



FAIRWEST ENERGY CORPORATION

FORM 51-101F1

Statement of Reserves Data and Other Oil and Gas Information

As at December 31, 2010

Prepared on April 26, 2011

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ABBREVIATIONS

In this document, the abbreviations set forth below have the following meanings:

Natural Gas

GJ	gigajoule
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet per day
MMcf/d	Million cubic feet per day
MMscf	Millions of standard cubic feet of gas (gas volume of 60°F and 14.65 psia)
MMBTU	Millions of British Thermal Units

Oil and Natural Gas Liquids

Bbl	Barrel
Bbls/d	Barrels per day
MBbls	Thousand barrels
Mstb	Thousand stock tank barrels of oil
NGLs	Natural Gas Liquid
Stb	Stock tank barrel of oil

Other

\$M	thousands of dollars
API	American Petroleum Institute ⁽¹⁾
Boe	barrels of oil equivalent ⁽²⁾
Boe/d	barrels of oil equivalent per day
MBoe	thousand barrels of oil equivalent ⁽²⁾
MMBTU	million British Thermal Units
WTI	West Texas Intermediate ⁽³⁾

- (1) “⁰API ” or “degrees API” is an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specific gravity of 28⁰ API or higher is generally referred to as light crude oil
- (2) Natural gas is equated to oil on the basis of 6 Mcf of natural gas = 1 barrel of oil equivalent (Boe). Boes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf per 1 Boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (3) The reference price paid in US dollars at Cushing, Oklahoma for crude oil of standard grade.

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

“**associated gas**” means the gas cap overlying a crude oil accumulation in a reservoir.

“**Boe**” means barrel of oil equivalent. In this report, natural gas is equated to oil on the basis of 6 Mcf of natural gas = 1 barrel of oil equivalent (Boe). Boes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf per 1 Boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

“**Corporation**” or “**Company**” or “**FairWest**” means FairWest Energy Corporation

“**crude oil**” or “**oil**” means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

”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.

”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.

“development costs” means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs or support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

“development well” means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

“ERCB” means the Energy Resources Conservation Board.

“exploration costs” means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);

(b) costs of carrying and retiring unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

“exploratory well” means a well that is not a development well, a service well or a stratigraphic test well.

“field” means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to denote localized geological features, in contrast to broader terms such as “basin”, “trend”, “province”, “play” or “area of interest”.

“future prices and costs” means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

“future income tax expenses” means future income tax expenses estimated (generally, year-by year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net revenues relating to the reporting issuer’s oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

“future net revenue” means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coalbed methane and other non conventional reserves) estimated using constant prices and costs or forecast prices and costs.

“gross” means:

(a) in relation to the Corporation’s interest in production or reserves, its “gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

“natural gas” means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

“natural gas liquids” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

“net” means:

(a) in relation to the Corporation’s interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interest in production or reserves;

(b) in relation to the Corporation’s interest in wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and

(c) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

“NI 51-101” means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

“non-associated gas” means an accumulation of natural gas in a reservoir where there is no crude oil.

“operating costs” or **“production costs”** means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“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 the estimated proved plus probable reserves.

“production” means recovering, gathering, treating, field or plant processing (e.g., processing gas to extract natural gas liquids) and field storage of oil and gas.

“property” includes:

(a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interest, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operating of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

“property acquisition costs” means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land, including rights to hydrocarbons, is purchased in fee;

(c) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

”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.

“proved property” means a property or part of a property to which reserves have been specifically attributed.

“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 (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) 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 estimates.

“reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“service well” means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

“solution gas” means natural gas dissolved in crude oil.

“SPEE” means Society of Petroleum Evaluation Engineers.

“Sproule” means Sproule Associates Limited.

“Sproule Report” means the consolidated summary report of Sproule evaluating the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2010 and dated April 8, 2011.

“stratigraphic test well” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon

exploration. Stratigraphic test wells are classified as (a) “exploratory type” if not drilled into a proved property; or (b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.

“**support equipment and facilities**” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

“**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, probable, possible) 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 sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

“**unproved property**” means a property or part of a property to which no reserves have been specifically attributed.

