ORDER NO. G-21-97

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3
CANADA

BRITISH COLUMBIA UTILITIES COMMISSION

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

IN THE MATTER OF
the Utilities Commission Act, S.B.C. 1980, c. 60, as amended

and

An Application by Pacific Northern Gas Ltd.
for Approval of its 1997 Revenue Requirements

BEFORE:	M.K. Jaccard, Chairperson; and	)	
	L.R. Barr, Deputy Chairperson	)	February 27, 1997

O R D E R

WHEREAS:

A. On November 5, 1996 Pacific Northern Gas Ltd. (“PNG”) filed with the Commission, pursuant to Sections 64 and 106 of the Utilities Commission Act (the "Act"), a 1997 Revenue Requirements Application ("the Application") to increase rates effective January 1, 1997 on an interim basis, to be made permanent at a later date; and

B. The Commission reviewed the Application and issued Order No. G-112-96 and Notice of Pre-Hearing Conference to commence on December 18, 1996 to discuss potential issues in the Application; timing of the Alternative Dispute Resolution (“ADR”) or public hearing process; and for participants to clarify and have questions answered regarding the Application; and

C. On December 12, 1996 PNG filed revisions to the Application to reflect changes due primarily to the 1997 Return on Equity (“ROE”) set for PNG under the automatic adjustment mechanism and changes in the equity component to reflect the proposed acquisition of the utility operations of Centra Gas Fort St. John Inc. at Dawson Creek, Pouce Coupe and Rolla, B.C.; and

D. Following input from the pre-hearing conference the Commission by Order No. G-126-96, approved for PNG an interim rate increase effective January 1, 1997 and scheduled an ADR process to commence on January 29, 1997 and, if required, a hearing to commence on March 3, 1997; and

E. The ADR process was held on January 29 and 30, 1997. The Commission was informed by PNG, ADR Participants and Commission staff that a Settlement Agreement had been reached on the Application; and

F. Submissions were received from both a registered intervenor and an interested party objecting to the inclusion of a strike adjustment clause in the Application; and

G. The Commission has reviewed the Settlement Agreement and considers that approval of the Settlement Agreement is in the public interest.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for PNG the Settlement Agreement attached as Appendix A.

2. The submissions on the strike adjustment clause will be treated as a complaint. Accordingly, the utility and registered intervenors are to provide written submissions to the Commission regarding this issue no later than March 14, 1997. The complainant will then be provided an opportunity to reply in writing before the Commission makes its decision on this matter.

3. PNG is to inform all customers of the ADR process and the Settlement Agreement's effect on rates.

4. PNG is to file permanent Gas Tariff Rate Schedules that are in accordance with the terms of the ADR settlement and this Order.

5. The interim increase in effect since January 1, 1997 is to be refunded with interest in accordance with the terms contained in Order No. G-126-96.

6. The public hearing into the Application that was tentatively scheduled for March 3, 1997 is cancelled.

DATED at the City of Vancouver, in the Province of British Columbia, this 28th day of February, 1997.

BY ORDER

Original signed by:

Dr. Mark K. Jaccard
Chairperson

Attachment

BRITISH COLUMBIA UTILITIES COMMISSION

WILLIAM J. GRANT
EXECUTIVE DIRECTOR,
REGULATORY AFFAIRS & PLANNING

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

~~CONFIDENTIAL~~

VIA COURIER February 12, 1997

Mr. Craig P. Donohue
Manager of Regulatory Affairs
Pacific Northern Gas Ltd. &
Pacific Northern Gas (NE) Ltd.
1400 - 1185 West Georgia Street
Vancouver, B.C.
V6E 4E6

Dear Mr. Donohue:

Re: Proposed Settlement of Issues
Concerning the Revenue Requirement Application
of Pacific Northern Gas Ltd.("PNG")

The purpose of this letter is to forward the enclosed settlement we have achieved with respect to specific issues in the PNG Revenue Requirements Application. This letter remains confidential until it is submitted to the Commission hearing panel for consideration. I, therefore, ask that you provide to me a communication of endorsement for the proposal so that we may forward it to the Commission and make it public by Friday, February 14, 1997. The terms of the settlement proposal will then be circulated to all registered intervenors for comments to be received by the Commission by Wednesday, February 26, 1997. These comments will be used by the Commission in determining whether or not a public hearing will be necessary on March 3, 1997.

