Oil & Gas Modeling: – Quiz Questions

Module 3 – Valuation and Simplified NAV Model

1. **Some people argue that you SHOULD factor in the Net Value of Derivatives used for commodity price hedging when calculating Enterprise Value (EV) for an E&P company, since derivatives are cash-like items. Why might you decide NOT factor them in?**

    a. Because derivatives are directly related to the company's operations and we do **NOT** include operational items in the EV calculation – only financing-related items.

    b. Because including derivatives in the EV calculation is effectively "double-counting," since metrics such as revenue, EBIT, and EBITDAX already reflect the impact of hedging.

    c. Because you should only include derivatives related to FX rate and interest rate hedging, i.e. ones that are more financial and less operational in nature.

    d. All of the above.

    e. None of the above – you always factor in the net value of all derivatives when calculating Enterprise Value for any E&P company.

2. **Which of the following metrics should be used for COMPARATIVE purposes when analyzing sets of oil & gas comparable companies, but not for approximating actual cash flow generated?**

    a. Unlevered Free Cash Flow.

    b. EBITDAX.

    c. EBITDA.

    d. Proved Reserves.

    e. Levered Free Cash Flow.

    f. Daily Production.

3. **Should you use Equity Value or Enterprise Value when calculating valuation multiples based on Proved Reserves and Daily Production?**

    a. Equity Value for both, since you often calculate metrics such as Proved Reserves per Share and Daily Production per Share – both of those are on a per share basis, so it indicates that you should use Equity Value in the multiples.

    b. Either Equity Value or Enterprise Value could be used, since neither one is a traditional financial metric – net interest expense cannot possibly show up in either one of them.

    c. Enterprise Value should be used since Proved Reserves and Daily Production are available to ALL investors in the company – not just equity investors.

    d. Enterprise Value should be used for Proved Reserves and Equity Value should be used for Daily Production, since Proved Reserves are available to all investors but the company's production is only available to equity investors.

4. **For this question and the next 3 questions, please review Exhibits 3.4.01, 3.4.02, and 3.4.03 below, which depict partial versions of the 3 financial statements for EOG Resources:**

Exhibit 3.4.01 – EOG Partial Income Statement

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME
(In Thousands, Except Per Share Data)

Net Operating Revenues	
Natural Gas	$ 2,050,963
Crude Oil, Condensate and Natural Gas Liquids	1,348,510
Gains on Mark-to-Market Commodity Derivative Contracts	431,757
Gathering, Processing and Marketing	407,116
Gains on Property Dispositions, Net	535,436
Other, Net	13,177
Total	4,786,959
Operating Expenses	
Lease and Well	579,290
Transportation Costs	283,329
Gathering and Processing Costs	57,632
Exploration Costs	169,592
Dry Hole Costs	51,243
Impairments	305,832
Marketing Costs	397,375
Depreciation, Depletion and Amortization	1,549,188
General and Administrative	248,274
Taxes Other Than Income	174,363
Total	3,816,118
Operating Income	970,841

Exhibit 3.4.02 – EOG Balance Sheet

EOG RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Data)

ASSETS		
Current Assets		
Cash and Cash Equivalents	$	685,751
Accounts Receivable, Net		771,417
Inventories		261,723
Assets from Price Risk Management Activities		20,915
Income Taxes Receivable		37,009
Other		62,726
Total		1,839,541
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)		24,614,311
Other Property, Plant and Equipment		1,350,132
Total Property, Plant and Equipment		25,964,443
Less: Accumulated Depreciation, Depletion and Amortization		(9,825,218)
Total Property, Plant and Equipment, Net		16,139,225
Other Assets		139,901
Total Assets	**$**	**18,118,667**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$	979,139
Accrued Taxes Payable		92,858
Dividends Payable		36,286
Liabilities from Price Risk Management Activities		27,218
Deferred Income Taxes		35,414
Current Portion of Long-Term Debt		37,000
Other		137,645
Total		1,345,560
Long-Term Debt		2,760,000
Other Liabilities		632,652
Deferred Income Taxes		3,382,413
Commitment and Contingencies (Note 7)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized: 252,627,177 Shares and 249,758,577 Shares Issued at December 31, 2009 and 2008, respectively		202,526
Additional Paid in Capital		596,702
Accumulated Other Comprehensive Income		339,720
Retained Earnings		8,866,747
Common Stock Held in Treasury, 118,525 Shares and 126,911 Shares at December 31, 2009 and 2008, respectively		(7,653)
Total Stockholders' Equity		9,998,042
Total Liabilities and Stockholders' Equity	**$**	**18,118,667**

