure, and assuming an increase in the maximum operation pressure to 6,700 kPa for the section of pipeline that had been of concern (Exhibit 28). Operating the line for 22 or 23 hours per day, the capacity of the southern section of the line would be approximately 3,630 to 3,795 m^3/d (T4: 645). The northern section of the pipeline would have a capacity at least 1,650 m^3/d higher than the southern section.

In other words, Plateau's load forecast of 1,600 m^3/d to Prince George and 3,900 m^3/d to Kamloops is approximately equal to the capacity of the pipeline with the 75 percent restriction on maximum operating pressure. Based on this information, Plateau asserted that all of the oil currently flowing to Edmonton could not be accommodated on the Western System while the 75 percent restriction is in effect (Plateau Reply Argument, p. 15).

The OGC's August 23, 2000 letter indicated that it would review the 75 percent restriction upon the successful completion of a leak and strength test. Plateau considered that the hydrostatic test in the northern section of the line would qualify as a successful test, but it had not inquired if the OGC is prepared to lift the 75 percent restriction. The restriction was not a concern as long as the pipeline is limited to delivering oil to Husky at Prince George (T2: 207-209). Also, Plateau had not designed a hydrostatic test for the Prince George to Kamloops section of the line, and had not inquired whether the OGC would permit operation of the section at the full maximum operating pressure upon successful completion of a test (T2: 240).

The evidence did not clarify the requirements of the OGC for removal of the condition restricting Plateau's maximum operating pressure to 75 percent of the certified operating pressure. Nevertheless, based on the evidence and consistent with the requirements of CSA Z662, the BCUC anticipates that the restriction would be lifted when Plateau demonstrates the integrity of the pipeline to the OGC by successfully completing a properly designed hydrostatic test, and requests removal of the restriction. The Commission notes that total actual deliveries to Prince George and Kamloops in 1998 averaged 7,614 m^3/d, but accepts Plateau's assessment of sustainable pipeline capacity as a conservative estimate. **For the purpose of setting rates, the Commission determines that the expected capacity of the pipeline from Taylor, after completion of a successful hydrostatic test, is at least 7,100 m^3/d.**

3.3 Viability of the Husky Refinery

Plateau indicated that it was concerned about continued operation of Husky's refinery beyond 2004, when it is anticipated that new Federal standards on the sulphur content of gasoline will take effect (T3: 333). Husky responded that there still was a significant amount of discussion about the regulations, and therefore it had not made any decision on upgrades to its refinery (T6: 1092). Husky also indicated that refinery economics are sensitive to crude pricing, quality of feedstock and required capital. Furthermore, the uncertainty about future tolls and service availability on the Western System made it difficult to reach any clear conclusions as to the economics of continued operations (Exhibit 5A, p. 2).

Plateau stated that if pipeline tolls are competitive at the end of 2004, the Husky volumes would likely flow to Kamloops if the refinery closed (Exhibit 1C, p. 81). Chevron confirmed it held a similar view (T7: 1304).

So long as Western System tolls are competitive, the Commission accepts that crude volumes that are not taken by the Prince George refinery will likely continue to flow from Taylor to Kamloops to serve refineries in southern B.C. and Washington state. **The Commission finds that the uncertain future of the Husky refinery is not a material factor in forecasting the throughput of the Western System beyond 2004, or in assessing the long-term competitiveness of the Western System.**

3.4 Deemed Deliveries

Plateau calculated tolls for the September 7 to December 31, 2000 stub period and 2001 by using the revenue requirement for the period divided by the actual and forecasted delivery volumes for that period (T5: 816). Plateau acknowledged that the toll calculation is volume-sensitive and that recovering a full year's revenue requirement over less than a normal year's volume can lead to high tolls (T5: 818).

The Application projected a volume of 1,600 m^3/d to Prince George for September 7 to December 31, 2000, because Husky's refinery was the only source of demand on the Western System over that period. Plateau did not change the forecast of volumes to Prince George for 2001 as this volume is consistent with historical throughput levels (Exhibit 1, Tab 6, p. 5; T4: 727).

Plateau's forecast volume of 5,500 m^3/d for 2001 for the Western System included 1,600 m^3/d to Prince George and 3,900 m^3/d to Kamloops. Plateau confirmed that its forecast of 5,500 m^3/d is the same as the volume commitment it required from shippers over ten years (T4: 727). The forecast was based on Plateau's assumption that some B.C. crude would be nominated for transportation east to Edmonton on Pembina's other pipeline systems. Crude oil deliveries from Taylor to Edmonton averaged 84 m^3/d in 1999. During the first seven months of 2000, the average volume of B.C. crude shipped east was 397 m^3/d, the highest occurring during July at 630 m^3/d (Exhibit 1C, p. 83). Plateau also confirmed that all of the oil shipped east over this time period was Boundary Lake crude (T4: 731). There is other evidence that indicated the Northern system moved an average of 134 m^3/d of Boundary Lake crude in January to July 2000, with a maximum monthly delivery in June of 270 m^3/d (Exhibit 22). This implies that 397 m^3/d may overstate deliveries to Edmonton.

Plateau assumed that, with the Taylor to Kamloops tolls it applied for, in 2001 approximately 1,100 m^3/d of Boundary Lake crude would be shipped east because of better economics. This is about half of the current Boundary Lake crude production, and is a significant increase over the amount that moved east in the first seven months of 2000 (T3: 454; T4: 731). Plateau did not offer any independent market forecast information to support its forecast, but indicated that its projections considered that Imperial Oil had signed a long-term agreement for Boundary Lake crude and that this may cause large amounts of oil to go east. The agreement is the commitment that Imperial Oil made to Federated, which permits the oil to be shipped on either the Northern system or the Western System (T4: 735 and 736; T7: 1134 and 1135).

Plateau stated that it did not know the exact amount of current B.C. crude production at Taylor that is committed by shippers under Federated facility agreements, but assumed that it would be about 50 percent of total B.C. crude production, or approximately 3,300 m^3/d (T4: 733). Plateau stated that it did not propose to change these agreements, therefore shippers with Federated facility agreements would continue to have the option to move their oil on either system (T3: 520).

Plateau was hesitant to offer an estimate of how much Boundary Lake crude would have flowed east in 2001 if the Pine River spill had not happened. It stated that it saw a trend growing through 2000 but would not speculate about what increase in volume would have occurred in 2001 under circumstances that existed before the spill (T4: 737). Plateau agreed that 4,770 m^3/d (30,000 barrels per day) diverted onto other Pembina systems would have been shipped on the Western System had the Pine River spill not taken place (T3: 382 and 383).

As noted in Table 3-1 deliveries to Prince George over the period averaged 1,576 m^3/d, which is consistent with Plateau's forecast. Deliveries to Kamloops over the period ranged from a low of 4,035 m^3/d in 1995 to a high of 6,053 m^3/d in 1998, and averaged 5,093 m^3/d. Over the period since 1998, when shippers gained the ability to ship oil east as an alternative to using the Western System, deliveries to Kamloops averaged 5,483 m^3/d.

When it established the value of the Western System prior to purchasing it, Pembina used throughput volumes of approximately 6,650 m^3/d through 2003 in its economic model. Pembina forecasted deliveries to decline by about 2 percent per year for 2004 and 2005, and after that applied a decline rate of 3 percent per year (T2: 314; Pembina Undertaking at T4: 725).

Plateau agreed that reductions to transportation tolls on other Pembina pipeline systems leaving Taylor could create an economic incentive for a B.C. crude shipper to move its crude to Edmonton, rather than down the Western System. However, toll differentials would only be one factor influencing movements of crude from Taylor. Improvements in market conditions in Edmonton, service on other transportation systems, product quality and competing product on the West Coast are other factors that would affect movements of B.C. crude (T3: 431 and 457).

Husky based the 2001 toll calculation in its direct evidence on deliveries to Prince George and Kamloops of 6,600 m^3/d in total. This volume was based on historical throughputs on the Western System and on a normal year of operation (T7: 1171; Husky Argument, p. 55). Husky accepted Plateau's forecast of 1,600 m^3/d for calculating tolls for the period of September 7 to December 31, 2000 (T7: 1241). Husky stated that the pipeline will continue to be fully utilized if reasonable tolls and terms and conditions of service are offered (Husky Argument, p. 41).

Chevron supported a volume forecast that was close to historical volumes. It thought that a forecast of 6,600 m^3/d was reasonable, assuming a competitive toll to Kamloops (T7: 1322 and 1323). Chevron also stated that, in order to determine that a change was occurring in movements of oil between markets, a longer term assessment would be required. Chevron believed it would be wrong to project that small movements of crude east for the last few months prior to the line break constituted a long-term trend, and disagreed with Plateau's assumption that significant volumes of Boundary Lake oil would continue to move to Edmonton (T7: 1322 and 1323).

The Commission recognizes that the factor with the greatest impact on the amount of crude shipped on the Western System will be the toll to Kamloops, relative to alternatives that are available to shippers. This load forecast is determined on the assumption that Western System tolls remain competitive with other transport options, and comparable to the tolls that were in effect prior to the line break. The competitiveness of Western System tolls is determined in Chapter 8.

The Commission has concluded that approximately 7,200 m^3/d of crude oil will be available at Taylor, and that the expected capacity of the pipeline is at least 7,100 m^3/d. Also, the Federated facility agreements will not hinder shippers that wish to move oil on the Western System.

If the Western System was in service with competitive tolls, the evidence indicates that most if not all of the volumes going east will be redirected to the Western system. Plateau indicated that BC Light crude represents about 67 percent of the total amount of crude connected to Taylor, and this crude oil is in demand by both Husky at Prince George and coastal refineries. Some Boundary Lake crude may continue to go to Edmonton, but the evidence does not indicate the amount will exceed the average delivery in 2000 prior to the line break, providing tolls are competitive. Deducting 400 m^3/d of Boundary Lake crude from the total crude oil that is expected to be available at Taylor results in approximately 6,800 m^3/d to be shipped on the Western System.

However, the Commission recognizes that Plateau may not immediately be successful in its efforts to have the OGC lift the restriction to 75 percent of maximum operating pressure. For example, the OGC may restrict the operating pressure of the pipeline to less than 100 percent of the certified operating pressure while it reviews Plateau's Operational Analysis and Integrity Management Plan. As well, the timing of upgrades such as pressure reducing valves and mainline isolation valves may also temporarily restrict the capacity of the pipeline. Moreover, it is possible that some shippers may have made commitments to move crude oil to Edmonton for a period of time, and so may not be able to immediately redirect the oil to the Western System. **The Commission concludes that initially throughput on the pipeline may be**

restricted to approximately the level of Plateau's load forecast, but expects the pipeline to be in full operation by about the end of October 2001.

For the purpose of establishing throughput volumes for the test period of this toll setting, the Commission must recognize the unique circumstances related to the pipeline rupture and the prudency of returning the line to active service. In Chapter 2, the Commission found that the northern section of the pipeline was tested and returned to service efficiently and that the southern section should have been tested and returned to service by December 1, 2000. In these circumstances, rather than using actual throughputs, the Commission will determine normal throughput volumes and use these deemed normal deliveries to calculate tolls. The tolls and time periods will be used to apportion responsibility for the pipeline's revenue requirements.

The Commission determines that for calculating tolls, deemed normal forecast deliveries to Prince George of 1,600 m^3/d commencing September 7, 2000 will be used. The Commission determines that for calculating tolls, relatively conservative deemed normal forecast deliveries to Kamloops of 3,900 m^3/d will be used for September 7, 2000 to October 31, 2001, and 5,000 m^3/d will be used commencing November 1, 2001.

4.0 RATE BASE

4.1 Regulatory Precedents and Risk

As described in Section 1.1.1 the Commission regulates common carrier oil pipelines on a reporting basis except in the event of complaints. The Commission considers that this method of regulation is sufficiently flexible to accommodate individual circumstances, avoids unnecessary administrative and compliance costs but provides the opportunity for review if parties are unable to reach agreement on tolls or conditions of service. Shippers and pipeline owners are considered to be sophisticated parties who have specialized knowledge and access to appropriate expertise required for these negotiations.

Given the contentious nature of hearings and the obligation for the Commission to comprehensively review methodologies, terms and conditions and other related matters, common carriers and shippers have been motivated to come to resolutions that balance their needs. Settlement negotiations work best in circumstances where a limited number of shippers can negotiate knowledgeably with the pipeline owner. When Plateau and its shippers were unable to come to an agreement on tolling in the fall of 2000, the Commission was required to undertake its first comprehensive review of an oil pipeline regulated under the

Pipeline Act. In this Decision, the Commission has taken into account the considerable testimony, the application of regulatory principles on revenue requirements and rate design, and related tribunal decisions.

The Commission's reporting requirements were communicated to the operator of the Taylor to Kamloops pipeline in letters dated February 6, 1990 and July 13, 2000 (Exhibits 32 and 31). Plateau acknowledged that it received Exhibit 31 prior to closing its acquisition of the Federated pipelines, including the Western System. Mr. Webb stated that as part of Pembina's due diligence for the purchase of the Federated pipelines it made inquiries of Commission staff and confirmed that there had not been disputed hearings in B.C. for crude oil pipelines. The Federated acquisition involved seven pipelines and it did not have the time or the concern to inquire of the Commission how it historically regulated pipelines and the methodologies commonly employed to set tolls in contested proceedings (T2: 338; T4: 667).

Plateau recognized that under complaint based regulation, the pipeline owner and shippers could agree on a toll setting methodology that would be approved by the Commission when filed. Plateau also recognized that if it was unable to reach agreement with its shippers, it would be subject to the regulatory risk that a proposed toll setting methodology may not be acceptable to the Commission (T4: 673-676).

The Commission finds that it must consider the full range of regulatory options, as well as the previous Incentive Tolling Agreement, to come to a Decision which is fair to both the shippers and Pembina.

4.2 Rate Base Concepts

4.2.1 Semi-Depreciated Rate Base

Plateau requested approval of a semi-depreciated rate base methodology where the plant in service portion of rate base would be calculated as the average gross plant less one-half of the average accumulated depreciation for the period. Plateau also included capitalized major expenses in rate base on a semi-depreciated basis. In the Application, Plateau stated that a semi-depreciated rate base is commonly used within the feeder pipeline business and within the oil and gas community. Plateau further stated that this practice reflects the reality that an operating pipeline has value even if the book value has been fully depreciated. The vanishing rate base places substantial pressure on the pipeline to lower rates during the later portion of a pipeline's life which can cause tolls to be substantially lower than the value of the service. Plateau added that without the use of the semi-depreciated rate base methodology, there would be no financial resources available to absorb unpredicted events (Exhibit 1, Tab 3).

In response to an Information Request, Plateau expanded on the evidence in the Application and discussed the issue that the actual economic life of a pipeline often extends beyond its theoretical economic life. Plateau argued that a traditional original cost (also called historical cost or fully depreciated historical cost) methodology cannot be considered for heavily depreciated assets (Exhibit 1C, pp. 10-14).

