



## Forward-Looking Statements



*Certain information regarding PERPETUAL ENERGY in this presentation may constitute forward-looking statements under applicable securities laws. Forward-looking statements may be identified by words like "forecast", "estimated", "expected" or similar expressions. These forward looking statements are based on certain assumptions that involve a number of risks and uncertainties and are not guarantees of future performance. Risks and uncertainties may include, without limitation, risks associated with gas exploration, development, exploitation, production, marketing and transportation, changes to the proposed royalty regime prior to implementation and thereafter, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources.*

*These forward looking statements are based on certain assumptions that involve a number of risks and uncertainties and are not guarantees of future performance. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements as a result of changes in Perpetual's plans, changes in commodity prices, regulatory changes, general economic, market and business conditions as well as production, development and operating performance and other risks associated with oil and gas operations.*

*Furthermore, the forward-looking statements contained in this presentation are made as at the date of this presentation and Perpetual does not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.*

## Market Profile – Paramount Energy Trust (PET)



• Trust Units Outstanding at June 16, 2010 (PMT.UN)	142.5 million
• Management Ownership	21 %
• Unit Price (5 day weighted average)	\$ 5.27
• Current Distribution (monthly)	\$ 0.05
• Current Annualized Yield	11 %
• 2010 Average Daily Trading Volume	466,041
• Market Capitalization at June 16, 2010	\$ 768 million
• Convertible Debentures (PMT.DB.A; PMT.DB.C; PMT.DB.D; PMT.DB.E)	\$ 290 million
• Net Bank Debt	<u>\$ 229 million</u>
• Enterprise Value	\$ 1.3 billion

**Corporate conversion to Perpetual Energy Inc. July 1, 2010**  
**Dividend maintained at \$0.05 per Unit per month**

3

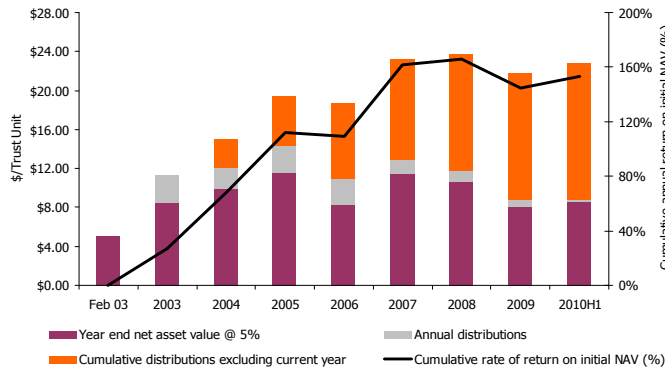
## PET Historical Value Creation



PET Spin Out NAV  
 \$5.05/Unit

Distributions to  
 June 30, 2010  
 \$14.06/Unit

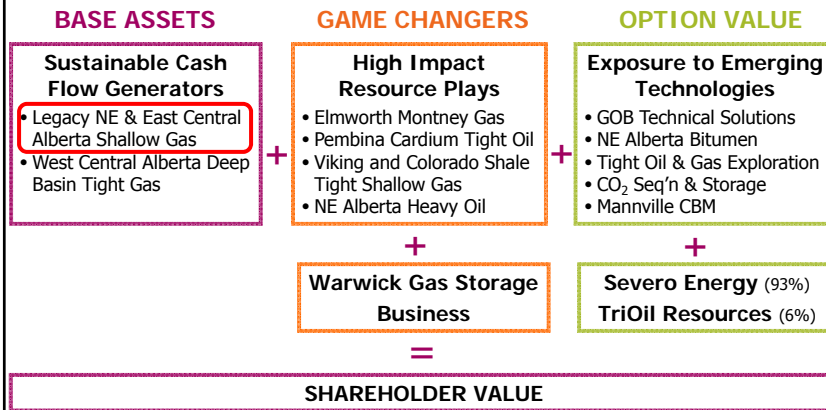
NAV June 2010  
 \$8.02/Unit



**Average Annual Return on Spin Out NAV = 45%**  
**Net Asset Value Growth per Unit Since Inception = 337%**

4

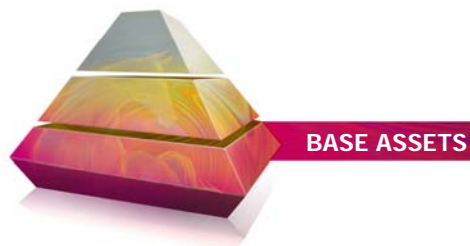
# Perpetual's Business in a Snapshot



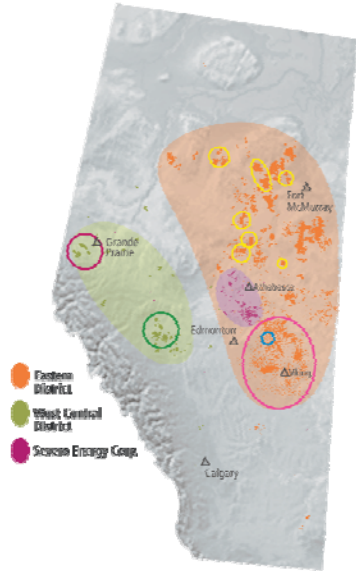
## Cash Flow Management Strategy – Focused on Maximizing Value

- Reinvestment in Shallow Gas & Deep Basin Base Assets for Sustainability
- Investment in New Ventures for Growth
- Distribute Excess Cash Flow

5



# Current Operations Profile



## Natural Gas Focused Asset Optimization - Base Assets

- Conventional Shallow Gas
- Deep Basin Tight Gas Resource Plays

## E&P New Venture Growth Strategy – Game Changers

- Elmworth Montney
- Pembina Cardium Tight Oil
- Viking and Colorado Shale Tight Shallow Gas
- NE Alberta Heavy Oil and Bitumen
- Warwick Gas Storage

Current Daily Production	160 MMcfe/d (26,667 BOE/d)
Gas over Bitumen Deemed Production <sup>(1)</sup>	26.3 MMcf/d
P+P Reserves <sup>(2)</sup>	511.5 Bcfe
Reserve to Production Ratio (P+P) (RLI)	8.9 Years

(1) Includes 10.5 MMcf/d interim shut-in order issued by ERCB effective October 31, 2009  
 (2) As evaluated by McDaniel and Associates and GLJ proforma for March 2010, including acquisitions and net of dispositions

# Sustainability Equation

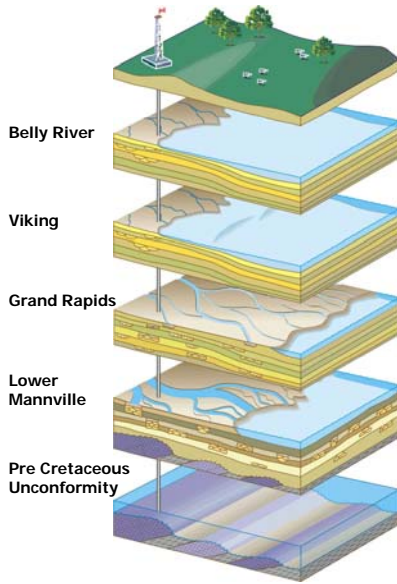


$$\text{Base Production (160 MMcf/d)} - \text{Annual Decline (32 MMcf/d)} + \frac{\text{Reinvestment } (\$96\text{MM})}{\text{Capital Efficiency } (\$3\text{ MM/MMcfd})} = \text{Base Production (160 MMcf/d)}$$