The settlement participants agree with the content and details of the Application, save for the following adjustments and identification of specific issues. It is recognized by all the parties that the agreement represents a package proposal within which there has been give and take by all parties. No issue is to be severed from the proposed settlement without allowing signatories the opportunity to address other related issues in the package.

The terms of the settlement are as follows:

Revenue Requirement:

1. Long-Term Debt

   It is agreed that the 1997 long-term debt issue will be removed. It is understood that PNG may apply to the Commission for approval to issue long term debt in 1997. The Commission's approval of a long term debt issue would provide that the impact on 1997 debt costs would be recorded in a deferral account for recovery in rates in 1998.

2. Short-Term Debt Interest Rate

   It is agreed that the forecast interest rate on short-term debt will be reduced from 5.25 percent to 4 percent.

3. Capital Projects

   It is agreed that the capital projects scheduled for 1997 will be adjusted by the removal of the Skeena River and Kitimat River Crossings capital projects ($2.684 and $1.272 million respectively). The removal of these projects will also have the consequence of reducing disposals by $1.164 million and increasing accumulated depreciation by $0.240 million (a net difference of $0.924 million). The Kitimat River Crossing may be substituted with an alternative solution which would require PNG to apply to the Commission for approval. Such approval would be predicated on PNG being kept revenue neutral.

4. Lead/Lag Study

   The Lead/Lag study is to be adjusted by the removal of depreciation and return from the working capital calculations. The result is a reduction in working capital from $1.509 million to $.703 million.

5. Amortization for Stress Corrosion Cracking ("SCC")

   The amortization period applicable to SCC costs is to be increased from 5 years to 10 years to be consistent with the amortization period applicable to pipeline rehabilitation and repair costs.

6. Long-Term Debt Issuance Costs

   The impact of not deducting long term debt issuance costs of $50,000 for income tax purposes in 1997 is an increase in revenue requirements of $40,090.

7. 1997 Lump Sum Reduction

   It is agreed that the 1997 revenue requirement will be further reduced by a lump sum of $395,000.

The result of the above adjustments is a revenue surplus of $540,000. Subsequent to the ADR settlement reached on January 30, 1997, Methanex, a major industrial customer of PNG and party to the ADR settlement process, and PNG revised the projected revenue stream to be received from deliveries to Methanex in 1997 to reflect the impact of actual 1996 deliveries to Methanex.

When preparing its application to the Commission, PNG had assumed the balance of deficiency volumes applicable to Methanex would be a certain figure based on budgeted deliveries in December 1996. The actual deficiency volumes as of December 31, 1996 were greater than forecast as of December 12, 1996 when an updated Application was prepared. Consequently, more deliveries of interruptible gas in 1997 are reclassified to firm margin in 1997 than was forecast as of December 12, 1996. This results in more revenue projected to be received from Methanex in 1997.

In addition, PNG has adjusted its operating expenses subsequent to the ADR settlement by an increase of $56,000. This reflects an increase in Company use gas supply costs resulting from changing the peak day allocators for residential and commercial customers. More demand charges have been allocated to the other categories including the Company use gas category. The total projected 1997 gas supply costs has not changed but the allocation of demand charges has changed.

The combined impact of the above two changes is an increase in the revenue surplus of $20,000. Therefore, the effective ADR settlement revenue surplus has increased from $540,000 to $560,000.

Other Matters:

The following issues were also agreed to in the process of reaching an ADR settlement:

1. The issue of how the gains on PNG's 1996/97 contract year hedge will be passed through to its customers will be dealt with separately. The resolution of this issue will impact the calculation of the 1996 and 1997 gas supply cost deferral account balances. Intervenors may provide written submissions to the Commission suggesting appropriate disposition of the funds.

2. The issue of WEI/PNG shared services will be dealt with through a workshop and/or written/oral hearing process once the report on shared services has been finalized by Coopers and Lybrand. Any decision on this matter will have no impact on the 1997 ADR settlement.

3. PNG will ensure that Commission staff and interested parties are kept advised of any CIS initiatives. The intent is to ensure that the issue is addressed fully before PNG makes any commitments to a new CIS system.

4. The 1997 rate design study will include an analysis of the different risks imposed on the system by each customer class with particular emphasis on the issue of the risk imposed by the large industrial customers.