In Final Argument, Plateau highlighted its reasons for the methodology, focusing on the historical precedence of the 1995 to 1999 Incentive Tolling Agreement that was accepted by shippers on the Western System and approved by the Commission (Plateau Argument, p. 9). Plateau also argued that the methodology is employed by pipelines in other jurisdictions. Plateau stated that the Western system is at a crossroads and that the system had nearly been depreciated by the time of the Federated acquisition (Plateau Argument, p. 10). In conclusion, Plateau argued that the returns under a fully depreciated methodology would not satisfy any feeder pipeline company of which Plateau is aware (Plateau Argument, p. 11).

Husky supported a fully depreciated methodology where the full amount of accumulated depreciation was deducted in the calculation of rate base. Husky stated that under a semi-depreciated method, the pipeline recovers the full cost of depreciation but only deducts one-half of the accumulated depreciation in determining rate base. Husky's view was that any regulated entity is entitled to recover its laid down capital through depreciation and a fair return on that capital. Husky's concern was that an owner could receive more return on capital with a semi-depreciated rate base method than would be achieved under a fully depreciated methodology and this was not the intention of the semi-depreciated methodology (Exhibit 5, Tab C, pp. 2-6).

Husky further stated that there should not be a concern about vanishing rate base due to asset renewal (Exhibit 5, Tab C, p. 8). Husky added that it was not aware of any regulatory approvals for semi-depreciated rate base methodologies in a contested rate case (Exhibit 5, Tab C, p. 8; Exhibit 5B, p. 21). Husky concluded that it was reasonable to assume that Pembina accepted the risks of a low net book value and the regulatory risks when it acquired the Western System and it should live with the consequences of those business decisions (Husky Argument, pp. 28-29).

Although Chevron's primary concerns related to other areas of the Application, it stated that semi-depreciated rate based methodology did not produce just and reasonable tolls for feeder pipelines (Exhibit 7B, p. 10). Chevron stated that Plateau failed to present a persuasive and defensible position in support of its semi-depreciated rate base methodology (Chevron Argument, p. 8). It further stated that Pembina has not provided any applicable and relevant regulatory precedents rendered under comparable circumstances. Finally, Chevron argued that if Plateau makes the proposed capital additions, any issue of declining rate base will not arise for many years (Chevron Argument, p. 9).

In information requests and cross-examination, CAPP also questioned the use of the semi-depreciated methodology. CAPP referenced Pembina's reliance on the Ernst and Whinney Management Consultants' report prepared for the Canadian Petroleum Association in 1982 and Plateau's acknowledgement that the report had never been used in a public hearing as a basis to set tolls (CAPP Argument, p. 6; T4: 651). CAPP argued that the method did not reflect the declining value of assets. CAPP noted that Pembina assessed the economics of purchasing the pipeline based on an expected life of 25 years even though it applied for a ten-year depreciation period. CAPP concluded that with a traditional toll methodology that depreciated and expensed assets over the expected remaining life, tolls may be sufficiently reasonable and competitive to allow the long-term viability and operation of the pipeline (CAPP Argument, pp. 7 and 8).

Encal reiterated arguments provided by Husky, Chevron and CAPP, specifically stating that a clear distinction should be drawn between those circumstances where shippers, through a negotiation process, voluntarily agree to a specific tolling methodology and circumstances where no agreement can be reached (Encal Argument, p. 3).

Imperial Oil supported Plateau's use of the semi-depreciated methodology. Imperial Oil argued that there was no evidence of a case where semi-depreciated rate base was applied for and denied and there is not enough evidence to warrant changing the methodology that industry agreed to since 1995 (Imperial Oil Argument, p. 2).

The Commission rejects Plateau's assertion that approval of the 1995 agreement between shippers and the pipeline owner set any precedent for semi-depreciated rate base. The nature of the Commission's complaint based regulation of pipelines is that tolling agreements that are fully supported by shippers will be accepted without detailed review. The Commission considers that a pipeline owner should be entitled to a fair return on the cost of assets that have been devoted to public use. The Commission also considers that a fully depreciated rate base properly represents the net investment that has been made by the pipeline owner. The corresponding return on that net investment is determined by an examination of the appropriate cost of capital for the pipeline. The Commission finds that the semi-depreciated methodology inflates the rate base and unnecessarily complicates the determination of the return on investment. However, the substantial capital investments required to bring the pipeline back into service will increase the asset base and should address Plateau's concerns about a vanishing rate base.

The Commission determines that the fully depreciated historical rate base methodology, rather than the semi-depreciated rate base methodology, is appropriate for the Western System.

4.2.2 Historical Rate Base and Market Revaluation

Plateau calculated the rate base and tolls in its application based on a market revaluation of the assets using the Federated purchase price of $10.785 million as the opening asset value in 1995 (Exhibit 1, Tab 3, pp. 1 and 2). Plateau argued that because the methodology was accepted by the shippers and filed with and approved by the BCUC, it should be used as the basis for new toll calculations. It noted that a matter of critical importance to Plateau is that the resulting revenue requirement must reflect the value of the asset, the cost of upgrading the asset and the risk associated with the asset (Plateau Argument, pp. 8 and 9).

Husky's position in argument and in testimony by Mr. Matwichuk opposed the inclusion of the purchase price premium in the rate base, citing that Canadian regulators have not allowed these premiums because they lead to an escalating rate base and therefore higher tolls. Husky further argued that although higher purchase prices are paid, acquiring entities should not be able to achieve a higher return on capital to the detriment of shippers (Husky Final Argument, pp. 30 and 31). Husky cited BCUC decisions and Orders No. G-31-87 and G-34-93, where purchase price premiums were paid in transactions but not permitted to be included in rate base (Exhibit 5, Tab C, p. 10).

Encal argued that the original cost rate base of Plateau would comprise solely the capital costs incurred by Plateau's predecessors in constructing the Western System less accumulated depreciation from the date the facilities were placed into services and any proceeds on the sale of tangibles removed from service (Encal Argument, p. 6). Encal submitted that the appropriate opening rate base for 2000 (exclusive of working capital) was that given by Mr. Matwichuk's direct evidence (Exhibit 5, Tab C, Appendix, p. 7).

CAPP and Chevron contended that rates should be set utilizing a traditional regulated pipeline cost of service toll methodology (CAPP Argument, p. 5; Chevron Argument, p. 2).

As in the earlier decisions referred to in this section, the Commission believes that the purchase of assets which remain in regulated service should continue to reflect the historic, depreciated value of the assets.

4.3 Net Additions to September 6, 2000

The net additions to plant in service from 1994 to 1999 on the Western System were summarized in asset continuity schedules. The net additions were shown on a historical cost basis in Exhibit 1C, IR 1.10 and on a 1994 revalued basis in Exhibit 1C, IR 1.2. Net additions of $6.605 million were made to plant in service from 1994 to 1999 which included pipeline integrity costs totalling $2.812 million. Under the terms of the 1995 to 1999 incentive tolling agreement (Exhibit 1D, IR 9), the expenditures for pipeline integrity costs were included as a sharing adjustment in the calculation of incentive tolls rather than plant additions. The pipeline integrity costs were separately removed from plant additions in the asset continuity schedules.

Plateau identified a few plant additions that it considered should be removed from the rate base of the Western System as these assets are partly or fully used to provide crude oil to the Northern system (Exhibit 1C, pp. 2 and 3). The reductions to plant additions total $1.8 million and were reflected in a revision to the Application dated March 23, 2001. A corresponding reduction of $0.187 million was made to accumulated depreciation.

The plant additions in 1997 include a cost of $977,000 to connect the Sunset Prairie battery to the Western System (Exhibit 1C, IR 1.2). The cost to connect the Sunset Prairie battery was removed from the Western System plant assets as part of the 1997 pipeline integrity deduction of $1.811 million (T4: 699). Plateau stated that the toll revenue collected by the Sunset Prairie pipeline was not included in the revenue of the Western System (T3: 371).

The Commission accepts that the Sunset Prairie pipeline has been properly accounted for on the Western System.

At the hearing, Plateau was asked to restate the table in Exhibit 1C, IR 1.10 to show the activity in plant in service from January 1 to September 6, 2000 (T4: 690). The requested information was provided in an April 19, 2001 undertaking response and the changes to plant in service and accumulated depreciation from 1994 to September 6, 2000 are summarized as follows:

Table 4-1

	Historical Cost		Revalued	
	Gross Plant ('000s)	Accumulated Depreciation ('000s)	Gross Plant ('000s)	Accumulated Depreciation ('000s)
Opening – 1994	$ 43,511	$ 42,210	$ 43,511	$ 42,210
Revalued in 1994			(43,511)	(42,210)
Revised Value			10,785	239
Net Additions – 1994 to Sept. 6, 2000	6,605	3,433	6,605	3,194
Less: Pipeline Integrity – 1994 to 1999	(2,812)	0	(2,812)	0
Less: Revision No. 1	(1,792)	(187)	(1,792)	(187)
Closing – September 6, 2000	$ 45,512	$ 45,456	$ 12,786	$ 3,246

The Commission determines that the September 6, 2000 closing balances on a historical cost basis in Table 4-1 above will be shown as the opening balances for gross plant and accumulated depreciation on September 7, 2000 in the toll calculations in Appendix A to this Decision.

4.4 Depreciation and Amortization Rates

Plateau expects that the Western System will be in operation until 2010 and has used an annual straight line depreciation rate based on the years remaining until 2010 to ensure that the net book value is fully depreciated by the end of 2010 (T3: 568 and 569). Plateau acknowledged that the pipeline may well be in usable condition after 2010 but it was concerned that shippers would not be willing to move oil down the pipeline (T4: 697). Plateau considers that, as volumes to be moved have alternative routes to market, using a depreciation rate that extends the recovery of the plant investment over a period beyond the commitment period would place Plateau at the unacceptable risk of being unable to recover its investment (Exhibit 1C, p. 6).

Plateau reported that in 1993 and 1994, Numac had depreciated its assets on a declining balance basis of 20 percent per annum and from 1995 to 2000 Federated used a straight line basis over 20 years (Exhibit 1C, p. 5). Plateau assumed that Federated may have used a depreciation rate that matched the valuation model used when Federated purchased the Western System in 1994 (T4: 646).

Plateau was unable to provide an estimate of the physical life and economic life of the Taylor to Prince George and Prince George to Kamloops segments of the pipeline but expected that the vast majority of the pipeline could continue in service for decades if properly maintained. Plateau considered that the pipeline or pipeline segments may have an economic life in alternative service such as refined products or natural gas transmission but the pipeline may not have any remaining life if upgrades are not made (Exhibit 1C, p. 4).

Plateau identified the plant assets listed on Exhibit 1D, IR 10, that could have lengthy continuing service (T4: 695 and 696). The assets identified were buildings, control centre, pumping equipment, below ground pipe, tanks and land. The other plant assets were expected to have shorter lives and be replaced as needed. Plateau reported that depreciation has not been calculated by asset type and it was unable to provide the net book value of the Taylor to Prince George and Taylor to Kamloops pipeline excluding the 1994 Federated purchase premium.

Recognizing the age of the pipeline and that the planned capital additions will have a useful life for toll setting that is dependent on the life of the entire pipeline, a physical life of 20 years seems appropriate for depreciation. The net book value of the existing assets by asset type is not known, therefore a composite depreciation rate on the existing assets will be used.

The Commission considers that a depreciation rate of 5 percent straight line is appropriate to be applied to both the existing net plant assets and capital additions.

Plateau also included major operating expenses in a rate base deferral account where the additions for the year were added to the deferral account. The annual amortization amount was based on the total expected additions for the five years from 2000 to 2004 divided by five. Husky suggested that a more conservative approach would be to amortize the major operating expenses for five years following the expenditure.

The Commission considers that major operating expenses summarized in Table 2-2 of this Decision should be amortized over a five year period commencing in the year of the expenditure.

4.5 Working Capital

Plateau proposed that the working capital component of rate base be set as one-eighth of the normal operating expenses for the year (Exhibit 1, Tab 3, pp. 3 and 4). Plateau stated that it had not performed a lead/lag study and considered that the use of the one-eighth of operating expenses would be appropriate since it is the same percentage used by Numac in a 1993 filing and in a March 2000 filing by the Northeast British Columbia pipelines (T4: 704). The working capital component would be based on forecasted normal operating expenses and adjusted when actual normal operating expenses are known. The variance between actual and forecasted working capital would be reflected in the next year's tolls (T3: 561 and 562).

Husky estimated that the one-eighth ratio proposed by Plateau represented about 45 out of 365 days of normal operating expenses. Husky suggested that if a lead/lag study had been performed, a typical revenue lag of 40 to 45 days and an operating expense lag of 30 to 35 days would likely be found. Husky considered that a net lag of 15 days of normal operating expenses would be more representative rather than the 45 days or one-eighth ratio proposed by Plateau (Exhibit 5, p. 23).

The Commission considers that forecasting working capital as one-eighth of the normal operating expenses, which is similar to approach used by Numac, is an acceptable approximation to be used in the absence of a lead/lag study.

5.0 OPERATING AND MAINTENANCE EXPENSES

5.1 Operating Expenses and Overhead

Operating Expenses are the ongoing costs to operate and maintain the pipeline, such as salaries, travel, maintenance and operations materials and services, property taxes, insurance, electrical and the pipeline control centre. The forecast in the Application represented the actual costs for most categories, plus an allocation of shared expenses for shop supplies, field office insurance and the control centre. Expenses were subtotaled under the various categories for reporting. In addition to normal Operating Expenses, Plateau identified major Operating Expenses that were discussed in Chapter 2 of this Decision.

In the Application, Plateau reported actual normal Operating Expenses for the period September 7 to December 31, 2000 of $2.971 million. The estimate for 2001 was $7.448 million (Exhibit 1, Tab 6, p. 6, as revised March 23, 2001). The Application indicated a historical average cost of $7.276 million per year for the period 1995-1999. The actual costs for 1998 and 1999 excluding major expense items were $7.053 and $7.114 million, respectively (Exhibit 1C, p. 21).

Right-of-way maintenance, legal and regulatory, and the 2000 line fill purge costs were addressed in the hearing, as they did not appear in the information provided for 1998 and 1999. Save for these exceptional items, Intervenors were not opposed to the applied-for normal expense budget. Right-of-way maintenance is discussed in Section 2.3.2 of this Decision.

Plateau estimated $350,000 for regulatory and legal costs in 2001 associated with BCUC proceedings, but stated that it believed the amount did not adequately cover costs to be billed by the OGC or the Ministry of Environment, Lands and Parks. Plateau felt that the full amount should be recovered in 2001, as there are likely to be ongoing regulatory and legal costs (T5: 870 and 871). **The Commission accepts the regulatory and legal expense estimate of $350,000 for 2001, but considers this overstates the level of ongoing costs and will use $200,000 for estimating 2002 tolls.**

Plateau used somewhat different operating and maintenance expense categories than previous owners, which made it difficult to compare a particular expense in the Application to information from previous years. Although itemization of expenses differed from that of 1998 and 1999, the total costs in the Application for 2000 and 2001 are very close to the historical amounts.

Subject to the adjustments that will be discussed subsequently in this Chapter, the Commission approves the normal Operating Expense estimates in the Application for September 7 to December 31, 2000 and for 2001.