“**well abandonment costs**” means 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.

FORWARD-LOOKING STATEMENTS

This statement of Reserves Data and Other Oil and Gas Information (“**Statement of Reserves**”) contains forward-looking information and forward-looking statements (collectively “**forward-looking statements**”). These forward-looking statements relate to future events or the Corporation’s future performance. All statements other than statements of historical fact may be forward looking statements. Forward-looking statements are often, but not always, identified by the use of words such as “seek”, “anticipate”, “budget”, “plan”, “continue”, “estimate”, “expect”, “forecast”, “may”, “will”, “project”, “predict”, “potential”, “targeting”, “intend”, “could”, “might”, “should”, “believe”, and similar expressions. Such statements represent the Corporation’s internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital expenditures, anticipated future debt levels and revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in the forward-looking statements. In addition, this Statement of Reserves may contain forward-looking statements attributed to third party industry sources. FairWest believes that the expectations reflected in those forward-looking statements are reasonable; however, undue reliance should not be placed in these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur.

Forward-looking statements in this Statement of Reserves include, but are not limited to, statements with respect to: In particular, this FORM 51-101 F1 contains forward-looking statements pertaining to the following:

- the performance characteristics of the Company’s oil and natural gas properties;
- the Company’s oil and natural gas production levels;
- the size of the Company’s oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future development and exploration activities and the timing thereof;
- future land expiries;
- future liquidity and financial capacity;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of risk factors set forth below and elsewhere in this Statement of Reserves:

- volatility in market prices for oil and natural gas;

- liabilities inherent in oil and natural gas operations;
- general economic conditions in Canada;
- the ability of management to execute its business plan;
- risks and uncertainties involving geology of oil and gas deposits;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- risks inherent in marketing operations, including credit risk;
- the ability to enter into or renew leases;
- incorrect assessments of the value of acquisitions;
- potential delays or changes in plans with respect to exploration and development projects or capital expenditures;
- shut-ins of connected wells resulting from extreme weather conditions;
- insufficient storage or transportation capacity;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- geological, technical, drilling and processing problems; and
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts.

Statements relating to “reserves” or “resources” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Statement of Reserves are expressly qualified by this cautionary statement. Except as required by applicable securities law, FairWest does not undertake any obligation to publicly update or revise any forward-looking statements.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The Company retained the services of Sproule Associates Limited (“Sproule”) to prepare a third party independent appraisal of the oil and gas reserves owned by FairWest as of December 31, 2010. (the “Sproule Report”).

All of the oil and gas reserves owned by FairWest and its subsidiaries are onshore in Canada.

The Sproule Report was prepared using current geological and engineering knowledge, techniques and computer software. It was prepared within the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta (“APEGGA”). The Sproule Report adheres in all material aspects to the “best practices” recommended in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) which are in accordance with principles and definitions established by the Calgary Chapter of the Society of Petroleum Evaluation Engineers. The COGE Handbook is incorporated by reference in National Instrument 51-101.

The reserves definitions used in preparing this report are those contained in the COGE Handbook and the Canadian Securities Administrators National Instrument 51-101 (“NI 51-101”).

Evaluation procedures used by Sproule are as follows:

- The Company provided Sproule with recent revenue statements to determine certain economic parameters.
- The forecasts of product prices used in this evaluation were based on Sproule’s December 31, 2010 price forecasts as set forth herein.
- Well abandonment and disconnect costs were included in the Sproule Report at the entity level for wells which have reserves assigned. No allowances for reclamation or salvage values were made.
- Estimates of the Capital Gas Cost Allowance component and tax pools have been included in the Sproule Report
- Sproule used a reserves evaluation software model.

The oil and natural gas reserves were estimated volumetrically, from production decline curve analyses, using analogy techniques, or by material balance methods. Volumetric reserves were estimated using the net pay encountered at the wellbore and an assigned drainage area, or, where sufficient well data were available, using reservoir volumes

calculated from isopach maps of net pay. Reservoir rock and fluid property data were obtained from available core analyses, well logs, PVT data, gas analyses, and published information, either from the pool in question or from a similar reservoir producing from the same zone. Reservoir pressures were derived from drillstem and AOF test data, pressure surveys, and published reports. Recovery factors for oil reserves were selected either from the results of detailed reservoir analyses, or by comparing the reservoir under study with similar reservoirs that have more firmly established recovery factors from extended production histories. Recovery factors for gas reserves were estimated by taking into account well depths, deliverability characteristics, product prices, and operating cost information.