5. The allocation of the projected 1997 gas supply costs is to be adjusted to reflect a peak day demand based upon the current rate design allocation. The attached 1997 rates include this adjustment.

Attached to this letter are Schedules 1 to 5 showing the impact of the revenue surplus of $560,000 as a result of the above adjustments. Also enclosed are the relevant pages from the "Rates" section of the Application revised to reflect the allocation of the revenue surplus of $560,000 to each customer category on a gross margin basis. It is proposed that these rates be made permanent effective January 1, 1997.

In closing, I wish to commend the efforts of PNG and all intervenors in the settlement discussions. The efforts made by all parties to understand each issue along with the concerns and interests of other parties has allowed this settlement to come to fruition.

Yours truly,

Original Signed by:

W.J. Grant

FSJ/ssc
Attachments

Pacific Northern Gas Ltd.

UTILITY INCOME & RETURN

SCHEDULE 1
(000's)

Line No.		Test Year 1997	Normalized 1996	Forecast 1996	Decision 1996
1	Energy sales (TJ)	8 229	7 265	7 354	7 449
2	Average rate per GJ	$3.69	$3.12	$3.14	$3.08
3	Per cent increase in rates	18.34%	1.29%	2.05%	16.76%
4					
5	Transportation service (TJ)	30 262	29 157	30 202	28 689
6	Average rate per GJ	$0.97	$1.01	$1.00	$0.98
7	Per cent increase in rates	-4.24%	3.15%	1.55%	7.06%
8					
9	Total deliveries (TJ)	38 491	36 422	37 556	36 138
10					
11	Utility revenue				
12	Energy sales	$30,556	22,666	23,115	22,943
13	Interim rates - sales	(174)			
14	Transportation service	29,681	29,475	30,058	29,660
15	Interim rates - transportation	(386)			
16					
17		59,677	52,141	53,173	52,603
18	Cost of sales	17,128	9,652	9,887	11,219
19					
20	Gross margin	42,549	42,489	43,286	41,384
21					
22	Operating expenses	8,606	7,492	7,562	7,148
23	Maintenance expenses	864	666	666	892
24	Admin. & general expenses	4,231	4,251	4,251	3,956
25	Property taxes, BC capital tax	2,909	2,823	2,823	2,823
26	Depreciation	5,716	4,984	4,984	4,984
26	Amortization	836	1,430	1,430	960
26	Investment income, other revenue	(758)	(874)	(874)	(759)
28					
29		22,404	20,772	20,842	20,004
30					
31	Earned return before income taxes	20,145	21,717	22,444	21,380
32	Income taxes	6,374	7,027	7,355	6,453
33					
34	Earned return	$13,771	14,690	15,089	14,927
35					
36	Utility rate base	$142,970	142,552	142,552	142,026
37					
38	Return on rate base	9.63%	10.31%	10.59%	10.51%

Pacific Northern Gas Ltd.

UTILITY RATE BASE

SCHEDULE 2
(000's)

Line No.		Test Year 1997	Normalized 1996	Forecast 1996	Decision 1996
1	Plant in service beginning of year	$206,335	196,611	196,611	196,611
2	Additions	8,739	9,879	9,879	11,523
3	Disposals	(279)	(155)	(155)	(155)
4					
5	Plant in service end of year	214,795	206,335	206,335	207,979
6	Accumulated depreciation	56,076	49,929	49,929	50,359
7					
8	- Net plant in service end of year	158,719	156,406	156,406	157,620
9					
10	Net plant beginning of year	156,534	151,351	151,351	151,351
11					
12	Net plant in service midyear	157,627	153,879	153,879	154,486
13	Adjustment - expenditure timing	(39)	547	547	547
14	Contributions for construction	(5,346)	(4,252)	(4,252)	(4,945)
15	Construction advances	(563)	(583)	(583)	(583)
16	Deferred income taxes	(14,915)	(14,915)	(14,915)	(14,915)
17	Work in progress, no AFUDC	550	550	550	550
18	Unamortized deferred charges	3,444	4,336	4,336	3,540
19	Conversion loans	1,100	1,184	1,184	1,400
20	Cash working capital	702	931	931	931
21	Other working capital	410	875	875	1,015
22					
23	Utility rate base, midyear	$142,970	142,552	142,552	142,026

Pacific Northern Gas Ltd.

