

**STATEMENT OF RESERVES DATA  
AND OTHER OIL & GAS INFORMATION**

Effective Date of Statement: March 31, 2008  
Preparation Date of Statement: July 19, 2008

Martin & Brusset Associates, independent well evaluators, ("M & B") prepared a report dated June 5, 2008 (the "M & B report") evaluating the oil and gas reserves owned by Great Pacific International Inc. ("Great Pacific, "the Company", "we") effective March 31, 2008. This appraisal was based on escalating price and cost estimates.

The M & B report is summarized in this Form 51-101F1 report dated July 19, 2008. It should not be assumed that the discounted future net revenues contained herein represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions presented herein will be attained and variances may be material. Moreover, the recovery and reserves figures presented herein are estimates only, and the actual reserves may be greater or less than those estimated.

While the aggregate reserves and future net revenues reported herein are considered to be compliant with the confidence levels required by National Instrument 51-101 ("NI51-101"), extraction of specific evaluations for an individual property or group of properties in isolation will not necessarily reflect the same confidence levels as expressed in this report for the aggregate. Moreover, the reader is cautioned that because proved reserves have only been assigned to a relatively small number of wells in this evaluation, the aggregate proved reserves estimates will not achieve the same confidence levels as a larger group of properties evaluated to the same standard.

The oil and gas reserves presented in this report have been estimated by deterministic methods as most commonly used in current industry evaluation practice. These deterministic reserves estimates are single value estimates derived to satisfy the degree of certainty, or confidence level, targeted for the specific reserves categories according to NI51-101.

Our oil and gas reserves have been determined by one or a composite of petroleum engineering method, considering all of the available data. The methods used for determining reserves for each entity evaluated were considered the most appropriate under the current circumstances. The reserves methodologies that may have been used in this report are as follows:

- Decline curve analysis
- Material balance
- Volumetric estimate
- Mathematical reservoir stimulation
- Analogy
- Performance predictions

## TERMS AND DEFINITIONS

In this Form 51-101F1, the abbreviations and terms set out below shall have the following meanings:

**“Crude oil”** A mixture, consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbon compounds, but does not include liquids obtained from the processing of natural gas. Classes of crude oil are often reported on the basis of density, sometimes with different meanings. Acceptable ranges are as follows:

Light:	Less than 870 kg/m <sup>3</sup> (greater than 31.1° API)
Medium:	870 to 920 kg/m <sup>3</sup> (31.1 to 22.3° API)
Heavy:	920 to 1,000 kg/m <sup>3</sup> (22.3 to 10° API)
Extra-heavy:	Greater than 1,000kg/m <sup>3</sup> (less than 10° API)

**“Natural gas”** A mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

**“Reserves”** Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- Analysis of drilling, geological, geophysical and engineering data;
- The use of established technology;
- Specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimate.

- a. Proved Reserves: Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- b. Probable Reserves: Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of estimated proved + probable reserves.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories.

“Developed reserves” are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

“Developed producing reserves” are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

**TERMS AND DEFINITIONS (Continued)**

**“Reserves” (continued)**

“Developed non-producing reserves” are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

“Undeveloped reserves” are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved and probable) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing.

The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

The qualitative certainty levels contained in the definitions are applicable to individual Reserve Entities, which refers to the lowest level at which reserves calculations are performed, and to Reported Reserves, which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported Reserves target the following levels of certainty under the specific economic conditions:

- At least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- At least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves;

**“Gross reserves”** are defined as the total recoverable reserves associated with the acreage of interest.

**“Gross remaining reserves”** are defined as the total remaining recoverable reserves associated with the acreage of interest at the effective date of the estimate.

**“Gross company interest reserves”** are defined as the applicable working interest share of remaining recoverable gross reserves before deduction of any royalties.

**“Net company interest reserves”** are defined as the applicable working interest share and/or royalty interest share of the remaining reserves, less all royalties and interests owned by others.

**“Net production revenue”** is income derived from the future sale of net reserves of oil, pipeline gas, and by-products less all capital and operating costs, except that no allowance has been made for well abandonment and lease reclamation costs upon depletion of the reserves, unless otherwise stated.

**“Well abandonment costs”** as defined in NI 51-101 are costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the well site.

**TERMS AND DEFINITIONS (Continued)**

Abbreviations used herein are as follows

A & R	Abandonment and reclamation
Bbls	Barrels
Boe	Barrels of oil equivalent
GORR	Gross overriding royalty
ha	Hectares
MCF	Thousand cubic feet
MMBtu	Million British thermal units
MMCF	Million cubic feet
NPV	Net present value
NRI	Net revenue interest
P & NG	Petroleum and natural gas
WI	Working interest

**Note on barrels of oil equivalent conversion:**

Volume units of gas and oil are converted to a “barrels of oil equivalent” measure based on the relative energy content of the two commodities, not the relative prevailing prices. Thus, 6 mcf gas = 1 bbl oil = 1 boe.

**Note on per-day measures**

Daily production rates presented herein represent average daily rates for the entire period presented (i.e. they are calendar-day daily rates).

**DISCLOSURE OF RESERVES DATA, Forecast Case**

All disclosed reserves are attributable to property interests owned by Great Pacific International Inc. (“the parent company”), and the 100%-owned consolidated subsidiary of the Company.