- Predictable production profile from shallow gas asset base
  - Managable base decline of < 20%
- High netbacks
  - High working interest
  - Dominant infrastructure ownership and operatorship
  - Minimal processing - dehydration and compression
- Opportunity inventory for cost-effective production & reserve additions
  - < \$20,000/flowing BOE; \$14.34 per BOE 2009 F,D&A costs
  - Production optimization activities (clean outs, water shut-offs, etc.)
  - Uphole completions
    - 96 booked in reserve report and 1,100 identified in prospect inventory
  - Pool extensions and concentric exploration
    - 35 conventional drills booked in reserve report and 780 identified in prospect inventory
- Undeveloped land to feed the prospect inventory
  - 3 to 4 times sector average relative to size
  - Replenish through ongoing land acquisition strategy
  - Active stewardship of undeveloped lands that don't meet risk/reward profile
    - Farmouts, dispositions, share exchange deals, swaps, fee simple land sales

**~\$96 MM (50% of 2010 cash flow) required to hold production flat**

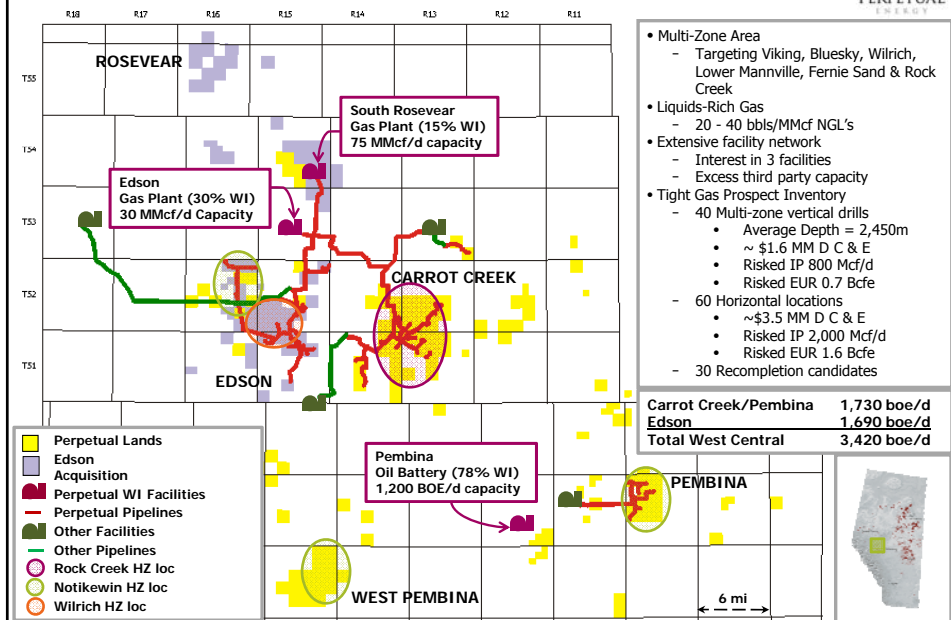
# Conventional Shallow Gas Inventory

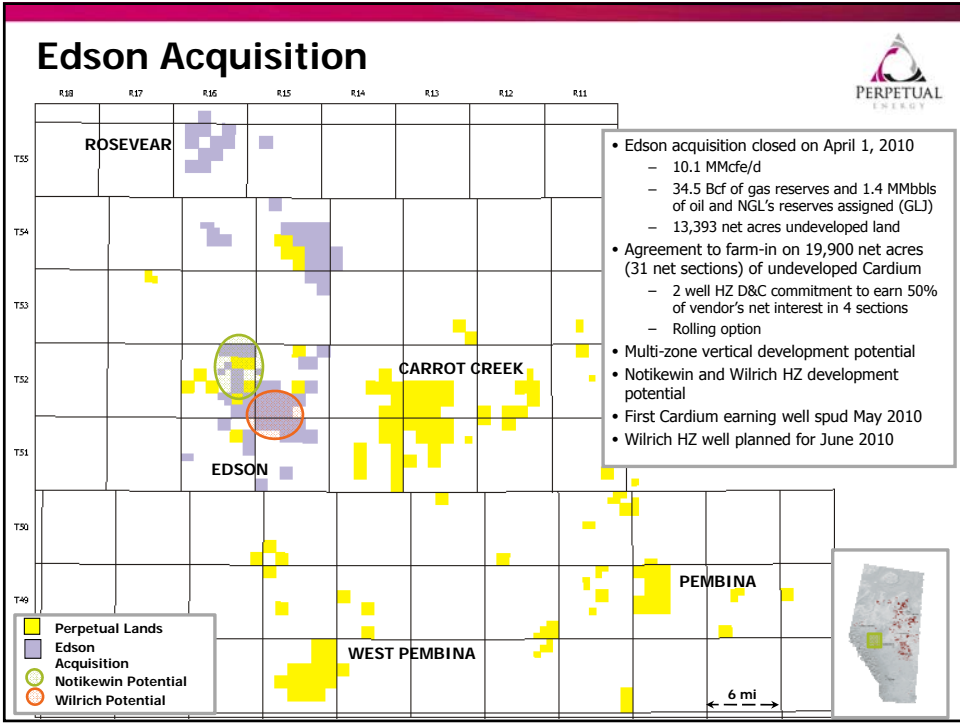


- East Central and Northeast Alberta
- Cretaceous and Devonian sweet shallow gas
- Multiple stacked zones and play types
- 1,200 uphole recompletions awaiting depletion of producing zones
  - Low cost production and reserves adds (<\$10,000/flowing BOE; <\$1/Mcf)
  - Typically ~150 recompletions per year
- 800+ new drill prospects in various stages of technical delineation
  - Seismic definition and step out of infrastructure drive prospects to drill ready
  - Historical drilling success > 90%
  - Multi-zone drills generally convert to reserves in 1 or 2 zones with additional zones captured as uphole completions in prospect inventory
  - Typically ~ 55 new drills per year
  - Average well \$0.4 MM D C & E
  - Risked IP 300 Mcf/d; EUR 0.3 Bcf (<\$20,000/flowing BOE; <\$1.50/Mcf)

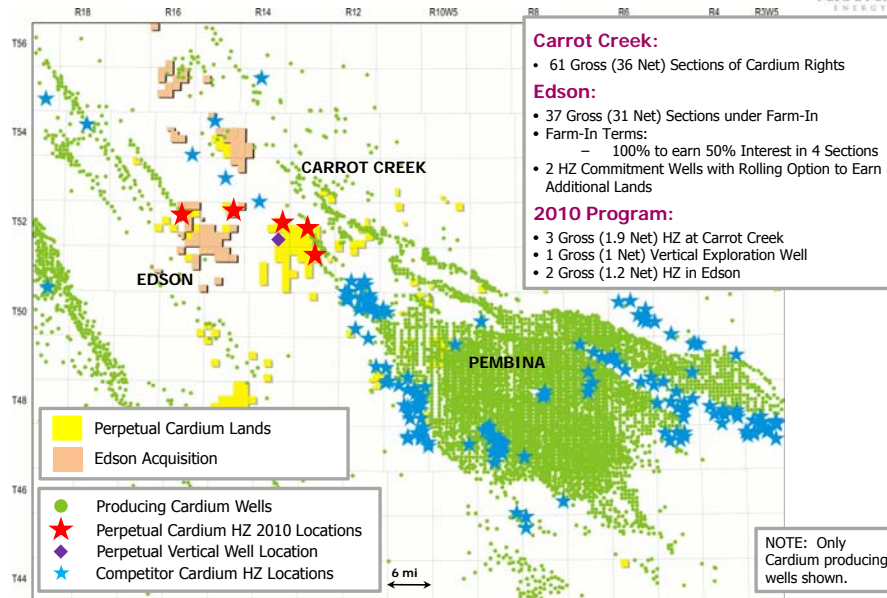
9

# West Central Alberta – Deep Basin Tight Gas





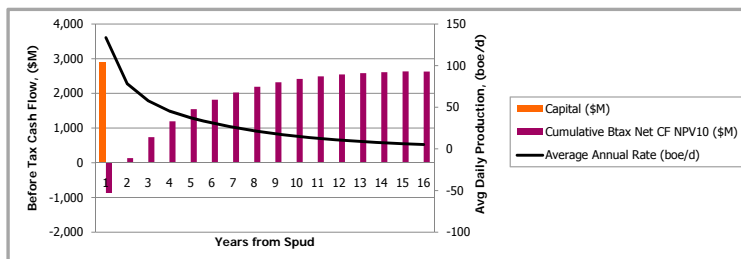
# Pembina Cardium Tight Oil HZ Development



