Oil & Gas Property Evaluation: A Geologist's View*

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Abstract

The acquisition of producing oil and gas properties for exploitation has been a popular, and very successful, business model for the past 20 years. In order to be successful, one must have a clear understanding that the business purpose is to make a profit by buying smart, whereby your purchase price is recoverd AND the property's revenue generates an acceptable return on your investment. Financial evaluation of existing production is most often performed via discounted cash flow (DCF) analysis. Alternatively a simple cash-flow multiple may be useful or appropriate. In its simplest form reserves are categorized as proven or unproven and either producing or non-producing. Non-producing resereves entities are often defined as Proved-Developed-Behind-Pipe (PDNP), Proved-Undeveloped (PUD), Probable (PROB) and Possible (POSS). Non-producing reserves entities are best valued via DCF analysis and may add considerable value often equalling or exceeding the value of current production. Therefore the evaluation or creation of these entities is extremely critical to both evaluation for purchase and exploitation of owned properties. In a competitive bid scenario the winner is often the one who sees the value of the "Non-producing Upside". It's often the geologist's role to delineate or evaluate non-producing reserves – both proven and unproven. How do you convert your geological opinion into a number that can be useful in formulating a purchase offer for example? And how can you do this in the compressed time frame of bid formulation? I will suggest a method that will allow you to convert your creative prospect ideas or geological opinion of a property into a useful number. The method is equally applicable to individuals or to interdisciplinary teams. Property Evaluation requires the geologist to consider the entire "earth-cube" and produce necessary geological interpretations for reserves additions in producing zones, shallower or deeper zones, offsets, and via seismic, or secondary, tertiary and unconventional projects. By understanding the concepts of reserves entities such as PDNP, PUD, PROB, and POSS the geologist will see a direct line between idea generation and the company's bottom line success.

References

Megill, R.E., 1992, Exploration Economics: Chapter 10: Part III. Economic Aspects of the Business, *in* The Business of Petroleum Exploration, R. Steinmetz, ed.: AAPG Treatise of Petroleum Geology Handbook of Petroleum Geology 2, p. 107-116.

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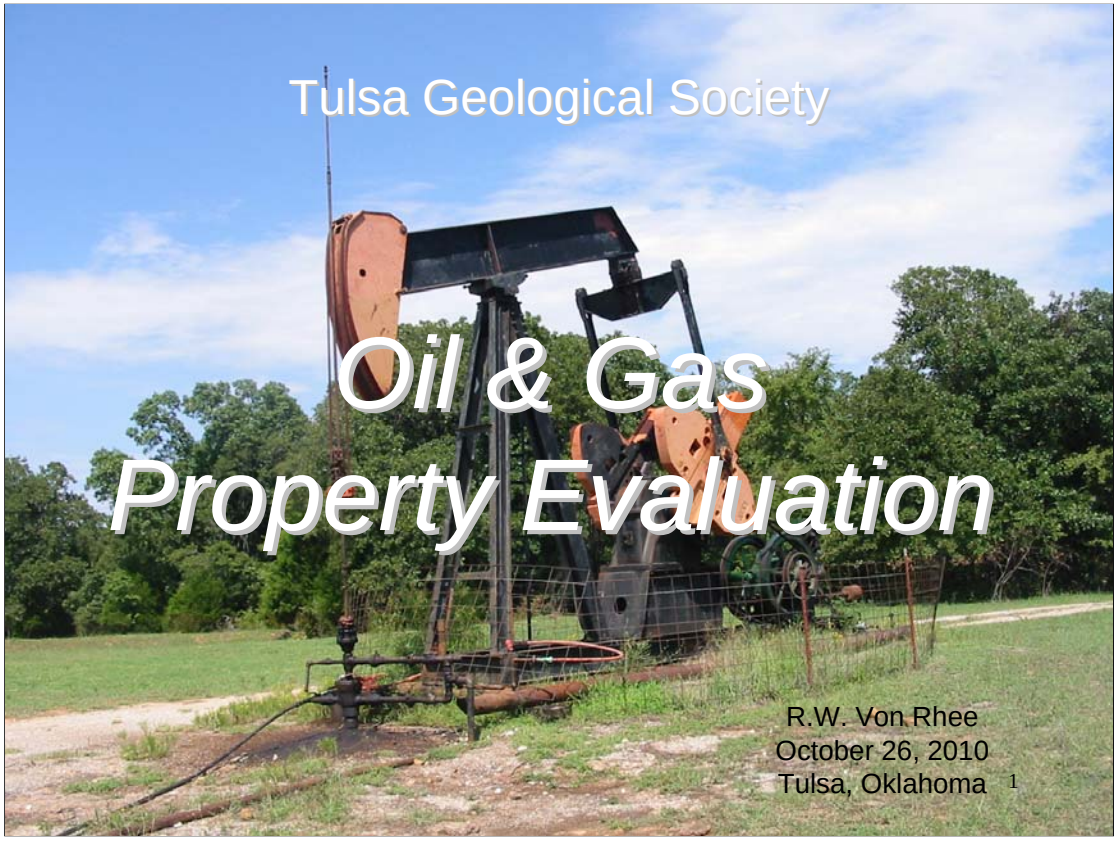