The estimates of future net revenue do not give account to any company overheads or administration costs other than those directly charged to a well or facility.

Data presented is calculated using assumptions of future commodity prices and escalated future production costs as estimated by Martin & Brusset Associates, our qualified reserves estimators. The reader should note that future oil and gas production realized by Great Pacific may involve prices and costs significantly different than those estimated herein. Please see “Pricing Assumptions” for disclosure of the forecast prices used in these future net revenue estimates.

All oil reserves referred to herein refer to light and medium oil.

Breakdown of Proved and Probable Reserves, forecast case

Canada:

Oil reserves

	Gross company interest reserves (bbls)	Net company interest reserves (bbls)
Proved developed producing oil reserves	17,000	17,000
<b>Total proved oil reserves</b>	17,000	17,000
Probable oil reserves	27,000	26,000
<b>Total proved plus probable oil reserves</b>	44,000	43,000

Natural gas reserves

	Gross company interest reserves (Mmcf)	Net company interest reserves (Mmcf)
Proved developed producing natural gas reserves	2	2
<b>Total proved natural gas reserves</b>		
Probable natural gas reserves	67	52
<b>Total proved plus probable natural gas reserves</b>	69	54

Probable reserves to our net company interest consists of the following:

	Oil (bbls)	Natural gas (Mmcf)
Probable developed	10,000	2
Probable undeveloped	16,000	50
Probable oil and gas reserves	26,000	52

**Net Present Value of Future Net Revenue**

Undiscounted future net revenue expected to be earned from Company reserves, assuming forecast case prices and escalated costs, is as follows:

<b>Future revenue attributable to the production and sale of:</b>	
Proved reserves	<u>\$1,414,000</u>
<i>Probable developed reserves</i>	937,000
<i>Probable undeveloped reserves</i>	<u>1,835,000</u>
Probable reserves	<u>2,772,000</u>
<b>Future gross sales revenue from proved plus probable oil and gas reserves</b>	<b>\$4,186,000</b>
<b>Less:</b>	
Royalties	\$215,000
Operating costs	1,620,000
Development costs	320,000
Abandonment and reclamation costs	<u>119,000</u>
<b>Future net revenue (before tax)</b>	<b>\$1,917,000</b>
Future income tax expenses	<u>166,000</u>
<b>Future net revenue (after tax)</b>	<b><u>\$1,751,000</u></b>

A breakdown of future net revenue before and after deducting future income tax expenses is as follows:

**Before-tax case**

<i>Discounted future net revenue attributable to:</i>	Discount rate				
	0%	5%	10%	15%	20%
Proved developed producing reserves	<u>\$613,000</u>	<u>\$549,000</u>	<u>\$497,000</u>	<u>\$455,000</u>	<u>\$421,000</u>
<b>Proved reserves</b>	613,000	549,000	497,000	455,000	421,000
Probable reserves	1,299,000	1,018,000	818,000	672,000	563,000
<b>Proved plus probable reserves</b>	<u>\$1,912,000</u>	<u>\$1,567,000</u>	<u>\$1,315,000</u>	<u>\$1,127,000</u>	<u>\$984,000</u>

**After-tax case**

<i>Discounted future net revenue attributable to:</i>	Discount rate				
	0%	5%	10%	15%	20%
Proved developed producing reserves	<u>\$613,000</u>	<u>\$549,000</u>	<u>\$497,000</u>	<u>\$455,000</u>	<u>\$421,000</u>
<b>Proved reserves</b>	613,000	549,000	497,000	455,000	421,000
Probable reserves	1,138,000	882,000	704,000	576,000	480,000
<b>Proved plus probable reserves</b>	<u>\$1,751,000</u>	<u>\$1,431,000</u>	<u>\$1,201,000</u>	<u>\$1,031,000</u>	<u>\$901,000</u>

**Net Present Value of Future Net Revenue (continued)**

Future net revenue attributable to each class of reserves, on a boe basis, is presented below, in the before-tax case at a discount rate of 10% per year:

	Oil reserves (bbls)	Gas reserves (mcf)	Total reserves (6:1 boe)	Future net revenue, before- tax, discounted at 10% per year	Future net revenue, per boe reserves
Proved developed producing	17,000	2,000	17,333	497,000	\$29
Probable	26,000	52,000	34,667	818,000	\$24
Proved plus probable	43,000	54,000	52,000	1,315,000	\$25

**PRICING ASSUMPTIONS**

**Forecasted Prices Used in Estimates**

Estimates of oil and gas reserves and future net revenues disclosed under the forecast case scenario use the following forecasted prices, adjusted in certain cases for expected price differentials:

Year	Edmonton Light Sweet 40° API (C\$/Bbl)	Alberta Avg. Field (\$/MMBTU)	Exchange Rate \$US/\$Cdn	Cost Inflation %/Year
2008 Q1	98.31	7.62	1.00	
Q2	99.00	8.15	1.00	
Q3	97.00	7.95	1.00	
Q4	95.00	8.05	1.00	
2009	91.00	7.85	1.00	2
2010	87.00	7.65	1.00	2
2011	83.00	7.55	1.00	2
2012	82.00	7.55	1.00	2
2013	82.00	7.65	1.00	2
2014	83.00	7.80	1.00	2
2015	85.00	8.00	1.00	2
2016	87.00	8.20	1.00	2
2017	89.00	8.40	1.00	2
2018	91.00	8.60	1.00	2

Thereafter: +2.0%/year

\*Prices used in the Tables were provided by Martin & Brusset Associates, Oil & Gas Reserves Evaluators.