Plateau calculated overhead expense as 15 percent of the normal Operating Expense as a proxy for an actual allocation of general and administrative costs from Pembina's corporate office. Plateau stated that for 2000 the average overhead allocation from Pembina was 16.1 percent and 2001 is forecast at 13 percent. Plateau considers that the amount of overhead time and effort that has been spent and is expected to be spent on the Western System is considerably higher than the corporate average (Exhibit 1D, p. 27). Husky argued that a 10 percent overhead rate was appropriate as previous owners of the Western System charged overhead rates ranging from 7 to 12 percent (Exhibit 5, Tab C, p. 22; Husky Argument, p. 38).

The Commission accepts an overhead rate of 15 percent of normal Operating Expenses for the Western System for the 2000 stub period and the year 2001.

5.2 Line Fill Purge in 2000

Last fall, Plateau used nitrogen to displace crude oil from the southern section of the pipeline to Kamloops. The actual cost of the nitrogen purge was $834,000, and Plateau proposed to recover this amount as a normal Operating Expense in 2000 (Exhibit 1F, Tab Encal, p. 18).

In a letter to update shippers dated September 18, 2000, Pembina noted two Kamloops shippers had requested the return of their line fill and that it planned to use nitrogen to displace the oil to Kamloops in October (Exhibit 6K). The Commission received a copy of this letter.

Plateau's tolls are payable when oil is delivered from the line, so shippers paid the interim toll for the delivery of their oil at Kamloops (T3: 584-586). Plateau estimated the inventory delivered from line fill to shippers on the southern section at 30,000 cubic metres (T3: 492). Using Plateau's estimate and the $\$6.40/m^3$ interim toll indicates that Plateau received about $192,000 on delivery of the shippers' inventory. The net cost of the line fill purge was therefore approximately $642,000.

Plateau maintained that purging the line fill at the shippers' request was prudent and responsible given the safety issues and economic uncertainty surrounding the pipeline (Plateau Reply Argument, p. 26). Husky took the position that there was no reason that return of line fill could not have been coordinated with hydrostatic testing of the southern section (Husky Argument, p. 57).

While Plateau had an alternative to purging the line with nitrogen, it took the action to return the oil at the request of shippers. Regulated companies are generally assumed to have acted prudently unless it is demonstrated that an imprudent action has occurred. The Commission considers that the circumstances related to the line fill purge do not adequately meet the high standards that are required to declare the expenditure imprudent. **The Commission determines that the net amount of $642,000 should be included as a normal Operating Expense in the calculation of rates for the September 7 to December 31, 2000 period, as a one-time exceptional expense.**

5.3 Insurance Premium and Deferral Account

Normal Operating Expenses for September 7 to December 31, 2000 and 2001 include forecasts of insurance costs for the entire Taylor to Kamloops pipeline and for the Taylor to Prince George segment. The current property and liability insurance policies of the Pembina Pipeline group are due for renewal on May 31, 2001 (Exhibit 1, Tab 5). Pembina allocates the insurance premium among the individual pipelines based on the insured value of each pipeline. For the past three years, the insurance premiums for the Pembina Pipeline group averaged $500,000 per year but with the 2000 acquisition of the Federated pipelines, the insurance premiums increased by approximately $624,000 for the remaining term until May 31, 2001 (Exhibit 1D, p. 50). The allocation of insurance premiums for Taylor to Kamloops were shown as about $97,000 for the 2000 stub period and $258,000 for 2001. The allocation of insurance premiums for the Taylor to Prince George segment alone was forecasted as approximately $58,000 for the 2000 stub period and $77,000 for 2001 (Exhibit 1, Tab 6, p. 6).

The estimate for 2001 is a considerable increase from the actual cost of $72,000 in 1999 (Exhibit 1C, p. 21). Plateau attributed the increase to the expected impact of the Pine River spill on Pembina's insurance premium, and requested a non-rate base deferral account for variations in insurance premiums beyond the amount estimated in the Application (Exhibit 1, Tab 5). The deferral account would accrue interest at the rate of 7 percent.

Plateau also expected that its insurance deductible would increase after May 2001 from the current $100,000, but was unable to estimate the new deductible. The Application requested approval of an interest-bearing deferral account to accumulate the amount of the deductible in effect from time to time, to cover Plateau's liability in the event of another rupture on the Western System that caused the pipeline to cease operations.

Husky stated that there were many uncertainties regarding the insurance costs and the costs should be disallowed or deferred (Exhibit 5, Tab C, pp. 19 and 20; T7: 1253).

The Commission considers that the estimate for insurance costs is generous but not unreasonable, and notes that insurance premiums are a cost that should be recovered in rates. **The Commission accepts the estimate of $258,000 for 2001, and approves a deferral account to record any difference between this amount and the actual insurance premium cost. Plateau may also record future insurance deductible outlays in this deferral account, and can expect to recover such amount in rates, after a prudency review.**

5.4 Power Costs

In its Application, Plateau forecasted costs for electricity and natural gas required to move oil through its system. These power costs were about $244,000 for the Taylor to Prince George segment alone and $310,000 for the Taylor to Kamloops segment for September 7 to December 31, 2000 (Exhibit 1, Tab 6, p. 6, as revised March 23, 2001). The costs were based on deliveries of 1,600 m^3/d to Prince George and no volumes delivered to Kamloops. Plateau explained that these were the actual costs for the period, and that the power cost for Taylor to Kamloops represents the total of the power costs from Taylor to Prince George and the fixed power costs of the Prince George to Kamloops segment that are incurred whether electric power and gas are consumed or not (Plateau Undertaking at T5: 868).

For the year 2001, Plateau forecasted power costs for Taylor to Prince George of $780,000 assuming volumes of 1,600 m^3/d. Power costs of $2,100,000 were forecasted for Taylor to Kamloops assuming deliveries of 1,600 m^3/d to Prince George for the entire year and volumes of 3,900 m^3/d to Kamloops starting on July 1, 2001. In the March 23, 2001 revision to the Application, Plateau delayed the reactivation date for the Prince George to Kamloops segment to September 1, 2001 but did not adjust the forecasted power costs of $2.1 million (Exhibit 1, Tab 6, pp. 5 and 6).

The Commission determined that the Prince George to Kamloops segment could have returned to service by the end of November 2000 and volumes of 3,900 m^3/d could have flowed to Kamloops until October 31, 2001. The Commission considers that the volumes delivered on the Kamloops segment could have increased to 5,000 m^3/d effective November 1, 2001. Accordingly, an adjustment to the power costs for the 2000 stub period and the year 2001 is required to provide for variable power costs related to those additional volumes.

In determining an adjustment for 2001, the Commission notes that the power cost was $1.98 million in 1998 when daily volumes to Prince George and Kamloops averaged 7,614 m^3/d and $1.75 million in 1999 when daily volumes averaged 6,754 m^3/d (Exhibit 1C, p. 21). While electricity rates have been frozen during this time period, the cost of natural gas has risen. The Commission considers that a power cost of $2.1 million in 2001 is reasonable for a year of deliveries of 1,600 m^3/d to Prince George and 3,900 m^3/d to Kamloops. These power costs have been prorated for the 2000 stub period. For the 116 days between September 7 to December 31, 2000, the power costs have been increased to $667,000 for the calculation of tolls based on normal volumes.

Plateau stated that power cost for the Prince George to Kamloops segment would be $2.68 million for a volume of 6,750 m^3/d (Plateau Undertaking at T5: 868). The Commission accepts that an annual power cost of $2.1 million is appropriate for the period from January 1 to October 31, 2001 for deliveries of 1,600 m^3/d to Prince George and 3,900 m^3/d to Kamloops. The Commission considers it necessary to increase the 2001 power cost forecast effective November 1, 2001 to reflect an adjusted volume of 5,000 m^3/d delivered to Kamloops and recognize power costs of $2.68 million per year for the November 1 to December 31, 2001 period. Power cost of $2.10 million per year for ten months and $2.68 million per year for two months, gives an adjusted 2001 power cost of $2,197,000.

The Commission determines power costs of $667,000 for September 7 to December 31, 2000 and $2,197,000 for 2001 for the calculation of tolls.

6.0 CAPITAL STRUCTURE AND RETURN

Plateau's Application proposed an equity component of 100 percent and an after-tax return on equity ("ROE") of 15 percent. It justified its proposal on the basis that 100 percent equity and 15 percent ROE was part of the incentive tolling methodology that had been previously accepted by shippers and approved by the Commission (Exhibit 1C, p. 91). Plateau also provided additional arguments to support its proposed capital structure and ROE. These will be examined in this Chapter as well as the corporate and capital structures of Pembina's companies and their relevance to the capital structure used in establishing tolls on the Western System.

6.1 Corporate Organization and Capital Structure

Plateau described the ownership of the Western System by the Pembina group of companies in Exhibit 1D, p. 3:

> "On July 31, 2000 immediately following the acquisition of all of the shares of Federated Pipe Lines Ltd. by Pembina Pipeline Corporation, Pembina Pipeline (a general partnership, partners of whom were Pembina Pipeline Corporation and Pembina Oil Ltd.) purchased all of the assets of the Federated Pipe Lines (Western) Ltd., including the Taylor to Kamloops pipeline. Pembina Pipeline, in turn, immediately sold the asset to Pembina West Limited Partnership."

Figure 6-1 provides a corporate organization chart for the Pembina Group of companies. The Pembina West Limited Partnership owns the Western System and collects tolls on the pipeline (T1: 43). Plateau operates the Western System. Plateau is not a publicly traded company and does not have any employees or assets, aside from its interest in the Pembina West Limited Partnership (T1: 43; T5: 784).

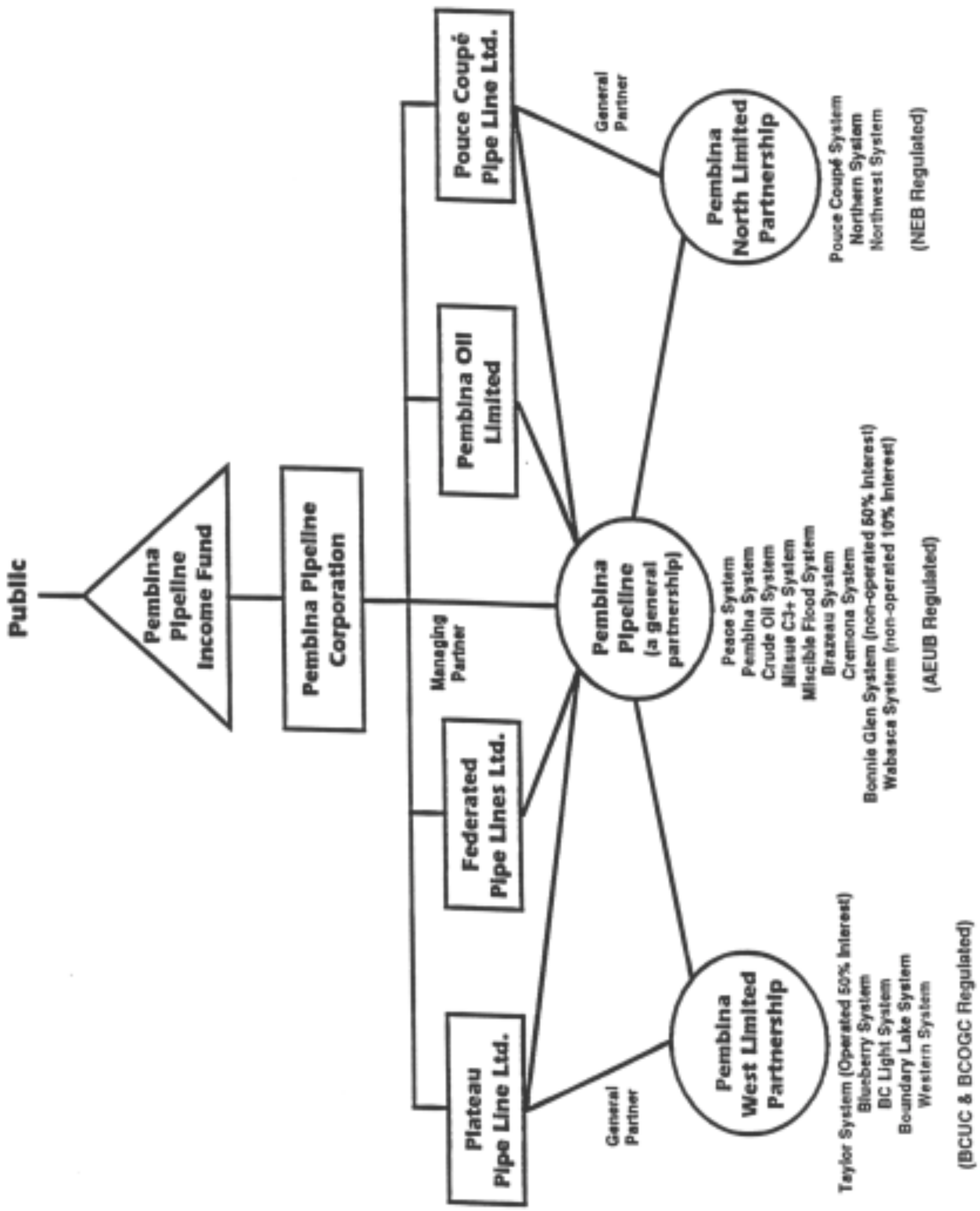
The Pembina Pipeline Income Fund ("the Fund") has 100 percent ownership of Pembina Pipeline Corporation ("Pembina"). Pembina owns the Pembina Pipeline partnership which in turn owns the Pembina West Limited Partnership and the Pembina North Limited Partnership. Pembina also owns the shares of Plateau. Pembina is not a public company and there are no public investors in the Pembina West Limited Partnership (T3: 541 and 542).

A distinction between Plateau as the operator of the Western System and Pembina as the owner of the Western System either directly through shares or partnership interest was not always clear. While Plateau filed the application for 2000 and 2001 tolls and suspension of service, Plateau has no employees or assets. During the hearing, the owner/operator relationship was recognized by Plateau's counsel when the toll application was identified as a "Pembina Plateau case" (T1: 7).

The Commission considers that Plateau has filed the application for 2000 and 2001 tolls and suspension of service on its own behalf as operator of the Western System and on behalf of Pembina as the owner of the Western System.

Plateau's capital structure was not introduced as evidence during the hearing. Plateau stated that the Pembina West Limited Partnership was formed immediately after the acquisition of Federated (Exhibit 1D, p. 3; T5: 542). Plateau explained that it had not reviewed the financial statements of the Pembina West Limited Partnership, therefore the Partnership's capital structure was not introduced as evidence during the hearing (T5: 784). The Pembina West Limited Partnership is not able to issue debt or equity as its assets have been pledged as security under a general loan agreement with Pembina and in turn Pembina has pledged its interests in the partnerships as security for its loans (T5: 783).

