

GAS ROYALTY CALCULATION INFORMATION BULLETIN September 2004

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PLEASE ENSURE YOUR PRODUCTION ACCOUNTANTS RECEIVE A COPY OF THIS DOCUMENT.

A. PRICING RATES AND TRANSPORTATION INFORMATION

For Pricing, Royalty Rates and Transportation Information for July 2004, refer to [Attachments 1, 1A, 2, 2A, and 3](#).

B. NOTICES

Royalty and Related Information (RRIR) Training

In conjunction with the upcoming changes to the unit operating cost rate (UOCR) regime, the Department of Energy cordially invites you to attend one of the following town hall training sessions in Calgary. Please note the dates, times and registration deadlines:

Date	Time	Deadline For Registration
Monday, November 1 st	9:30 a.m. to 12:00 noon or 1:15 p.m. to 3:30 p.m.	Friday, October 22 nd
Tuesday, November 2 nd	9:30 a.m. to 12:00 noon or 1:15 p.m. to 3:30 p.m.	Friday, October 22 nd
Wednesday, November 17 th	9:30 a.m. to 12:00 noon or 1:15 p.m. to 3:30 p.m.	Monday, November 8 th
Thursday, November 18 th	9:30 a.m. to 12:00 noon or 1:15 p.m. to 3:30 p.m.	Monday, November 8 th

All training sessions will be held at: Rosebud Room, McDougall Centre
455 - 6th Street SW
Calgary, Alberta

Training will focus on changes to existing rate calculation processes, filing requirements, allowable cost forms and the introduction of an annual adjustment for operating costs.

As seating capacity for these town hall sessions is limited, please choose one of the available sessions along with an alternate and register at your earliest convenience with Edith Villarica @ (780) 422-9211 by the respective deadlines. Depending on the level of interest, the number of sessions may be reduced for the purpose of condensing training into one day for each week.

Clients should direct any inquiries regarding RRIR changes to the operating cost regime to Rose Ann Summers, Manager, Gas Royalty Calculation @ (780) 422-6684, Will Wong, Team Lead, Gas Royalty Calculation @ (780) 415-0755 or the Client Services Operational Analyst for your company as identified in [Section F - Points of Contact](#).

Business Design Committee

On July 22, 2004, representatives from the Department of Energy (DOE) and the Canadian Association of Petroleum Producers (CAPP) met to discuss the future role of the Business Design Committee. A review of the last two years shows that attendance at Business Design Meetings was minimal and no new matters were brought forward for discussion. In view of this, it is agreed that for better utilization of time and to better serve industry, the Business Design Committee meetings be discontinued and Department staff be available, monthly in Calgary, for clients who need assistance with royalty reporting. This change will be implemented in October 2004.

Effective October 2004, Gas Royalty Calculation staff will be available monthly to meet with clients who need assistance with royalty reporting. Royalty clients requiring assistance are encouraged to call Mr. David Nichiporik, Manager Client Services (780-422-9239) or e-mail david.nichiporik@gov.ab.ca two business days before the meeting date to arrange an appointment.

Where:

Monenco Place

Room 437

801-6 Avenue S.W.

Calgary, AB

Phone: 403-297-8954

(Industry must go to the 3rd Floor Reception upon arrival to sign-in and be given a visitor tag)

When – 9:30 am to 3 pm

October 13, 2004

November 17, 2004

December 15, 2004

Facility Cost Centre (FCC) Type Data Cleanup

Note: To ensure that the December 31, 2004 submission deadline is met, operators who need to terminate existing FCCs for non-designated facilities may set up new FCCs for the 2004 production year only, without any need to resubmit forms for prior production years, unless they choose to correct the FCC type retroactive to an earlier non-statute barred production year. However, it is critical to correct the FCC types for designated facilities, retroactive to the 2001 production year, since the gathering and compression survey rates for the non-designated facilities will be escalated each year, using an index based on a rate of change for similar costs in the designated facilities.

FCC operators are asked to review their FCC Type set-ups, using the determination criteria outlined in the supplement to the March 2004 Gas Royalty Calculation Information Bulletin, and submit amended AC1s where necessary. The corrective action is dependent on whether the FCC Type has been identified incorrectly from its start date, and whether or not that start date falls within a statute-barred production year, or the FCC Type has changed over time.