The M & B report uses benchmark oil price forecasts adjusted for individual pools to account for variances in oil gravity, sulphur content and transportation charges. Adjustments were made on the basis of the relationship between actual prices received and the applicable benchmark prices where such information was available.

The M & B report use benchmark gas price forecasts for gas production at base conditions of 14.65 psia and 60°F. The applicable benchmark prices were adjusted for heating value and pipeline cost of service where necessary.

Great Pacific is not subject to any agreements that contractually commit or bind us to supply oil and gas in the future at some fixed or presently determinable future price.

**PRICING ASSUMPTIONS (Continued)**

In the twelve months ended March 31, 2008, the Company realized the following per-unit product prices:

Oil: \$98/bbl

Gas: \$5.8/mcf

The Company's operators sell the Company's oil and gas production at spot prices with no dedication of volume or price.

**RESERVES RECONCILIATION**

Factors	Light and Medium Oil			Total Oil		
	Gross Proved Mbbbl	Gross Probable Mbbbl	Gross Proved Plus Probable Mbbbl	Gross Proved Mbbbl	Gross Probable Mbbbl	Gross Proved Plus Probable Mbbbl
March 31, 2007	18.0	32.0	50.0	18.0	32.0	50.0
Technical Revisions	1.2	-5.0	-3.8	1.2	-5.0	-3.8
Production	-2.2	0.0	-2.2	-2.2	0.0	-2.2
March 31, 2008	17.0	27.0	44.0	17.0	27.0	44.0
Factors	Associated and Non-Associated Gas			Total Gas		
	Gross Proved Mmcf	Gross Probable Mmcf	Gross Proved Plus Probable Mmcf	Gross Proved Mmcf	Gross Probable Mmcf	Gross Proved Plus Probable Mmcf
March 31, 2007	0.0	65.0	65.0	0.0	65.0	65.0
Technical Revisions	2.0	2.0	4.0	2.0	2.0	4.0
Production	0.0	0.0	0.0	0.0	0.0	0.0
March 31, 2008	2.0	67.0	69.0	2.0	67.0	69.0
Factors	Total Boe (6:1)					
	Gross Proved Mbbbl	Gross Probable Mbbbl	Gross Proved Plus Probable Mbbbl			
March 31, 2007	18.0	42.8	60.8			
Technical Revisions	1.5	-4.7	-3.2			
Production	-2.2	0.0	-2.2			
March 31, 2008	17.3	38.2	55.5			

The reserves evaluation presented herein relates to the "Mistahiya-group" properties. Great Pacific purchased the Mistahiya-group properties in March, 2007, and began participating in the operations of these properties at April 1, 2007, as per the terms of the acquisition agreement.

Technical revisions are year-over-year changes to reserve estimates made on carried forward properties in the year ended March 31, 2008. These technical revisions reflected re-appraisals of previously evaluated accumulations based on such factors as commodity price changes, and an evolved understanding of the characteristics and performance of the assessed reservoirs accruing from an additional year's worth of production data.

**RESERVES RECONCILIATION (Continued)**

Fiscal 2008 production volumes presented in the reconciliation do not include the production volumes earned by the Company from non-participating penalties held by the Company against non-participating joint partners in the wells identified, if those non-participation penalties were both earned and paid-out (i.e. lapsed) in the same fiscal year. Thus, production volumes included in the reserves reconciliation reflect only those quantities associated with our normalized 36% share of production, The Company earned 1.6mmbbls of oil production not accounted for in the reconciliation of production volumes pursuant to temporary working interest increases earned via non-participation penalty interests.

**ADDITIONAL INFORMATION RELATING TO RESERVES DATA**

**Undeveloped Reserves**

Reserves classified as undeveloped are those that are expected to be recovered from known accumulations, where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production.

Great Pacific has probable undeveloped reserves. Probable undeveloped reserves are undeveloped reserves, as defined above, that are characterized by a lower certainty of recovery than proved undeveloped reserves. Specifically, probable undeveloped reserves are undeveloped oil and gas accumulations that have the property that, in the estimation of the qualified reserves evaluator, the likelihood that the actual amount of hydrocarbons recovered from that accumulation will be greater than the stated amount of proven and probable reserves attributed to that accumulation is equal to the likelihood that the amount of hydrocarbons recovered will be less than the stated amount of proven and probable reserves attributed to that accumulation.

Undeveloped reserves are defined as probable based on the determination of our qualified well evaluators, who arrived at their determination using a composite of petroleum engineering methods considering all of the available data.

Great Pacific has interests in four properties which have been assigned probable undeveloped reserves:

- Grand Forks (oil)
- Kidney E/33 (oil)
- Rainbow Lake (oil)
- Redwater (gas)

The Rainbow Lake and Kidney E/33 leases expire in FY-2009 and FY-2011, respectively.