Exhibit 1.04.03 – EOG Partial Cash Flow Statement

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

Cash Flows From Operating Activities	
Reconciliation of Net Income to Net Cash Provided by Operating Activities:	
Net Income	$ 546,627
Items Not Requiring (Providing) Cash	
Depreciation, Depletion and Amortization	1,549,188
Impairments	305,832
Stock-Based Compensation Expenses	95,180
Deferred Income Taxes	174,392
Gains on Property Dispositions, Net	(535,436)
Other, Net	6,761
Dry Hole Costs	51,243
Mark-to-Market Commodity Derivative Contracts	
Total Gains	(431,757)
Realized Gains (Losses)	1,277,584
Excess Tax Benefits from Stock-Based Compensation	(76,134)
Other, Net	18,862
Changes in Components of Working Capital and Other Assets and Liabilities	
Accounts Receivable	(47,818)
Inventories	(50,146)
Accounts Payable	(153,565)
Accrued Taxes Payable	90,929
Other Assets	(5,515)
Other Liabilities	(12,305)
Changes in Components of Working Capital Associated with Investing and Financing Activities	118,517
Net Cash Provided by Operating Activities	2,922,439
Investing Cash Flows	
Additions to Oil and Gas Properties	(3,176,783)
Additions to Other Property, Plant and Equipment	(326,226)
Proceeds from Sales of Assets	212,000
Changes in Components of Working Capital Associated with Investing Activities	(118,221)
Other, Net	(5,321)
Net Cash Used in Investing Activities	(3,414,551)

Based on the screenshots above, which of the following items are CORRECT add-backs or adjustments if you're calculating EBITDAX for EOG, starting from the Operating Income figure on its Partial Income Statement?

a. Add back the entire Depreciation, Depletion & Amortization (DD&A) expense.

b. Add back only the Depreciation & Amortization portion of the DD&A expense.

c. Subtract the Gains on Mark-to-Market Commodity Derivative Contracts as shown on the Income Statement.

d. Subtract only the non-cash portion of the Income Statement Gains on Mark-to-Market Commodity Derivative Contracts.

e. Subtract the Gains on Property Dispositions, Net.

f. Go to the cash flow statement and subtract only the non-cash portion of the Gains on Property Dispositions, Net.

g. Add back the Impairment Expense (listed on the IS and CFS).

h. Add back Exploration Costs.

i. Add back Dry Hole Costs.

j. Add back "Taxes Other Than Income."

5. **Based on your response above and the screenshots shown in Exhibits 3.4.01 through 3.4.03, please calculate EBITDA and EBITDAX for EOG Resources. Assume that Stock-Based Compensation IS added back to both numbers (it could go either way, but please assume that it IS an add-back here). All the numbers below are in MILLIONS, i.e. $1,540 million = $1.54 billion.**

    a. TTM EBITDA = $1,045; TTM EBITDAX = $1,167.

    b. TTM EBITDA = $1,405; TTM EBITDAX = $1,617.

    c. TTM EBITDA = $1,450; TTM EBITDAX = $1,671.

    d. TTM EBITDA = $1,540; TTM EBITDAX = $1,761.