- If the FCC Type has been identified incorrectly from its start date, the FCC operator must
 - a. Amend AC1 (Part 5) for the FCC, if its start date does not fall within a statute-barred production year, to change the FCC Type for its entire effective date range, without late filing penalty implications nor requirement to file retroactive AC2 and AC4 forms, or
 - b. Terminate the existing FCC, if its start date falls within a statute-barred production year, and set up a new FCC of the correct FCC Type within the operator effective date range, effective on or before the 2001 production year for designated facilities and on or before the 2004 production year for non-designated facilities.

- If the FCC Type has changed over time and subsequently comprised part of a different type of EUB facility (e.g. removed from a gathering system to form part of a gas plant), the FCC operator must terminate the existing FCC, as of or after the date of the move, and set up a new FCC of the new FCC Type within the operator effective date range, effective on or before the 2001 production year for designated facilities and on or before the 2004 production year for non-designated facilities.

AC1 amendments (including changes to Part 5, terminations and set-ups) to correct FCC Types must be submitted to the Department by December 31, 2004. For any amendments involving a closed production year, the operator must submit a Year End Close Out (YECCO) form or a written request to open the system for amendment processing, but may provide a comprehensive list of FCCs that require amendments under a single request. For retroactive FCC terminations and set-ups, the operator must also resubmit any applicable AC2 and AC4 forms, along with a written request to have the corresponding late filing penalties reviewed.

If you have any questions regarding this data cleanup exercise, please contact the Client Services Operational Analyst for your company as identified in [Section F - Points of Contact](#).

Canada Post Mail Delivery

Canada Post standards require a suite or room number to be used for correspondence to a company within an office building. In order to guarantee delivery of Canada Post mail to the Calgary office of the Department of Energy the address must be:

Name of addressee
Business Unit
300, 801 - 6th Avenue SW
Calgary, Alberta
T2P 3W2

C. MONTHLY INFORMATION

July 2004 Royalty Due October 31

- **Royalty clients are to remit the total amount payable shown on the October 2004 Statement of Account by October 31, 2004.** If the amount payable includes accrued current period interest, the interest has only been accrued to the statement issue date. Clients must also include the additional interest that has accrued from the statement issue date to the date of payment, using the per diem amount provided.
- **The October 2004 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your July 2004 Invoice amount and any applicable current period interest charges. It also identifies refunds resulting from overpayments.**
- Current period interest will not be charged on current invoice charges for the production month of July 2004 if it is paid in full by October 31, 2004.
- Current period interest will accrue on any overdue charges commencing the first day after the due-date until it is paid in full.

Note: If the due date falls on a non-business day, payments will be accepted on the next business day.

- Cheques are payable to the Minister of Finance, Province of Alberta.

August 2004 VA4 Due October 15

The VA4 forms for the production month of August 2004 are due in the Department offices by October 15, 2004.

Note: If the due date (15th) falls on a non-business day, the next business day will apply as the due date for VA4 forms.

August 2004 Production Reporting

August 2004 production reporting is submitted through the Registry. The deadline for submission of SAF, OAF, and Volumetrics is posted in the Registry Reporting Calendar at:

<http://www.petroleumregistry.gov.ab.ca>

Changes to this calendar will be posted on the Registry web site home page in “Broadcast Messages.”

Interest Rate September 2004

The Department of Energy’s interest rate for September 2004 is 4.75%.

June Provisional Assessment Charge

The summary of Provisional Assessment Charges for all production periods for the June 2004 billing period was:

First Time Provisional Assessment	Reversals of Provisional Assessments	Net Provisional Assessment
\$5,685,734.01	(\$25,334,379.52)	(\$19,648,645.51)

June Charges

The revised penalty table below shows at the form level, the total penalty charges and reversals, for the June 2004 billing period:

FORM	Penalty Charges	Penalty Reversals	Net Penalty Charges for 2004/06
AC2	\$109,100	(\$300)	\$108,800
AC4	\$20,000	(\$200)	\$19,800
AC5	\$7,300	(\$12,100)	(\$4,800)
GR2	\$0	\$0	\$0
NGL1	\$0	\$0	\$0
VA2	\$0	(\$1,000)	(\$1,000)
VA3	\$0	\$0	\$0
VA4	\$100	\$0	\$100
Total	\$136,500	(\$13,600)	\$122,900