# Carrot Creek/Edson Cardium Value Potential

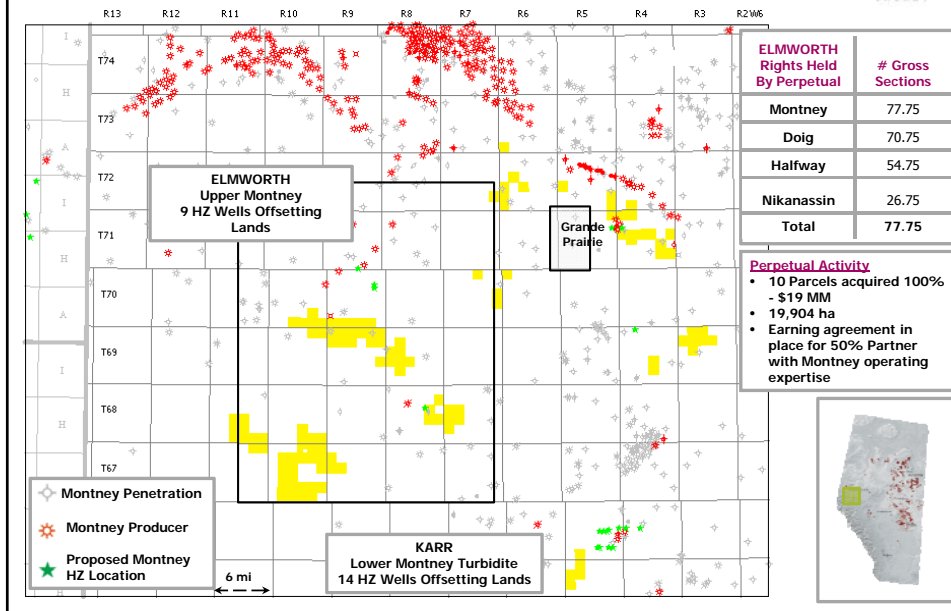


Economics per Drilling Location		Assumptions	
Capital (D,C & T)	\$2.9 MM (multi-well program estimate)	Oil / Gas Pricing	\$75/bbl; \$6/Mcf
NPV @ 10 % (May 27, 2010 Royalty Adj.)	\$2.6 MM (\$0.4 MM increase)	Operating Costs	\$13.00/BOE
ROR (May 27, 2010 Royalty Adj.)	61% (72%) BT 41% (48%) AT	Well Depth	2,750 m HZ; 1,750 TVD
F&D	\$20.40/BOE	Type Curve	IP 150 bbls/d, 1yr Di 75%, 2yr Di 30%, 3 yr Di 25%
Capital Efficiency	\$23,544 BOE/d	Royalties	New Royalty Framework (May 27, 2010 Estimated Adjustment); 5% New well royalty rate for 70,000 bbls/30 months; no drilling credits included
Scope			
Carrot Creek	94 gross (52 net) unrisksed locations		
Edson Farm-In	44 gross (19 net) unrisksed locations		



14

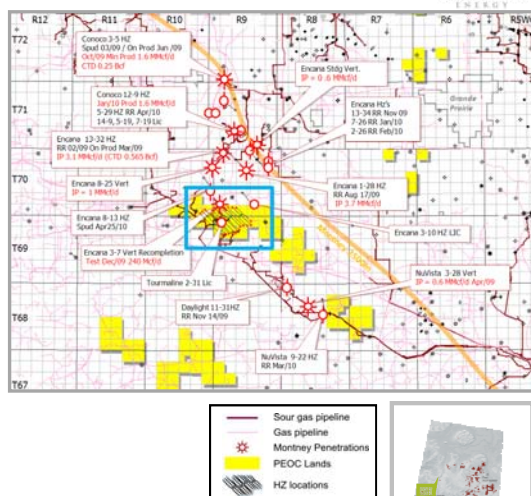
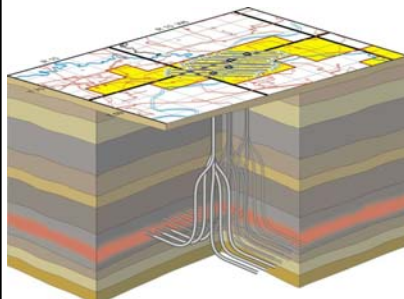
# Elmworth Montney Tight Gas Exploration



## Elmworth Montney



- 78 Sections of Montney Exposure**
- Acquired 100% WI in 2008
- \$5 - 6 MM Drill and Complete**
- Up to \$4.5 MM NGDDP royalty credit per well
  - Additional \$900 M drilling credit until March 2011
- Gross Reserve Potential: 3 - 5 Bcf /Well**
- 80 -100 Bcf+ (North Block preliminary development)
  - Potential Location Inventory
    - North and East Block only: 120+ gross wells
    - Additional 38 gross sections of prospective acreage
- Competitor activity in past 18 months**
- 4 HZ and 4 Vertical wells on production
  - 6 add'l HZ wells rig released
  - 4 new HZ wells licensed
- Viability of Play to be confirmed in 2010**
- 3 well drilling commitment in 2010 by Tourmaline Oil with Montney operating expertise
  - PEOC carried 100% on DC&E for the first 3 wells
  - Partner to earn 50% working interest in all lands

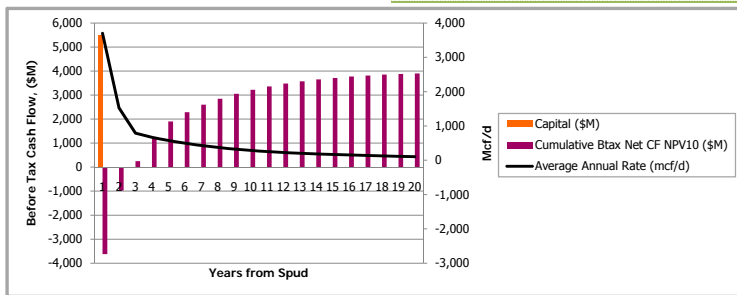


# Elmworth Montney Value Potential



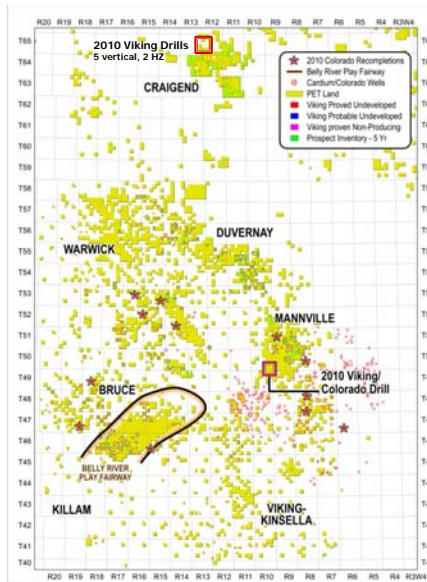
Economics per Drilling Location	
Capital (D.C & T)	\$5.5 MM
NPV @ 10 %	\$3.9 MM
ROR	49% BT, 36% AT
F&D	\$1.27/Mcfe (\$7.62/BOE)
Capital Efficiency	\$2,105/Mcfe/d (\$12,630/BOE/d)
Scope	
North & East Block	41 gross sections (3 wells/section)
Unrisked Potential	120+ wells @ 50% WI
West Block	Add'l 38 gross sections
Unrisked Potential	90+ wells @ 50% WI