INCOME TAXES

SCHEDULE 3
(000's)

Line No.		Test Year 1997	Normalized 1996	Forecast 1996	Decision 1996
1	**Calculation of Taxable Income**				
2	Earned return before income taxes	$20,145	21,717	22,444	21,380
3	Interest	(7,998)	(8,590)	(8,579)	(8,558)
4	Permanent differences	18	2	2	2
5	Timing differences	395	207	207	(263)
6					
7	Taxable income	$12,560	13,336	14,074	12,561
8					
9	**Calculation of Income Tax Expense**				
10	Income taxes payable	$5,589	5,935	6,263	5,590
11	Part I.3 tax	367	372	372	375
12	Deferred income tax	418	720	720	488
13					
14	Income tax expense	$6,374	7,027	7,355	6,453
15					
16	**Particulars of Timing Differences**				
17	***A. Tax Effects Subject To Flowthrough***				
18	Depreciation	$5,716	4,984	4,984	4,984
19	Amortization	836	1,430	1,430	960
20	Capital cost allowance	(5,067)	(4,975)	(4,975)	(4,975)
21	Other	(150)	(135)	(135)	(135)
22					
23		$1,335	1,304	1,304	834
24	***B. Tax Effects Subject To Deferral***				
25	Deferred charges	(940)	(1,097)	(1,097)	(1,097)
26					
27	Timing differences	$395	207	207	(263)
28					
29	Payable tax rate	44.50%	44.50%	44.50%	44.50%
30	Deferred tax rate	44.50%	44.50%	44.50%	44.50%

Pacific Northern Gas Ltd.

COMMON EQUITY

SCHEDULE 4
(000's)

Line No.		Test Year 1997	Normalized 1996	Forecast 1996	Decision 1996
1	Opening balance				
2	Share capital	$8,774	8,757	8,757	8,757
3	Contributed surplus	1,712	1,662	1,662	1,662
4	Retained earnings	43,577	40,619	40,619	40,619
5					
6		54,063	51,038	51,038	51,038
7		-			
8	Net income	7,188	6,257	6,660	6,363
9	Shares issued	0	67	67	0
10	Preferred dividends	(338)	(338)	(338)	(338)
11	Common dividends	(3,369)	(3,364)	(3,364)	(3,363)
12					
13	Closing balance	$57,544	53,660	54,063	53,700
14					
15					
16	Midyear common equity	$55,804	$52,349	52,551	52,369
17	CWIP subject to AFUDC		0	0	
18	Investment in subsidiary	(4,648)	(1,263)	(1,263)	(1,263)
19					
20		$51,156	51,086	51,288	51,106

Pacific Northern Gas Ltd.

RETURN ON CAPITAL

SCHEDULE 5
(000's)

Line No.		Test Year 1997	Normalized 1996	Forecast 1996	Decision 1996
1	Short term borrowings	$13,697	9,121	8,919	8,576
2	proportion	9.58%	6.40%	6.26%	6.04%
3	rate of return	4.00%	5.55%	5.55%	5.55%
4	return component	0.38%	0.36%	0.35%	0.34%
5					
6	Long term debt	$73,116	77,344	77,344	77,344
7	proportion	51.140%	54.26%	54.26%	54.46%
8	rate of return	10.19%	10.452%	10.452%	10.450%
9	return component	5.21%	5.67%	5.67%	5.69%
10					
11	Preferred shares	$5,000	5,000	5,000	5,000
12	proportion	3.50%	3.51%	3.51%	3.52%
13	rate of return	7.01%	7.01%	7.01%	7.01%
14	return component	0.25%	0.25%	0.25%	0.25%
15					
16	Common equity	$51,156	51,086	51,288	51,106
17	proportion	35.78%	35.84%	35.98%	35.98%
18	rate of return	10.59%	11.25%	12.01%	11.75%
19	return component	3.79%	4.03%	4.32%	4.23%
20					
21	Total capitalization	142,970	142,552	142,552	142,026
22					
23	Return on rate base	9.63%	10.31%	10.59%	10.51%
24					
25	Utility rate base	$142,970	$142,552	$142,552	$142,026