Forecasts of net revenue were prepared by predicting annual production from the reserves, and product prices. Annual production was forecast taking into account historical production trends of the Company's producing wells, applicable regulatory conditions, existing or anticipated contract rates, and by comparison with other wells in the vicinity producing from similar reservoirs.

Reserve Definitions

- (1) "Gross Reserves" are defined as FairWest's working interest share of the remaining reserves before deduction of any royalties.
- (2) "Net Reserves" are defined as the gross remaining reserves of the properties in which FairWest has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.
- (3) Definitions used for reserves categories in the Sproule Report are set out by the Canadian Securities Administrators in National Instrument 51-101 and in the COGE Handbook. They are as follows:

(a) Reserves Categories

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 (i) analysis of drilling, geological, geophysical, previous production, and engineering data; (ii) the use of established technology, and (iii) 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 estimates.

"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.

"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 the estimated proved plus probable reserves.

(b) Development and Production Status

Each of the reserves categories (proved, probable, and possible) 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.

"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, probable, possible) 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. This allocation should be based on the evaluator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

(c) Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Section 5.4.1 (COGE Handbook) are applicable to individual Reserves 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 should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

Reserves Data, Forecast Prices and Costs

The following table sets forth a summary of reserves and economic values for FairWest, effective December 31, 2010 based on forecast prices and costs.

**SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2010
FORECAST PRICES AND COSTS**

RESERVE CATEGORY	RESERVES ⁽¹⁾							
	LIGHT AND MEDIUM OIL		NATURAL GAS (non-associated & associated)		NATURAL GAS (solution)		NATURAL GAS LIQUIDS	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
Proved								
Developed Producing	65.0	61.2	1,668.5	1,509.2	18.0	16.8	6.9	4.8
Developed Non-Producing	30.9	21.1	647.8	580.1	40.8	24.2	5.8	4.0
Undeveloped	2.5	2.3	81.3	73.3	0.0	0.0	1.5	1.1
Total Proved	98.4	84.7	2,397.7	2,162.6	58.8	41.1	14.2	9.8
Probable	126.3	108.2	2,139.1	1,924.2	44.8	37.1	16.5	11.5
Total Proved Plus Probable	224.7	192.8	4,536.8	4,086.8	103.5	78.1	30.7	21.3

(1) The Company has no heavy oil or coalbed methane.

(2) Numbers may not add due to rounding

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2010
FORECAST PRICES AND COSTS

BEFORE INCOME TAXES, DISCOUNTED AT (% /year)						
RESERVES CATEGORY	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	UNIT VALUE ⁽¹⁾ (Discounted at 10%/year) \$/Boe
Proved Developed Producing	5,971.4	5,152.2	4,569.0	4,127.0	3,777.6	14.26
Proved Developed Non-Producing	1,935.9	1,555.4	1,301.7	1,115.3	970.0	10.35
Proved Undeveloped	377.1	301.8	243.0	196.5	159.2	15.58
Total Proved	8,284.5	7,009.3	6,113.8	5,438.8	4,906.8	13.24
Probable Additional	12,168.0	9,033.3	7,018.4	5,619.8	4,598.9	15.72
Total Proved Plus Probable Additional	20,452.4	16,042.6	13,132.1	11,058.6	9,505.7	14.46
AFTER INCOME TAXES, DISCOUNTED AT (% /year)						
RESERVES CATEGORY	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	
Proved Developed Producing	5,971.4	5,152.2	4,569.0	4,127.0	3,777.6	
Proved Developed Non-Producing	1,935.9	1,555.4	1,301.7	1,115.3	970.0	
Proved Undeveloped	377.1	301.8	243.0	196.5	159.2	
Total Proved	8,284.5	7,009.3	6,113.8	5,438.8	4,906.8	
Probable Additional	12,168.0	9,033.3	7,018.4	5,619.8	4,598.9	
Total Proved Plus Probable Additional	20,452.4	16,042.6	13,132.1	11,058.6	9,505.7	