Alberta Royalty Tax Credit Program Quarterly Rate

For the third quarter of 2004, the Alberta Royalty Tax Credit rate will be .2500. This rate is based on a royalty tax credit reference price of \$417.19 per cubic metre. The Alberta Royalty Tax Credit rates for the past year were:

Second Quarter, 2004	.2500
First Quarter, 2004	.2500
Fourth Quarter, 2003	.2500
Third Quarter, 2003	.2500

If you have any questions, please contact Kent Nelson of Tax Services at (780) 427-9425, ext. 44066.

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

Please note a BA Identifiers Report is published daily at the following Internet address:

<http://www.petroleumregistry.gov.ab.ca>

This report is a directory of Business Associate (BA) names; codes, status (e.g. struck, active, amalgamated, etc.), status effective dates and will now, effective August 2004, include Working Interest Owner (WIO) role start/end dates.

The Department would like to remind the Business Associates to review their WIO role to ensure the start and end dates are reflected correctly. If the BA does not have an active WIO role, the operators cannot allocate volumes to the BA for the relevant production periods through the SAF/OAF allocations.

- If a BA has a WIO start date, then that BA can receive allocations from the stated date forward.
- If a BA has a WIO start and end date, then they can only receive allocations from the stated start date until the end date. Any allocations after the end date will be rejected.
- If a BA does not have a WIO start date, then that BA cannot receive allocations at all.

Please contact Client Registry at (780) 422-1395 if you have any questions regarding the information supplied on this listing.

Projects/Blocks

The following projects/blocks have been rescinded by the EUB. If further information is required on these or any other projects, please contact Isabelle Warwa at 427-8952.

Project/ Block Name	Effective Date	Operator	Stream ID
Farrow Glauconitic J Block No 1	August 31, 2004	0K13	WG 02669
Mitsue Gilwood A Project No 347	August 31, 2004	0HK7	WG 02670
Virgo Keg River E Project No 1	August 31, 2004	0007	WG 01508

Struck Clients

Clients must ensure that all royalty documents are completed using only valid client names and IDs. It is critical that royalty clients use current legal client names and their appropriate IDs on all documents to ensure accurate royalty calculation and to prevent provisional assessment and penalties. Rejects will occur when invalid IDs are used.

If you require information regarding client names or IDs, please contact Client Registry at (780) 422-1395.

The following is a list of struck, dissolved, revived and cancelled clients:

Company Name	Client ID	Struck Date
Alberta Gas Processors Ltd.	0M03	August 2, 2004
Gower Petroleum Ltd.	0G3W	August 2, 2004
Silvecor Resource Management Ltd.	0HD6	August 2, 2004
Springfield Energy Corporation	0YE5	August 2, 2004
Lanka Exploration Ltd.	0H8D	August 2, 2004
Kalta Energy Corp.	0YH2	August 2, 2004
728859 Alberta Ltd.	410C	August 2, 2004
Can-Am Energy Systems Inc.	0637	September 2, 2004
Spindle-Top Investments Ltd.	0M6N	September 2, 2004
Company Name	Client ID	Dissolved Date
Aventura Energy Inc.	0HF4	August 4, 2004
La Luz Mines Limited	0H7H	September 9, 2004
Company Name	Client ID	Revived Date
Triple V Consulting Ltd.	0A8D	August 4, 2004
Company Name	Client ID	Cancelled Date
Canterra Energy Ltd.	0L73	September 2, 2004

Nova Tolls - Multiple Gas Reference Prices

Royalty information related to the implementation of the Factor Model negotiated with industry for determining Multiple Gas Valuation Prices is provided on the Department Internet site at:

www.energy.gov.ab.ca

E. REMINDERS

Producer Direct Marketing Allowance

Following a review of direct marketing costs incurred and treatment of other marketing costs, the Department of Energy has determined it is appropriate to provide an allowance in the Alberta Gas Reference Price to reflect the cost of marketing direct sales of natural gas by producers. This allowance will be implemented on a go-forward basis effective with the May 2004 production month.