Figure 6-1
Pembina Group of companies
(Reference: Exhibit 1D, p. 1, attachment)



In the Pembina group of companies, only the Fund can obtain equity financing which is done through the issuance of trust units. The Fund is a public company that invests the proceeds of an equity issue in notes or subordinate debt of Pembina. The Fund restricts its investments to either shares or debt of Pembina (T4: 744-750). The capital structure for the Fund at the end of 1999 and 2000 was summarized in Exhibit 44 where the equity component at the end of 2000 was shown as 52.75 percent including deferred income taxes or 63.4 percent excluding deferred taxes. Plateau explained that the Pine River spill did not have a major impact on the Fund’s ability to raise equity. The Fund sold additional trust units beginning in September 2000 but found that its cost of equity was more than expected. Plateau believed that its higher cost was a result of investors’ concerns with the spill's impact on Pembina (T4: 756).

Only Pembina issues debt and its capital structure was described as almost 100 percent debt in the form of internal and external debt (T3: 544; T4: 744).

6.2 Equity Component - Deemed or Actual

Plateau argued that, on a stand-alone basis, it could not raise the capital required to finance the repairs and upgrades of the Western System. Plateau indicated that expenditures on the Western System would be financed by an equity investment from its parent company, Pembina. Pembina’s sources of financing are intercorporate debt from the Fund or third-party credit facilities provided by a bank. Plateau considered that Pembina’s investment in the Western System must be financed by 100 percent equity because neither Pembina nor the Pembina West Limited Partnership have the credit available to finance the required expenditures. If Pembina was to finance the upgrades on the Western System, Pembina would use the borrowing capacity available from its other systems (Plateau Final Argument, p. 35).

During cross-examination, Plateau explained why a regulator might choose to deem a capital structure rather than rely upon a pipeline's actual or forecast capital structure. Plateau stated that regulators typically deem a capital structure to address not only an inefficient capital structure, but to reach a balance for all parties including the owner by looking at comparable pipelines (T5: 796).

Plateau agreed that when TMPL became a regulated pipeline in the late 1970s its actual equity component was approximately 90 percent. However, this capital structure was unacceptable to the NEB and the NEB deemed TMPL’s equity component to be in the range of 50 percent (T5: 895). Plateau also indicated that the current equity component of TMPL was 45 percent (T5: 791).

Plateau argued that it is not appropriate to compare the Western System to Enbridge or TMPL because Plateau believed that it faces different risks and rewards than these pipelines (Exhibit 1C, p. 93). Plateau argued that larger diameter export pipelines such as Enbridge and TMPL can access northeast B.C. crude as well as crude shipped to Edmonton from other feeder lines in Alberta. It also considered the Western System to be a feeder pipeline as it can only access crude from a limited area and transport it to Husky's refinery or to TMPL at Kamloops (Exhibit 1C, p. 20).

Husky suggested that a capital structure of 50 percent debt and 50 percent equity would be appropriate for the Western System (T7: 1157). Husky considered that the risk profiles of the Western System and TMPL were relatively the same. Husky argued that TMPL faced higher risks related to mountainous terrain, potential for a larger oil spill and operating complexity. However, Husky considered that to be conservative, the equity component for the Western System should be 5 percent higher than TMPL's approved equity component of 45 percent (Exhibit 5, Tab C, p. 13; T7: 1142; T7: 1157).

Husky noted that Plateau's proposed capital structure creates a mismatch between the capital structure used to establish tolls and the capital structure of the company providing the financing. As a result of this mismatch, capital is not used efficiently (Exhibit 5, p. 12). In final argument, Husky stated that regulators routinely deem a debt and equity ratio so that a utility's customers or users of a pipeline can expect that capital is used efficiently and that a certain amount of capital will be funded with relatively low cost debt. Furthermore, how trusts structure their affairs on an intercorporate or tax basis is not relevant to determine an appropriate capital structure (Husky Argument, p. 36).

Imperial Oil rejected Husky's suggestion for ROE and capital structure because it may result in tolls that are too low. Low tolls could prevent pipeline capacity from reaching new fields because pipeline companies would not be willing to take risks greater than a low risk utility and receive a return comparable to low risk utilities (Imperial Oil Argument, p. 7).

CAPP argued that for a traditionally regulated pipeline, the capital structure should reflect a balance of debt and equity. CAPP considered that balance could be based on the capital structure of NEB regulated pipelines such as TMPL (CAPP Argument, p. 8).

Encal stated that no capital structure exists for the Western System or Plateau and proposed that a capital structure should be imputed based on the Fund. Encal argued that not attributing some portion of Pembina's debt to the Western System ignores that these assets were wholly financed by debt. In addition, charging tolls on an assumed 100 percent equity structure would result in a subsidy by the shippers on the Western System for the benefit of other Pembina pipelines due to the added leverage of lower cost debt financing. Encal submitted that an imputed capital structure of 35 percent debt and 65 percent equity should be used for establishing tolls for the Western System. However, it acknowledged that 65 percent equity component would be significantly above the equity component of other regulated pipelines and therefore there is no need to increase the ROE above Pembina's actual cost of equity (Encal Argument, p. 8).

The Commission recognizes that the Western System is not a publicly traded company. Given this situation, the Commission would anticipate that the Applicant's ordinary course of action would be to apply for a capital structure based on the legal capital structure of the parent company. In this case, the Western System has not chosen to do so but instead has applied for a capital structure in which many of the elements appear to be deemed rather than actual.

The capital structure for Plateau and the Pembina West Limited Partnership was not entered into evidence. In an undertaking response, Plateau provided Pembina's actual consolidated capital structure for the September 7 to December 31, 2000 period and a forecast for the year 2001. For the 2000 stub year, Pembina's average equity component is shown as 0.5 percent and for 2001 the average equity component is forecasted to be negative. The Commission does not consider that Pembina's consolidated capital structure with its low equity component is appropriate for setting tolls on the Western System in the 2000 stub period and 2001. Equally, the Commission does not consider that allowing a 100 percent equity return for the Western System is appropriate when the investment provided by Pembina is mainly debt. The Commission must determine a deemed capital structure which would be efficient in allowing Pembina to raise debt and equity at reasonable risk and cost to shareholders and shippers.

The Commission notes Plateau's statement that the Fund had an equity component of 60 percent at the time of the Federated pipeline acquisitions and a current equity component of 70 percent, but considers that an equity component in this range would be excessive in setting tolls on the Western System and would not properly balance the interests of the owner and the shippers (T3: 545; T4: 624; T5: 893). In any case, the Commission does not regulate the Fund. The Western System is owned by Pembina.

Plateau acknowledged that natural gas utilities typically have an equity component in the range of 30 to 40 percent. Plateau also commented that NEB regulated pipelines, due to their higher risks, have an equity component in the range of 40 to 50 percent (T5: 791). As discussed during the hearing, feeder pipeline systems are regulated on a complaint basis, therefore their capital structures and ROE do not necessarily provide a valuable comparison for establishing the capital structure for the Western System. With respect to the other larger export pipeline systems, the Commission understands Plateau's argument that it may not be fair to compare individual aspects of the Western System with larger pipelines. However, the Commission believes that it is appropriate to compare the approved capital structures of oil pipelines that are in broadly similar circumstances to assist in establishing an equity structure.

On balance the Commission determines that an equity component of 50 percent of the capital structure is deemed appropriate in establishing the average cost of capital for the period September 7, 2000 to December 31, 2000 and for the year 2001.

6.3 Risk and Return on Equity

Plateau argued that the capital structure of the Western System should be based on a 15 percent return after tax for a 100 percent equity component since Pembina must be in position to recover a return on its investment that is not less than its cost of capital (Plateau Final Argument, p. 35). Plateau also considered that a 15 percent after-tax ROE on a 100 percent equity component was appropriate as that capital structure and cost of capital was part of the incentive tolling methodology that was previously accepted by shippers and approved by the Commission.

Plateau stated that the Fund's weighted average cost of capital at the time of purchase of the Federated shares was in the range of 12 to 13 percent based on a 60 percent equity component and a 40 percent debt component with a 15 to 16 percent cost of equity and 8 percent cost of debt (Plateau Final Argument, p. 35). Plateau considered that the issuance of $90 million trust units by the Fund in the fall of 2000 at an issue price of $7.80 per unit with an expected distribution of $1.05 per unit represented a 13.5 percent cost of equity for the Fund. In Plateau's view, this reflected the market's assessment of the risks and required return of all of Pembina's pipelines (Exhibit 1C, IR 6.1; Plateau Final Argument, p. 35).

In an undertaking response, Plateau reported the ROE for the Fund for the years, 1999, 2000 and forecasted 2001 as 4 percent, 9 percent and 6 percent respectively. Plateau stated that ROE is not normally used as a measure for an income trust, as all earnings are distributed to unitholders.

Plateau commented that, on a stand-alone basis, the Western System faces considerably higher risks than Pembina's combined operations due to its small rate base, the financial consequences of a spill and the adverse terrain traversed by the Western System. Plateau considered that a cost of equity of 15 percent would be a minimum requirement for the Western System (Exhibit 1C, IR 6.1). During the hearing, Plateau clarified that the difference between its proposed 15 percent ROE and 13.5 percent cost of equity for the Fund was not considered to be a risk premium but it had been the historical rate of return sought by Federated (T5: 801).

Plateau argued that it was concerned about the risks of a future spill and it was unnecessary to assume additional risk by opening the Prince George to Kamloops section of the line following the break (Exhibit 1C, p. 35). Plateau acknowledged that if a successful hydrotest was performed before opening the southern section of the line, the risk of a future spill might be reduced but it would be difficult to quantify the extent of the risk reduction (T5: 804-806). Plateau also commented that financial risk and environmental damage might be mitigated if various elements such as additional valves were approved. Plateau stated that the installation of valves would reduce the amount of spillage in the event of a leak and therefore reduce the damage to the environment and future insurance claims. Similarly, improved communication and leak detection would reduce the environmental impact of a spill and this would be beneficial to the company and the public (T5: 802). Plateau acknowledged that if tolls on the Western System were lower than the tolls via Edmonton it would make the Western System more competitive and reduce its business risk (T5: 807-811).

During the hearing, Plateau was provided a copy of Commission Letter No. L-61-00 which describes the derivation of the 9.25 percent ROE for a benchmark low risk utility approved for 2001 in accordance with the Commission's Generic Formula for ROE (Exhibit 35). Plateau objected to using the Commission's Generic Formula to establish the ROE for the Western System. Plateau argued that since it was not a utility and it is in a different business compared to the gas and electric distribution companies, the formula should not form the basis of regulating the Western System (T5: 776). Despite Plateau's objection to using the Commission's formula, Plateau agreed that the automatic adjustment mechanism worked on the basis that the ROE for a benchmark low risk utility would rise or fall with a forecast of the yield of long-term Canada bonds for the upcoming year (T5: 787).

Commission Letter No. L-39-94 shows that in 1995 the allowed ROE for a low risk utility was 12.0 percent (Exhibit 37). Given that a 15 percent ROE was considered as part of the Incentive Tolling Agreement in 1995, this implies a premium of 3 percent above the low risk utility. Plateau agreed that a 12 percent ROE for 2001 would provide it with approximately the same premium that the Western System's owner received in 1995 (T5: 789).

Husky argued that there is no evidence before the Commission that Western System shippers agreed to any particular tolling methodology or rate of return in the 1995 Incentive Tolling Agreement. Husky stated that the incentive agreement provided for flat fixed tolls subject to certain adjusting mechanisms. Husky also argued that the Fund's ROE of 13.5 percent was inflated and that the after-tax return of equity to investors is closer to 6 percent. Husky indicated that ROE must be calculated after-taxes and 13.5 percent is calculated on a before-tax basis. Furthermore, the historical and projected ROE for the Fund is in the range of 4 to 6 percent (Husky Final Argument, p. 34 and 35).

Husky suggested that a reasonable ROE would be 9.25 percent in accordance with the Commission's formula (Exhibit 5, Tab C, p. 13). As support for its recommended ROE, Husky explained that there was not much difference to its toll calculations if a 9.61 percent ROE, as allowed for NEB regulated pipelines for 2001 (Exhibit 34), was used instead of 9.25 percent. Furthermore, given the Western System's location, it made more sense to abide by the methodology and formula used in British Columbia for determining ROE (T6: 1050).

Imperial Oil was concerned that Husky's proposed ROE for the Western System was too low, would not adequately compensate Pembina and would retard the development of new oil fields. Imperial Oil did agree that if the Commission established a long-term tolling methodology then annual changes to ROE and tolls would be appropriate. These annual changes to ROE would prevent a windfall gain or loss to either the pipeline or the shippers as market interest rates change (Imperial Oil Argument, pp. 6 and 7).

Encal argued that the market yield of the Fund is a clear proxy for the return on the units and should be used by the BCUC in determining the ROE (Encal Argument, p. 7).

The Commission recognizes that the perceived risk for the Western System may have changed from 1995 to 2000 as a result of the spill and the assessment of the pipeline's integrity which may be offset by the planned improvements to the pipeline. The Commission finds that its Generic Formula is an appropriate mechanism to determine the ROE for the Western System provided an appropriate risk premium can be established to recognize the business, financial and regulatory risk facing Pembina.

In considering the risks facing Pembina, the Commission notes that the many improvements to the pipeline approved in this Decision and the pressure testing should add investor confidence to the integrity of the pipeline. The tolls that are approved in this Decision are very competitive with other options available to shippers which will improve the business risk of the pipeline even without the shipper commitments requested by Pembina. The regulatory risk is also clarified by this Decision.

Although the evidence did not include detailed evaluation of each risk which would impact the appropriate setting of the ROE for the period from September 7 to December 31, 2000 and the year 2001, the Commission is satisfied that maintaining the risk premium of 3 percent above the low risk utility that existed in 1995 is a reasonable approximation of the appropriate return for Pembina. The after tax ROE for rate making purposes is approved at 12.25 percent for the 2000 and 2001 test period.

6.4 Debt Component and Interest Costs

While Plateau applied for a 100 percent equity capital structure it agreed that the capital structure of a pipeline must balance the objectives of minimizing the cost of capital while providing sufficient equity to efficiently raise debt and equity. Plateau also agreed that equity has the highest cost of capital due to taxes, and long-term debt is lower cost capital. Plateau acknowledged that long-term debt has an advantage over short-term debt as it provides more certainty of the cost of future debt payments. In addition, Plateau agreed that with long-term debt there is not a need to continuously acquire more short-term financing (T5: 790-795).

Plateau acknowledged that short-term debt is usually an unsecured loan that is typically limited to between 5 to 15 percent of the capital structure (T5: 795). When a cost of short-term debt of 5 to 6 percent and a cost of long-term debt of 6 to 7.5 percent was suggested to Plateau, the Applicant responded that those debt costs would depend on the entity and its credit rating (T5: 793). Plateau reported that when Pembina was evaluating the acquisition of the Federated pipelines, the Fund had a cost of debt of 8 percent for a 35 percent debt component. While it is somewhat unclear as only Pembina can raise debt, presumably the debt component and cost of debt refers to the consolidated Fund which would include Pembina (T3: 545 and 546; T4: 626). In an undertaking response, Plateau reported that for Pembina consolidated, the average cost of debt for September 7 to December 31, 2000 was 10.35 percent and for 2001 is forecasted as 11.12 percent.