See notes following

Presenter's Notes:
How much is it worth? Over the past 20 years, our industry has seen significant growth and maturity of the secondary market of buying and selling producing O&G properties. This is the "Acquisitions & Divestitures" you hear about – the "A&D" portion of our industry. In order to be successful, one must have a clear understanding that the business purpose is to make a profit by buying smart, whereby your purchase price is recovered AND the property's revenue generates an acceptable return on investment. In a competitive bid scenario the winner is often the one who sees the value of the "Non-producing Upside". It is therefore often the geologist's role to delineate or evaluate non-producing reserves – both proven and unproven. Some years ago, in a new role as Chief Geologist for an Oklahoma Independent, I was part of a data room team to evaluate a significant package of producing properties for purchase. Afterwards, the president of the company asked me how much, in dollars, I would "pay up" for the package based upon the upside potential (non-producing). I was embarrassed to find that I could not quantify that opinion; thereafter I developed better skills at quantifying that opinion. For the past 17 years, I have focused mainly on the acquisition and exploitation of producing oil and gas properties. I trust that some of my observations contained in this presentation may be of some use to other geologists in similar roles. Many newly capitalized ventures begin by acquiring producing properties and many other companies, public and private add to their reserve base and exploration acreage by acquiring producing properties. For geologists involved in the process – either selling or buying – it is helpful to have a working knowledge of the principles and terminology involved. As geologists, we are well trained in the science of petroleum and geology, but we may find ourselves lacking in economic analysis and understanding of oil and gas reserves.

The premise of my talk is that the geologist is evaluating a set of producing properties for sale and each property has HBP leasehold associated with it. The evaluation is usually complicated due to the short time constraints placed on assessing and submitting a bid on a property for sale.

In order to effectively convert a geological opinion or idea into a number, it is helpful to have a functional understanding of the methodology and terminology of evaluating the monetary value of a producing oil and gas property. The same applies to reserves terminology and reserves categories. I will introduce the concept of present value and also certain reserves categories; however, this is not a formal presentation about formal economic analysis, or the current reserves definitions according to the SEC, SPE and AAPG. Rather it an attempt to introduce some terminology and methodology for converting geological ideas into valued reserve entities that then may be used in formulating a purchase offer.