- (1) Unit values are based on net reserve volumes
- (2) Numbers may not add due to rounding
- (3) Net Present Value of Future Net Revenue include all resource income:
 - a. sale of oil, gas, by-product reserves
 - b. processing third party reserves
 - c. other income
- (4) Income taxes:
 - a. Includes all resource income
 - b. Apply appropriate income tax calculations
 - c. Include prior tax pools

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2010
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOPMENT COSTS (M\$)	ABANDONMENT AND RECLAMATION COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved	26,531.5	2,758.9	12,906.4	1,225.1	1,356.7	8,284.5	0.0	8,284.5
Proved Plus Probable	54,866.1	6,063.3	23,196.7	3,520.4	1,633.2	20,452.4	0.0	20,452.4

**FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2010
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (Discounted at 10%/year)	UNIT VALUE ⁽¹⁾ (Discounted at 10%/year)
Proved		(M\$)	(\$/Boe)
	Light and Medium Crude Oil (including solution gas and associated by-products)	2,391.4	26.15
	Natural Gas (including associated and non-associated gas and by-products)	3,209.2	8.67
	Other Revenue (corporate and facility)	513.2	0
Proved Plus Probable			
	Light and Medium Crude Oil (including solution gas and associated by-products)	5,338.2	25.94
	Natural Gas (including associated and non-associated gas and by-products)	7,261.1	10.34
	Other Revenue (corporate and facility)	532.9	0

- (1) Unit values are based on net reserve volumes, before taxes
- (2) The Company has no heavy oil or coalbed methane
- (3) Numbers may not add due to rounding.

Pricing Assumptions

Sproule's short-term outlook for oil and gas prices adopts the NYMEX futures market for the forecast period ending December 31, 2013. The forecast used in the Sproule Report was derived as of December 31, 2010, and reflects the arithmetic average of the futures market at the close of trading each day, for the month prior to the Termination of Trading date for a January contract. The oil price forecasts are based on the NYMEX Division light, sweet (low-sulphur) crude oil futures contract, which specifies the West Texas Intermediate crude as a deliverable, and the gas price forecasts are based on the NYMEX Division Henry Hub natural gas futures contract.

The NYMEX oil and gas futures prices are the foundation of Sproule's energy pricing models in the early years. This data is combined with Sproule's assumptions respecting long-term prices, inflation rates, and exchange rates, together with estimates of transportation costs and prices of competing fuels, to forecast wellhead and plantgate prices for Canadian oil, natural gas, and natural gas by-product production.

Sproule's forecast prices for crude oil and natural gas and by-products as at December 31, 2010 used in the preparation of the Sproule Report and are set forth below.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2010
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$Cdn/Bbl)	Cromer Medium 29.3°API (\$Cdn/Bbl)	AECO Gas Prices (\$Cdn/MMBTU)	Edmonton Butanes (\$Cdn/Bbl)	Edmonton Pentanes Plus (\$Cdn/Bbl)	INFLATION RATES (%/Year)	EXCHANGE RATES (\$US/\$Cdn)
Historical								
2004	41.42	52.91	45.72	6.87	41.37	53.91	1.4	0.770
2005	56.46	69.29	57.36	8.58	45.20	69.13	1.3	0.826
2006	66.09	73.30	62.35	7.16	59.32	75.03	1.5	0.882
2007	72.27	77.06	65.36	6.65	63.71	77.33	2.0	0.935
2008	99.59	102.85	93.05	8.15	75.09	104.70	1.0	0.943
2009	61.63	66.20	62.77	4.19	47.07	68.13	2.0	0.880
2010	79.43	77.81	73.66	4.16	57.04	84.21	1.0	0.971
Forecast								
2011	88.40	93.08	85.63	4.04	62.44	95.32	1.5	0.932
2012	89.14	93.85	86.34	4.66	62.95	96.11	1.5	0.932
2013	88.77	93.43	85.02	4.99	62.67	95.68	1.5	0.932
2014	88.88	93.54	84.18	6.58	62.75	95.79	1.5	0.932
2015	90.22	94.95	85.45	6.69	63.69	97.24	1.5	0.932
Thereafter	Escalation rate of 1.5 % thereafter							