Pacific N Jas Ltd

1997 Revenue Requirements Application

Summary of Proposed Rates Effective January 1, 1997

Revised February 11, 1997 to Reflect ADR Settlement

Customer Class	$/GJ (unless otherwise indicated)						
	Permanent Rates Jan. 1/96	1995 Rate Design Changes	Allocated Share of 1997 ADR Settlement	1996/97 Gas Supply Cost Change	Proposed Rates Jan. 1/97	1996/97 Total Changes	
Residential (RS1)							
First GJ	6.555	0.284	(0.049)	0.912	7.702	1.147	17.5%
Additional GJs	5.476	0.284	(0.049)	0.912	6.623	1.147	20.9%
Commercial Sales (RS2)							
First GJ	5.497	0	(0.028)	0.864	6.333	0.836	15.2%
Additional GJs	4.324	0	(0.028)	0.864	5.160	0.836	19.3%
Commercial Transport (RS3)							
Basic Charge Per Month	$ 125.00	0			125.00	0.00	0.0%
Additional GJs	2.167	0	(0.030)	0.023	2.160	(0.007)	(0.3%)
Commercial Interr. (RS4)							
First 220 GJ or less	$ 542.86	0	(4.180)	51.100	589.78	46.92	8.6%
Additional GJs	2.154	0	(0.019)	0.232	2.367	0.213	9.9%
Small Industrial (RS5)							
First 320 GJ or less	$ 824.70	(6.464)	(3.84)	156.72	971.12	146.42	17.8%
Additional GJs	2.534	(0.020)	(0.012)	0.490	2.992	0.458	18.1%
Seasonal Off-Peak (RS6)							
(Off Peak) First 220 GJ or less	$ 670.77	0	(5.72)	39.75	704.80	34.03	5.1%
Additional GJs	2.549	0	(0.026)	0.181	2.704	0.155	6.1%
(Peak) First 6 GJ or less	3.049	0	(0.026)	0.181	3.204	0.155	5.1%
Additional GJs	6.178	0	(0.026)	0.181	6.333	0.155	2.5%
NGV (RS7)							
First GJ or less	3.841	(0.031)	(0.014)	0.446	4.243	0.402	10.5%
Additional GJs	2.329	(0.031)	(0.014)	0.446	2.731	0.402	17.3%

Pacific Northern Gas Ltd

1997 Revenue Requirements Application

Summary of Proposed Rates Effective January 1, 1997

Revised February 11, 1997 to Reflect ADR Settlement

Customer	Supp. No.	Permanent Rates Jan. 1/96	1995 Rate Design Change	Allocated Share of 1997 ADR Settlement	1996/97 Gas Supply Cost Change	Proposed Rates Jan. 1/97	1996/97Total Changes	
epap Prince Rupert	1							
irm T-Service ($\$/10^3m^3$)		42.5385	(1.0549)	(0.5506)	0.8855	41.8185	(0.7200)	(1.7%)
T-Sales Below CD ($/GJ)		1.1073	(0.0274)	(0.0143)	0.0230	1.0886	(0.0187)	(1.7%)
T-Service Below CD ($\$/10^3m^3$)	1A	Same as Firm T-Service Rate						
acer Dome/Equity	2							
irm T-Service ($\$/10^3m^3$)		35.0359	(0.8008)	(0.4620)	0.8855	34.6586	(0.3773)	(1.1%)
T-Sales Below CD ($/GJ)		0.9073	(0.0208)	(0.0120)	0.0230	0.8975	(0.0098)	(1.1%)
irocan	3							
irm T-Service ($\$/10^3m^3$)		35.0620	(0.6776)	(0.4582)	0.8855	34.8117	(0.2503)	(0.7%)
T-Sales Below CD ($/GJ)		0.9107	(0.0176)	(0.0119)	0.0230	0.9042	(0.0065)	(0.7%)
T-Service Below CD ($\$/10^3m^3$)	3A	Same as Firm T-Service Rate						
infor	6							
irm T-Service ($\$/10^3m^3$)		34.3039	(0.8008)	(0.4620)	0.8855	33.9266	(0.3773)	(1.1%)
T-Sales Below CD ($/GJ)		0.8910	(0.0208)	(0.0120)	0.0230	0.8812	(0.0098)	(1.1%)
can	7							
irm T-Service ($\$/10^3m^3$)		46.9124	(1.5015)	(0.6006)	0.8855	45.6958	(1.2166)	(2.6%)
T-Sales Below CD ($/GJ)		1.2185	(0.0390)	(0.0156)	0.0230	1.1869	(0.0316)	(2.6%)
T-Service Below CD ($\$/10^3m^3$)	7A	Same as Firm T-Service Rate						
ethanex	16,17&							
irm T-Service ($\$/10^3m^3$)	25	36.0438	(0.7007)	(0.4697)	0.8855	35.7589	(0.2849)	(0.8%)
T-Sales Below CD ($/GJ)		0.9362	(0.0182)	(0.0122)	0.0230	0.9288	(0.0074)	(0.8%)
T-Service Below CD ($\$/10^3m^3$)	16A	Same as Firm T-Service Rate						