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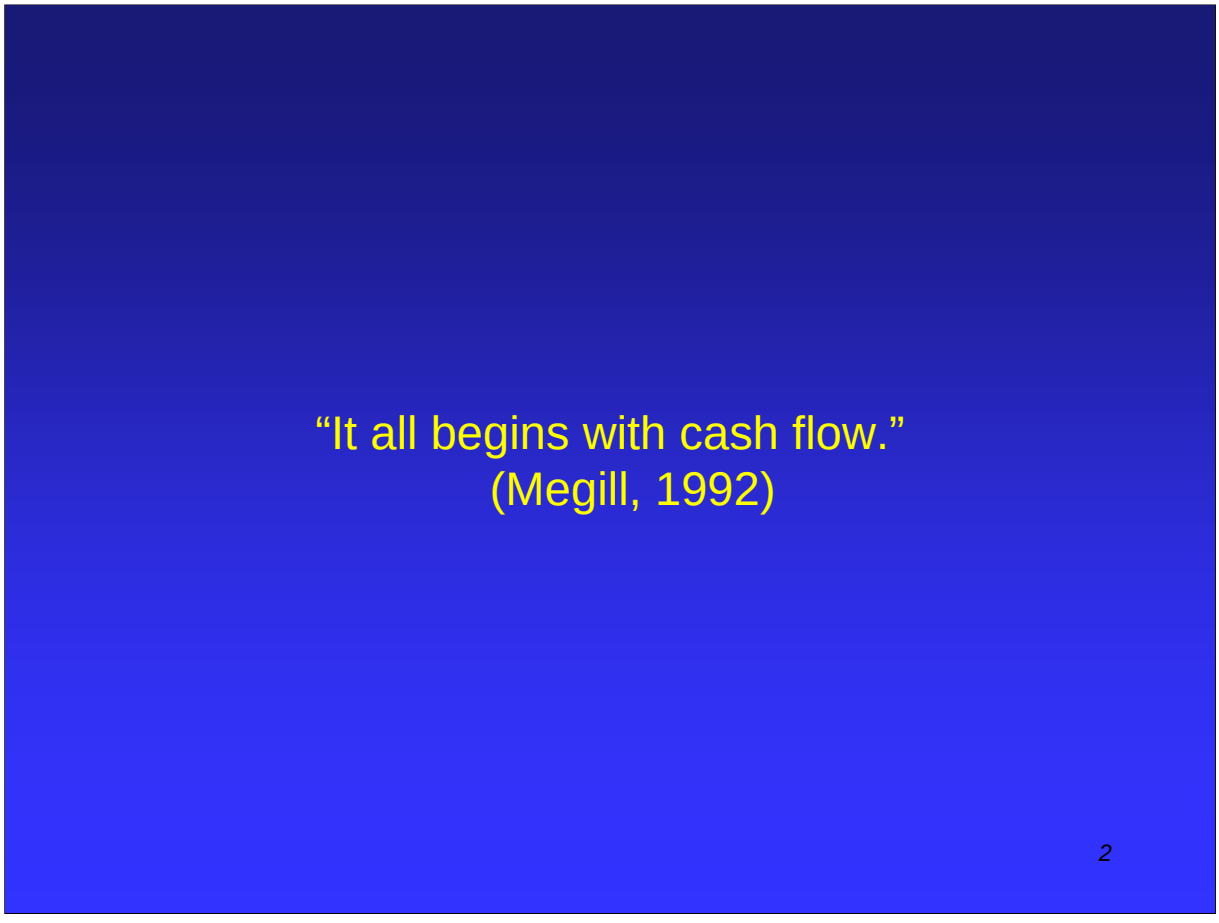
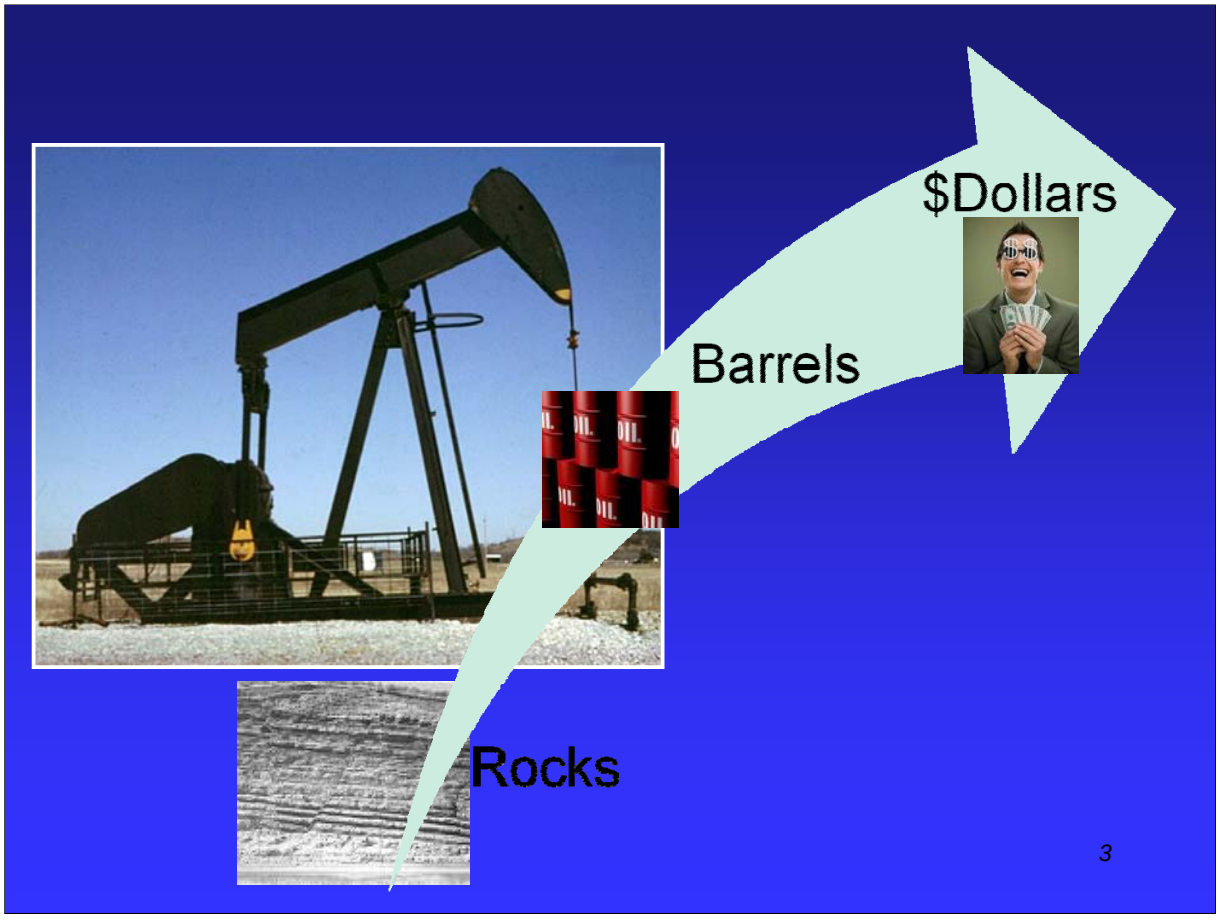