6. **Suppose that EOG Resource's current Diluted Equity Value is $22,289 million (i.e. $22.3 billion). Clearly, we would subtract Cash on the Balance Sheet ($686 million) and add Debt on the Balance Sheet (~$2.8 billion total) to calculate the company's Enterprise Value. However, there may also be items NOT listed explicitly on the Balance Sheet that will factor into Enterprise Value as well.**

   Which of the following choices represent items that WOULD factor into Enterprise Value and which are either 1) NOT listed on EOG's Balance Sheet, or 2) Which ARE listed but which MAY be embedded in other line items, and are NOT already included in the Cash and Debt numbers quoted above?

   a. Net Value of Derivatives.

   b. Investments in Equity Interests.

   c. Preferred Stock.

   d. Capital Leases.

   e. Noncontrolling Interests.

   f. Asset Retirement Obligation.

   g. Unfunded Pension Obligations.

   h. Short-Term Marketable Securities.

   i. Cash Portion of Deferred Income Taxes.

7. As shown above, EOG's Cash Flow from Investing in this year is negative $3.4 billion, while its Cash Flow from Operations is $2.9 billion. What do those numbers imply about its financing needs in future years?

a. It means the company will likely raise debt or issue equity this year, but beyond that you cannot say much since only one (1) year of the financial statements is shown above.

b. It implies that the company will likely need to raise substantial funding in each subsequent year because there are no one-time or extraordinary items that impact the cash flow generated here.

c. Since most of the cash flow shortfall is driven by changes in Operating Working Capital (i.e. Current Assets Excluding Cash Less Current Liabilities Excluding Debt), it means that the company has a short-term cash flow crunch, but won't necessarily need ongoing funding sources in the future.

d. We can't say anything here because DD&A is only about 50% of CapEx, which is unusual for an E&P company and indicates non-standard cash flow.

8. You are valuing a small E&P company that has recently found significant oil and gas reserves with a very high probability of recovery. However, it will take at least 2 years to acquire all the appropriate licenses, move a drilling rig into the area, and complete all the required infrastructure before production can begin.

Which of the valuation multiples and/or methodologies listed below would be MOST APPROPRIATE to value a company in this situation?

a. Net Asset Valuation (NAV).

b. EV / Revenue.

c. EV / EBITDAX.

d. A "Longer-Term" DCF that forecasts FCF over 10-20 years rather than 5-10 and which uses the Gordon Growth Method for the Terminal Value.

e. EV / Proved Reserves.

f. EV / Daily Production.

9. **For this question, please consider the screenshot below, which depicts a set of public comps in the E&P sector. Key operating and financial metrics are shown in the top area, and key valuation multiples are shown below:**

Comparable Companies - North American Oil & Gas E&P Companies with Over 10 Tcfe Proved Reserves
($ in Millions Except Per Share, Reserve, and Production Data)

Operating Statistics	Capitalization		EBITDAX[3]			Proved	Daily		Proved		R / P
	Equity	Enterprise				Reserves	Production	Production	Developed	Oil	Ratio
Company Name	**Value[1]**	**Value[1][2]**	**TTM**	**Year 1**	**Year 2**	**(Bcfe)**	**(MMcfe)**	**Areas**	**/ Proved**	**Mix % [4]**	**(Years)**
Chesapeake Energy Corporation	$ 15,489	$ 29,710	$ 4,509	$ 4,571	$ 4,949	14,254.0	2,480.8	US Diversified	58.4%	7.8%	15.7
Anadarko Petroleum	28,937	40,880	5,743	8,099	9,908	13,824.0	3,624.0	International; US-Focused	70.5%	30.9%	10.5
Occidental Petroleum Corporation	61,989	64,381	8,447	12,659	16,428	19,350.0	3,870.0	International	77.3%	76.2%	13.7
Apache Corporation	32,252	37,384	5,989	8,264	9,694	14,199.5	3,499.7	International	69.1%	47.8%	11.1
Devon Energy Corporation	28,999	37,353	4,797	6,364	5,613	16,398.0	3,830.1	US & Canada	70.3%	18.0%	11.7
EOG Resources, Inc.	22,289	24,882	1,761	4,375	5,507	10,776.1	2,118.0	US, Canada & Trinidad	54.4%	15.6%	13.9
Maximum	$ 61,989	$ 64,381	$ 8,447	$ 12,659	$ 16,428	19,350.0	3,870.0		77.3%	76.2%	15.7
75th Percentile	31,439	40,006	5,927	8,223	9,855	15,862.0	3,778.6		70.4%	43.6%	13.9
Median	**$ 28,968**	**$ 37,368**	**$ 5,270**	**$ 7,232**	**$ 7,654**	**14,226.8**	**3,561.9**		**69.7%**	**24.5%**	**12.7**
25th Percentile	23,951	31,620	4,581	5,019	5,534	13,917.9	2,735.5		61.1%	16.2%	11.3
Minimum	15,489	24,882	1,761	4,375	4,949	10,776.1	2,118.0		54.4%	7.8%	10.5
XTO Energy Inc.	**$ 24,542**	**$ 34,686**	**$ 7,150**	**$ 6,818**	**$ 7,416**	**14,827.3**	**2,863.6**	**US Diversified**	**60.7%**	**13.9%**	**14.2**