Pacific Northern Gas Ltd

1997 Revenue Requirements Application

Summary of Proposed Rates Effective January 1, 1997

Revised February 11, 1997 to Reflect ADR Settlement

Customer	Supp. No.	Permanent Rates Jan. 1/96	1995 Rate Design Change	Allocated Share of 1997 ADR Settlement	1996/97 Gas Supply Cost Change	Proposed Rates Jan. 1/97	1996/97 Total Changes	
lateau Forest	18							
Firm T-Service ($\$/10^3m^3$)		36.6905	(0.8008)	(0.4620)	0.8855	36.3132	(0.3773)	(1.0%)
IT-Sales Below CD ($/GJ)		0.9580	(0.0208)	(0.0120)	0.0230	0.9482	(0.0098)	(1.0%)
/est Fraser (PIR)	19							
Firm T-Service ($\$/10^3m^3$)		37.5633	(0.8008)	(0.4620)	0.8855	37.1860	(0.3773)	(1.0%)
IT-Sales Below CD ($/GJ)		0.9757	(0.0208)	(0.0120)	0.0230	0.9659	(0.0098)	(1.0%)
epap Smithers	20							
Firm T-Service ($\$/10^3m^3$)		39.6491	(0.8008)	(0.4620)	0.8855	39.2718	(0.3773)	(1.0%)
IT-Sales Below CD ($/GJ)		1.0298	(0.0208)	(0.0120)	0.0230	1.0200	(0.0098)	(1.0%)
epap Terrace	21							
Firm T-Service ($\$/10^3m^3$)		39.7089	(0.8008)	(0.4620)	0.8855	39.3316	(0.3773)	(1.0%)
IT-Sales Below CD ($/GJ)		1.0314	(0.0208)	(0.0120)	0.0230	1.0216	(0.0098)	(1.0%)
'ecker Lake	23							
Firm T-Service ($\$/10^3m^3$)		39.2155	(0.8008)	(0.4620)	0.8855	38.8382	(0.3773)	(1.0%)
IT-Sales Below CD ($/GJ)		1.0186	(0.0208)	(0.0120)	0.0230	1.0088	(0.0098)	(1.0%)
urnslake	24							
Firm T-Service ($\$/10^3m^3$)		39.2155	(0.8008)	(0.4620)	0.8855	38.8382	(0.3773)	(1.0%)
IT-Sales Below CD ($/GJ)		1.0186	(0.0208)	(0.0120)	0.0230	1.0088	(0.0098)	(1.0%)

Pacific Northern Gas Ltd.

1997 Revenue Requirements Application

Summary of Proposed Rates Effective January 1, 1997

Revised February 11, 1997 to Reflect ADR Settlement

Customer	Supp. No.	Permanent Rates Jan. 1/96	1995 Rate Design Changes	Allocated Share of 1997 ADR Settlement	1996/97 Gas Supply Cost Change	Proposed Rates Jan. 1/97	1996/97 Total Changes	
B.C. Hydro	10							
Monthly Demand Charge ($)		1,569.93	0	(20.33)	0	1549.60	(20.33)	(1.3%)
IT-Sales ($/GJ)		1.0451	0	(0.0139)	0.0230	1.0542	0.0091	0.9%
IT Sales Above CD ($/GJ)	17							
Methanex		0.2156	0	(0.0031)	0.0230	0.2355	0.0199	9.2%
All Others		1.0451	0	(0.0139)	0.0230	1.0542	0.0091	0.9%
IT Service Above CD ($/$10^3m^3$)								
Methanex	16A	8.3001	0	(0.1194)	0.8855	9.0662	0.7661	9.2%
All Others	1A,3A,7A	40.2366	0	(0.5352)	0.8855	40.5869	0.3503	0.9%