In Husky's toll calculations in Exhibits 5 and 5D, a 50 percent debt component was used with a cost of debt of 7.25 percent (Husky Argument, p. 36).

Encal argued that a debt/equity ratio of 35:65 with a debt cost of 8 percent and an ROE of 10.8 percent should be used in setting tolls for the 2000 stub period and 2001. Alternatively, Encal considered the debt/equity ratio of 47.25:52.75 could be used from Exhibit 44. Plateau disagreed with Encal's calculation of a 10.8 percent ROE as the rate was based on a market yield for a single day and it would be inappropriate to apply that yield for the entire year (Plateau Reply Argument, p. 36).

CAPP stated that if financial arrangements limit the actual debt component for the Western System, the Commission could deem a debt component (CAPP Final Argument, p. 8).

The Commission considers that a short-term debt component of approximately 10 percent is appropriate for the Western System. The evidence did not clarify what the appropriate cost of short-term debt would be for a stand alone pipeline with the risk profile of the Western System. The Commission is also not certain that the cost of debt reported by Plateau was reflective of

commercial borrowings from arms-length companies. The Commission considers that the cost of short-term debt of 6 percent is a generous estimate for establishing permanent tolls for the period of September 7, 2000 to December 31, 2000 and for the year 2001. As discussed in Section 6.5 of this Decision, deferred income tax balances should be included in the capital structure as no-cost capital and will displace the balance in short-term debt as required.

The Commission considers that a long-term debt component of 40 percent at a cost of debt of 7.5 percent is appropriate for the period of September 7, 2000 to December 31, 2000 and for the year 2001.

6.5 Deferred or Flow-Through Income Taxes

Plateau calculated its tolls for the 2000 stub period and 2001 based on the normalized or deferred method of accounting for income taxes. The applicant stated that this method of accounting for income taxes was also used in the historic tolls of the Western System. Plateau considered that given the short life of this pipeline, the normalized method would be appropriate for the calculation of income taxes (Exhibit 1, Tab 6, p. 2).

An alternative method of accounting for income taxes was discussed at the hearing, which is the flow-through or current income tax method used by public utilities under the Commission's jurisdiction. A description of the normalized and flow-through methods of income tax and their relative advantages was provided by Plateau (Exhibit 1C, IR 1.11, Husky/Peace contract). In calculating income taxes, there may be timing differences between when an expense is deductible in the books of account and when those expenses are allowed for income tax purposes. Under the flow-through method, only the currently payable income taxes are recognized as an income tax expense. Under the normalized method, the income taxes that have been deferred or postponed are also included as an income tax expense in the current year.

Plateau considered that there could be a disadvantage in using the flow-through method as it may lead to stranded costs. Plateau explained that under flow-through income taxes, the actual cash taxes may be a lot lower in the initial years because the capital cost allowance may be higher than the depreciation in the books of account. That will create a deferred tax liability and if this pipeline has a limited number of years in operation then the deferred tax liability may not be recovered from shippers in the remaining life of the pipeline (T5: 880).

The Commission considers that the Western System will have competitive tolls for 2000 to 2004 based on the evidence provided at the hearing. With competitive tolls and the expectation of crude supply and shipment volumes continuing at historic levels, if a shipper decides not to continue shipping, it is expected that another shipper will utilize the available capacity and volume. However, with the majority of intervenors unwilling to provide long-term commitments and the possibility that Husky may not ship after 2004, the use of flow-through income taxes does not seem appropriate.

The Commission considers that deferred income taxes are appropriate for the 2000 stub period and 2001 in the calculation of tolls and has included the deferred income tax balances in the capital structure as no-cost capital.

7.0 TOLLS AND RATE DESIGN

7.1 Allocation of Tolls to Northern and Southern Sections

The historical treatment of tolls on the Western System was to include all costs in one cost centre in determining the revenue requirement and then to calculate tolls so that the Taylor to Prince George rate was 65 percent of the Taylor to Kamloops rate (Exhibit 1D, p. 26). Plateau stated it was indifferent as to how the allocation between Prince George tolls and Kamloops tolls is carried out provided it is able to recover its revenue requirement (Plateau Argument, p. 29).

In the past, Husky accepted the 65 percent allocation as fair and reasonable (T7: 1240). Husky requested tolls for 2001 consistent with its filed evidence, which allocated costs on a volume/distance basis using 1,600 m^3/d for deliveries to Prince George and 5,000 m^3/d for deliveries to Kamloops. The volume/distance methodology would result in tolls to Prince George that are lower than tolls determined using the 65 percent allocation (Exhibit 5, Tab C, pp. 24 and 25).

Chevron did not have specific comments regarding the toll allocation from Taylor to Prince George. It stated that the economics of the pipeline are based on deliveries to Kamloops, and that the most economic toll to Kamloops will be needed to keep the pipeline full. Consequently, Chevron supported a postage stamp toll that would be the same for deliveries to Prince George or Kamloops (T7: 1301-1303).

CAPP stated that the two sections appear to face different circumstances surrounding risk, future capital investments, shipper alternatives and alternative markets. Based on those considerations, CAPP suggested consideration of options that recognize these differing circumstances when considering the tolling methodology (CAPP Argument, p. 10). Imperial Oil supported the historical tolling methodology (Imperial Oil Argument, p. 6).

The Commission agrees that the northern and southern sections of the line face slightly different circumstances. However, as Chevron pointed out, the viability of the pipeline depends on delivery of crude oil from Taylor to Kamloops. Many costs relate to the pipeline system as a whole, and the Commission considers Husky has not demonstrated that a volume/distance tolling methodology is appropriate for the Western System. At the same time, it is not evident that a postage stamp approach is needed to provide an economic toll to Kamloops. **The Commission finds that the toll for deliveries to Prince George will be maintained at 65 percent of the corresponding toll for deliveries from Taylor to Kamloops.**

In the Application, Plateau recalculated the rate base for an alternative situation where only the Taylor to Prince George segment was in service, by allocating a portion of the pipeline investment to that section. Plateau allocated 46 percent of the pipeline to the northern section based on distance, where the Taylor to Prince George segment was 232.4 miles and Taylor to Kamloops was 504.3 miles. Pump stations No. 1 to 4 were allocated to the Taylor to Prince George section. The Taylor Tank farm was allocated to the northern section but no part of the Kamloops Tank farm was allocated to this section (Exhibit 1D, pp. 18-20). Intervenors did not take exception to the percentage rate base allocation.

Plateau allocated power costs 37 percent to the Taylor to Prince George section. Other operating expenses were allocated based on distance (Exhibit 1C, p. 21). The load forecast was the expected deliveries to Prince George of 1,600 m^3/d (Exhibit 1, Tab 6).

The Commission accepts the rate base and operating expense allocations and load forecast as applied for by Plateau, in the event the Prince George to Kamloops segment does not return to service.

7.2 Reallocation of Other Pembina Revenue to the Western System

As previously discussed, except for the deliveries to Husky at Prince George, the throughput that would have gone down the Western System was rerouted to the Northern system and the Taylor-Peace system after the pipeline break (Exhibit 20, p. 10). In cross-examination, Plateau agreed that 4,770 m^3/d (30,000 barrels per day) would have otherwise been shipped on the Western System had the Pine River spill not taken place (T3: 382). The Federated facility agreements allow a shipper to satisfy its obligations by shipping on either the Northern system or the Western System (T3: 351).

Husky submitted that Pembina has very little incentive to resume full service on the Western System given its ownership and control of the Northern system. Husky stated it believed that if Federated had not been purchased by Pembina, the Western System would have been fully operational following the OGC authorization to resume operation (T6: 961). Chevron argued that Pembina appears to have an incentive to close the Western System, since its closure will cause B.C. crude oil to be diverted to the Edmonton delivery systems, which have underutilized capacity.

In both its evidence and oral testimony, Husky suggested that additional revenue from B.C. crude oil going eastward in the other Pembina systems should be credited back to the Western System, because the volumes were not part of planned throughput on either the Northern or Taylor-Peace systems (T6: 1076-1090). Husky referred to decisions of the Canadian Radio-Television & Telecommunications Commission which deemed revenue from non-regulated activities as a credit to the regulated entity's revenue requirement (Husky Undertaking at T6: 1077). In argument, Husky clarified that it was not taking the position that revenue from the Northern and Taylor-Peace systems should be credited to the Western System. Rather, it suggested that the Commission should consider Pembina's dominant market position and ability to earn revenue on volumes diverted east to Edmonton, when assessing the reasonableness of shipper commitments and the delivery volume used to calculate tolls (Husky Argument, pp. 42-44).

Plateau argued that there is no precedent or authority for crediting revenue from other Pembina pipelines to the Western System, and that the Commission does not have jurisdiction to direct such cross-subsidization. Plateau also referred to the Federated facility agreements, and stated that crude pricing differentials between Edmonton and the West Coast may have accounted for increased volumes on the pipelines running east. Finally, Plateau argued that the Prince George to Kamloops section of the pipeline was closed due to serious concerns regarding pipeline integrity and the cost recovery of any repairs or upgrades (Plateau Argument, pp. 30-34).

The Commission is concerned by the market power that Pembina has in the transportation of B.C. crude oil, and recognizes that total Pembina revenue is not impaired when the Western System is out of service, or in the event throughput levels are reduced on that system. However, the Commission's jurisdiction extends only to the Taylor portion of the Taylor-Peace system and the pipelines that gather crude oil into Taylor, in addition to the Western System. With regard to the diversion of revenue to the Western System, the Commission concurs with Plateau that it does not have jurisdiction to divert revenues from the Northern and Taylor-Peace systems.

7.3 January 1 to September 6, 2000 Tolls

Commission Order No. P-3-00 approved a one-year extension for 2000 of the 1995 to 1999 incentive tolling methodology. This toll methodology provided that variances between actual and reference volumes, inflation, municipal taxes and pipeline integrity expenditures were shared between the pipeline operator and the shippers. The 2000 incentive tolls were based on a reference volume of 1,510 m^3/d from Taylor to Prince George and 4,910 m^3/d from Taylor to Kamloops.

Commission Order No. P-6-00 approved Plateau's application to end the incentive tolls effective September 6, 2000 and set the current tolls as interim effective September 7, 2000. This Order required Plateau to provide a calculation of the incentive sharing adjustments and on January 11, 2001 Plateau filed the calculation (Exhibit 1A). Consistent with previous incentive toll filings, the sharing adjustments from 1998 and 1999 had been included in the 2000 tolls approved by Order No. P-3-00 on the assumption that the adjustments would be recovered over a full year's volume. With the 2000 incentive tolls ending on September 6, 2000 Plateau calculated that the incentive sharing adjustments for 1998 to September 6, 2000 that had not been recovered in tolls totaled about $115,000 and should be charged to shippers.

At the hearing, Husky stated that it had concerns that the 2000 reference volumes were too low and held meetings with other shippers and the operator (T5: 1104-1108; T7: 1218-1223). Husky also had concerns that, with the pipeline break on July 31st, and no volumes shipped by September 6, 2000, the 2000 incentive toll methodology would require that the difference between the daily reference volume and the actual volume shipped be shared 50/50 between Plateau and the shippers. No complaint was received by the Commission regarding the 2000 incentive tolls and Husky acknowledged at the hearing that it would be too late to file a complaint on the incentive tolls (T7: 1223-1225).

The Commission accepts the incentive toll sharing adjustments for the January 1 to September 6, 2000 period as filed and includes the amount of $115,000 in a non-rate base interest-bearing deferral account with interest at 7 percent per annum that is amortized to tolls in 2002.

7.4 September 7 to December 31, 2000 Permanent Rates

Plateau calculated a revised toll of $25.39/$m^3$ on the Taylor to Kamloops pipeline for the period from September 7 to December 31, 2000 assuming that the Taylor to Prince George and Taylor to Kamloops segments of the pipeline would be returning to service (Exhibit 1, Tab 6, p. 3). The toll was calculated based on a revenue requirement of $4.708 million for this 2000 stub period and an expected volume of 1,600 m^3/d for the 116 days in the period. The toll represented the volume and revenue requirement on the

Taylor to Prince George segment only and would be charged on Prince George deliveries. The revenue requirement for the Prince George to Kamloops segment for the 2000 stub period was carried forward to the 2001 tolls. Plateau proposed that the tolls for the 2000 stub period and 2001 could be capped at a rate of $\$12.50/m^3$ provided that the uncollected tariff revenue and a carrying cost of 7 percent interest was recovered in years 2002 to 2004.

Plateau described its derivation of the revenue requirement for the 2000 stub period in the Application and testimony (Exhibit 1, Tab 6, page 3; T5: 853-857). The rate base included the revalued plant assets resulting from the Federated purchase of the pipeline in 1994 and the net plant additions to September 6, 2000. The capitalized major expenses were also included as a rate base deferral account and resulted in a total rate base of $12.178 million for the 2000 stub period (Exhibit 1, Tab 3, p. 3). In calculating tolls for the 2000 stub period, Plateau prorated the rate base between the Taylor to Prince George segment and Prince George to Kamloops segment based on the miles of pipe where Taylor to Prince George represents 46 percent of the overall pipeline length (T5: 813 and 845). A 15 percent return on rate base for the Taylor to Prince George segment was included in tolls for the 2000 stub period and a 15 percent return on rate base for the Prince George to Kamloops segment was carried forward to the 2001 revenue requirement.

Other items used in the toll calculation were income taxes on a deferred tax method, depreciation of existing plant assets and additions over the remaining years up to 2010, overhead at 15 percent of normal operating expenses and the actual normal operating expenses that were incurred for the 2000 stub period.

Husky proposed an alternative toll calculation for a normal year based on a volume/distance method and volumes of 1,600 m^3/d from Taylor to Prince George and 5,000 m^3/d from Taylor to Kamloops (Exhibit 5, Tab C; Exhibit 5D). Husky estimated tolls for a normal year of $\$2.11/m^3$ from Taylor to Prince George and $\$4.58/m^3$ from Taylor to Kamloops.

The Commission has calculated tolls for Taylor to Prince George and Taylor to Kamloops for the 2000 stub year and years 2001 to 2004 based on the Commission determinations in this Decision. The tolls are shown in Appendices A, B and C to this Decision. For the 2000 stub year, rates for the Taylor to Prince George segment and the Taylor to Kamloops segment were based on deemed volumes of 1,600 m^3/d to Prince George and 3,900 m^3/d to Kamloops where the toll from Taylor to Prince George is 65 percent of the toll from Taylor to Kamloops.

The allowed revenue requirement for the 2000 stub period is based on plant in service recorded at a fully depreciated historical cost method with depreciation over 20 years and major operating expenses added to deferred charges in the year incurred, with amortization over the next five years. Income taxes are calculated on a deferred method and overhead is included as 15 percent of normal operating expenses. The normal operating expenses allowed for the 2000 stub period are determined in Chapter 5 of this Decision.