The producer direct marketing allowance is part of the calculation of the gas reference price, with application only to producers that had elected to pay gas royalties using the Alberta Gas Reference Price. Producers that elected to pay gas royalties based on their actual Corporate Average Price (CAP) will continue to follow the CAP rules.

The methodology for calculating the producer direct marketing allowance will be consistent with the recommendation developed by industry and department staff earlier this year. The methodology is described in [Attachment 4](#).

If you have any questions regarding this matter, please contact Bill Zanewick, Director, Gas Royalty Valuation and Markets at (403) 297-5465.

Re-Allocation of Allowable Capital Costs under the Natural Gas Royalty Regulations

The following information is provided for clarification of the business rule and regulations relating to re-allocation of allowable costs (AC3 Form).

The Natural Gas Royalty Regulations, 2002, Section 20(1) defines “allowable costs” as the costs to which the “Minister consents”. A particular cost must be consented to before it can be considered to be an “allowable cost”. This section further identifies that the costs consented to by the Minister shall be deducted from Crown royalty owing, and that under Section 20(3) the Minister “may determine” the amount of the allowable costs identified in 20(1).

The allowable costs consented to and determined by the Minister under Section 20 are restricted to the “aggregate royalty compensation calculated under section 17(3) in respect of that royalty client for that year” by Section 20(5). The amount of allowable costs deducted for a royalty client in a given year may not exceed the total royalty owed to the Crown for that year nor can the Crown share of allowable cost be carried forward to another year.

Section 20(15) provides that a Royalty client may allocate the allowable capital costs, that arise in relation to its facility capital costs, as provided for in the context of Section 20, (described in part above) to one or more other royalty clients that are owners of that facility, own natural gas or gas products processed at that facility, or pay royalty compensation on behalf of an owner of that facility. The re-allocation of allowable capital cost allows the department to match the allowable capital cost with volumes that are re-allocated on the RMF2 form. If a company transfers their volumes for which Crown royalties were due and payable to another royalty client then the Crown would allow the transfer of the associated allowable capital costs. If a company is not entitled to any allowable capital costs in relation to Section 20, they have no allowable capital costs to re-allocate.

If you would like further clarification on the above information please contact the Client Services Operational Analyst for your company as identified in [Section F - Points of Contact](#).

F. POINTS OF CONTACT

Petroleum Registry of Alberta

The Petroleum Registry of Alberta Service Desk is the focal point for communications with the Registry regarding preparations for, access to, or utilization of the Registry. To contact the Petroleum Registry of Alberta Service Desk call: 1-800-992-1144.

Department of Energy Hotline & Internet

Prices, Royalty Rates, and Transportation Information are available on the Department of Energy Internet address or hotline: (403) 297-5430. In addition, both the Gas Royalty Calculation Information Bulletin and Information Letter are also available on the Internet address:

www.energy.gov.ab.ca

Note: To access the sulphur price call the Department of Energy hotline at (403) 297-5430. Wait to hear the recorded list of options, then press #1 on your touch-tone phone for Natural Gas Information. Again, wait for the recorded list of options, then press #3 for Gas Royalty Rates.

Gas Royalty Client Services

The Gas Royalty Client Services Help Desk is structured as a Business Associate client portfolio system, which assigns a given Business Associate to one of four Help Desk teams. Listed below is the portfolio breakdown along with Client Service Team Leads and phone numbers. The portfolios are divided by company name and not by BA ID.

Example: If your company name is “The Gas Company” you would call C – G team at (780) 644-1202.

Business Associate	Phone Number	Team Lead
Numbered companies, A, B & L	(780) 644-1201	Mary Carrie
C – G	(780) 644-1202	Renée Matsuba
H – P (excluding L)	(780) 644-1203	Chris Nixon
Q – Z	(780) 644-1204	Kamal Rajendra

Gas Royalty Reception: (780) 427-2962

Fax: (780) 427-3334 or (780) 422-8732

Alberta Toll Free: (780) 310-0000

Hours of operation are 8:15 a.m. to 4:30 p.m.

Voice messages left after 4:30 p.m. will be answered the next business day.

In situations where a company has just amalgamated or purchased another company, the general rule is to call the team that is responsible for the “Supra” business associate, or Royalty payer. Below are some guidelines for clients who are unsure which Client Services Team to call regarding their questions.