A historical summary of probable undeveloped reserves held by the Company is as follows:

Probable undeveloped reserves			March 31, 2008:
	March 31, 2008	March 31, 2007	NPV (before tax) 10% annual discount rate
Oil (bbls)	16,000	16,000	\$373,000
Gas (mcf)	50,000	50,000	172,000
Total (boe)	24,333	24,333	\$545,000

The Company had no probable oil and gas reserves at March 31, 2006 or prior.

We expect to commence development on the Kidney E/33 project in fiscal 2009. We are also evaluating the feasibility of conducting the Rainbow Lake re-entry as part of a larger north-west Alberta work-program in fiscal 2009, which would include the Haro East project, located approximately 75km south-east. Both development plans are subject to obtaining project financing and are pending a suitable participation arrangement with our joint participants on these properties.

The Redwater and Grand Forks leases do not expire in the near-term, and our non-operated working interests in those wells are <10%. As these locations do not lapse in the coming two years, we intend to reserve near-term capital spending to more time-sensitive tenures. Accordingly, it is unlikely that we will develop these properties in the next two years.

### Undeveloped Reserves (Continued)

In general, the Company is a minority non-operated interest-holder in the probable undeveloped properties. Accordingly, our ability to develop those resources is significantly impacted by the participation of our joint partners.

In the calculation of the net present value of our reserves, it was projected that the development costs presented would be incurred in the fiscal year ended March 31, 2009 and 2010.

Future net revenue estimates presented herein include deductions of \$320,000 (net) for the costs of development activities which are required to bring our probable undeveloped reserves to the point of extraction.

The work required to test and extract our probable undeveloped reserves is as follows:

<u>Property</u>	<u>Development required</u>	<u>Estimated capital cost included in future net revenue (net)</u>
Grand Forks	Drill & complete	\$40,000
Kidney E/33	Drill & complete	156,000
Rainbow Lake	Re-enter and workover	69,000
Redwater	Drill & complete	55,000
		<u>\$320,000</u>

Subsequent to the completion date of the independent NI51-101 reserves assessment reported herein, management has re-estimated capital costs to be \$420,000, an increase of \$100,000 from the amount of capital costs included in the evaluation of future net revenue. These additional amounts include an accrual of \$72,500 (net) to reactivate the Keg River KK well (classified as proved developed producing, but suspended due to bottom-hole equipment failure) and an accrual of \$27,500 (net) for an increase in estimated drilling costs on the Kidney E/33 well.

Development, capital and exploration costs disclosed in this section relate only to those properties for which the company holds assigned reserves at March 31, 2008. At the preparation date of this report, the Company has planned additional development, capital and exploration expenditures on properties not evaluated herein. No effect of these planned expenditures has been recorded in this reserves evaluation. Our MD & A dated July 19, 2008, available on [www.sedar.com](http://www.sedar.com) discloses these additional planned expenditures.

Management expects to fund its development costs primarily through the proceeds of private placement sales of common shares of the Company. There is no assurance that management will obtain adequate financing on economic terms in a timely manner. Failure to obtain adequate financing would likely prevent the development and production of undeveloped reserves.

### **SIGNIFICANT FACTORS OR UNCERTAINTIES**

Great Pacific faces a number of operational, business and economic risks, including risks common to all businesses, risks common to the oil and gas sector, and risks that are common to development stage enterprises.

Great Pacific is considered to be in the development stage of its oil and gas business operations. We have not yet achieved significant or self-sustaining levels of revenue or operating cash flows. As a result, we are reliant on external financing, raised primarily through the private placement of equity, to provide working capital, fund business operations and pay for all planned oil and gas development and capital expenditures. To a large extent, our ability to realize the net revenues forecasted in this reserves evaluation is dependent upon our ability to raise sufficient funds to carry out the development of these properties. There is no assurance that we will be successful in obtaining adequate funding in a timely manner. Similarly, the financial uncertainties common to development stage enterprises may make it difficult in the future to obtain those resources required to carry out the development of our reserves.

**SIGNIFICANT FACTORS OR UNCERTAINTIES (Continued)**

The failure to obtain working capital in a timely manner through equity financing may prevent us from developing our properties, notwithstanding the fact that such properties may be assessed to have valuable hydrocarbon reserves. Management is currently identifying financing opportunities in order to address our lack of capital, but there is no assurance that we can obtain adequate financing in a timely manner.

The value of Great Pacific's reserves are sensitive to the prevailing market price for oil and gas realized at the time of sale. Oil and gas prices are highly volatile, and the reader is cautioned that future spot prices realized at the time of sale may differ significantly from the estimated future prices used in the reserves valuation. This commodity price risk can arise from changes in the price of oil and gas, which is driven by global demand and supply factors. Commodity price risk also arises from foreign exchange risk, since global oil prices are denominated in U.S. dollars, and our operational costs are denominated in Canadian dollars. All else held equal, a fall in the price of U.S. dollars relative to Canadian dollars will reduce our gross sales revenue. Oil prices are also sensitive to such macro-scale factors as global economic output, which drives energy demand, and global geo-political developments, which may restrict supply and trade in oil. Currently, our future production is expected to be sold in the spot market.