Presenter's Notes: IT'S NOT ALWAYS ABOUT THE ROCKS….It's always about money. "It all begins with cash flow" Megill, R.E., (1992) Exploration Economics, p.107, *in* The Business of Petroleum Exploration, Steinmetz, R., ed.: AAPG Treatise of Petroleum Geology, Beaumont, E.A., and N. H. Foster, Treatise eds.



Presenter's Notes: As geologists we have to transition from thinking about rocks, barrels, and mcf's and begin to think of oil and gas production and prospects in terms of dollars. Therefore we need some language and techniques for expressing our prospect ideas in dollar terms.

In the last Oil Boom, everyone said I ought to own some oil wells….

But just what IS a producing oil and gas property?

Well, think about it……

A hole in the ground with a bunch of mechanical equipment is able to bring natural gas and crude oil to the surface and sell it to someone who wants it. You really don't want the stuff – *you want the cash from selling it!*

So each month I get a check from the purchaser until I no longer produce enough to cover my expenses, right?

Yep – so what is a producing property?

Presenter's Notes: Producing property yields cash flow stream.

A producing oil and gas property is essentially a:

SERIES OF CASH PAYMENTS PROJECTED INTO THE FUTURE

…the question becomes – “How do we value a series of future cash payments?”

Answer… by determining its

Present Value

Presenter’s Notes: Present value (PV) is the technique of valuing a future cash flow stream in “today’s dollars.”

Think on This…

If I invest $1,000 at 10% APR compounded annually, I'll have $2,590 bucks after 10 years.

The "Future Value" (FV) of my $1,000 in this scenario is $2,590.

What if you want to buy a cash flow stream that will have a FV of $2,590?
Because of the "TIME VALUE OF MONEY," you certainly wouldn't pay $2,590 for it; would you?

So, what you need is a method of figuring out what is the "Present Value" (PV) of this cash flow stream and you can do that by "Discounting" the future cash flow at some annual interest rate.

See notes following

Presenter's Notes:
Most of us would not keep our savings in a mason jar buried in the yard nor in our mattress. We would naturally seek an interest-bearing repository. Because of inflation, a dollar ten years from now is not worth what it is today. This is one reason we expect to earn interest on our money. Using the example in this slide, if someone offered to sell you the cash flow payments that would result in $2,590 dollars ten years from now, you wouldn't pay them that total amount of money; would you? If you had $2,590 dollars today, you would expect to invest it to earn interest so that it would be worth MORE than that in ten years. That is why you would pay less today for a given future value (FV).

Because of inflation and the ability to invest today's dollars for a given rate of return (interest), a cash flow stream purchased today needs to be characterized by calculating the future revenue in today's dollars. This is the concept of Present Value or PV.

Present Value = “PV”

The value of a series of future cash flows expressed in today’s dollars.

The valuation may be achieved informally or formally by:

CASH FLOW MULTIPLE (CFX)
OR
DISCOUNTED CASH FLOW (DCF)

When PV is calculated by discounting, it is quoted with the associated discount rate (e.g., 10%) or:

“PV10”

Presenter’s Notes: In the acquisition and divestiture of oil and gas properties, there are essentially two methods of calculating Present Value. The formal method is to select a discount factor and apply the mathematics of discounting to a future cash flow stream and calculate the present value for a given discount rate. A simple informal, but effective, order of magnitude method is to calculate a simple multiple of current cash flow.