- (1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
 - (2) Inflation rates for forecasting prices and costs.
 - (3) Exchange rates used to generate the benchmark reference prices in this table.
- Note: Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Reconciliation of Reserves

RECONCILIATION OF COMPANY GROSS RESERVES BY PRODUCT TYPE
as of December 31, 2010
FORECAST PRICES AND COSTS

FACTORS	LIGHT AND MEDIUM OIL			ASSOCIATED AND NON ASSOCIATED GAS			SOLUTION GAS			NATURAL GAS LIQUIDS		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcfc)	Gross Probable (MMcfc)	Gross Proved Plus Probable (MMcfc)	Gross Proved (MMcfc)	Gross Probable (MMcfc)	Gross Proved Plus Probable (MMcfc)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
December 31, 2009	143.4	178.7	322.2	4,497	2,861	7,358	79	59	138	36.5	24.2	60.7
Infill Drilling	0.0	0.0	0.0	144	85	230	0	0	0	1.3	0.8	2.1
Extensions	0.0	0.0	0.0	0	0	0	0	0	0	0.0	0.0	0.0
Improved Recovery	15.5	1.5	17.0	0	0	0	0	0	0	0.0	0.0	0.0
Technical Revisions	31.3	(2.2)	29.1	(973)	(657)	(1,630)	25	5	29	(19.0)	(7.4)	(26.4)
Discoveries	0.0	0.0	0.0	0	0	0	0	0	0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0	0	0	0	0	0	0.0	0.0	0.0
Dispositions	(73.4)	(49.6)	(123.0)	(141)	(77)	(218)	(27)	(17)	(44)	(1.2)	(0.7)	(1.9)
Economic Factors	(0.2)	(2.1)	(2.3)	(372)	(73)	(455)	(6)	(2)	(7)	(0.9)	(0.4)	(1.2)
Production	(18.2)	0.0	(18.2)	(757)	0	(757)	(12)	0	(12)	(2.5)	0.0	(2.5)
December 31, 2010	98.4	126.3	224.7	2,398	2,139	4,537	59	45	104	14.2	16.5	30.7

- (1) Gross reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.
- (2) The Company has no heavy oil or coalbed methane.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are defined as 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. Proved undeveloped 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. Undeveloped 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 the estimated proved plus probable reserves.

During 2011, FairWest expects to drill 3 wells at Berry Creek and 1 well at Neutral Hills to convert proved undeveloped and probable undeveloped reserves to proved reserves.

Undeveloped reserves for each product type is set forth below, based on forecast price and cost assumptions.

UNDEVELOPED RESERVES VINTAGE BY PRINCIPAL PRODUCT TYPE As of December 31, 2010 FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	First Attributed Gross Mbbl	Booked Gross Mbbl	First Attributed Gross MMcf	Booked Gross MMcf	First Attributed Gross Mbbl	Booked Gross Mbbl
Proved Undeveloped						
Prior to Dec. 31, 2008	19.0	19.0	871	871	4.0	4.0
Dec. 31, 2008	13.0	13.0	0	0	0.0	0.0
Dec. 31, 2009	17.6	18.1	81	81	1.1	1.1
Dec. 31, 2010	0.0	2.5	0	81	0.0	1.5
Probable Undeveloped						
Prior to Dec. 31, 2008	107.0	165.0	8,677	11,279	13.0	13.0
Dec. 31, 2008	8.4	8.4	0	0	0.0	0.0
Dec. 31, 2009	102.7	103.1	295	295	3.9	3.9
Dec. 31, 2010	0.0	67.8	0	295	0.0	5.5

(1) The Company has no heavy oil or coal bed methane

Significant Factors or Uncertainties Affecting Reserves Data

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Company's estimates are based on current production forecast, prices and economic conditions. All of the Company's reserves are evaluated by Sproule Associates Limited, an independent engineering firm.