Pacific Northern Gas Ltd

SUMMARY OF PROPOSED RATE CHANGES
EFFECTIVE JANUARY 1, 1997

Revised February 11,1997 to Reflect ADR Settlement

Customer Classification	1997 Test Year Gas Deliveries (GJ)	Gross Margin ($)	Allocation of ADR Settlement ($)	Proposed Rate Changes ($/GJ)
Residential (Rate 1)	2,094,733	7,834,958	(102,642)	(0.049)
Commercial				
Small Commercial (Rate 2)	1,281,839	2,789,365	(35,892)	(0.028)
Large Commercil Firm (Rate 2)	192,200	440,334	(5,382)	(0.028)
Commercial Transport (Rate 3)	123,569	284,116	(3,707)	(0.030)
Large Commercial Interr (Rate 4)	89,250	133,326	(1,696)	(0.019)
Total Commercial	1,686,858			
Seasonal Off-Peak (Rate 6)	25,800	52,509	(671)	(0.026)
NGV (Rate 7)	65,500	70,894	(917)	(0.014)
Small Industrial				
Sales (Rate 5)	345,700	358,112	(4,148)	(0.012)
Transport	1,200,340	1,106,938	(14,404)	(0.012)
Interruptible	27,660	29,544	(384)	(0.0139)
Total Small Industrial	1,573,700			
Large Industrial				
Methanex				
Firm Transportation	23,418,348	22,036,664	(285,704)	(0.0122)
Interruptible	1,242,399	296,436	(3,851)	(0.0031)
Deficiency	958,558	90,536		
Sub-total	25,619,305			
Repap Enterprise Inc.				
Firm Transportation	2,924,380	3,225,302	(41,819)	(0.0143)
Interruptible	975,620	1,042,061	(13,561)	(0.0139)
Sub-total	3,900,000			
Eurocan Pulp & Paper				
Firm Transportation	2,723,265	2,494,779	(32,407)	(0.0119)
Interruptible	41,735	44,578	(580)	(0.0139)
Sub-total	2,765,000			
Alcan Smelters & Chemicals				
Firm Transportation	435,810	524,061	(6,799)	(0.0156)
Interruptible	314,190	335,586	(4,367)	(0.0139)
Sub-total	750,000			
B.C. Hydro - Interruptible	10,000	29,520	(383)	(0.0383)
Total Large Industrial	33,044,305			
TOTAL	38,490,896	43,219,619	(559,313)	

NOTE: * This amount will passed through as follows:
10000 GJ * ($0.0139)/GJ = ($139.00)

Pacific Norther[illegible] [illegible]td

DERIVATION OF GAS SUPPLY COST RATE CHANGES EFFECTIVE JANUARY 1, 1997
Revised February 4, 1997

Customer Classification	Gas Supply Costs Effective January 1, 1996 (1) Demand (2)	Commodity (3)	Company Use Gas	Gas Supply Costs Effective January 1, 1997 (1) Demand (2)	Commodity (3)	Company Use Gas (4)	Proposed Rate Changes Effective January 1, 1997
Residential (RS1)	1.250	0.908	0.051	1.550	1.497	0.074	0.912
Commercial Firm (RS2)	1.277	0.905	0.051	1.550	1.474	0.074	0.864
Commercial Interruptible (RS4)		0.711	0.051		0.920	0.074	0.232
Small Industrial (RS5)	0.758	0.797	0.051	0.828	1.193	0.074	0.490
Seasonal Off Peak (RS6)	0.406	0.627	0.051	0.431	0.759	0.074	0.181
NGV (RS7)	0.460	0.779	0.051	0.522	1.141	0.074	0.446
Transportation Service			0.051			0.074	0.023

Notes:
1. These figures are set forth at Tab 4, page 1 of PNG's application to the Commission dated July 31, 1996 entitled "Determination of Rate Changes Effective January 1, 1996 to Reflect: 1996 Revenue Requirements Decision, 1995 Rate Design Decision and Disposition of 1995 Gas Supply Cost Deferral Account."