Assumptions	
Gas Price	\$6/Mcf
Operating Costs	\$1.85/Mcf
Well Depth	4,500 m HZ; 2,600 m TVD
Type Curve Deliverability	IP 5MMcf/d to 1MMcf/d in 12 mths, 18% Di after 12 mths
EUR	3.3 Bcf/well
NGL's	5 - 20 bbls/MMcf of raw gas
Royalties	New Royalty Framework; 5% new well royalty rate for 18 mths.; Natural Gas Deep Drilling Program; no drilling credits included

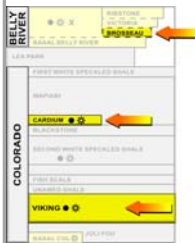


17

# Viking/Colorado Tight Shallow Gas



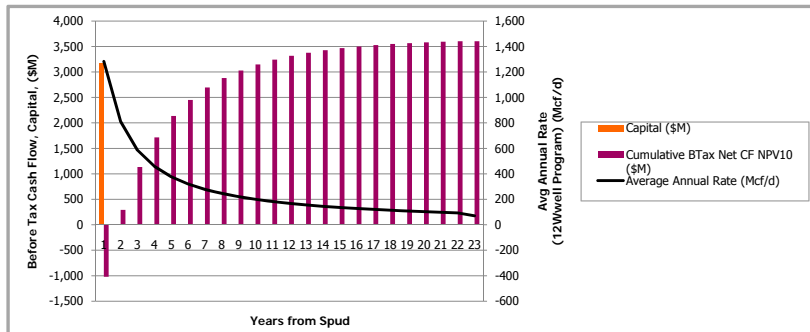
- Vast Play Fairway**
- Existing wellbores and infrastructure and potential to combine both resource plays and conventional Belly River enhances economics
  - Evolving stimulation and production technologies, royalty incentives and reduced costs improves profitability
  - 2 evaluation programs planned for 2010
- Reserves**
- ~10 Bcf P+P Producing
  - 15 Bcf P+P Developed Non-Producing
  - 101 Bcf P+P Undeveloped
  - 913 drills in future development capital
    - Average 138 MMcf/well gross
- Prospect Inventory**
- 1,210 unrisked add'l possible locations catalogued
    - Average 111 MMcf/new drill



# Viking/Colorado Shale Value Potential

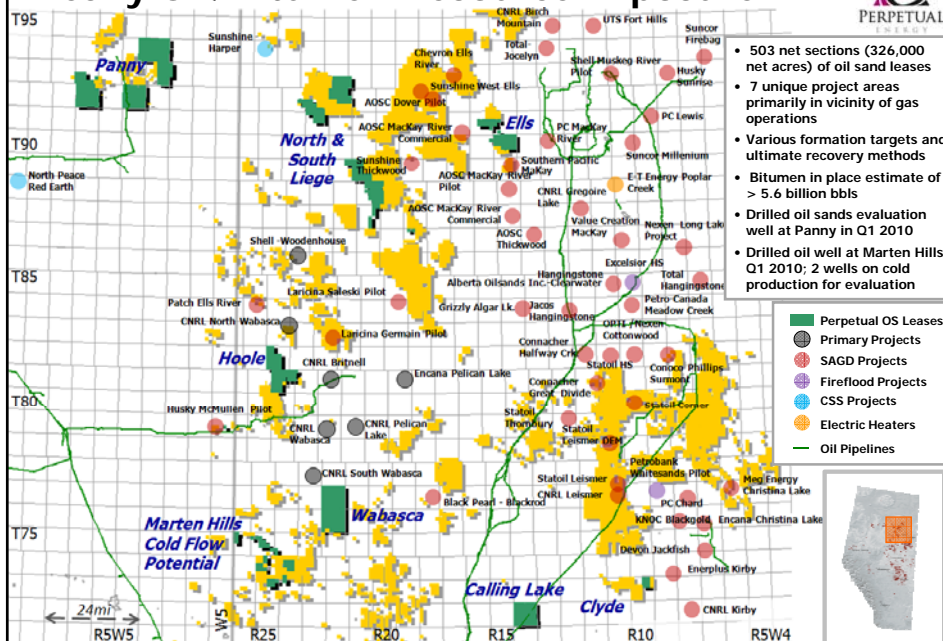


Economics per Drilling Location		Assumptions	
Capital (D.C & T)	\$3.2 MM/12 well program; \$265M/well	Gas Pricing	\$6/Mcf
NPV @ 10 %	\$3.6 MM/12 well program	Operating Costs	Fixed-\$800/well/mth, Variable - \$0.25/Mcf
ROR	64% BT, 44% AT	Well Depth (12 well program)	625 m Vertical, Dual completion
Scope		Type Curve Deliverability	Qi 150 Mcf/d/well, 50% Di yr 1 to 24% yr 3, Qf 8 Mcf/d/well,
Birchway East	625 sections @ 4 wells/section = 2,500 locations	EUR	200 MMcf/well
Birchway West	Additional inventory of 900 sections	Royalties	Crown; NRF, 5% NWRR for 12 months