As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort has been made by the Company to ensure that reserves estimates are accurate, revisions may arise as new information becomes available. As new geological, production and economic data is incorporated into the process of estimating reserves the accuracy of the reserve estimate improves.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserve categories noted below:

FUTURE DEVELOPMENT COSTS – FORECAST PRICES AND COSTS

	Total Proved Undiscounted \$M	Total Proved Plus Probable Undiscounted \$M
2011	1,225.1	3,040.0
2012	-	403.5
2013	-	-
2014	-	77.0
2015	-	-
Thereafter	-	-
Total for all years	1,225.1	3,520.5

The Company estimates that its internally generated cash flow and other sources of capital will be sufficient to fund the future development costs disclosed above. FairWest typically has four sources of funding to finance its capital expenditure programs: (i) internally generated cash flow; (ii) debt financing; (iii) new equity issued; and (iv) property sales.

If there is a significant reduction in commodity prices, the Company may not be in the position to drill its probable reserves. In such a case the Company may farmout these prospects to independent third parties.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

All of the Company's existing oil and gas production is in Canada and, specifically, in the provinces of Alberta and Saskatchewan. The Company operates the majority of its existing production. The following summarizes the Company's interest as at December 31, 2010 in wells which are producing or which are non-producing.

AREA	GROSS		NET	
	Producing	Non-Producing	Producing	Non-Producing
<i>Alberta</i>				
Gas	112	67	49.1	46.6
Oil	50	14	29.8	8.8
Other	0	82	0	60.8
Total Alberta	162	163	78.9	116.2
<i>Saskatchewan</i>				
Gas	387	6	71.6	2.2
Oil	0	0	0	0
Other	0	2	0	0.9
Total Saskatchewan	387	8	71.6	3.1
Total	549	171	150.5	119.3

Principal Properties

The following table sets out the Company's consolidated land holdings by area as at December 31, 2010.

PROPERTY	AVERAGE WORKING INTEREST	GROSS ACRES	NET ACRES
Alberta			
Antelope	57.9	16,000	9,265
Berry Creek	30.1	8,960	2,700
Kirkpatrick/Youngstown	92.5	28,487	26,363
Provost/Neutral Hills	39.7	35,135	13,934
Other	55.7	8,635	4,810
Total Alberta	58.7	97,217	57,072
Saskatchewan			
Burstall	24.5	43,169	10,592
Other	-	647	161
Total Saskatchewan	24.5	43,816	10,753
Total	48.1	141,033	67,825

Kirkpatrick Lake/Youngstown, Alberta

The Company owns various working interests in approximately 28,487 acres (26,363 net) of land located north of Youngstown, Alberta. Production is subject to Alberta Crown Royalties and in some cases Freehold and Gross Overriding Royalties. Total proved plus probable reserves valued at \$2.2 million have been estimated for this property. The property produced 398,435 Mcf of gas and 2,943 barrels of oil and natural gas liquids for a total of 69,349 barrels of oil equivalent during 2010, representing 46.6% of the Company's total production. Future capital expenditures of \$197,000 is included in the Sproule Report all of which is planned during 2011.

Provost/Neutral Hills, Alberta

Provost/Neutral Hills is located north of Veteran, Alberta. FairWest's Provost area covers 35,135 gross acres (13,934 net) of land and includes properties at Ribstone, Bowview/Richdale, Neutral Hills and various properties in the Provost Field. Total proved plus probable reserves of \$5.1 million have been estimated for this area. Approximately \$4.6 million of this value is attributed to the Neutral Hills property. Production from this area totaled 149,867 Mcf of gas and 15,294 barrels of oil and natural gas liquids for a total of 40,272 barrels of oil equivalent in 2010, representing 27% of total production. Future capital expenditures of \$1,159,075 is included in the Sproule Report, \$851,975 of which is planned during 2011.