The Commission determines that tolls for the 2000 stub period as shown in Appendix A of this Decision are $4.42/m^3 for Taylor to Prince George and $6.81/m^3 for Taylor to Kamloops. For the period from September 7 to September 20, 2000 the entire pipeline was out of service and Plateau should be held harmless for the deemed toll revenue that would have been recovered from deliveries to Prince George and Kamloops. For the time period that the Prince George to Kamloops segment was out of service while a hydrostatic test could have been performed, Plateau should be held harmless on the deemed toll revenue on Kamloops deliveries. From the date that the Kamloops segment could have returned to service following a hydrostatic test which is determined to have been December 1, 2000, the deemed toll revenue on deliveries to Kamloops is the responsibility of the shareholder.

For the September 7 to September 20, 2000 period, toll revenue of $471,000 is transferred to the unrecovered revenue deferral account. For the September 21 to November 30, 2000 period, the deemed toll revenue on the Kamloops segment of $1.885 million is transferred to the unrecovered revenue account. The unrecovered revenue deferral account accrues interest at the rate of 7 percent and is amortized into tolls over three years commencing in 2001.

7.5 2001 Permanent Rates

Plateau calculated the revenue requirement and tolls for 2001 in the same manner as the tolls for the September 7 to December 31, 2000 stub period that were described in Section 7.4 of this Decision. For 2001 a rate base of $20.108 million for the Taylor to Kamloops pipeline was used on a semi-depreciated basis with a 15 percent return on rate base after tax. The 2001 return on rate base was increased to include the return on rate base from the Prince George to Kamloops segment that was not included in 2000 tolls (T5: 812-816). Plateau calculated a 2001 revenue requirement of $20.693 million and forecasted deliveries of 1,600 m^3/d to Prince George and deliveries of 3,900 m^3/d to Kamloops. Plateau expected that deliveries to Prince George would occur all year and service to Kamloops would resume on September 1, 2001 (Exhibit 1, Tab 6, p. 3 as revised March 23, 2001). The forecasted volumes delivered to Prince George and Kamloops in 2001 totaled 1,059,800 m^3 and, when divided into the revenue requirement of \$20.693 million, produced a toll of \$19.52/m^3. The same toll of \$19.52/m^3 would be charged to Prince George deliveries and Kamloops deliveries as Plateau did not address whether a different toll should be charged to Prince George or Kamloops deliveries (T5: 817).

As described in Section 7.4 of this Decision, Husky proposed an alternative toll calculation for a normal year based on a volume/distance method and volumes of 1,600 m^3/d from Taylor to Prince George and 5,000 m^3/d from Taylor to Kamloops (Exhibit 5, Tab C; Exhibit 5D). Husky estimated tolls for a normal year of \$2.11/m^3 from Taylor to Prince George and \$4.58/m^3 from Taylor to Kamloops.

The Commission has calculated 2001 tolls for the Taylor to Prince George segment and the Taylor to Kamloops segment based on volumes of 1,600 m^3/d to Prince George and deemed volumes of 3,900 m^3/d to Kamloops from January 1 to October 31, 2001 then deemed volumes of 5,000 m^3/d from November 1 to December 31, 2001. The toll from Taylor to Prince George is 65 percent of the toll from Taylor to Kamloops.

The toll calculation in Appendix B to this Decision is also based on a fully depreciated historical cost rate base with depreciation over 20 years and major operating expenses added to deferred charges in the year incurred with amortization over the next five years. Income taxes are calculated on a deferred method and overhead is included as 15 percent of normal operating expenses. The normal operating expenses allowed for the 2001 are addressed in Chapter 5 of this Decision. The unrecovered revenue from the 2000 stub period described in Section 7.4 of this Decision is amortized to the revenue requirement over three years commencing in 2001.

As detailed in Appendix B, the Commission determines that a 2001 toll for deliveries from Taylor to Prince George of \$4.27/m^3 and from Taylor to Kamloops of \$6.56/m^3 is appropriate based on the expected volumes and the date when service to Kamloops is forecasted to resume. The Commission considers that Plateau has the opportunity to return the Prince George to Kamloops segment to service and recover the revenue requirement related to that segment from tolls charged to shippers. The Commission considers that the Prince George to Kamloops segment could have returned to service by December 1, 2000. The Commission expects Pembina to move expeditiously to design and complete a pressure test of the pipeline from Prince George to Kamloops to meet the obligations of Section 42 of the *Pipeline Act*.

8.0 COMPETITIVE TOLLS, SHIPPER COMMITMENTS AND ACTION PLAN

8.1 Maximum Competitive Toll on Western System

The Western System faces competition from the two pipeline systems that transport oil from Taylor east to Edmonton. The current spot toll on the Northern system is $9.00/m^3, and on the Taylor-Peace system is $9.00/m^3 or $7.00/m^3 depending on the volume shipped. The toll to ship crude oil from Edmonton to Burnaby on TMPL was reported as $11.139/m^3, and the toll to ship from Kamloops to Burnaby was $4.93/m^3 (Exhibit 1C, p. 79). Assuming a toll of $7.00/m^3 from Taylor to Edmonton, the effective toll to Kamloops via Edmonton is $13.209/m^3. This should represent the maximum toll that could be charged for delivery on the Western System from Taylor to Kamloops if the present tolls on the alternative pipelines continue into the future. The amount would be increased by TMPL's terminal charge, if the oil is held in tankage in Edmonton.

Plateau acknowledged that tolls on the Peace system and provincially regulated portions of the Federated system, which are regulated by the Alberta Energy and Utilities Board, may be changed by the pipeline company without obtaining regulatory approval (T3: 438 and 439). Pembina could impact the maximum toll that can be charged on the Western System by changing tolls on the provincially regulated pipelines in Alberta (Chevron Argument, p. 5).

The Western System is capable of delivering BC Light crude as a segregated stream, while the Northern and Taylor-Peace systems blend BC Light crude into the Boundary Lake, Peace sweet and Peace sour streams. No evidence was provided at the hearing that quantified the difference in value for BC Light crude as a segregated stream compared to a blended stream, as detailed information about refinery economics is proprietary commercial information. However, Chevron provided information showing that, in December 2000, Boundary Lake and Peace sour crudes were priced $32/m^3 to $34/m^3 lower than the price for Peace sweet (Chevron Undertaking at T7: 1310). This supports the view that the value of BC Light crude is lower when delivered to Edmonton in a mixed stream.

The maximum toll that could be charged on the Western System may also be considered in terms of a customer's alternate cost of crude oil delivery. Husky reported that, with construction of additional facilities, crude oil could be supplied by rail to its Prince George refinery at a delivery cost of $13 to $15/m^3 (Exhibit 5A, p. 3). During the summer of 2000 when pipeline service was disrupted, Husky trucked crude to its refinery, at a trucking cost of $30/m^3 to $50/m^3.

Chevron testified that marine shipments, trucking or rail are not practical for large volume deliveries due to logistical constraints, and that only pipeline delivery provides a means of maintaining a financially viable refinery in Burnaby (T7: 1279). Chevron stated that it would compare the cost of buying crude at Taylor and shipping it to Kamloops at the Western System toll to the cost of buying oil at Edmonton and shipping it down TMPL, and make a supply purchase decision in the best economic interest of Chevron at that time (T7: 1288).

It is evident that the maximum competitive Western System toll is not solely dependent on the tolls of competing pipeline systems. Other factors to consider include the crude oil price in alternative markets available to producers and the price of other crude supply accessible to refiners, as well as the quality of various crude streams and their value as refinery feedstock. However, the evidence in the hearing indicates that BC Light crude, in particular, is sought after by refiners in British Columbia, and the Commission considers that the comparison of tolls is a reasonable approximation of overall competitiveness.

The tolls calculated for the Western System for the 2000 stub period and for 2001 are only slightly higher than the rates that were in effect prior to the line rupture, and the toll of $6.56/m^3 for 2001 is approximately one-half of the lowest cost pipeline alternative. The Commission prepared Appendix C, which is a forecast of tolls on the Western System for the years 2002 to 2004 that is generally based on a projection of 2001 tolls assuming that normal operating expenses would inflate at two percent per year as forecasted by Plateau (T4: 738 and 739). The toll to Kamloops is expected to decrease to $6.32/m^3 for 2004, which is lower than the rate of $6.40/m^3 that was in effect prior to the line break.

Producers have sustained the crude oil reserve life index for the past 15 years and, based on current levels of drilling activity, the Commission anticipates that the supply of crude at Taylor will be maintained for the foreseeable future. The Commission expects Plateau's proposed upgrades and maintenance activities will significantly extend the physical life of the pipeline, and the revenue generated by the approved tolls will enable Plateau to recover its costs and earn a reasonable return.

Based on the evidence, the Commission concludes that the tolls for September 7 to December 31, 2000 and for 2001 are competitive with the other oil pipelines from Taylor, which supports the load forecast for the Western System that was determined in Chapter 3. The Commission considers that, in the absence of unexpected changes to tolls on competing pipelines, the Western System will be financially viable for the foreseeable future.

8.2 Shipper Commitments

The Application stated that bringing the Western System up to a reasonable standard would entail significant expenditures which Plateau was reluctant to incur unless it had reasonable assurance of recovering the costs in tolls. Plateau requested that the Commission approve, as a condition in accordance with Section 42 of the *Pipeline Act*, a requirement that shippers provide a volume commitment for a period of time at the proposed tolls. This would provide Plateau with revenue assurances to underwrite the expenditures and retire them over a period of time to smooth the costs, and would also protect shippers who remain on the Western System from declines in volume (Exhibit 1, Tab 7, pp. 1 and 2). Plateau proposed that the toll for delivering uncommitted volumes should be 5 percent higher than the toll charged for committed volumes (Exhibit 1, Tab 7, p. 4). Plateau indicated that the shipper commitments and the requested tolls were the two conditions required by its parent company, Pembina, before any debt or equity financing for investments in the Western System would be forthcoming (T4: 756).

To reopen the pipeline to Kamloops, Plateau required a volume commitment under deliver or pay contracts, or reserve dedication agreements, of 5,500 m^3/d for a period of ten years. The commitment was shown as 1,600 m^3/d delivered to Prince George and 3,900 m^3/d delivered to Kamloops. Plateau accepted that approximately 3,000 m^3/d presently committed to the Northern system under Federated facility agreements would count as part of the 5,500 m^3/d. This would leave 2,500 m^3/d of further commitments (Plateau Argument, p. 38). The deliver or pay commitments would be annual with an adjustment in the 13th month (Exhibit 1F, p. 18).

In the event the southern Prince George to Kamloops section did not reopen, Plateau required a volume commitment under deliver or pay contracts, or reserve dedication agreements on the northern Taylor to Prince George section of 1,600 m^3/d for a period of five years.

Plateau argued that the tolls and shipper commitments should be an all or nothing condition. Unless it received the tolls it applied for and the shipper commitments, Plateau stated it would request permission to shut down the pipeline, and intended to put the line up for sale (T3: 405-407).

Plateau provided the following rationale for requiring the commitments (Exhibit 1, Tab 7, pp. 1 and 2):

1. Plateau faces significant risk as producers and shippers have a choice of market options available from Taylor.

2. Volumes presently shipped to the Husky refinery at Prince George are at risk, especially after 2004.

3. Chevron may increase its use of synthetic crude from Athabasca Oil Sands and use of the Scotford Refinery to reduce its demand for British Columbia produced petroleum.

4. Refiners in the Pacific Northwest and the Lower Mainland may use more crude from Alaska North Slope and less from British Columbia.

Plateau cited a number of examples where the NEB recognized the need for commitments in the form of mandatory payments or fixed terms for shipments. Husky and Encal contended that the examples cited by Plateau were not relevant to the circumstances of the Western System, as they were instances of new services or construction of new facilities in a competitive environment.

Husky, Chevron, Encal, Imperial Oil and CAPP all opposed the request for shipper commitments on the basis that such commitments were not required on the Western System prior to the break, including when Pembina did its assessment of risk factors prior to purchasing the pipeline. Competitive tariffs would ensure that volumes that are consistent with those Pembina used in its assessment of the Western System would continue to move on the pipeline without the need for shipper commitments.

Husky stated that shippers receive no rate certainty from Plateau in the form of flat tolls, nor do they receive assurance Pembina will keep the system operational in the future (Husky Argument, p. 41). Husky suggested that the requested commitments would result in discriminatory treatment of shippers, as it would create two classes with different access to Pembina's pipeline systems. One class of shippers would hold facility commitments and could use either the Western System or the Northern system, while the other class making new volume commitments could ship solely on the Western System (Husky Argument, pp. 45 and 46). Plateau was not prepared to provide a similar reciprocal arrangement for the new commitments, as this could strand the investment required to upgrade the Western System (Exhibit 1C, p. 90).

Chevron stated that shippers who are not producers may find it difficult to ensure that they have continual access to crude supplies given the relatively small size of the market for B.C. crude (Chevron Argument, p. 5). Chevron noted that Plateau could not guarantee to shippers that the tariffs on the other pipelines to Edmonton would remain fixed for the same period of time, and explained that without certainty on the cost of transportation of B.C. crude to Edmonton, shippers to Kamloops could not be certain of the economics of the tariff to Kamloops (Chevron Argument, p. 5). Imperial Oil commented that pricing relationships may change between West Coast and Chicago markets, so that shippers with commitments may not be able to sell their crude in the most advantageous market (Imperial Oil Argument, p. 8).

Chevron also stated that its interests in the Athabasca Oil Sands project would not have an impact on its demand for B.C. crude. Even if the Burnaby refinery was able to process material from the Scotford Upgrader outside Edmonton, this feedstock would replace existing synthetic crude purchases rather than crude oil (Exhibit 7A, p. 1). Chevron stated that it has no plans at this time to shut down its Burnaby refinery, and that it will upgrade the refinery to meet Federal gasoline standards required in 2005 (Exhibit 7B, p. 7). In addition, Chevron commented that Washington state refineries seldom vary their monthly purchases of Canadian crude and when they do reduce their demand for B.C. crude, other buyers such as Chevron have entered the market to purchase the surplus (Exhibit 7A, p. 2).

The Commission has determined that Western System tolls are expected to remain competitive with other pipeline alternatives for the foreseeable future. Throughput on the Western System at the forecast volumes and at the allowed tolls will result in Plateau receiving a reasonable rate of return on rate base and recovery of its expenses and system upgrading expenditures.

The Commission is aware that shippers are unwilling to provide the requested commitments and these risks are reflected in the ROE that has been established for the pipeline. Shippers will be expected to comply with all reasonable requests for forecasts of expected shipments, such as the five year forecasts that have been provided in the past on the Western System.

The Commission denies Plateau's request for approval of a requirement that shippers provide volume commitments.