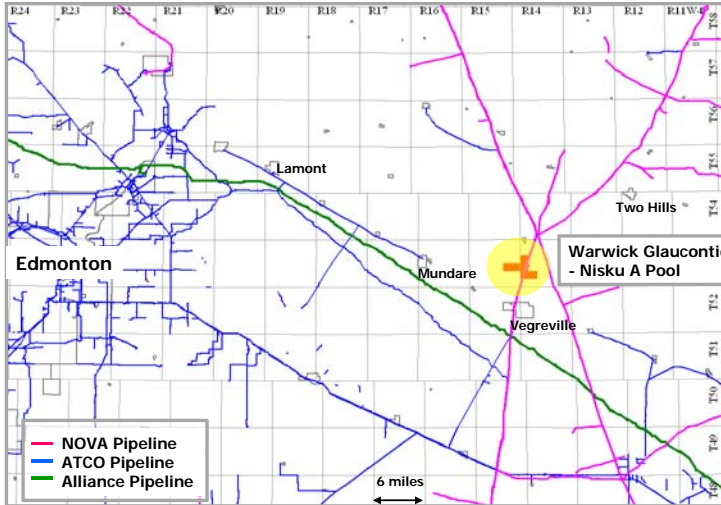


19

# Heavy Oil/Bitumen Resource Exposure



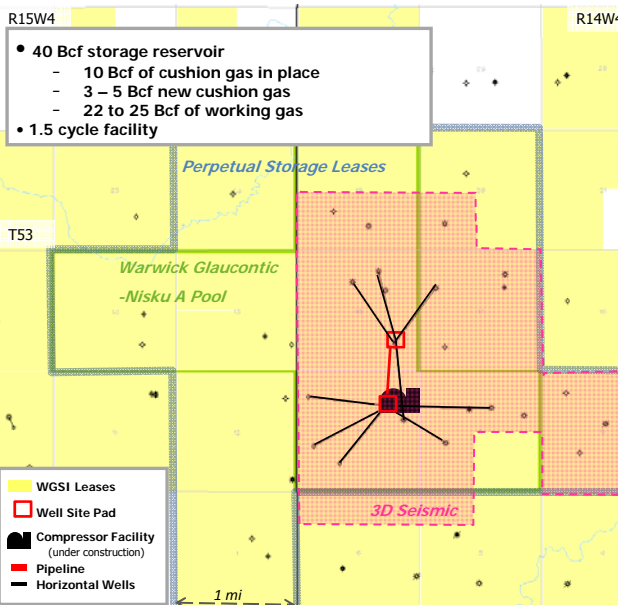
# Warwick Gas Storage Project



Strategic location close to Nova, Alliance and ATCO distribution system



# Warwick Gas Storage Project



## Project Development Plan

- 40 Bcf storage reservoir
  - 10 Bcf of cushion gas in place
  - 3 - 5 Bcf new cushion gas
  - 22 to 25 Bcf of working gas
- 1.5 cycle facility

### Project Viability Evaluation Phase:

- H2 2009 - \$10.8 MM
- 3D Seismic
- First horizontal well (11-8)
- Withdrawal and injectivity test

### Delineation and Testing Phase:

- Q1 2010 - \$9.4 MM
- 8 additional horizontal wells
- First Injection May 2010

### Full Scale Development:

- Q2-Q4 2010 - \$37.3 MM
- First Withdrawal November 2010
- 2 compressors; 3 Bcf cushion gas
- 8-10 Bcf yr. 1 working gas; 17 Bcf yr. 2
- 105 MMcf/d-150 MMcf/d max withdrawal
- ~\$7 MM forecast 2010 cash flow
- ~\$15-20 MM forecast 2011+ cash flow

### First Expansion:

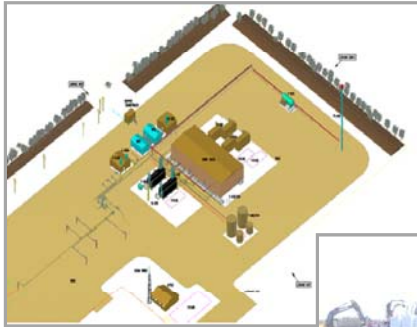
- 2011-2012
- 2-3 additional horizontal wells
- 1 additional compressor
- Up to 2 Bcf additional cushion gas
- 25 Bcf working gas
- 200 MMcf/d max withdrawal
- ~\$20-30 MM forecast cash flow/year

### Future Salt Cavern Development Potential

## Warwick Gas Storage - Under Construction



Facility Schematic



TCPL Meter Station



Injection Header System



23

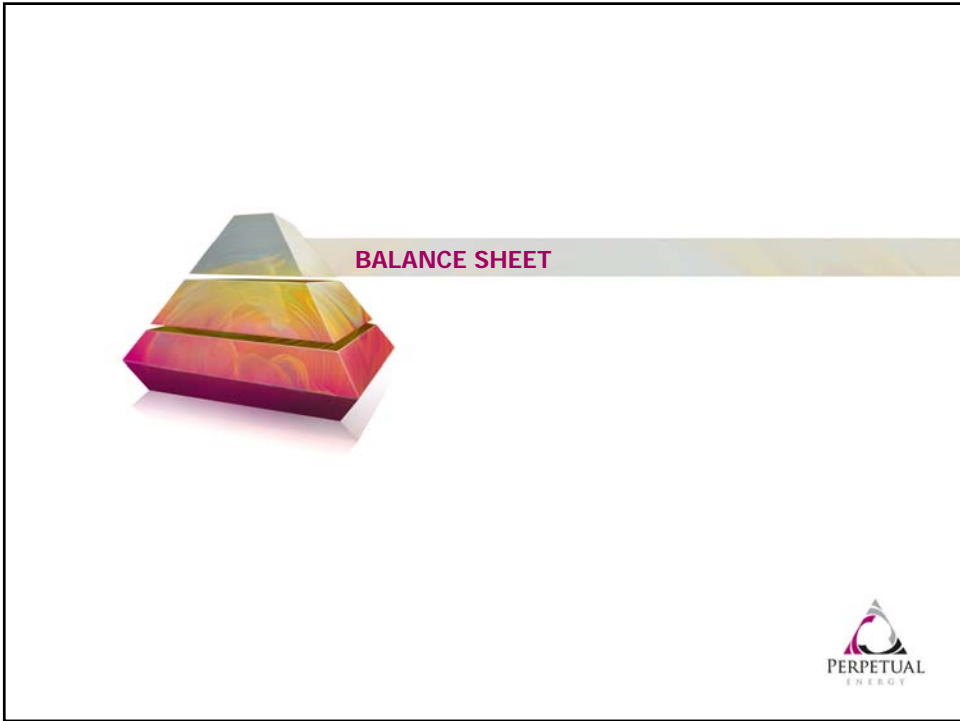
## Game Changers – Timeline of Key Events



- Warwick Gas Storage
  - First Injection May 2010/First Withdrawal November 2010
  - \$11 MM spent in 2009
  - \$9 MM spent in Q1 2010
  - \$37 MM Q2 – Q4 2010
  - \$57 MM total
- Heavy Oil/Bitumen - April 2010
  - 2 evaluation wells in Panny and Marten Hills
- Deep Basin Tight Gas Exploration - August 2010
  - Wilrich Horizontal evaluation well
- Pembina Cardium Tight Oil - September 2010
  - 5 well horizontal (3.0 net) Cardium evaluation wells
  - 22 (13 net) follow up locations surveyed for follow-up program
- Elmworth Montney Gas - October 2010
  - 3 horizontal (1.5 net) evaluation wells
- Viking/Colorado Shallow Unconventional Gas – October 2010
  - 2 programs evaluating horizontal and vertical development

**2009 - Capture**  
**2010 - Define Resource**  
**2011 - Full Scale Project Execution**

24



## Balance Sheet

- Net current bank debt: ~\$229 million
- Combined borrowing bases on credit facilities \$346 million
  - Perpetual - \$340 million
  - Severo - \$6 million
- Convertible debentures: \$290 million
  - Net proceeds from recent debenture issue will be used to repay PMT.DB.A on June 30, 2010
  - Effectively represents long term debt with the maturities from 2012 to 2015

TSX Symbol	Amount Outstanding	Coupon Rate	Conversion Price	Maturity Date	10 Day Weighted Avg. Trading Price
PMT.DB.A	\$ 55.3 million	6.25%	\$ 19.35	June 30, 2010	\$ 100
PMT.DB.C	\$ 74.9 million	6.50%	\$ 14.20	June 30, 2012	\$ 100
PMT.DB.D	\$ 100.0 million	7.25%	\$ 7.50	January 31, 2015	\$ 102
PMT.DB.E	\$ 60.0 million	7.00%	\$ 7.00	Dec. 31, 2015	\$ 100

- Premium DRIP Plan implemented September 2009
  - Currently ~60% participation
- 2010 ending net bank debt to 2010 cash flow ratio projected at ~1.5 times
- \$50 million in-the-money hedge position