Berry Creek, Alberta

Berry Creek is located near the town of Cessford, Alberta. The Company owns various working interests in 8,960 gross acres (2,700 net) of land in this area, which contains several producing oil and gas wells and a number of identified drilling locations. The Company owns a 60% working interest in the Berry Creek gas plant with processing capacity of 8.5 MMscf/day of natural gas. The plant process includes refrigeration and the Company extracts approximately 18 barrels of NGLs per million cubic feet of natural gas throughput. Ownership of this gas plant provides for third party processing fee revenue. Total proved plus probable reserves valued at \$2.8 million have been estimated for this area. Production from this area totaled 51,738 Mcf of gas and 1,717 barrels of oil and natural gas liquids for a total of 10,340 barrels of oil equivalent in 2010, representing 6.9% of total production. Future capital expenditures of \$1,756,300 is included in the Sproule Report, \$1,679,400 of which is planned during 2011.

Properties with No Attributed Reserves

All of FairWest's properties are in Canada, more particularly in Alberta and Saskatchewan. The Company has 39,944 undeveloped gross acres (21,698 net), of which approximately 90% are unproved with no attributed reserves. For the period from January 1, 2011 through December 31, 2011, 13,963 gross acres (9,050 net) are due to expire unless

otherwise developed or continued. Most of the lands scheduled to expire contain wellbores capable of production. These leases will be continued beyond the primary term of the lease by application to the government.

Forward Contracts

At December 31, 2010 the Company had no long-term forward averaging natural gas contracts. The Company enters into various monthly physical contracts for between 500 and 1,000 GJ/day at prevailing market prices at the time.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and disconnection costs have been included in the cash flows for the final event of any particular well. The abandonment cost does not impact the economic limit and is included in the final year of production. For marginal wells nearing the end of their economic life these costs may result in a negative net present value.

All abandonment costs, based on forecasted costs, were input as an expense in the year incurred and deducted from operating income to arrive at cash flow. The following table accounts for costs for only the wells which were evaluated by Sproule and have not included other shut-in or suspended wells in the Company's inventory or its facilities and pipelines.

YEAR	TOTAL PROVED		TOTAL PROVED PLUS PROBABLE	
	Discounted at		Discounted at	
	0% \$M	10%/year \$M	0% \$M	10%/year \$M
2011	25.0	23.4	0.0	0.0
2012	87.8	76.0	25.4	21.7
2013	105.1	82.0	51.5	41.8
Thereafter	<u>1,138.8</u>	<u>541.6</u>	<u>1,556.3</u>	<u>592.6</u>
Total for all years	1,356.7	723.0	1,633.2	656.1

The Company's asset requirement obligations result from net ownership interests in petroleum and natural gas assets. For wells in Alberta the Company utilizes ERCB Directive 011 as a guideline to estimate abandonment and lease restoration costs. ERCB Directive 011, which has been made available to the public as a guideline to estimate liability for well abandonment and site restoration, includes the general areas, number of zones to be abandoned, well depth and presence of tubing and rods, etc. The Company estimates costs net of salvage to abandon wells and restore leases separately.

The total estimated undiscounted cash outflows adjusted for inflation, required to settle the Company's asset retirement obligations is approximately \$8.5 million. Using a credit-adjusted risk-free rate of 5.75% and an inflation rate of 1.5% this amount is approximately \$4.6 million. The Company estimates that the settlement of the majority of these obligations will occur between 2011 and 2030.

Tax Horizon

The following tax pools, effective as of December 31, 2010 are included in the total net present values of the Company's reserves. The Company's tax pools exceed the forecast income tax; therefore, the Company is deemed to be non-taxable. The non-capital losses have been included in the Reserve Report as tax adjustments in order to write them off where appropriate.

TAX POOL	DECEMBER 31, 2010 \$
COGPE	971,599
CDE	9,429,936
CEE	9,737,276
Foreign E&D	8,658,403
UCC Class 10, Other Equipment	773,937
UCC Class 41, Oil and Gas Equipment	13,118,957
Financing Cost	628,908
Non-capital Loss	9,623,796
Total	52,942,812

Costs Incurred

The following table sets forth the costs incurred for proved and unproved properties, exploration costs and development costs for the year ended December 31, 2010.