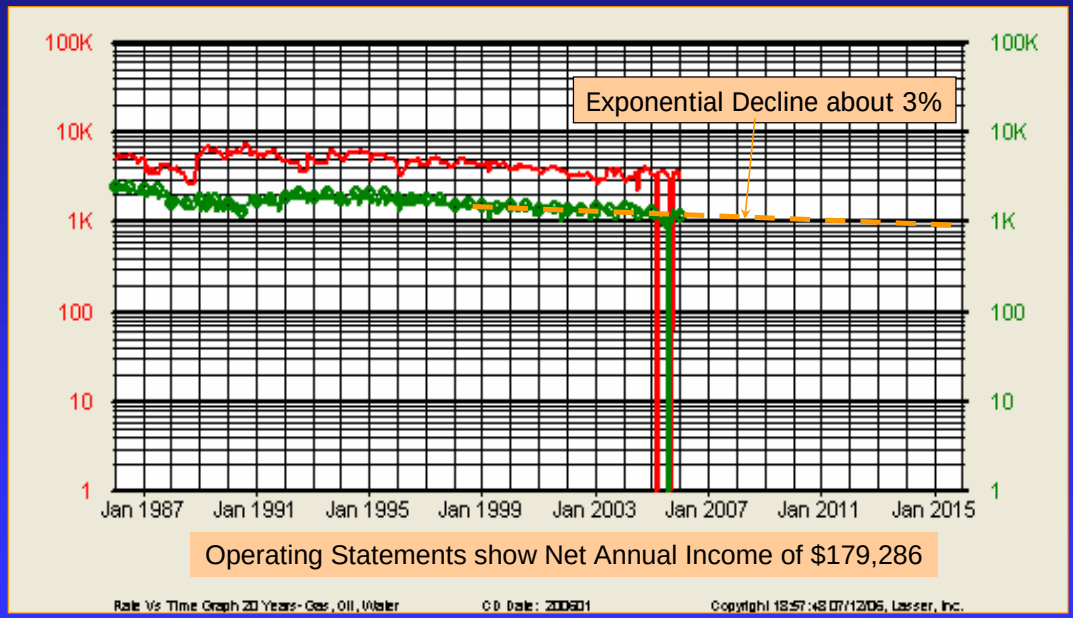
Cash Flow Multiple

For a series of cash payments into the future, this method provides an informal, quick method of valuation.

Provides an “order of magnitude.”

Presenter’s Notes: The Cash Flow Multiple: So simple, one might even do this in one’s head.

Sledge “B” Decline Curve



Presenter’s Notes: Here is a simple example. Production is declining at a steady 3% decline rate (very stable and uniform). From Lease Operating Statements for this property, we determined it had an annual net income after operating expenses of $179,286. Note that this well is in the latter part of its producing life, and decline is very stable. Were this property in the early stages of decline or declining at a significant rate, the CFX method might be too simple and inappropriate.

Sledge “B”
Cash Flow Multiple Valuation

Cash Flow for Sledge "B" current Year is $179,286					
YEARS	(months)	Cash Flow Multiple			
1	12	$179,286			
2	24	$358,572			
3	36	**$537,858**	"36 to 72 months Cash Flow"		
4	48	**$717,144**			
5	60	**$896,430**			
6	72	**$1,075,716**			
7	84	$1,255,002			
8	96	$1,434,288			

Presenter’s Notes: Cash flow multiple method of establishing value (“CFX”). the cash flow multiples are **ORDER OF MAGNITUDE ESTIMATES OF PRESENT VALUE: The future total cash flow expressed in terms of today’s dollars.** It is common in onshore domestic producing areas to speak of value in terms of 36 to 72 months’ Cash Flow. We have therefore estimated a PV of from $538M to $1076M.

Discounted Cash Flow

A formal method of calculating the present value (PV) relative to a chosen Discount Rate (%)

Presenter's Notes: Discounting a Future Cash Flow is the formal method of calculating a Present Value. If you are seeking third-party financing for the acquisition, this method becomes mandatory.

Discounted Cash Flow analysis requires the forecast of:

Production volume and ultimate recovery (Reserves)
Future commodities price
Future lease operating expenses (LOE)

E.G.: (BBL x $ x NRI) – (LOE x WI) = Future Cash Flow

The Future Cash Flow is discounted to today's dollars to calculate a Present Value

When PV is calculated by Discounting, it is quoted with the associated discount rate (e.g. 10%) or:

"PV10"

See notes following

Presenter's Notes:

The future cash flow is highly dependent on three items.

1) The forecast rate of production decline provides future volume and timing. How much oil or gas remains (the "Reserves") to be produced from the property?
2) What will the future price of oil or natural gas be? Reflecting on the past 24 months in our industry, what would your forecast have been in 2007?