The ability to economically extract the volumes of hydrocarbons stated in our reserves valuation is dependent on the realizing the expected geological conditions. There can be no assurance that realized local geological conditions will permit the economic and viable drilling and operation of oil and gas wells, and there can be no assurance that such factors as the actual size, volume, pressure, water content, and hydrocarbon content of oil and gas accumulations will reflect those characteristics forecasted and attributed to the well or property in the reserves evaluation. Actual recoverable reserves and well performance (i.e. the realized hydrocarbon flow rate, reservoir pressure and depletion rate) may materially differ from the forecasted levels implicit in this reserves evaluation.

Further, our low number of operating wells and development targets leaves us more exposed to normal variations in realized oil and gas reserves than would be the case with a larger company.

There are a number of operational risks inherent in oil and gas exploration and production. These risks include the difficulties often encountered in drilling an oil or gas well, and the likelihood that observed geological conditions may differ significantly from expected geological conditions. In addition, several of our oil and gas property interests are in "muskeg" regions – swampy terrain common to northern Alberta. These oil and gas property interests can only be drilled and operated in the winter months, when the ground is frozen sufficiently solid to permit truck and drilling rig access to the well site. As a result of this, we expect our earnings and capital expenditures to show material seasonality. We also face operational risks such as the risk that a drilling operation may encounter unknown formations, the costs associated with encountering unexpected geological conditions unfavourable to drilling or well installation, or the risk of premature downhole or surface equipment failure. The drilling and operation of wells is also subject to the risk of blowouts, spills or pollution, untoward gas emissions or fire, and well equipment failure. Management uses reliable and experienced contractors to mitigate these risks, and our operating well sites are covered by blow-out, property and casualty and business interruption insurance which may also partially insulate against these risks.

The oil and gas industry has literally thousands of participants. As a result, Great Pacific faces significant competition in the markets for such service and production resources as drilling rigs, human resources (including managerial, geological, engineering, operational and administrative talent), and risk capital. Our ability to capture the net present value identified in this report, is materially sensitive to our ability to obtain such resources in a timely manner at a feasible cost. The competition for such inputs is also exerting inflationary pressures on oil and gas exploration and production costs, which, if it exceeds our forecasted levels, may reduce our realized future net revenue relative to these projections.

Such competition within the oil and gas industry, when coupled with the aging of the Western Canadian sedimentary basin, will make it more difficult to obtain economic oil and gas property interests in the future. While this report is focused on the evaluation of existing wells, the investor should be cautioned that the ability to sustain the revenue levels inherent in these projections, and the ability to maintain a level of cash flows sufficient to cover general and corporate overhead requires us to expand and increase reserves through further property acquisition. The likelihood of acquiring a sufficient portfolio of additional economic oil and gas property interests, in the face of a competitive market for such properties, is indeterminate.

**SIGNIFICANT FACTORS OR UNCERTAINTIES (Continued)**

Associated with the price, geological and supply risks discussed above, is marketing risk. Our ability to earn the future revenues implicit in our reserve valuation depends on our ability to successfully market our product at a level significantly close to the prevailing quoted spot price for light crude delivered to Edmonton. Our ability to earn such revenues depends on the realized grade of our hydrocarbon, our access to transportation for our inventory, which, in the case of most of our properties is by tanker truck, and continued access to refining capacity.

Our reserves are located on properties that are held jointly, with one or more interest-holders owning a working and net revenue interest in each property. On all properties identified as containing economic reserves, we hold a minority non-operated working interest. Therefore, our ability to bring undeveloped properties into production may depend on the willingness of other joint interest participants to participate according to their working interest. As the discounted net present values of our estimated reserves, as provided in this report, are materially sensitive to the passage of time, any delays in developing non-producing reserves due to this or other reasons, may materially reduce the realized value of our reserves.

The Company is also subject to regulatory risk, given the regulated nature of the oil and gas business. The ability to drill our properties in a timely manner is dependent on the receipt of appropriate well licenses and our ability to demonstrate an ecologically sound drilling, operating and remediation plan.

**FUTURE DEVELOPMENT COSTS**

Development costs deducted in the estimate of future net revenue attributable to proved and probable reserves total \$320,000, broken-down as follows:

<b>Property Class</b>	<b>Future development costs included in net revenue forecasts</b>	<b>Additional future development costs accrued subsequent to effective date</b>	<b>Total</b>	<b>Estimated Expenditure Date</b>	
Proved developed	\$ -	\$ 72,500	\$ 72,500	Fiscal 2009	Keg River KK
Probable undeveloped	40,000	-	40,000	Fiscal 2010	Grand Forks
Probable undeveloped	156,000	27,500	183,500	Fiscal 2009	Kidney E/33
Probable undeveloped	69,000	-	69,000	Fiscal 2009	Rainbow Lake
Probable undeveloped	55,000	-	55,000	Fiscal 2010	Redwater
	<b>\$ 320,000</b>	<b>\$ 100,000</b>	<b>\$ 420,000</b>		

The \$100,000 of additional future development costs presented above were identified subsequent to the effective date of the M & B report, and were thus not deducted from the net revenue values presented herein.