1. **Amalgamation/consolidation** - Call the team responsible for the “Supra” business associate (Royalty Payer).
 - i.e. ABC Oil and Gas amalgamates with Zed Exploration and Zed is the amalgamator (royalty payer). When calling Client Services regarding business for ABC Oil and Gas you would call Team 4 (Q-Z) (780-644-1204) because Zed Exploration is now the Supra business associate and royalty payer. This rule would apply even if you were calling regarding business that is prior to the acquisition or amalgamation.

2. **Asset Purchase** - Call the team responsible for your company.
 - i.e. 123 Gas purchases the assets of TSP Exploration, but not the company. When calling Client Services regarding business for 123 Gas you would call Team 1 (# Co., A, B, & L) (780-644-1201) because you have only purchased assets. You would not be entitled to information regarding business for TSP Exploration that is prior to the asset purchase.

3. **Consultants/service providers** - If you have a contract to provide production accounting services to a company, call the team responsible for your client’s company.
 - i.e. Paul Snow Consulting Services enters into a contract with Duckback Oil and Gas and Olive Oil and Gas. Paul Snow would contact Team 2 (C-G) (780-644-1202) to discuss Duckback Oil business and Team 3 (H-P excluding L) (780-644-1203) to discuss Olive Oil and Gas business. At the time the contract is signed, Paul Snow would have had each company notify the appropriate team that he was authorized to access information for their company.

Calgary Information Centre

300, 801 – 6th Avenue S.W.
Calgary, Alberta T2P 3W2
Telephone (403) 297-6324
Fax (403) 297-8954

Alberta Royalty Tax Credit Information

Alberta Tax and Revenue Administration
Tax Services
Telephone: (780) 427-3044
Alberta Toll Free: (780) 310-0000
Fax: (780) 427-5074
For further information, please contact Tax Services at (780) 427-9425.

Deen Khan
Director, Gas Royalty Calculation
Gas Development

2004 GAS AND ISC PRICES

MONTH	Gas Reference Price (\$/GJ)	Methane ISC Reference Price (\$/GJ)	Methane ISC Par Price (\$/GJ)	Ethane ISC Reference Price (\$/GJ)	Propane ISC Reference Price (\$/GJ)	Butanes ISC Reference Price (\$/GJ)	Pentanes plus ISC Reference Price (\$/GJ)
JAN	6.10	6.06	6.06	6.38	6.48	6.52	6.54
FEB	5.83	5.80	5.80	6.07	6.13	6.17	6.19
MAR	5.49	5.42	5.42	5.87	6.00	6.07	6.10
APR	5.64	5.58	5.58	6.02	6.16	6.20	6.23
MAY	6.28	6.23	6.23	6.56	6.67	6.72	6.75
JUN	6.47	6.45	6.45	6.68	6.69	6.72	6.76
JUL	6.17	6.13	6.13	6.43	6.49	6.53	6.56
AUG							
SEPT							
OCT							
NOV							
DEC							

Natural Gas and NGLs Select Prices for 2004		
Commodity	2004	
New Methane	1.333 \$/GJ	
Old Methane	0.392 \$/GJ	
New Ethane	1.333 \$/GJ	
Old Ethane	0.392 \$/GJ	
Propane	1.333 \$/GJ	
Butanes	1.333 \$/GJ	
Pentanes plus	47.65 \$/m3	
Royalty Factors for Pentanes plus		
	Base	Marginal
New Pentanes	22	35
Old Pentanes	22	50

DETAIL OF THE JULY 2004 GAS AND ISC REFERENCE PRICES						
	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	6.422	6.397	6.571	6.576	6.592	6.595
Deductions: Intra – Alberta Transportation	0.280	0.298	0.170	0.120	0.092	0.070
Marketing Allowance	0.022	0.022	0.022	0.022	0.022	0.022
Price Before Pipeline Factor	6.120	6.077	6.379	6.434	6.478	6.503
Pipeline Fuel/Loss Factor	.990	.990	.990	.990	.990	.990
Price before Special Adjustment	6.058	6.015	6.313	6.369	6.412	6.437
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	6.058	6.015	6.313	6.369	6.412	6.437
Amendments: Carry forward (from previous RP month)	-0.002	-0.001	0.002	0.004	0.005	-0.004
Prior Period Amendment Adjustment (current RP month)	0.346	0.370	0.316	0.264	0.280	0.245
Calculated RP after Amendments	6.402	6.384	6.631	6.637	6.697	6.678
JULY 2004 Reference Price	6.17	6.13	6.43	6.49	6.53	6.56
Difference = value carried forward to next RP month	0.232	0.254	0.201	0.147	0.167	0.118
Adjusted IATD (before Prior Period Amendments)	n/a	0.295	0.168	0.118	0.091	0.069
Prior period Amendments (IATD and Pipeline Fuel Loss)	n/a	0.000	0.000	0.000	0.000	0.000
Adjusted IATD (after Prior Period Amendments)	n/a	0.295	0.168	0.118	0.091	0.069