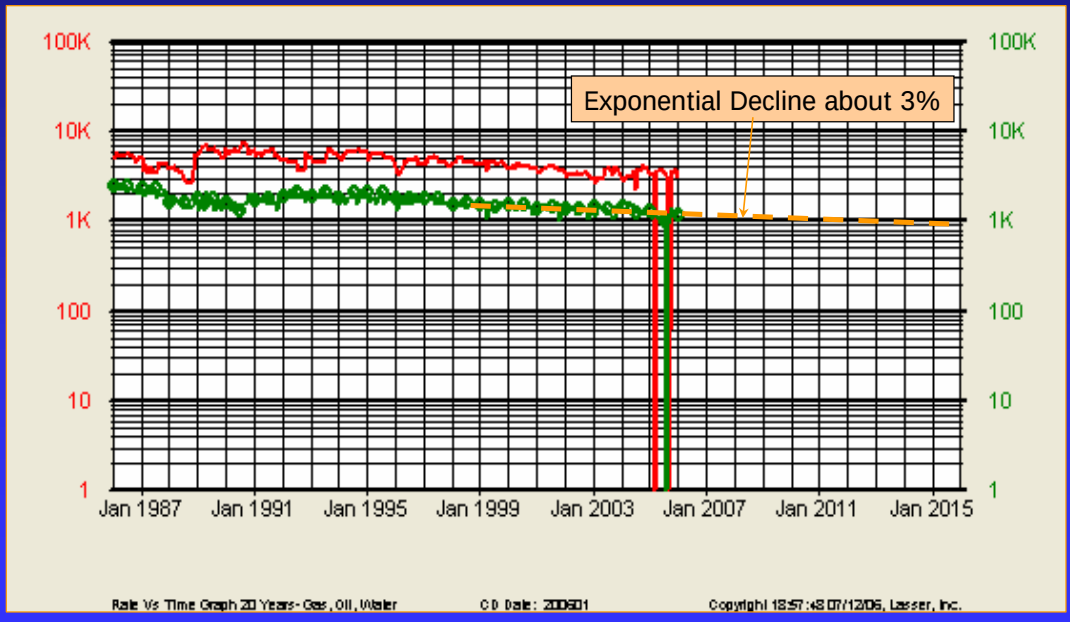
3) What will the future operating expenses (LOE) be?

Simple Future Cash Flow is:

Production volume X Price/BBL X NRI (your share) minus LOE X WI (your share).

Of course you also must deduct any Severance Taxes.

Sledge “B” Decline Curve



Presenter’s Notes: Let’s re-examine the Sledge “B” Lease and its decline curve. This time we’ll calculate a present value (PV).

Sledge "B"
Discounted Cash Flow Valuation

Discount Factor	Decline Rate	PV		Discount Factor	Decline Rate	PV10	LIFE Years
99%	3%	$196,821		10%	35%	$174,523	2.3
45%	3%	$408,540		10%	17%	$380,149	5.2
30%	3%	$581,331		10%	11%	$562,289	8.3
25%	3%	$676,039		10%	8%	$723,889	11.7
20%	3%	$806,496		10%	6%	$886,133	15.8
15%	3%	$996,177		10%	4%	$1,126,488	24.0
10%	3%	$1,292,037		10%	3%	$1,292,037	32.0

See notes following

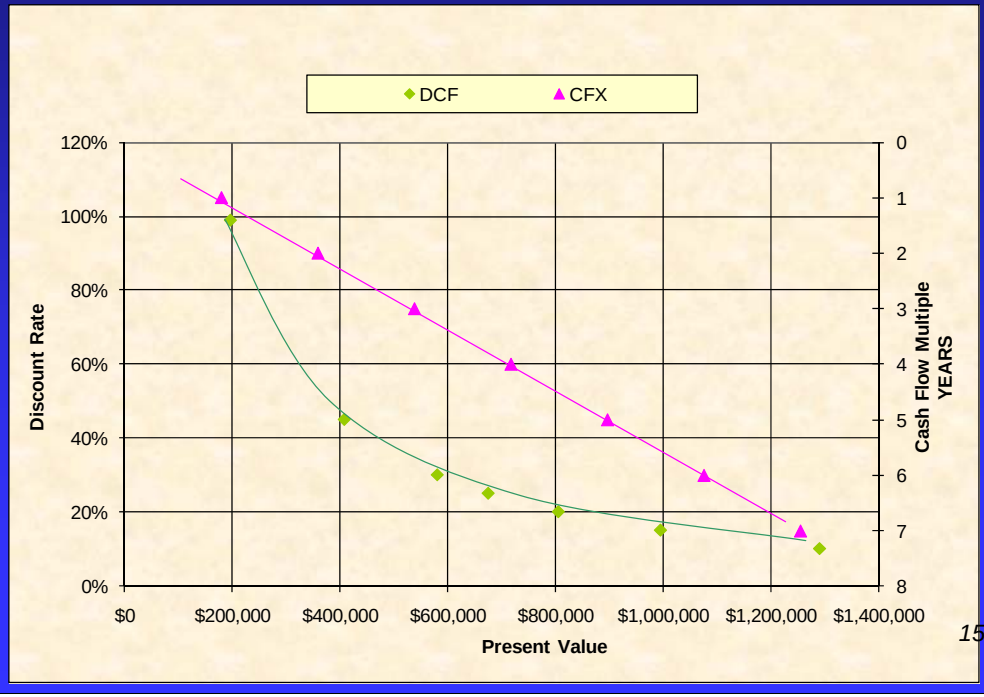
Presenter's Notes:
The discounted cash flow (DCF) method determines PV for various Discount Factors. In this example, decline, product price, and lease operating expenses are constant.