## **OTHER OIL AND GAS INFORMATION**

Additional oil and gas properties held by the Company at March 31, 2008 (other than those evaluated in our reserves report) include the following, by area of interest

### Peerless Lake Area of Interest (north-central Alberta)

- 1.) Farm-in rights to 1 net section of petroleum and natural gas leases in the area of Peerless Lake and Red Earth village, north-central Alberta (the "RLE Red Earth farm-in lands"). Management believes this acreage holds a Devonian oil target identified on 2-D seismic. Our farm-in rights to these lands will expire on December 1, 2008 if not drilled by that time.
- 2.) A 75% interest (subject to a 5-15% convertible royalty) to 176 hectares of petroleum and natural gas leases near Peerless Lake, Alberta. These lands were acquired pursuant to our participation in the 3-20 project. Management believes this acreage holds a Devonian oil target identified on 2-D seismic.
- 3.) 100% interest in approximately 480 hectares of petroleum and natural gas leases in the Kidney field.

### Other Western Canadian locations

- 1.) Farm-in rights to 3 net sections of petroleum and natural gas rights near the Chinchaga River in north-west Alberta, holding two Bluesky-gas targets ("the Haro East project"). These will be forfeited if not drilled by December, 2008 (subject to access).
- 2.) Approximately 3,080 gross hectares (2,890 net hectares) of petroleum and natural gas leases in Alberta, Canada.
- 3.) Approximately 880 gross hectares (740 net hectares) of mineral leases in Manitoba, Canada, considered prospective for unconventional shale gas. Substantially all of this land will expire in the current fiscal year.

### United States property interests

- 1.) We hold a 2.2% net revenue interest in a producing natural gas well located in the Arkoma Basin, Arkansas.
- 2.) We hold participation rights, to a 13% working interest (9.75% net revenue interest) in an 8.25mile<sup>2</sup> prospect area located in the Midland Basin area of west-central Texas. Retaining our interest in this prospect area requires us to participate, to our interest, in the drilling and development of this property. It is expected that at least 2 wells will be drilled on this prospect area in the current fiscal year.

Our development plans for fiscal 2009 (ended March 31, 2009) are expected to include the development of these un-evaluated properties as follows:

1. Drilling 1 test well on the RLE Red Earth farm-in lands;
2. Drilling 2 earn-in wells on the Haro East targets; and
3. Drilling 1-2 gross (0.1 – 0.3 net) earn-in wells on the Midland Basin, TX prospect area.

As these development plans relate to properties not evaluated in the M & B report effective March 31, 2008, they have not been included in the estimate of future development costs presented elsewhere in this report. The total net development costs for these projects is estimated at approximately \$2,000,000.

We are also continuing with geological evaluation and trade seismic acquisition and interpretation for the purposes of target identification on our Alberta petroleum and natural gas leases.

**OTHER OIL AND GAS INFORMATION (Continued)**

In addition to these exploration and development properties, our land portfolio also includes working interests in 2 net (7 gross) suspended oil wells and 1 gross (1 net) suspended gas well holding no assigned reserves. Of these properties, 2 are considered to hold marginal re-work potential at current commodity prices. However, the balance of these wells are believed to be exhausted, with no further exploration or development potential. The Company believes there are material abandonment and reclamation costs associated with the de-commissioning of these leases and wells, as disclosed

<u>Property group</u>	<u>Producing wells</u>		<u>Suspended – assigned proved or probable reserves</u>		<u>Suspended – no reserves assigned</u>		<u>Total</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Peerless Lake								
Area of interest (oil)	6.0	2.2	1.0	0.4	6.0	1.9	12.0	4.1
Rainbow Lake (oil)	-	-	1.0	0.2	-	-	1.0	0.2
Grand Forks (oil)	-	-	1.0	0.1	-	-	1.0	0.1
Acadia/Empress (gas)	1.0	0.0	-	-	1.0	0.0	2.0	0.1
Manitoba	-	-	-	-	1.0	1.0	1.0	1.0
Arkansas (gas)	1.0	0.0	-	-	-	-	1.0	0.0
<b>Total</b>	<b>8.0</b>	<b>2.2</b>	<b>3.0</b>	<b>0.6</b>	<b>8.0</b>	<b>3.0</b>	<b>18.0</b>	<b>5.5</b>

The Company is obliged to participate in the retirement and reclamation of all 5.5 net wells held.

**ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS**

The Company estimates the abandonment and reclamation (A & R) costs for each property based on the relevant contractual, statutory and regulatory site reclamation and restoration requirements in existence at the effective date. For developed properties, the Company estimates the cost of abandonment, reclamation and remediation work that would be required to abandon and remediate developed properties at the effective date.

For undeveloped properties for which reserves have been attributed, management estimates the anticipated cost of abandoning, reclaiming and remediating planned well sites based on the nature, design and scope of all future property development contemplated for that property.

In the forecast case, these amounts are escalated forward to the expected well abandonment date. For properties to which reserves have been attributed, the expected well abandonment date is determined by the qualified reserves evaluator.

Both for developed and undeveloped properties, A & R costs are estimated on a gross basis, and the present value of the net amount of the estimated A & R costs (that is, the portion of gross A & R costs proportionate to the Company's working interest in the property) is considered the Company's future A & R cost. This amount is deducted from the reported amount of future net revenues and is used in the determination of oil and gas reserves.