2003 Weighted Average Reference Price (\$/GJ)
5.830

2003 Weighted Average OMAC (\$/GJ)
0.021

2004 NATURAL GAS LIQUIDS PRICES

MONTH	Ethane Reference Price (\$/GJ)	Ethane Par Price (\$/GJ)	Propane Reference Price (\$/m3)	Propane Par Price (\$/GJ)	Propane Floor Price (\$/m3)	Butanes Reference Price (\$/m3)	Butanes Par Price (\$/GJ)	Butanes Floor Price (\$/m3)	Pentanes plus Reference Price (\$/m3)	Pentanes plus Par Price (\$/m3)	Sulphur Default Price (\$ per tonne)
JAN	6.38	6.38	208.59	6.48	172.19	269.04	6.52	211.06	296.01	283.35	26.73
FEB	6.07	6.07	187.63	6.13	164.69	237.75	6.17	166.16	301.09	290.27	24.94
MAR	5.87	5.87	168.28	6.00	143.27	229.80	6.07	171.58	329.21	318.81	32.65
APR	6.02	6.02	178.48	6.16	158.79	235.53	6.20	189.59	339.05	326.36	30.26
MAY	6.56	6.56	201.30	6.67	181.31	265.89	6.72	213.92	377.36	349.25	37.15
JUN	6.68	6.68	200.53	6.69	179.15	266.36	6.72	211.96	338.99	325.57	37.27
JUL	6.43	6.43	218.71	6.49	193.22	268.54	6.53	236.07	335.42	319.89	34.15
AUG											
SEPT											
OCT											
NOV											
DEC											

ANNUAL SULPHUR DEFAULT PRICE				
1999	2000	2001	2002	2003
\$10.54	\$11.03	\$0.28	\$6.74	\$31.25

2004
NGL TRANSPORTATION ALLOWANCE AND DEDUCTIONS

MONTH	PENTANES PLUS (a)				PROPANE AND BUTANES (b)				PENTANES PLUS, PROPANE & BUTANE (c)				FRAC. ALLOW. (per m3)
	REGION				REGION				REGION				
	1	2	3	4	1	2	3	4	1	2	3	4	
JAN	11.09	13.04	21.07	10.50	10.34	3.20	8.30*	14.13	18.54	17.98	28.23	16.49	10.50
FEB	7.83	10.98	18.12	13.54	16.85	-1.86	11.93*	14.34	14.92	15.62	23.08	14.50	10.50
MAR	12.39	7.58	4.31	15.77	5.88	-0.27	11.45*	9.67	16.35	18.39	27.02	16.69	10.50
APR	13.09	4.89	19.42	15.22	7.61	4.76	6.83*	5.24	24.05	22.98	30.06	19.43	10.50
MAY	32.23	18.47	25.21	32.08	6.70	2.36	5.48*	-0.31	13.74	18.17	28.78	19.82	10.50
JUN	11.50	9.53	19.87	18.36	2.67	-0.30	1.87*	2.16	16.60	14.70	34.62	14.83	10.50
JUL	11.86	18.49	18.71	16.55	6.89	3.63	6.02*	10.35	14.65	19.86	33.71	18.82	10.50
AUG													
SEPT													
OCT													
NOV													
DEC													

- (a) Pentanes Plus obtained as a specification gas product,
- (b) Propane and Butanes obtained as specification products, and
- (c) Pentanes Plus, Propane and Butane contained in a natural gas liquids mix.

* Current month calculated allowance is based on an estimate.