8.2.1 Deferral Account for Deliveries in Excess of Commitments

Plateau intended to calculate its tolls by dividing the revenue requirement by the committed volume (T5: 816). Plateau requested a deferral account to record the excess revenue in the event that actual volumes shipped exceeded the committed volume. The deferral account balance would attract interest, and the balance would be a credit when calculating the toll for committed volumes for the next year (Exhibit 1, Tab 5, p. 2). **The Commission has denied Plateau's request for shipper commitments, and therefore the requested deferral account is not required.**

8.3 Application for Suspension

The Application included an application for Suspension of Service, in the belief that shippers likely would not wish to commit to sufficient volumes at the requested tolls for a defined term. Pembina's final position requested the Commission approve the tolls and require the volume commitments identified in Section 1.3, items 1 or 2 and failing that, requested suspension of all or part of the Western System (Plateau Argument,

p. 44). Plateau proposed that, if the shippers failed to accept Plateau's criteria for resumption of service within a reasonable time frame, the Commission could, without further proceedings, issue an Order permitting suspension of operation of all or part of the Western System. Plateau proposed to keep the system under suspension while it considered the alternatives available, including possible sale of the pipeline (Exhibit 1, Tab 8, p. 1).

The Commission has determined that Western System tolls through 2004 are competitive with other pipeline alternatives. It has determined that at these rates, and with the anticipated crude oil supply and demand volumes, oil will continue to flow from Taylor to Kamloops at or near historic levels. The Commission has also determined that the tolls set out in Appendices A and B provide sufficient revenue to recover the approved operating expenses and capital costs over a reasonable time period and to provide for a fair return on equity.

In accordance with these determinations, the Commission denies the application for the Suspension of Service.

8.4 Action Plan

The Commission has determined permanent tolls for the Western System that place the pipeline on a sound financial foundation for the future. **The Commission directs Plateau to file tariff sheets setting out permanent tolls for the September 7 to December 31, 2000 period and the 2001 test year in accordance with the directions contained in this Decision, by July 31, 2001.**

The Commission is of the view that regulation of the Western System on a reporting basis reduces the cost of regulation, and generally is in the best interests of both the pipeline owner and shippers. With the pipeline on a sound foundation, the Commission expects that Plateau and shippers will work together so that regulation on a reporting basis can resume and Commission involvement will be minimal except in the event of a complaint.

Nevertheless, the Commission considers that timely actions to re-establish full operation of the Western System are needed to preserve the pipeline as a viable entity. Pembina may decide to sell the Western System but, until the sale is completed, such a decision does not reduce its responsibility to provide service to shippers. **Pursuant to Sections 42 and 43 of the *Pipeline Act*, the Commission directs Plateau and Pembina to proceed immediately with all steps that are necessary to resume full operation, specifically:**

1. **Within 30 days of the date of this Decision, file with the OGC, and copied to the BCUC and Intervenors, a hydrostatic test program for the southern section of the pipeline that:**

   - **addresses the certified operating pressure concern in the Bonaparte River and Loon Lake areas,**
   - **considers issues raised by the Canspec report, and**
   - **meets the OGC's requirements for removal of the restriction to 75 percent of the certified operating pressure.**

2. **Proceed with the hydrostatic test of the southern section as soon as possible after the OGC accepts the test program and, upon successful completion of the test, resume service to Kamloops.**

3. **Within 30 days of the date of this Decision, file with the BCUC, the OGC and Intervenors a detailed action plan for returning the pipeline to full operation as soon as possible, including a timetable that identifies target completion dates for the major activities.**

4. **File monthly progress reports with the BCUC, OGC and Intervenors on steps taken to resume service**.

Dated at the City of Vancouver, in the Province of British Columbia, this 26th day of June 2001.

Original signed by:
Peter Ostergaard
Chair

Original signed by:
Kenneth L. Hall
Commissioner

Original signed by:
Barbara L. Clemenhagen
Commissioner

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER P-3-01

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IN THE MATTER OF
the Pipeline Act, R.S.B.C. 1996, c. 364

and

An Application by Plateau Pipe Line Ltd.
for Approval of 2000 and 2001 Tolls and Suspension of Service

BEFORE: P. Ostergaard, Chair)
B.L. Clemenhagen, Commissioner) June 26, 2001
K.L. Hall, Commissioner)

O R D E R

WHEREAS:

A. On December 29, 2000 Plateau Pipe Line Ltd. ("Plateau") filed an Application for permanent tolls effective September 7, 2000 and January 1, 2001 in accordance with Order No. P-10-00. The Application, as revised on March 23, 2001, requested shipper volume commitments and approval of suspension of service if commitments were not forthcoming at the requested volumes and tolls. The Application also addressed the incentive tolls from January 1, 2000 to September 6, 2000 and the sharing adjustments pursuant to the Incentive Tolling Agreement approved by Order No. P-3-00 ("the Application"); and

B. The Application requested that the interim tolls approved by Order No. P-6-00 and in effect from September 7, 2000 of $4.16/m^3$ for deliveries to Prince George and $6.40/m^3$ for deliveries to Kamloops increase on a permanent basis to $12.50/m^3$ effective September 7, 2000 to December 31, 2001 for both delivery points, subject to shipper commitments of 5,500 m^3/d for ten years; and

C. If the pipeline is only to stay open from Taylor to Prince George, the Application requested permanent tolls of $18.64/m^3$ from September 7 to December 31, 2000 and $15.39/m^3$ for 2001 if Husky would commit to 1,600 m^3/d for five years. The system south of Prince George would be suspended; and

D. If commitments from Husky or Kamloops shippers failed to materialize, the Application requested the suspension of the entire pipeline; and

E. Commission Order No. P-1-01 amended the Regulatory Timetable for the review of the Application to provide additional time for the filing of evidence, issuing information requests and responses and rescheduled the public hearing to April 2, 2001 in response to a request by Plateau and letters of comment from Registered Intervenors; and

F. The Commission has considered the Application and the evidence adduced thereon, as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. Permanent rates are approved effective September 7, 2000 to December 31, 2000 of $4.42/m^3$ for deliveries from Taylor to Prince George and $6.81/m^3$ for deliveries from Taylor to Kamloops.

2. Permanent rates are approved effective January 1, 2001 of $4.27/m^3 for deliveries from Taylor to Prince George and $6.56/m^3 for deliveries from Taylor to Kamloops.

3. The request to require shipper commitments is denied.

4. The Application for suspension of service on the Western System is denied.

5. Plateau is to file permanent tariff sheets that are in accordance with the Commission's Decision.

6. Plateau and its parent company, Pembina Pipeline Corporation, are to comply with all directions contained in the Commission's Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 26th day of June 2001.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Calculation of Tariffs
September 7 to December 31, 2000
($'000)

	Application	Revised Application	Adjustments	No.		Adjusted Balances
Operating Expense	1,275	1,421	1,715	(1)		3,136
Amortization						
Major Operating Expense	2,269	2,276	(2,076)	(2)		200
Unrecovered Revenue						
Incentive Sharing Adjustment						
Overhead	191	213	257	(3)		470
Depreciation	346	296	(293)	(4)		3
Income Taxes	295	229	(197)			32
Earned Return	352	273	(213)	(5)		60
Revenue Requirement	4,728	4,708				3,900
Toll Calculation						
Volume: Taylor to Prince George (m3/d)	1600	1600			1600	
Toll: Taylor to Prince George	25.47	25.37				4.42
Volume: Taylor to Kamloops (m3/d)	0	0	3900	(6)	3900	
Toll: Taylor to Kamloops						6.81

Notes:

(1) To remove carryforward of Operating Expense from 2000 to 2001
To adjust actual Operating Expense for power costs and linefill purge revenue

Actual Operating Exp - Ex. 1, Tab 6, p. 6	2,971
Add: Revised Power Cost-Decision Section 5.4	667
Less: Original Power Cost-Ex. 1, Tab 6, p. 6	(310)
Less: Linefill Purge Revenue-Decision Section 5.2	(192)
Revised Operating Expense	3,136

(2) To adjust amortization of major operating expenses to five years commencing in year of addition

(3) To adjust overhead to 15% of normal operating expenses

(4) To adjust depreciation to 20 years based on fully depreciated historical cost

(5) To adjust earned return for allowed capital structure

(6) To include deemed volumes of Taylor to Kamloops for 116 days (452,400 m3)
Prince George volume for 116 days (185,600 m3)
Prince George toll is 65% of Kamloops toll
Kamloops toll=Rev. Req./((Prince George volume *65%)+(Kamloops volume))

(7) To transfer revenue requirement to unrecovered revenue deferral account

Sept. 7 to Sept. 20: Prince George and Kamloops toll revenue	
1600 m3*\$4.42*14 days+3900 m3*\$6.81*14 days=	471
Sept. 21 to Nov. 30: Kamloops toll revenue	
3900 m3*\$6.81*71 days=	1,885
Total	2,355

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Rate Base
September 7 to December 31, 2000
($'000)

	Application	Revised Application	Adjustments	No.	Adjusted Balances
Plant in Service					
Opening-Semi Depreciated	14,578	12,786	(12,786)	(1)	
Opening- Original Cost			45,512	(1)	45,512
Additions					
Closing	14,578	12,786			45,512
Mid-Year Average	14,578	12,786			45,512
Accumulated Depreciation					
Opening-Semi Depreciated	3,433	3,246	(3,246)	(1)	
Opening- Original Cost			45,456	(1)	45,456
Depreciation	346	296	(293)	(2)	3
Closing	3,779	3,542			45,459
Mid-Year Average	3,606	3,394			45,457
Average Plant in Service-Semi Depr	12,775	11,089			
Average Plant in Service-Orig Cost					55
Working Capital	159	159	233	(3)	392
Deferral Accounts	914	930	469	(4)	1,399
Rate Base	13,848	12,178			1,846

Notes:

(1) To restate from 1994 revaluation and semi-depreciated method to fully depreciated historical cost method

Semi-depreciated calculation:	Application	Rev. App
Mid-Year Plant	14,578	12,786
One-Half Acc. Depr.	1,803	1,697
Avg. Plant-Semi-Depr.	12,775	11,089

(2) To adjust depreciation from 10 year remaining life to 20 year straight line
Depreciation 5% per year on 2000 net plant and in the year following additions

(3) To adjust working capital to 1/8th of normal operating expense

(4) To adjust deferral accounts for capitalized major expenses from semi-depreciated method to fully depreciated historical cost method

Deferral Accounts (5) Major Operating Expense Projects	Opening 2000	Additions 2000	Amortization 2000	Closing 2000	Mid-Year 2000
Line Break Repair & Test	0	1,058	71	987	494
Insurance Deductible	0	100	7	93	47
Uninsured Costs	0	1,000	67	933	467
Hydrotest	0	777	52	725	363
Tank Cleaning and Inspection	0	0	0	0	0
Internal Line Inspection	0	0	0	0	0
Line Repairs	0	0	0	0	0
Turbine Repair	0	0	0	0	0
ROW, River Crossings	0	13	1	12	6
Risk Assessment & Integrity Mgt	0	50	3	47	23
Total	0	2,998	200	2,798	1,399

(5) 2000 amortization is 4 months of a 5 year (60 month) amortization period

Non-Rate Base Deferral Accounts	Opening 2000	Additions 2000	Interest 2000	Amortization 2000	Closing 2000
Unrecovered Revenue	0	2,355	0	0	2,355
Incentive SharingAdjustment	0	115	0	0	115
Total	0	2,470	0	0	2,470

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Income Taxes
September 7 to December 31, 2000
($'000)

	Application	Revised Application	Adjustments	No.	Adjusted Balances
Earned Return	352	273	(213)	(1)	60
Less Debt Interest			22	(1)	22
Accounting Income after Tax	352	273	(235)		38
Deduct: Timing Differences					
Add: Def Maj Op Exp Amort					200
Deduct: Deferred Maj Op Exp					238
Net Timing Differences			(38)	(2)	(38)
After Tax Income	352	273	(273)		0
Gross-Up	0.5438	0.5438			0.5438
Taxable Income	647	502			0
Tax Rate	0.4562	0.4562			0.4562
Income Taxes-current	295	229		(3)	0
Income Taxes-deferred	-	-		(3)	32
Total Income Taxes	295	229			32

Deferred Maj Op Exp Additions	2,998
Less: Carryforward	(2,760)
Add: Carryforward Used	
Deferred Maj Op Exp-Deducted	238

Notes:

(1) To adjust earned return from 100% equity and 15% ROE to allowed capital structure

(2) To include timing differences on deferral account expenses and amortization
Other timing differences such as Capital Cost Allowance deduction ("CCA") not identified in Application. Calculation assumes that depreciation expense add back is equal to CCA deduction

(3) Application income taxes and adjusted income taxes on deferred tax method

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Capital Structure
September 7 to December 31, 2000
($'000)

Application	Deemed Capitalization		Cost	Weighted Cost	Return	No.
Common Equity	13,848	100%	15%	15.000%	660	(1)
			Carryforward to 2001		(308)	(2)
					352	

Revised Application	Deemed Capitalization		Cost	Weighted Cost	Return	
Common Equity	12,178	100%	15%	15.000%	581	(1)
			Carryforward to 2001		(308)	(2)
					273	

Adjusted Balances	Deemed Capitalization		Cost	Weighted Cost	Return	
Short Term Debt	169	9%	6.00%	0.549%	3	
Deferred Income Taxes	16	1%	0.00%	0.000%	-	
Long Term Debt	738	40%	7.50%	3.000%	18	
Common Equity	923	50%	12.25%	6.125%	38	
	1,846			9.674%	60	(3)

Deferred Taxes Payable	Opening	Adds(Reduc)	Closing	Mid-year
2000	0	32	32	16

Notes:

(1) Calculates 15% return on rate base for 116 days from Sept. 7 to Dec. 31, 2000

(2) Carryforward is difference between full return for 116 days and Plateau's applied for return

(3) Adjusts earned return from 100% equity and 15% return to allowed capital structure

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Calculation of Tariffs
2001
($'000)

	Application	Revised Application	Adjustments	No.		Adjusted Balances
Operating Expense	8,599	8,998	(1,453)	(1)		7,545
Amortization						
Major Operating Expense	2,269	2,276	(833)	(2)		1,443
Unrecovered Revenue			840	(3)		840
Incentive Sharing Adjustment						
Overhead	1,290	1,350	(218)	(4)		1,132
Depreciation	2,091	1,936	(1,933)	(5)		3
Income Taxes	2,991	2,798	(2,338)			460
Earned Return	3,565	3,335	(2,480)	(6)		855
Revenue Requirement	20,805	20,693				12,278
Toll Calculation						
Volume: Taylor to Prince George (m3/d)	1600	1600		(7)	1600	
Toll: Taylor to Prince George	15.98	19.53				4.27
Volume: Taylor to Kamloops (m3/d)	3900	3900		(7)	3900	
Toll: Taylor to Kamloops	15.98	19.53		(7)	5000	6.56

Notes:

(1) To remove carryforward of 2000 O&M to 2001
To adjust forecast Operating Expense for power costs on deemed volume

Forecast Operating Exp.- Ex. 1, Tab 6, p. 6	7,448
Add: Revised Power Cost-Decision Section 5.4	2,197
Less: Original Power Cost-Ex. 1, Tab 6, p.6	(2,100)
Revised Operating Expense	7,545

(2) To adjust amortization of major operating expenses

(3) To amortize unrecovered revenue

(4) To adjust overhead to 15% of normal operating expenses

(5) To adjust depreciation to 20 years based on fully depreciated historical cost

(6) To adjust earned return for allowed capital structure

(7) To adjust volume for deemed Kamloops volumes of 3900 m3/day from Jan. 1 to Oct. 31, 2001 and 5000 m3/day from Nov. 1 to Dec. 31, 2001. Total Kamloops volume 1,490,600 m3. Prince George volume is 584,000 m3. Prince George toll is 65% of Kamloops tolls. Kamloops toll=Rev. Req./((Prince George volume *65%)+(Kamloops volume))

Application volumes: Kamloops deliveries commence July 1, 2001. Total Kamloops volume 717,600 m3 Prince George volume is 584,000 m3. Prince George toll is 100% of Kamloops toll.