Valuation Statistics	Capitalization		Enterprise Value / EBITDAX[3]			Enterprise Value /	
	Equity	Enterprise				Proved	Daily
Company Name	**Value[1]**	**Value[1][2]**	**TTM**	**Year 1**	**Year 2**	**Reserves**	**Production**
Chesapeake Energy Corporation	$ 15,489	$ 29,710	6.6 x	6.5 x	6.0 x	$ 2.08	$ 11.98
Anadarko Petroleum	28,937	40,880	7.1 x	5.0 x	4.1 x	2.96	11.28
Occidental Petroleum Corporation	61,989	64,381	7.6 x	5.1 x	3.9 x	3.33	16.64
Apache Corporation	32,252	37,384	6.2 x	4.5 x	3.9 x	2.63	10.68
Devon Energy Corporation	28,999	37,353	7.8 x	5.9 x	6.7 x	2.28	9.75
EOG Resources, Inc.	22,289	24,882	14.1 x	5.7 x	4.5 x	2.31	11.75
Maximum	$ 61,989	$ 64,381	14.1 x	6.5 x	6.7 x	$ 3.33	$ 16.64
75th Percentile	31,439	40,006	7.7 x	5.8 x	5.6 x	2.88	11.92
Median	**$ 28,968**	**$ 37,368**	**7.4 x**	**5.4 x**	**4.3 x**	**$ 2.47**	**$ 11.51**
25th Percentile	23,951	31,620	6.7 x	5.1 x	4.0 x	2.29	10.83
Minimum	15,489	24,882	6.2 x	4.5 x	3.9 x	2.08	9.75
XTO Energy Inc.	**$ 24,542**	**$ 34,686**	**4.9 x**	**5.1 x**	**4.7 x**	**$ 2.34**	**$ 12.11**

Which of the following conclusions about this set of comparable companies might you draw, based on the screenshot shown above?

a. Contrary to what you normally expect, there appears to be almost no correlation between EBITDAX growth and EV / EBITDAX multiples.

b. XTO Energy seems undervalued compared to the rest of the comps right now, since its operational metrics are in-line with the medians of the set but it trades below the median valuation multiples.

c. It seems like there is some correlation between the % oil produced and the reserves and production-based multiples.

d. One reason the multiples do not trend in a clear way with the operating metrics is that some of the companies have made acquisitions that distort the figures.

e. There appears to be a strong correlation between the Reserve Life Ratio and all the valuation multiples, as you normally expect.

f. There's also a clear correlation between the size of the Proved Reserves and the Daily Production volumes, and the respective valuation multiples for both of those.

10. Which of the following statements are TRUE regarding why a traditional DCF does not always work well for an E&P company?

a. Because the change in working capital is NOT meaningful for energy companies, so it is NOT possible to determine Free Cash Flow using traditional methods.

b. Because a DCF for an E&P company will be even more reliant on Terminal Value than a DCF for a normal company.

c. Because E&P companies have high CapEx requirements, which reduces Free Cash Flow and may result in a negative FCF in many years.

d. Because fluctuating commodity prices make it difficult to run the analysis and determine a reasonable terminal period growth rate.

e. Because it is very difficult to determine the proper discount rate to use, given the uncertainty that comes with searching for new oil/gas fields.