The A & R costs used by the well reserves evaluator in determining future net revenues do not include the estimated costs of abandoning and reclaiming surface installations (such as well equipment and roads), and do not give effect to the salvage value of equipment located on the well sites. In addition, future net revenues estimates disclosed herein also do not make provisions for the costs of reclamation on properties for which no reserves have been attributed. The present value of estimated future A & R costs associated with abandoning, reclaiming and retiring surface installations, equipment and lease-sites and abandoning and reclaiming properties with no assigned reserves are included in the amount of the future asset retirement obligation presented in the consolidated financial statements. However, the future asset retirement obligation amount stated on the balance sheet only measures the present value of estimated A & R costs on properties which are developed or under development at the balance sheet date.

**ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS**

The net revenue values (forecast case scenario) disclosed elsewhere herein include the following estimated A & R costs) as estimated at March 31, 2008:

<b>Property</b>	Undiscounted gross estimated A & R costs (2008 dollars)	Undiscounted net estimated A & R costs (at abandonment date)	Present value of net estimated future A & R costs
<i>Peerless Lake Area of Interest</i>			
Equisetum	\$120,000	\$44,250	\$21,370
Loon	30,000	14,000	4,000
Red Earth	90,000	40,300	16,100
Grand Forks	50,000	4,300	1,850
Rainbow Lake	50,000	10,150	5,700
Red Water	20,000	2,100	1,000
Empress/Acadia	15,000	600	450
	<b>\$375,000</b>	<b>\$115,700</b>	<b>\$50,470</b>

The future A & R costs presented above reflect both the estimated abandonment date costs of remediating wells that existed at March 31, 2008, and an estimate of the A & R costs that are expected to arise based on the operations that will be required to develop undeveloped properties to which reserves have been attributed. Of the undiscounted net estimated A & R costs, totaling \$115,700, presented above, \$23,550 relate to properties that are currently classified as undeveloped. Properties characterized in the latter fashion are those which, on the basis of holding probable undeveloped economic reserves as disclosed herein, are expected to be drilled and developed in the future, with such drilling and development invariably creating legal and contractual reclamation and retirement obligations.

Details of A & R costs deducted from the estimates of future net revenue are as follows:

<b>Property</b>	<b>Existing wells for which net A &amp; R obligations were recorded at March 31, 2007</b>		<b>Future (planned) wells for which net A &amp; R obligations were recorded at March 31, 2007</b>		<b>Existing and future net wells</b>	<b>Net A &amp; R costs included in net revenue calculation A &amp; R Costs</b>
	<b>Net Wells</b>	<b>A &amp; R Cost</b>	<b>Net Wells</b>	<b>A &amp; R Costs</b>		
<i>Peerless Lake Area of Interest</i>						
Equisetum	1.3	\$37,250	0.2	\$7,000	1.5	\$44,250
Loon	0.4	14,000	-	-	0.4	14,000
Red Earth	1.0	40,300	-	-	1.0	40,300
Grand Forks	-	-	0.1	4,300	0.1	4,300
Rainbow Lake	-	-	0.2	10,150	0.2	10,150
Red Water	-	-	0.1	2,100	0.1	2,100
Empress/Acadia	0.0	600	-	-	0.0	600
	<b>2.7</b>	<b>\$92,150</b>	<b>0.6</b>	<b>\$23,550</b>	<b>3.3</b>	<b>\$115,700</b>

**ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS (Continued)**

At the effective date of this report, management is of the opinion that there are additional reclamation costs related to surface installation abandonment and reclamation of leases. In addition, the Company faces future costs related to the abandonment of those suspended wells not evaluated herein. Due to industry-standard limitations in the scope of the independent reserves evaluation such future A & R costs were not included in the net revenue values disclosed herein. These additional A & R costs (estimated at abandonment date prices) are as follows, on an undiscounted basis and discounted at 10% per year. These additional costs relate exclusively to developed properties (whether proven or suspended), and thus are current obligations of the Company.

<b>Property</b>	<b>Undiscounted A &amp; R costs not included in net revenue estimates</b>	<b>Undiscounted net estimated A &amp; R costs not included in net revenue estimates</b>	<b>Net estimated A &amp; R cost not included in net revenue estimates, discounted at 10%</b>
<i>Peerless Lake Area of Interest</i>			
Equisetum	\$463,650	\$166,300	124,950
Loon	700,300	213,500	185,150
Red Earth	329,900	118,750	79,550
Other properties	105,150	47,550	38,100
	<u>\$1,599,000</u>	<u>\$546,100</u>	<u>\$427,750</u>

These values include the estimated A & R costs for the suspended Peerless Lake oil wells with no reserves assigned. These values also include accruals for the future remediation of the 3-20 well-bore, the Manitoba property, and the Logan County, Arkansas natural gas well-interest.

The amount reported in the annual financial statements at March 31, 2008 for "future asset retirement obligations" represents the total net future abandonment obligations that the Company is liable for based on the current state of its oil and gas assets. Thus, it is a broader measure than the A & R estimates deducted from future net revenue values presented herein, inasmuch as it includes the same wellbore remediation costs, but also includes surface equipment remediation and lease reclamation costs. That estimate of future asset retirement obligations also differs from the A & R figures referenced in the M & B report in that it does not include any accruals for future A & R costs on wells not yet develop.