## Warwick Gas Storage Funding



- 8 Bcf of cushion gas effectively collateralized to provide \$42 million for project financing
- Sale of 8 Bcf to a third party with delivery in Q1 2013 with concurrent 'park' transaction with the same term
  - Present value of sale and 'park' fee generates ~ \$42 million of current proceeds
  - Right to produce 'park' quantity stays with Warwick Gas Storage Inc. ("WGS")
  - Third party has first lien against reserves in Warwick Glauconitic-Nisku A pool and facilities
- WGS has obligation to deliver 8 Bcf of gas to third party in Q1 2013
  - Undiscounted mark-to-market cost of future obligation is \$46 million
    - 8 Bcf @ \$5.81/gj marked June 16, 2010
  - Recorded as deferred liability and mark-to-market financial instrument until actual delivery of gas
    - "Loan" payable to the third party with interest accreted monthly at 10% interest rate
      - Equates to \$54.7 million loan obligation by March 2013
    - Derivative representing the embedded natural gas forward price exposure recorded as an asset equal to hedging gain related to original forward sale transaction of ~\$8 million
      - $(6.78/gj - 5.81/gj) * 8 \text{ Bcf} = \$8 \text{ million}$

27

## Price Risk Management



### Strategy

- Protect the level of the Trust's monthly distributions and manage the balance sheet
- Enhance or protect the economics of an acquisition as prices vary from those forecast
- Enhance or protect capital program economics
- Capitalize on perceived market anomalies

### Current Hedge Position (June 9, 2010)

Term	Volumes at AECO (GJ/day)	Price (\$/GJ)	AECO/NYMEX Futures Price (\$/GJ) <sup>(2)</sup>	% of 2010E Production <sup>(3)</sup>
July 2010 – October 2010	52,500	\$4.44	\$4.15	27%
Nov. 2010 – March 2011	95,000	\$7.82	\$4.85	49%
April 2011 – October 2011	55,000	\$5.30	\$4.81	29%
Nov. 2011 – March 2012	60,000	\$5.33	\$5.42	31%
January 2013 – March 2013 <sup>(4)</sup>	89,679	\$6.78	\$5.81	47%

- (1) Additional "call" option contracts outstanding are as presented in management's discussion and analysis ("MD&A")  
 (2) Futures price reflects forward market prices as at June 9, 2010  
 (3) Calculated using production capability of 192,000 GJ/d, including actual and gas over bitumen deemed projected production  
 (4) Related to Warwick Gas Storage future financing arrangement

**Realized gains of \$72 million to-date in 2010**  
**Forward mark-to-market value of hedge book = \$50 million,**  
**excluding Q1 2013 position**

28



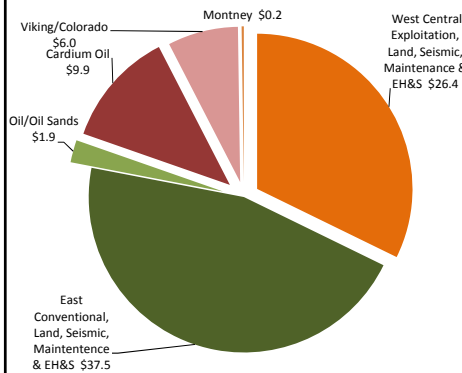
OUTLOOK



## 2010 Capital Budget



2010 Capital Spending by Asset (\$MM)



**2010 Capital Budget (excluding Gas Storage): \$82 MM**  
 \$29 MM Q1 spending (excluding \$9.4 million for gas storage)  
 \$53 MM after break-up for remainder of 2010  
 \$8.6 MM targeting oil projects

**Drilling: \$44 MM**

83 gross wells (70 net)  
 – 25 gross (20.6 Net) Q1 drills

**Includes Strategic Capital for:**

Q1: 2 Oil Sands Evaluation wells  
 H2: 2 Viking/Colorado Shale Program  
 Q1 – Q3: 5 gross Cardium oil HZ tests  
 H2: 3 well Elmworth Montney drilling commitment by partner

**Re Completions / Workovers: \$11 MM**

138 gross (128 net)

**Pipeline and Facilities: \$ 10 MM**

27 facilities-related projects

**Seismic and Land: \$11 MM**

\$11 Million for future prospect definition and capture

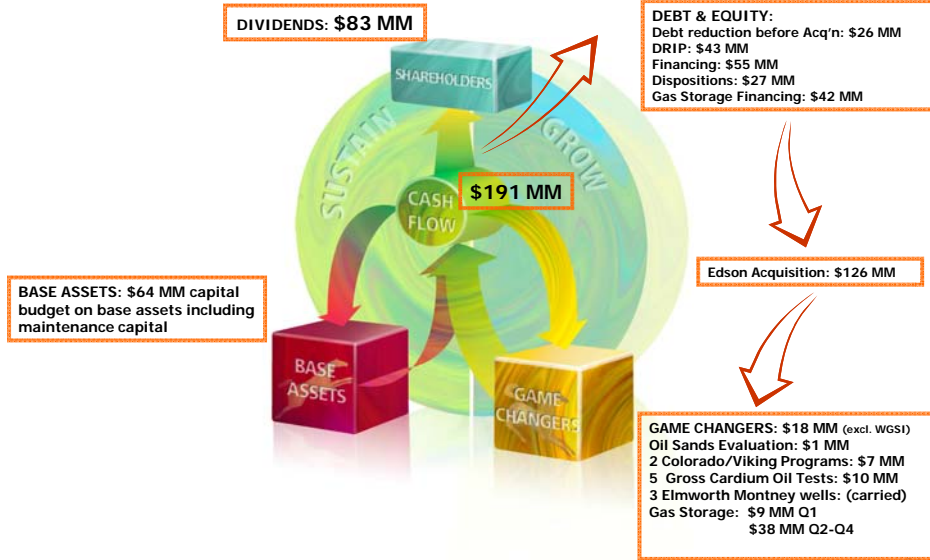
**Abandonment and Reclamation: \$6 MM**

63 gross abandonments

**Target Production Additions**

~36 MMcf/d (1st 12 month average)  
 Budget Capital Efficiency <\$15,000/flowing BOE/d

## 2010 Cash Flow Mechanics



\*Includes \$6 MM of forecast funds flow from Warwick Gas Storage

## January to December 2010 - Sensitivities



Current Forward Market <sup>(1)</sup>

AECO Monthly Index <sup>(1)</sup>	(\$/GJ)	\$ 4.00	\$ 5.00	\$ 6.00
Oil and Natural Gas Production	(MMcfe/d)	155	155	155
Perpetual Realized Gas Price	(\$/Mcf)	6.49	6.55	6.81
Funds Flow <sup>(4)</sup>	(\$millions)	191	200	207
Monthly Funds Flow Per Unit <sup>(4)</sup>	(\$/Unit/month)	0.113	0.119	0.123
Payout Ratio <sup>(2)</sup>	(%)	44	42	41
Ending Bank Debt <sup>(4)</sup>	(\$millions)	266	256	250
Ending Convertible Debentures	(\$millions)	235	235	235
Ending Warwick Gas Storage Project Financing <sup>(3)</sup>	(\$millions)	39	39	39
Ending Total Net Debt/Liabilities <sup>(5)</sup>	(\$millions)	540	530	524
Ending Net Debt To Funds Flow Ratio <sup>(6)</sup>	(times)	2.8	2.7	2.5