11. Which of the following statements are TRUE regarding the KEY DIFFERENCES in a DCF analysis for an E&P company?

a. Unlike with normal companies, in E&P you can use an industry-standard discount rate of 10% rather than calculating WACC.

b. To calculate Unlevered FCF for an E&P company, you need to add-back additional non-cash expenses that are specific to the sector.

c. The Terminal Value calculation for an E&P company can be based on a multiple of Proved Reserves or Daily Production, in addition to the more standard metrics.

d. You would create sensitivity tables based on commodity prices rather than revenue growth rates or EBITDA margins.

e. When you go from Enterprise Value to Equity Value, you will include slightly different Balance Sheet adjustments than in the standard analysis.

12. What items might you add back or subtract when calculating Unlevered Free Cash Flow for an E&P company that you would NOT add back for a normal company?

a. Depreciation, Depletion, and Amortization (DD&A) instead of normal D&A.

b. Gains and Losses on Asset Sales.

c. Non-Cash Derivative Gains / (Losses).

d. Taxes Other Than Income.

e. Stock-Based Compensation.

f. Accretion of Discount in Asset Retirement Obligation.

g. Goodwill Impairment.

h. Impairment of Natural Gas and Oil Properties.

i. Proceeds from the Sale of Natural Gas and Oil Properties.

13. **Why is the Net Asset Value (NAV) model, arguably, more conceptually sound than the DCF model when you are valuing E&P companies?**

    a. Because it is more conservative and does NOT assume indefinite future growth like the DCF analysis does.

    b. Because the NAV model uses a more realistic discount rate than the DCF analysis.

    c. Because the NAV model assumes that the company will eventually run out of resources, after an initial growth period, and values its cash flows on the basis of that assumption.

    d. Because natural resource companies are Balance Sheet-centric and the NAV model values such companies at the asset-level rather than the corporate-level.

    e. Because the NAV model assumes a higher growth rate in After-Tax Cash Flows than the Free Cash Flow growth rate assumed in in a DCF analysis.

14. **If the NAV valuation is very far out of line with the public comps and other methodologies, which of the following answer choices represent SOUND ways to adjust it downward so that it can still be compared to other methodologies, but also so that the NAV produces a lower relative value?**

    a. Adjust downward the annual Production Levels in the initial years of the model.

    b. Adjust downward the commodity prices in each different scenario.

    c. Increase the long-term production decline rate, but only in years after the initial period of the model.

    d. Increase the discount rate for the NAV model.

    e. If you're not already doing so, apply risking to non-Proved Reserves so that the value of cash flows derived from Probable and Possible Reserves is less than 100%.

15. **Which of the following statements is TRUE regarding a NAV model that produces a much higher or lower value than what is shown in a company's PV-10 in its filings?**

    a. It is an indication of a mistake, most likely because you did NOT use the industry-standard oil & gas discount rate.

    b. It is an indication of a mistake, most likely because you assumed too high of an Annual Production growth rate in the first few years.

    c. It is an indication of a mistake, most likely because you forgot to include the value of undeveloped land and non-E&P related segments.

    d. None of the above – it is not necessarily indicative of a mistake since commodity price swings can cause this to happen, and you can't even determine what caused the discrepancy without knowing the PV-10 assumptions.

16. **Suppose that you're building a NAV model where you want to factor in 5 different reserve types – Proved Developed Producing (PDP), Proved Developed Nonproducing (PDNP), Proved Undeveloped (PUD), Probable (PROB), and Possible (POSS). The company also produces oil and gas in 3 different regions of the US, and so you want to split the model by region as well.**

Which of the following answer choices represent how this model would be **DIFFERENT** from a simpler NAV model that groups all reserve types and regions together?

a. You would most likely assume different success probabilities ("reserve credits") for PDP, PDNP, and PUD reserves – you have to discount anything that is not yet producing or developed, after all.