Note: For details on “Prior Period Amendment Effects”, see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS												
NGL REFERENCE PRICES		JULY 2004										
	<i>Propane</i>	<i>Butanes</i>	<i>Pentanes</i>									
Price before amendments	218.700612	268.162400	335.788612									
Opening Rollover (from prior business mth)	0.004501	0.000134	0.000638									
Prior Period Amendment Adj. (NGL-1)	0.000000	0.000000	0.000000									
Prior Period Amendment Adj. (NGL-100)	0.000000	0.381348	-0.370759									
Published Reference Price	218.71	268.54	335.42									
TRANSPORTATION ALLOWANCES		JULY 2004										
	Pentanes Plus				Propane and Butanes				Pentanes Plus, Propane & Butane			
AMENDMENTS	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4
Opening Rollover (from prior business mth)	-0.004822	-0.000283	0.004249	0.003720	0.002252	0.001821	-0.004952	-0.003875	-0.003434	-0.002308	0.002221	-0.001661
Prior Period Amendment Adj. (NGL1)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Prior Period Amendment Adj. (NGL-100)	-0.370759	-0.389240	-0.370762	-0.489836	0.515545	-0.830214	0.150378	0.171291	0.104341	0.611937	0.048585	1.521483
Total Amendment Effect	-0.375581	-0.389523	-0.366513	-0.486116	0.517797	-0.828393	0.145426	0.167416	0.100907	0.609629	0.050806	1.519822
Calculated Transp. Differential	12.236666	18.879507	19.074233	17.040238	6.375050	4.458132	5.878634*	10.186081	14.547362	19.252705	33.659831	17.299515
Calculated Transp. Differential after Total Amendments	11.861085	18.489984	18.707720	16.554122	6.892847	3.629739	6.024060*	10.353497	14.648269	19.862334	33.710637	18.819337
Published Transportation Allowance	11.86	18.49	18.71	16.55	6.89	3.63	6.02*	10.35	14.65	19.86	33.71	18.82

Any estimates represented by () are calculated as the weighted average of the other regions for the same spec product transportation allowance, since the region is zero. The weightings are based on the previous year's production.

**Alberta Gas Reference Price
Calculation Methodology
Producer Direct Marketing Allowance**

1. The producer direct marketing allowance will be calculated annually like the VPA (Value Point Adjustment).
2. Producer direct sales supplied from proprietary gas would receive an allowance equal to the aggregators OMAC (Overhead, Marketing and Administration Charge) (If the aggregators OMAC were not available any longer, an annual survey of marketers providing fee for service to producers would be instituted).
3. Producer sales supplied by 3rd party purchases would be given an allowance equal to the VPA.
4. To minimize additional reporting burden along with administration and auditing, the Department will use existing information sources to calculate the percentage of proprietary versus 3rd party supply. This calculation would divide total field purchases (APMC 601) by total Alberta production to derive the percentage of gas production sold in the field. This percentage would be used as a proxy for the percentage of producers’ total sales that are supplied from 3rd party purchases. The difference (percentage of gas production not sold in the field) would be used as a proxy for the percentage of gas sold directly by producers to end users including distributors.
5. The market share percentage for aggregators, marketers and producers selling direct would continue to be calculated once a year using Gas Reference Price removal information.
6. The following is an example of what the calculation might look like:

	Market Share	Allowance	
Aggregators (OMAC)	10%	.02 \$/GJ	existing
Marketer (VPA)	46%	.05 \$/GJ	existing
Producers Direct	44% {28% X .05 \$/GJ} {72% X .02 \$/GJ}	.03 \$/GJ	new
Total	100%	.04 \$/GJ	

Reasons for Methodology

- It uses marketing cost information from non-producer sources, which ensures impartiality.
 - The aggregators OMAC is a reasonable proxy for producers selling their own production directly to end users. Under contracts with aggregators, producers receive a price netback from the market less marketing type costs (OMAC).
 - The VPA is calculated as the difference between a marketer’s purchase price and his sales price, adjusted for transportation and fuel. The VPA is also a reasonable proxy for a producer conducting similar business.
 - The method for determining the split between proprietary and 3rd party purchases is very approximate. Improving on this method would require additional reporting and auditing, as well as complex allocations, which are not desirable.