Revised Application volumes: Kamloops deliveries commence Sept. 1, 2001. Total Kamloops volume 475,800 m3. Prince George volume is 584,000 m3. Prince George toll is 100% of Kamloops toll.

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Rate Base
2001
($'000)

	Application	Revised Application	Adjustments	No.	Adjusted Balances
Plant in Service					
Opening-Semi Depreciated	14,578	12,786	(12,786)	(1)	
Opening- Original Cost			45,512	(1)	45,512
Additions	10,113	10,113		(2)	7,552
Closing	24,691	22,899			53,064
Mid-Year Average	19,635	17,843			49,288
Accumulated Depreciation					
Opening-Semi Depreciated	3,779	3,542	(3,542)	(1)	
Opening- Original Cost			45,459	(1)	45,459
Depreciation	2,091	1,936	(1,933)	(3)	3
Closing	5,870	5,478			45,462
Mid-Year Average	4,825	4,510			45,460
Average Plant in Service-Semi Depr	17,222	15,588			
Average Plant in Service-Orig Cost					3,828
Working Capital	1,075	1,121	(178)	(4)	943
Deferral Accounts	3,369	3,399	785	(5)	4,184
Rate Base	21,666	20,108			8,955

Notes:

(1) To restate from 1994 revaluation and semi-depreciated method to fully depreciated historical cost method

Semi-depreciated calculation:	Application	Rev. App
Mid-Year Plant	19,635	17,843
One-Half Acc. Depr.	2,413	2,255
Avg. Plant-Semi-Depr.	17,222	15,588

(2) To adjust plant additions to amounts in Decision-Chapter 2, Table 2-1

(3) To adjust depreciation from 10 year remaining life to 20 year straight line
Depreciation 5% per year on 2000 net plant and in year following additions

(4) To adjust working capital to 1/8th of normal operating expense

(5) To adjust deferral accounts for capitalized major expenses from semi-depreciated method to fully depreciated historical cost method

Deferral Accounts	Opening 2001	Additions 2001	Amortization 2001	Closing 2001	Mid-Year 2001
Major Operating Expense Projects					
Line Break Repair & Test	987	0	212	776	882
Insurance Deductible	93	0	20	73	83
Uninsured Costs	933	0	200	733	833
Hydrotest	725	1,200	395	1,530	1,128
Tank Cleaning and Inspection	0	600	120	480	240
Internal Line Inspection	0	660	132	528	264
Line Repairs	0	1,280	256	1,024	512
Turbine Repair	0	125	25	100	50
ROW, River Crossings	12	200	43	170	91
Risk Assessment & Integrity Mgt	47	150	40	157	102
Total	2,798	4,215	1,443	5,571	4,184

Non-Rate Base Deferral Accounts	Opening 2001	Additions 2001	Interest 2001	Amortization 2001	Closing 2001
Unrecovered Revenue	2,355	0	165	840	1,680
Incentive SharingAdjustment	115	0	8	0	123
Total	2,470	0	173	840	1,803

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Income Taxes
2001
($'000)

	Application	Revised Application	Adjustments	No.	Adjusted Balances
Earned Return	3,565	3,335	(2,480)	(1)	855
Less Debt Interest			307	(1)	307
Accounting Income after Tax	3,565	3,335	(2,786)		549
Deduct: Timing Differences					
Add: Def Maj Op Exp Amort					1,443
Deduct: Deferred Maj Op Exp					1,991
Net Timing Differences			(549)	(2)	(549)
After Tax Income	3,565	3,335	(3,335)		0
Gross-Up	0.5438	0.5438			0.5438
Taxable Income	6,556	6,133			0
Tax Rate	0.4562	0.4562			0.4562
Income Taxes-current	2,991	2,798		(3)	0
Income Taxes-deferred	-	-		(3)	460
Total Income Taxes	2,991	2,798			460

Deferred Maj Op Exp Additions	4,215
Less: Carryforward	(2,224)
Add: Carryforward Used	
Deferred Maj Op Exp-Deducted	1,991

Notes:

(1) To adjust earned return from 100% equity and 15% ROE to allowed capital structure

(2) To include timing differences on deferral account expenses and amortization
Other timing differences such as Capital Cost Allowance deduction ("CCA") not identified in Application. Calculation assumes that depreciation expense add back is equal to CCA deduction

(3) Application income taxes and adjusted income taxes on deferred tax method

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Capital Structure
2001
($'000)

Application	Deemed Capitalization		Cost	Weighted Cost	Return	No.
Common Equity	21,666	100%	15%	15.000%	3,250	(1)
			Carryforward from 2000		308	(2)
			Rounding		7	(2)
					3,565	

Revised Application	Deemed Capitalization		Cost	Weighted Cost	Return	(1) (2)
Common Equity	20,108	100%	15%	15.000%	3,016	
			Carryforward from 2000		308	
			Rounding		11	(2)
					3,335	

Adjusted Balances	Deemed Capitalization		Cost	Weighted Cost	Return	
Short Term Debt	634	7%	6.00%	0.425%	38	
Deferred Income Taxes	262	3%	0.00%	0.000%	-	
Long Term Debt	3,582	40%	7.50%	3.000%	269	
Common Equity	4,478	50%	12.25%	6.125%	549	
	8,955			9.550%	855	(3)

Deferred Taxes Payable	Opening	Adds(Reduc)	Closing	Mid-year
2001	32	460	492	262

Notes:

(1) Calculates 15% return on rate base

(2) Carryforward of 2000 return. Rounding difference possibly interest charge on carryforward

(3) Adjusts earned return from 100% equity and 15% return to allowed capital structure

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Calculation of Tariffs
2002 to 2004
($'000)

	2002	2003	2004	No.
Operating Expense	7,539	7,690	7,843	(1)
Amortization				
Major Operating Expense	1,848	2,008	2,276	
Unrecovered Revenue	899	962	0	
Incentive Sharing Adjustment	132			
Overhead	1,131	1,153	1,177	
Depreciation	380	475	535	
Income Taxes	769	801	783	
Earned Return	1,403	1,416	1,329	
Revenue Requirement	14,100	14,505	13,942	
Toll Calculation				
Volume: Taylor to Prince George (m3/d)	1600	1600	1600	
Toll: Taylor to Prince George	4.16	4.28	4.11	
Volume: Taylor to Kamloops (m3/d)	5000	5000	5000	
Toll: Taylor to Kamloops	6.40	6.58	6.32	

Note:
(1) Operating Expense for 2002 based on 2001 with adjustments and inflation. 2003 and 2004 is prior year plus inflation

	2002
Operating Expense from 2001	7,545
Less: 2001 Legal and Regulatory	(350)
Subtotal	7,195
Inflation: 2%	144
Add: 2002 Legal and Regulatory	200
Operating Expense for 2002	7,539

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Rate Base
2002 to 2004
($'000)

	2002	2003	2004
Plant in Service			
Opening- Original Cost	53,064	54,964	56,164
Additions	1,900	1,200	1,200
Closing	54,964	56,164	57,364
Mid-Year Average	54,014	55,564	56,764
Accumulated Depreciation			
Opening- Original Cost	45,462	45,842	46,317
Depreciation	380	475	535
Closing	45,842	46,317	46,853
Mid-Year Average	45,652	46,080	46,585
Average Plant in Service-Orig Cost	8,362	9,484	10,179
Working Capital	942	961	980
Deferral Accounts	5,659	5,144	4,073
Rate Base	14,964	15,590	15,232

Deferral Accounts Major Operating Expense Projects	Opening 2002	Additions 2002	Amortization 2002	Closing 2002	Mid-Year 2002
Line Break Repair & Test	776	0	212	564	670
Insurance Deductible	73	0	20	53	63
Uninsured Costs	733	0	200	533	633
Hydrotest	1,530	0	395	1,134	1,332
Tank Cleaning and Inspection	480	600	240	840	660
Internal Line Inspection	528	0	132	396	462
Line Repairs	1,024	1,100	476	1,648	1,336
Turbine Repair	100	125	50	175	138
ROW, River Crossings	170	200	83	287	228
Risk Assessment & Integrity Mgt	157	0	40	117	137
Total	5,571	2,025	1,848	5,748	5,659

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Rate Base
2002 to 2004
($'000)

Deferral Accounts Major Operating Expense Projects	Opening 2003	Additions 2003	Amortization 2003	Closing 2003	Mid-Year 2003
Line Break Repair & Test	564	0	212	353	458
Insurance Deductible	53	0	20	33	43
Uninsured Costs	533	0	200	333	433
Hydrotest	1,134	0	395	739	937
Tank Cleaning and Inspection	840	600	360	1,080	960
Internal Line Inspection	396	0	132	264	330
Line Repairs	1,648	0	476	1,172	1,410
Turbine Repair	175	0	50	125	150
ROW, River Crossings	287	200	123	364	326
Risk Assessment & Integrity Mgt	117	0	40	77	97
Total	5,748	800	2,008	4,540	5,144

Deferral Accounts Major Operating Expense Projects	Opening 2004	Additions 2004	Amortization 2004	Closing 2004	Mid-Year 2004
Line Break Repair & Test	353	0	212	141	247
Insurance Deductible	33	0	20	13	23
Uninsured Costs	333	0	200	133	233
Hydrotest	739	0	395	344	541
Tank Cleaning and Inspection	1,080	600	480	1,200	1,140
Internal Line Inspection	264	540	240	564	414
Line Repairs	1,172	0	476	696	934
Turbine Repair	125	0	50	75	100
ROW, River Crossings	364	200	163	402	383
Risk Assessment & Integrity Mgt	77	0	40	37	57
Total	4,540	1,340	2,276	3,605	4,073

Non-Rate Base Deferral Accounts	Opening 2002	Additions 2002	Interest 2002	Amortization 2002	Closing 2002
Unrecovered Revenue	1,680	0	118	899	899
Incentive SharingAdjustment	123	0	9	132	0
Total	1,803	0	126	1,031	899

Non-Rate Base Deferral Accounts	Opening 2003	Additions 2003	Interest 2003	Amortization 2003	Closing 2003
Unrecovered Revenue	899	0	63	962	0

Non-Rate Base Deferral Accounts	Opening 2004	Additions 2004	Interest 2004	Amortization 2004	Closing 2004
Unrecovered Revenue	0	0	0	0	0

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Income Taxes
2002 to 2004
($'000)

	2002	2003	2004
Earned Return	1,403	1,416	1,329
Less Debt Interest	486	462	396
Accounting Income after Tax	917	955	933
Deduct: Timing Differences			
Add: Def Maj Op Exp Amort	1,848	2,008	2,276
Deduct: Deferred Maj Op Exp	2,764	2,962	3,423
Net Timing Differences	(917)	(955)	(1,147)
After Tax Income	0	0	(214)
Gross-Up	0.5438	0.5438	0.5438
Taxable Income	0	0	(394)
Tax Rate	0.4562	0.4562	0.4562
Income Taxes-current	0	0	(180)
Income Taxes-deferred	769	801	962
Total Income Taxes	769	801	783
Deferred Maj Op Exp Additions	2,025	800	1,340
Less: Carryforward			
Add: Carryforward Used	739	2,162	2,083
Deferred Maj Op Exp-Deducted	2,764	2,962	3,423

Notes:

(1) To adjust earned return from 100% equity and 15% ROE to allowed capital structure

(2) To include timing differences on deferral account expenses and amortization Other timing differences such as Capital Cost Allowance deduction ("CCA") not identified in Application. Calculation assumes that depreciation add back is equal to CCA deduction

(3) Application income taxes and adjusted income taxes on deferred tax method

Plateau Pipe Line Ltd.
Taylor to Kamloops Pipeline
Capital Structure
2002 to 2004
($'000)

2002 Adjusted Balances	Deemed Capitalization		Cost	Weighted Cost	Return
Short Term Debt	620	4%	6.00%	0.249%	37
Deferred Income Taxes	876	6%	0.00%	0.000%	-
Long Term Debt	5,986	40%	7.50%	3.000%	449
Common Equity	7,482	50%	12.25%	6.125%	917
	14,964			9.374%	1,403

2003 Adjusted Balances	Deemed Capitalization		Cost	Weighted Cost	Return
Short Term Debt	(102)	-1%	6.00%	-0.039%	(6)
Deferred Income Taxes	1,661	11%	0.00%	0.000%	-
Long Term Debt	6,236	40%	7.50%	3.000%	468
Common Equity	7,795	50%	12.25%	6.125%	955
	15,590			9.086%	1,416

2004 Adjusted Balances	Deemed Capitalization		Cost	Weighted Cost	Return
Short Term Debt	(1,020)	-7%	6.00%	-0.402%	(61)
Deferred Income Taxes	2,543	17%	0.00%	0.000%	-
Long Term Debt	6,093	40%	7.50%	3.000%	457
Common Equity	7,616	50%	12.25%	6.125%	933
	15,232			8.723%	1,329

Deferred Taxes Payable	Opening	Adds(Reduc)	Closing	Mid-year
2002	492	769	1,261	876
2003	1,261	801	2,062	1,661
2004	2,062	962	3,024	2,543

APPEARANCES

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A.S. HOLLINGWORTH, Q.C. H.S. MUNDI	Plateau Pipe Line Ltd.
R.A. NEUFELD B. ROTH S. ANDERSON	Husky Oil Operations Limited
K.F. MILLER	Chevron Canada Resources
D. ARMSTRONG	Imperial Oil Resources
R.M. PERRIN D. STERNA	Encal Energy Ltd.
O. DEVRIES	Canadian Association of Petroleum Producers
M.W.P. BOYLE	Trans Mountain Pipe Line Company Ltd.
R. LEONG	Environment Canada
B. VAN OORT	Ministry of Energy and Mines
R. CAESAR	Oil and Gas Commission

P.W. NAKONESHNY J.B. WILLISTON G.J. CHARCHUN	Commission Staff
ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

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Engineering – Panel	F.E. WEBB B. HARRIS R. BURDYLO DR. E.C. HAMRE
Policy and Tolling – Panel	B.J. HAMILTON P.D. ROBERTSON R.B. MICHALESKI R. DEWOLF F.E. WEBB
District of Chetwynd – Panel	MAYOR C.A. LASSER
Chetwynd Environmental Society – Panel	W. SAWCHUK
South Peace Health Council – Panel	L. LAFLEUR
Husky Oil Operations Limited – Panel	G. MATWICHUK P.M.G. NETTLETON B. EACH V. CHIN D. LONG M. SPENCER
Chevron Canada Resources – Panel	R. INNIS W. SCOTT F. MCCUTCHEON

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