- (1) Average AECO settled and forward price for April 1 – December 31, 2010 as at June 9, 2010 was approximately \$4.21/GJ
- (2) Estimated payout ratio assumes distribution/dividend rate of \$0.05 per Trust Unit/month through December 2010
- (3) Warwick Gas Storage ("WGS") Project financing results in an obligation to deliver 8 Bcf in Q1 2013 which is marked to market
- (4) Includes \$6 million funds flow and \$37 million Q2-Q4 capital for Warwick Gas Storage project
- (5) Calculated as Bank Debt plus convertible Debentures plus mark to market cost of WGS 8 Bcf obligation
- (6) Calculated as ending net debt (including convertible debentures and WGS Project Financing) divided by estimated annual funds flow

32

## 2010 Sustainability Equation – With Hedging



### Cash Flow less Sustainability Capex and Dividends (\$MM)

Gas Price (\$/GJ)	Payout Ratio					Excess Annual Cash Flow after Capex & \$0.05 Monthly Dividends	Payout ratio @ \$0.05 Monthly Dividends	Sustainable Dividend
	20%	30%	40%	50%	60%			
\$4.00	58	41	23	6	(12)	16	44%	\$0.060
\$5.00	68	50	31	12	(7)	28	42%	\$0.068
\$6.00	74	55	35	16	(4)	35	40%	\$0.073
\$7.00	76	57	37	17	(3)	38	39%	\$0.074
\$8.00	80	60	40	19	-	43	39%	\$0.077

- (1) Cash flow at gas price including Perpetual's 2010 hedging  
 (2) Assumes \$90 million capex to keep production flat with production additions @ \$3MM/MMcf/d  
 (3) Excludes DRIP proceeds (currently ~ 60% of monthly distribution)

**With 2010 hedging, excess cash flow is generated, over and above that required to fund dividend of \$0.05 per Unit per month and sustainability capex, at gas price > \$3.50/GJ at AECO**

33

## Sustainability Equation – Without Hedging



### Cash Flow less Sustainability Capex and Dividends (\$MM)

Gas Price (\$/GJ)	Payout Ratio					Excess Annual Cash Flow after Capex & \$0.05 Monthly Dividend	Payout ratio @ \$0.05 Monthly Dividend	Sustainable Dividend
	20%	30%	40%	50%	60%			
\$5.00	9	(2)	(14)	(25)	(36)	(46)	69%	\$0.021
\$6.00	43	27	12	(4)	(19)	(4)	50%	\$0.047
\$7.00	72	53	34	15	(5)	33	41%	\$0.071
\$8.00	72	80	57	34	11	72	34%	\$0.096

- (1) Cash flow at gas price excluding hedging  
 (2) Assumes \$90 million capex to keep production flat with production additions @ \$3MM/MMcf/d  
 (3) Excludes DRIP proceeds (currently ~ 60% of monthly distribution)

**Current dividend of \$0.05 per Unit per month can be maintained at long term realized gas price of \$6.00/GJ at AECO, assuming capex reinvestment to sustain production**

34



## WHY INVEST IN PERPETUAL ENERGY INC.



## Net Asset Value of Reserves



Present Worth Evaluation (\$MM except per Trust Unit amounts) <sup>(1)</sup>	PV8%
Perpetual Reserves (P+P) <sup>(2)</sup>	\$1,355
FMV Undeveloped Land <sup>(3)</sup>	143
Hedge Value <sup>(4)</sup>	50
TriOil Shares <sup>(6)</sup>	7
Net Debt <sup>(7)</sup>	(519)
Future Abandonment Liabilities <sup>(5)</sup>	(50)
<b>Net Asset Value of Reserves</b>	<b>\$986</b>
<b>Trust Units Outstanding (millions) – basic</b>	<b>142</b>
<b>Net Asset Value<sup>(7)</sup></b>	<b>\$6.92</b>

- (1) Financial information is per Perpetual's 2009 unaudited consolidated financial statements  
 (2) Reserve values per McDaniel Report and GLJ as at December 31, 2009; includes acquisitions and dispositions  
 (3) Internal Estimate  
 (4) Value of Perpetual's open hedging transactions at year end 2009 assuming settlement against the McDaniel price forecast  
 (5) Amounts are net of salvage value and in addition to amounts in the McDaniel report for future well abandonment costs related to developed reserves  
 (6) 1.31 MM shares @ \$5.25/share  
 (7) Excludes Warwick Gas Storage project related financing and asset value