	\$
Property acquisition costs – proved	147,019
Property dispositions – proved	(1,977,391)
Property acquisition costs – unproved	10,501
Exploration costs	1,803,134
Development costs	1,991,269
Other	12,424
Total	1,986,956

Exploration and Development Activities

The following table summarizes the Company’s drilling results for the period ended December 31, 2010:

	EXPLORATORY		DEVELOPMENT		TOTAL	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	1	0.39	1	0.50	2	0.89
Natural Gas	0	0	0	0	0	0
Service	0	0	0	0	0	0
Dry	0	0	1	0.50	1	0.50
Total	1	0.39	2	1.00	3	1.39

Production Estimates

All of the Company’s production is in Canada and specifically, Alberta and Saskatchewan. FairWest has provided historical production by area – See “Production Volumes By Field”. Other than the principal properties at Provost, Alberta and Kirkpatrick Lake/Youngstown, no field represents more than 20% of total production. Production from the Provost area represents 34% of total production and production from Kirkpatrick Lake/Youngstown, Alberta represents 42.4% of total production.

The following table sets forth estimated volumes of production for the 12 months of 2011 as reflected in the estimates of future net revenue on a proved and proved plus probable basis in the Sproule Report.

ESTIMATED VOLUME OF PRODUCTION IN 2011

	LIGHT AND MEDIUM OIL (Stb)	SALES GAS (MMscf)	NATURAL GAS LIQUIDS (Bbl)
Proved	21,671.5	578.4	2,996.3
Proved Plus Probable	30,678.2	648.8	3,435.3

(1) The Company has no heavy oil

Production History

The following table sets out the production volumes by quarter and for the year ended December 31, 2010 by product type, before deduction of royalties, and as an average per unit of volume with the resulting netback.

	THREE MONTHS ENDED MARCH 31	THREE MONTHS ENDED JUNE 30	THREE MONTHS ENDED SEPTEMBER 30	THREE MONTHS ENDED DECEMBER 31	TWELVE MONTHS ENDED DECEMBER 31
Average Daily Production (1)					
Natural gas (Mcf/d)	2,371	1,949	1,966	2,141	2,106
Crude oil & NGLs (Bbls/d)	58	62	52	55	57
Average Prices					
Natural gas (\$/Mcf)	5.28	4.35	4.35	4.18	4.56
Crude oil & NGLs (\$/Bbl)	73.13	66.49	66.69	72.10	69.57
Royalties (2)					
Natural gas (\$/Mcf)	0.38	0.04	0.25	0.18	0.22
Crude oil & NGLs (\$/Bbl)	12.17	(9.20)	6.34	5.70	3.28
Production Costs (3)					
Natural gas (\$/Mcf)	3.08	3.95	3.85	4.61	3.85
Crude oil & NGLs (\$/Bbl)	18.44	22.92	14.10	27.98	20.89
Netbacks					
Revenue (\$)	1,507,852	1,146,523	1,105,161	1,186,265	4,945,801
Royalties (\$)	139,016	(44,088)	77,903	64,883	237,714
Operating Expenses (\$) (3)	744,886	829,789	769,261	1,049,653	3,393,589
Operating Netback (\$)	623,950	360,822	257,997	71,729	1,314,498

- (1) Production volume before deduction of royalties
- (2) Includes prior period adjustments to royalties
- (3) Net of processing fees revenue

Production Volumes By Field

No field accounts for more than 20% of FairWest's oil and gas production. The following table sets forth the production from the principal properties of FairWest for the year ended December 31, 2010:

PROPERTY	OIL (Stb)	NGLs (Stb)	NATURAL GAS (Mscf)	BARREL OF OIL EQUIVALENT (Boe)
Alberta				
Antelope	508	111	67,269	11,831
Berry Creek	736	981	51,745	10,341
Kirkpatrick/Youngstown	2,092	851	398,491	69,358
Provost/Neutral Hills	14,902	392	149,888	40,275
Other	7	77	36,819	6,221
	18,245	2,412	704,212	138,025
Saskatchewan				
Burstall	0	0	64,408	10,735
	0	0	64,408	10,735
Total	18,245	2,412	768,620	148,760