2. The demand charges represent the total fixed costs payable by PNG for its gas supply regardless of the quantity of gas purchased. Demand charges are paid to ensure gas supply will be firm and not interruptible by the gas supplier. Therefore, only those customers receiving gas on a firm basis should pay those charges. The allocation of the demand charges to the firm customer classes is shown on the Table attached hereto entitled "Allocation of 1997 Demand Charges to Firm Customer Classifications and Company Use Gas."

3. The commodity charges are payable for each GJ of gas purchased by PNG. The commodity charges represent PNG's projection of its commodity costs for 1997 based on its projected gas supply purchases. PNG is purchasing seasonal gas during the January, February, March, November and December winter months to meet its peak day requirements during colder winter days. The commodity cost of the seasonal gas supply is not included when determining the projected average commodity cost of gas for the commercial interruptible (RS4) and seasonal off-peak (RS6) customers. Gas deliveries to commercial interruptible customers can be interrupted at any time. Therefore, PNG does not purchase seasonal supply for commercial interruptible customers. The seasonal off-peak customers are not expected to purchase gas during the winter months. Consequently, the commodity cost applicable to commercial interruptible and seasonal off-peak customers is less than the commodity cost applicable to the firm customer classes due to exclusion of the cost of seasonal gas.

4. The unit company use gas cost is determined by dividing the total projected cost of company use gas (i.e. demand charges of $988,521 plus commodity charges of $1,864,113) by total projected 1997 deliveries. (i.e. $2,852,634 divided by 38 490 896 GJ equals $0.074 per GJ.)

97FCSTR4 XLS
2/4/97

Pacific Northern Gas Ltd

Allocation of Forecast 1997 Demand Charges
to Firm Customer Classifications and Company Use Gas
Revised February 4, 1997 to Reflect Line Pack Peak Shaving

Customer Classification	1997 Peak Day Requirement [1] (10^3m^3)	1997 Peak Day Requirement [1] (%)	Allocation of Demand Charges [2] ($)	Annual Requirements (GJ)	Unit Demand Charge [3] ($/GJ)
Residential (RS1)	455.9	47.5%	3,247,022	2 094 733	1.550
Commercial (RS2)	320.8	33.4%	2,284,567	1 474 039	1.550
Small Industrial (RS5)	40.2	4.2%	286,301	345 700	0.828
Seasonal Off Peak (RS6)	0.0	0.0%	11,128	25 800	0.431
NGV (RS7)	4.8	0.5%	34,185	65 500	0.522
Company Use	138.8	14.5%	988,521	38 490 896 [4]	----- [4]
Total	960.5	100.0%	6,851,724		
			6,840,596		

Notes: 1. PNG contracts for firm gas supply sufficient to meet the projected firm gas requirements assuming an average temperature of -20°C throughout PNG's service areas. The gas requirements for each customer category on the -20°C day is projected. PNG allocates its demand charges to each customer classification based on the proportion their peak day gas requirement bears to the total projected peak day gas requirement.

2. The figures in this column are determined by applying the peak day requirement percentage to the demand charge of $6,840,596 which is net of the demand charges allocated to the Seasonal Off Peak customers. The total demand charges payable by PNG in 1997 are projected to be $6,851,724. At a 100% load factor this is equivalent to $0.647/GJ. (i.e. $6,851,596 divided by 10 590 121 GJ) The seasonal off-peak (RS6) customers receive firm gas supply during the off-peak period (i.e. April 1 to October 31). They should bear some of the demand charges since they receive firm gas supply during that period. PNG considers their share should be based on adjusting the 100 percent unit demand charge by a 150 percent load factor. This results in a $0.431/GJ figure (i.e. $0.647/GJ divided by 150 percent). The 1997 projection of deliveries to the seasonal off peak customers is 25 800 GJ. Therefore, their share of the demand charges should be $11,128 (i.e 25 800 GJ times $0.431/GJ). The $6,840,596 figure is the difference between $6,851,724 and $11,128.

3. The unit demand charge is the allocated demand charge divided by the projected 1997 annual gas requirements for each customer classification and Company use gas.

4. There is no allocation of the demand charges for Company use gas as the demand charges and the commodity charges for company use gas are totalled and then spread over total deliveries (i.e. the sum of sales and transportation service.)

97FCSTR4 XLS
2/4/97