b. You would use different reserve credit levels for Probable and Possible reserves, but not for the Proved Reserves since there's an extremely high probability they can be recovered.

c. You would have to assume that some CapEx is spent constructing the wells for the PUD, PROB, and POSS reserves over time, but that the PDP and PDNP wells can start producing relatively quickly (or continue producing in the case of PDP).

d. You would assume different commodity prices for each region and each reserve type, since oil and gas can be sold for different amounts in different parts of the world.

e. You might assume different reserve credits for PROB and POSS reserves depending on the region as well.

f. You might assume different production growth curves, decline rates, and initial production levels in different regions.

17. **For this question and the next 4 questions, please consider the Net Asset Value (NAV) Model shown in the screenshots below for Occidental Petroleum [OXY]. Exhibit 3.17.01 shows the key model assumptions, Exhibit 3.17.02 shows the cash flow projections, and Exhibit 3.17.03 shows the NAV per share calculation at the end.**

Exhibit 3.17.01 – NAV Assumptions

NAV Analysis - Occidental Petroleum Corporation

($ in Millions Except Per Share, Acreage, Production Unit, and Other Per-Unit Data)

Occidental Petroleum Corporation - Net Asset Value (NAV) Model					
Company Name:	Occidental Petroleum Corporation	Discount Rate:	10.0%		
Mcf to Bbl Conversion Factor:	0.1666667	Effective Cash Tax Rate:	30.0%		
		Units:	1,000		
Proved Reserves by Type:					
Oil (MMBbls):	2,008	Production Costs:	$ 81,137		
Natural Gas Liquids (MMBbls):	280	Production per BOE:	$ 25.00		
Natural Gas (Bcf):	5,323	Development Costs:	$ 17,756		
Barrels of Oil Equivalents (MMBOE):	3,175	Development Years:	5		
Oil Production:		**NGL Production:**		**Natural Gas Production:**	
$ per Bbl:	$ 75.00	$ per Bbl:	$ 45.00	$ per Mcf:	$ 3.00
Previous Year:	11.6%	Previous Year:	9.1%	Previous Year:	28.1%
Current Year:	0.6%	Current Year:	20.8%	Current Year:	6.7%
Current Year Volume:	164	Current Year Volume:	29	Current Year Volume:	447
Year 1 Growth Rate:	2.0%	Year 1 Growth Rate:	8.0%	Year 1 Growth Rate:	5.0%
Yearly Growth Rates:		**Yearly Growth Rates:**		**Yearly Growth Rates:**	
Years 2 - 5:	1.0%	Years 2 - 5:	5.0%	Years 2 - 5:	3.0%
Years 6 - 9:	(1.0%)	Years 6 - 9:	(2.0%)	Years 6 - 9:	(2.0%)
Year 10 and Beyond:	(5.0%)	Year 10 and Beyond:	(5.0%)	Year 10 and Beyond:	(5.0%)