36

# Opportunity Inventory - Risk Discounted

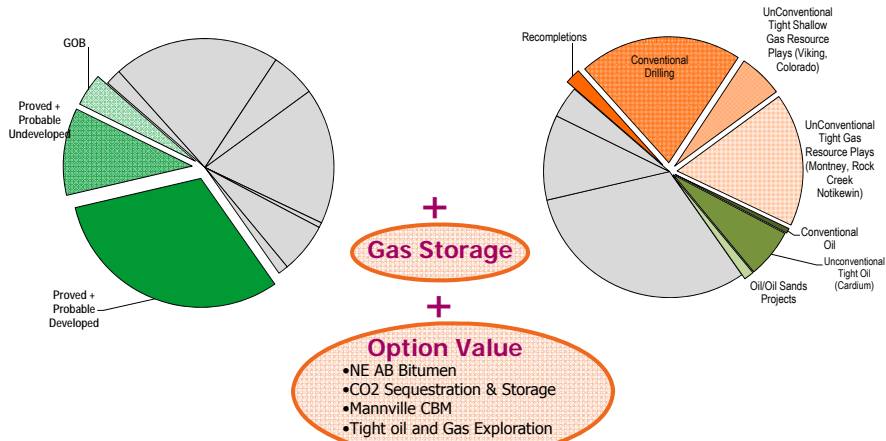


## Reserve Report

2009 Year End P + P Reserves = 511.5 Bcfe

## Current Recorded Prospect Inventory

Risk-Discounted Additional Reserve Potential = 598 Bcfe



**Reserves represent <50% of the risk-discounted reserve and value potential of Perpetual**

37

# Opportunity Inventory - Unrisked

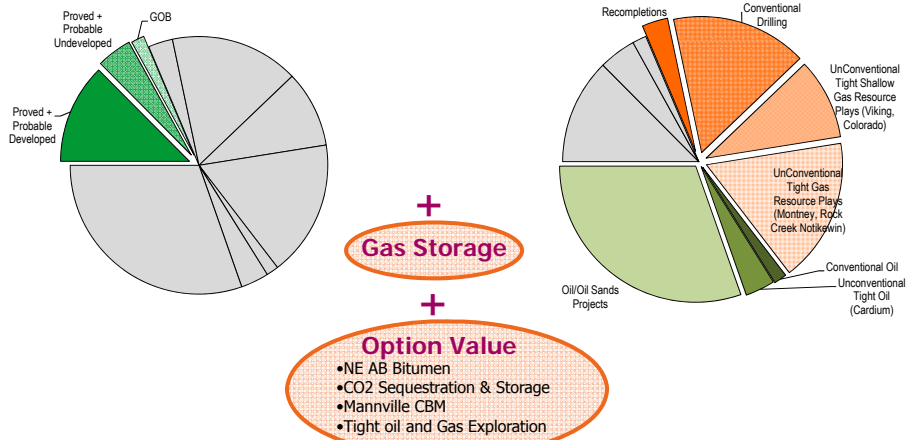


## Reserve Report

2009 Year End P + P Reserves = 511.5 Bcfe

## Current Recorded Prospect Inventory

Unrisked Additional Reserve Potential = 2,236 Bcfe

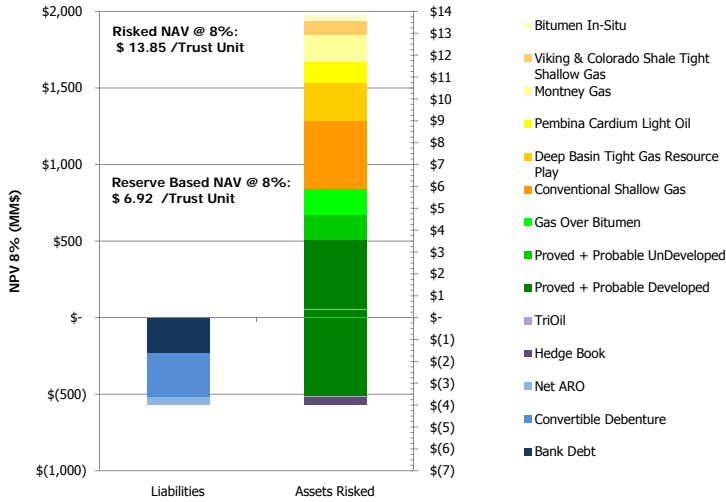


**As technical understanding advances risk assessment adjusts and risk-discounted potential grows**

38

# Net Asset Value with Prospect Inventory

## Risk Discounted – McDaniel January 2010 prices

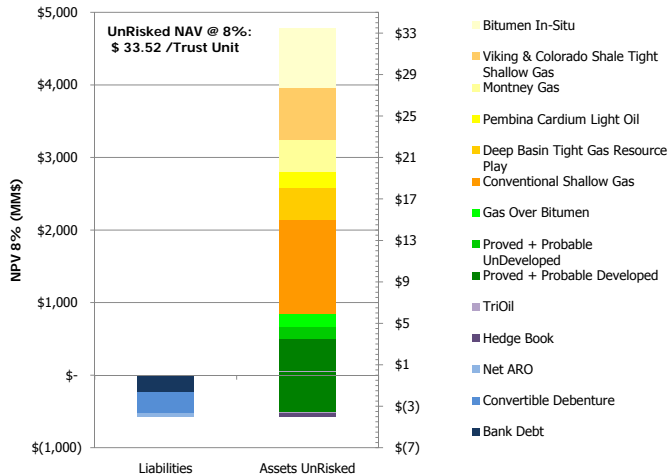


- (1) December 31, 2009 reserves adjusted for 2010 dispositions and acquisitions
- (2) Mark-to-McDaniels value of Perpetual hedge book at January 1, 2010 (\$50 MM)
- (3) Bank debt and convertible debentures at June 4, 2010 net of estimated working capital; net of dispositions
- (4) FMV of Undeveloped Land \$143 MM

39

# Net Asset Value with Prospect Inventory

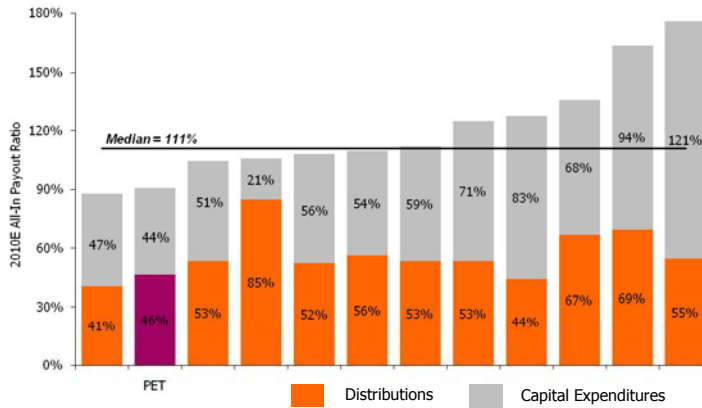
## Unrisked Potential – McDaniel January 2010 Prices



- (1) December 31, 2009 reserves adjusted for 2010 dispositions and acquisitions
- (2) Mark-to-McDaniels value of Perpetual hedge book at January 1, 2010 (\$50 MM)
- (3) Bank debt and convertible debentures at June 4, 2010 net of estimated working capital; net of dispositions
- (4) FMV of Undeveloped Land \$143 MM

40

## Sustainability – 2010E All-in Payout Ratio

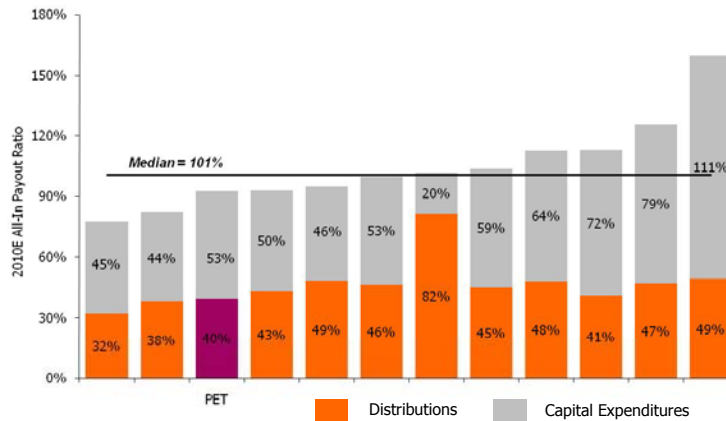


Source: BMO, June 7, 2010  
Consensus cash flow per Thomson One

**Perpetual is top quartile in projected distribution sustainability for 2010**

41

## Sustainability – 2011E All-in Payout Ratio

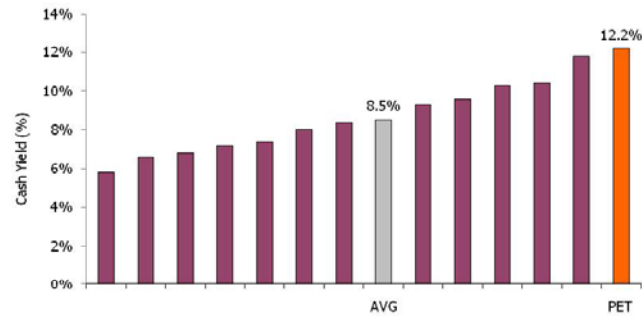


Source: BMO, June 7, 2010  
Consensus cash flow per Thomson One. Assumes 2011 capital program is equal to 2010.

**Perpetual is top quartile in projected distribution sustainability for 2011**

42

## Current Cash Yield



Source: BMO Nesbitt Burns  
(June 1, 2010)

**Current cash yield does not reflect low payout ratio and sustainability**

43

## Perpetual Energy Inc. (TSX: PMT)



- **Low cost base assets** well suited to sustainable partial cash flow distribution model
  - **Sustainable dividend** at \$ 0.05 per Unit per month
  - **Premium yield** at low payout ratio
  - **Cash flow generators** to capitalize growth
- Extensive internal **inventory of base opportunities** to fuel production and reserves replacement and generate future cash flow
- Exposure to multiple, exciting '**Game Changers**' to drive future **growth**
- '**Option Value**' intrinsic to asset base
- Track record of success making **value-driven acquisitions**
- **Improving balance sheet** to take advantage of opportunities
- **Extensive hedge book** to weather bottom of gas price cycle
- **Accountable and entrepreneurial team**, motivated by excellence



**Focused on Maximizing Shareholder Value**

44



**For Additional Information:**

Sue Fiddell Rose  
President & CEO  
Carm Sebastian  
VP Finance & CFO  
Sue Showers  
Investor Relations & Communications Advisor

*Build ideas for energy*  
3200, 605 5 Ave. SW  
Calgary, Alberta T2P 3H5  
T 403.269.4400  
F 403.269.4444  
TF 1.800.811.5522

perpetualenergyinc.com  
info@perpetualenergyinc.com