We anticipate that in the fiscal years 2009 to 2011 (inclusive), we will face total A & R expenditures of \$273,000 based on our estimate of the cost of performing our share of A & R obligations, and determined using the estimate of remaining well life provided by our qualified reserves evaluator.

**COSTS INCURRED IN FISCAL YEAR ENDED MARCH 31, 2008 AND 2007**

Costs incurred in the year ended March 31, 2008 are as follows:

	Fiscal year ended March 31,	
	2008	2007
	\$	\$
<u>Property acquisition costs</u>		
Western Canadian property interests	353,440	612,000
Arkansas natural gas well interest	32,166	-
	<u>385,606</u>	<u>612,000</u>
<i>Add: Future asset retirement obligations assumed upon purchase</i>	294,238	165,055
<b>Total acquisition expenditures</b>	<b>679,844</b>	<b>777,055</b>
Exploration costs	236,116	
Development costs	355,469	
<b>Total exploration and development</b>	<b>591,585</b>	<b>-</b>
<b>Total costs incurred</b>	<b>1,271,429</b>	<b>-</b>

In the years presented, the Company completed the 3-20 well (two zones) which proved non-economic.

**CURRENT EXPLORATION AND DEVELOPMENT ACTIVITIES**

Our current exploration and development activities are summarized by property group, as follows:

**Peerless Lake Area of Interest:**

We plan on participating in the drilling and re-working of one to four gross wells (one to two net wells) in the Peerless Lake Area of Interest in the coming drill season. Targets include the RLE Red Earth farm-in lands 11-89 test well, the Kidney E/2 location, and two past-producing, suspended wells which, at current commodity prices, the Company feels may have re-entry and work-over potential.

**Haro East**

We plan on developing the Haro East project area through the drilling of two natural gas wells in the winter drill season of fiscal year 2009.

**Midland Basin, TX**

We are participating in a two gross well prospect exploration drill program in the Midland Basin area of Texas, commencing summer 2008. Our participation is to a 13% working interest (9.75% net revenue interest) .Should these initial wells prove encouraging, we expect that an additional 3-5 development targets will be drilled in this prospect area. As we are a non-operating minority working interest holder, our exploration and development activities on this property will be subject to the capital plan set forth by the partners on this well.

**Other opportunities**

Management has placed a high priority on developing additional opportunities, and to that end the following activities are on-going:

- Petroleum and natural gas lease acquisition and trade seismic acquisition in Western Canada
- Continued evaluation of domestic and international participation and exploration opportunities

**PRODUCTION ESTIMATES**

The estimated values for net revenues disclosed herein are based on the following estimate of production for the fiscal year ended March 31, 2009.

	<b>Oil</b>	<b>Gas</b>	<b>Total (boe)</b>
Volume of expected production from proved developed producing reserves	3000 bbl	1100 mcf	3200 boe
Volume of expected production from probable developed reserves	300 bbl	150 mcf	300 boe
Total expected production, calendar 2007	3300 bbl	1250 mcf	3500 boe

The production estimates provided above are based on the appraisal of remaining reserves set forth in the M & B report.

These production estimates relate to reserves classified as developed at March 31, 2008. They do not give any effect to the likelihood of obtaining production from planned exploration and development activities.

Details on quarterly production, revenues and costs for the year-ended March 31, 2008 can be found in our quarterly Management Discussion and Analyses, and Unaudited interim financial statements, available on [www.Sedar.com](http://www.Sedar.com)

**TAX HORIZON**

The Company will not be liable for any income tax in the year ended March 31, 2008. The company believes that it has sufficient unrecorded future income tax assets, comprising non-capital losses carried forward and resource property costs, which can be carried forward and applied against net revenues from the reserves presented in this report such that there will be no income taxes payable with respect to the net revenues assessed in this report.

**FORM 51-101F2  
REPORT ON RESERVES DATA**

To the board of directors of Great Pacific International Inc. (the "Company):

- 1 We have evaluated the Company's reserves data as at March 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2008, estimated using forecast prices and costs.
- 2 The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGI Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and Petroleum (Petroleum Society).

- 3 Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstated. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
- 4 The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended March 31, 2008 and identifies the portions thereof that we have evaluated and reported on to the Company's management and board of directors.

Independent Qualified Reserves Evaluator	Description & Prep. Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) x 1000			
			Audited	Evaluated	Reviewed	Total
Martin & Brusset Assoc.	Mar 31/08	Canada	\$0	\$1,315	\$0	\$1,315


- 5 In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
- 6 We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

- 7 Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

**Martin & Brusset Associates**  
**Calgary, Alberta, Canada**

**July 22, 2008**



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**S. Neil Sedgwick, B.Sc., P.Eng.**



**Report of Management and Directors  
on Reserves Data and Other Information**

Management of Great Pacific International Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2008 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated and reviewed the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

"Thal S. Poonian"

"Mathew Hoogendoorn"

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Thal S. Poonian, President, Director

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Mathew Hoogendoorn, CFO

"Robert Leyk"

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Robert Leyk, Director

July 21, 2008

For the convenience of readers, CSA Staff Notice 51-324 *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* sets out the meanings of terms that are printed in italics in sections 1 and 2 of this Form or in *NI 51-101, Form 51-101F1, Form 51-101F2* or Companion Policy 51-101CP.

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Trading on TSX.V - Symbol GPI