Exhibit 3.17.02 – NAV Cash Flow Projections

	Oil			Natural Gas Liquids			Natural Gas			Revenue ($ in Millions)			Production & Development Expenses:				Cash Flows ($ in Millions)		
	Beginning Reserves (MMBbls)	Annual Production (MMBbls)	Avg. Price $ / Bbl	Beginning Reserves (MMBbls)	Annual Production (MMBbls)	Avg. Price $ / Bbl	Beginning Reserves (Bcf)	Annual Production (Bcf)	Avg. Price $ / Mcf	Oil & NGL	Natural Gas	Total Revenue	Annual MMBOE	Production Per BOE	Total Production Expenses	Total Development Expenses	Pre-Tax Cash Flows	Cash Tax Rate	After-Tax Cash Flows
Year 1	2,008	167	$ 75.00	280	31	$ 45.00	5,323	469	$ 3.00	$ 13,955	$ 1,408	$ 15,363	277	$ 25.00	$ 6,921	$ 3,551	$ 4,892	30.0%	$ 3,424
Year 2	1,841	169	75.00	249	33	45.00	4,854	483	3.00	14,151	1,450	15,602	282	25.00	7,060	3,551	4,990	30.0%	3,493
Year 3	1,672	171	75.00	216	35	45.00	4,370	498	3.00	14,352	1,494	15,846	288	25.00	7,204	3,551	5,091	30.0%	3,563
Year 4	1,501	172	75.00	181	36	45.00	3,872	513	3.00	14,558	1,539	16,096	294	25.00	7,352	3,551	5,193	30.0%	3,635
Year 5	1,329	174	75.00	145	38	45.00	3,359	528	3.00	14,769	1,585	16,353	300	25.00	7,505	3,551	5,298	30.0%	3,708
Year 6	1,155	172	75.00	107	37	45.00	2,831	518	3.00	14,604	1,553	16,157	296	25.00	7,398	-	8,759	30.0%	6,131
Year 7	982	171	75.00	70	37	45.00	2,313	507	3.00	14,441	1,522	15,963	292	25.00	7,293	-	8,670	30.0%	6,069
Year 8	812	169	75.00	33	33	45.00	1,806	497	3.00	14,156	1,492	15,647	285	25.00	7,121	-	8,526	30.0%	5,968
Year 9	643	167	75.00	-	-	45.00	1,309	487	3.00	12,541	1,462	14,003	248	25.00	6,211	-	7,792	30.0%	5,455
Year 10	476	159	75.00	-	-	45.00	822	463	3.00	11,914	1,389	13,303	236	25.00	5,900	-	7,403	30.0%	5,182
Year 11	317	151	75.00	-	-	45.00	359	359	3.00	11,318	1,076	12,395	211	25.00	5,268	-	7,127	30.0%	4,989
Year 12	166	143	75.00	-	-	45.00	-	-	3.00	10,752	-	10,752	143	25.00	3,584	-	7,168	30.0%	5,018
Year 13	23	23	75.00	-	-	45.00	-	-	3.00	1,689	-	1,689	23	25.00	563	-	1,126	30.0%	788
Year 14	-	-	75.00	-	-	45.00	-	-	3.00	-	-	-	-	25.00	-	-	-	30.0%	-
Year 15	-	-	75.00	-	-	45.00	-	-	3.00	-	-	-	-	25.00	-	-	-	30.0%	-
Year 16	-	-	75.00	-	-	45.00	-	-	3.00	-	-	-	-	25.00	-	-	-	30.0%	-
Year 17	-	-	75.00	-	-	45.00	-	-	3.00	-	-	-	-	25.00	-	-	-	30.0%	-
Year 18	-	-	75.00	-	-	45.00	-	-	3.00	-	-	-	-	25.00	-	-	-	30.0%	-
Year 19	-	-	75.00	-	-	45.00	-	-	3.00	-	-	-	-	25.00	-	-	-	30.0%	-
Year 20	-	-	75.00	-	-	45.00	-	-	3.00	-	-	-	-	25.00	-	-	-	30.0%	-

Present Value of Cash Flows from Proved Reserves: $ 30,709

Exhibit 3.17.03 – Implied NAV per Share Calculation

Undeveloped Land and Other Business Segments:		
Undeveloped Acres (Thousands):		19,565
Average $ Per Single Acre:	$	400
Value of Undeveloped Land:	**$**	**7,826**
Chemicals:		
Prior Year EBITDA:		861
Assumed EV / EBITDA Multiple:		6.0 x
Estimated Enterprise Value:	**$**	**5,166**
Midstream:		
Prior Year EBITDA:		448
Assumed EV / EBITDA Multiple:		7.0 x
Estimated Enterprise Value:	**$**	**3,136**
Enterprise Value for Entire Company:	**$**	**46,837**
Plus: Cash & Cash-Equivalents:		3,781
Plus: Equity Investments:		2,072
Less: Debt:		(5,871)
Less: Asset Retirement Obligation:		(1,089)
Implied Equity Value:	**$**	**45,730**
Diluted Shares Outstanding:		812.9
Implied Share Price:	**$**	**56.25**

In a simple NAV model, you often assume that production declines until the reserves are depleted entirely. In Exhibit 3.17.01 above, we're assuming a slight INCREASE in production across all natural resource segments in the first few years. If that is true, what other conditions must be TRUE in the model?

a. You must assume lower commodity prices to offset the increase in annual production.

b. You must assume a higher cash tax rate when calculating After-Tax Cash Flows since the increased annual production will reduce the Deferred Income Taxes.

c. In addition to projecting cash flows from PDP and PDNP reserves, you must also project cash flows from PUD reserves.

d. This assumption means that you need to change the reserve types and include Probable and Possible Reserves in addition to just Proved Reserves.

e. You must assume some amount of Development Expenses since it is NOT possible to increase annual production without drilling and developing more wells.

f. None of the above – you can assume an increase in annual production in the beginning years WITHOUT anything else above necessarily being true.

18. If we were to change the commodity price deck assumptions and assume different prices each year, where's the most logical place to do that?

a. You should only do this in Year 1, and only if current commodity prices differ significantly from your assumptions.

b. Years 1 through 3, since you might have more visibility into potential short-term price changes.

c. Only beyond Year 5 – assuming different prices earlier on might distort the model results too much since production levels are higher in earlier years.

d. The question premise is false because you should NEVER assume different commodity prices in any year in a NAV model – the entire point of the model is to avoid making these types of guesstimates.

19. In Exhibit 3.17.02 above under Natural Gas Liquids, Annual Production in Year 2 is 33 MMBbls (Note: Please see the cell circled in red in the exhibit above). Which of the answer choices below gives the CORRECT FORMULA for that cell, and which one correctly explains why we need it?

a. =MIN(Beginning Reserves Yr. 2, Annual Production Yr. 1 * (1 + Natural Gas Liquid Production Growth Rate)).

b. =MAX(MIN(Beginning Reserves Yr. 2, Annual Production Yr. 1 * (1 + Natural Gas Liquid Production Growth Rate)), 0).

c. We are using a MIN formula to make sure that the annual production never drops below 0.

d. We are using a MIN formula to make sure that we never produce more than the total amount of remaining reserves.

e. We are using a MAX formula to make sure that the annual production never drops below 0.

f. We are using a MAX formula to make sure that we never produce more than the total amount of remaining reserves.

20. In Exhibit 3.17.03 above, we add the value of Undeveloped Land, based on the average dollar per acre value, as well as the value of the Chemicals and Midstream segments. Which of the following choices represent ALTERNATE ways to factor in the value from these segments?

a. Similar to what you did for the E&P segment, you could use a NAV analysis for the Midstream segment instead of applying an EV / EBITDA multiple.

b. You could run a DCF analysis for the Midstream segment and for the Chemicals segments and add the implied values from that analysis.

c. You could assume that a certain percentage of the Undeveloped Land will contain reserves, split the reserves into different types, and run a NAV model for each reserve category (assuming that brand new wells are drilled).

d. None of the above – what's shown in Exhibit 3.17.03 is the most acceptable way of factoring in the values from these other segments.

21. **What is one possible PROBLEM with factoring in the value of Undeveloped Land the way we have here, vis-à-vis the assumptions and cash flow projections in Exhibits 3.17.01 and 3.17.02 above this one?**

    a. There is no problem – Undeveloped Land is completely separate from anything we assumed in the cash flow projections.

    b. Some of this Undeveloped Land may actually be included in the PUD Reserves, so we may need to adjust downward the value contributed by Undeveloped Land, or exclude from the analysis cash flows derived from those reserves.

    c. Although Undeveloped Land may be included in the company's reserves, there's no problem here because Undeveloped Land could only contain Probable and Possible Reserves – and in the NAV model we're ignoring those.

    d. If we factor in Undeveloped Land, we should NOT also be assuming Development Expenses (CapEx) in the cash flow projections.

22. **In which of the following geographies would you MOST likely use a discount rate higher than the O&G industry standard of 10%?**

    a. USA.

    b. Canada.

    c. Russia.

    d. Venezuela.