ON THE LEFT SIDE:
Hold decline rate constant and model Present Value for different Discount Rates and get various Present Values. The distribution of the PV values versus the accompanying discount rate is called a Present Value Profile (PVP)

ON THE RIGHT SIDE
Hold PV Constant and vary decline rate. This is a sensitivity analysis that shows variation of PV10 for different decline rates.

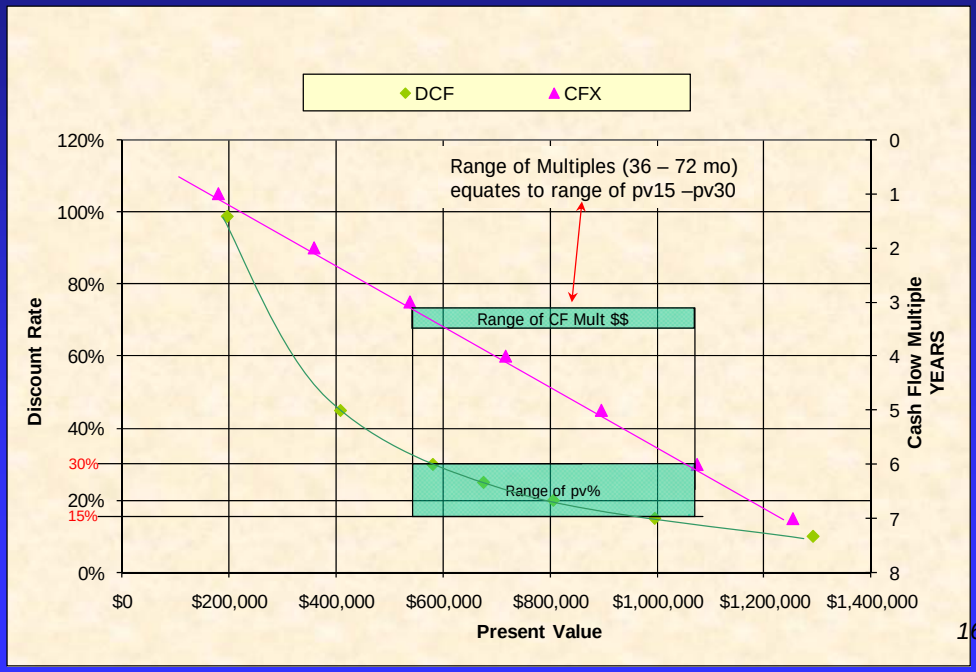
ON THE FAR RIGHT SIDE
You also see the future life of the property until it reaches its economic limit. Note how far into the future this analysis is extended! Usually the DCF model is automatically truncated after a certain amount of years.

Sledge “B” Present Value
CFX vs. DCF

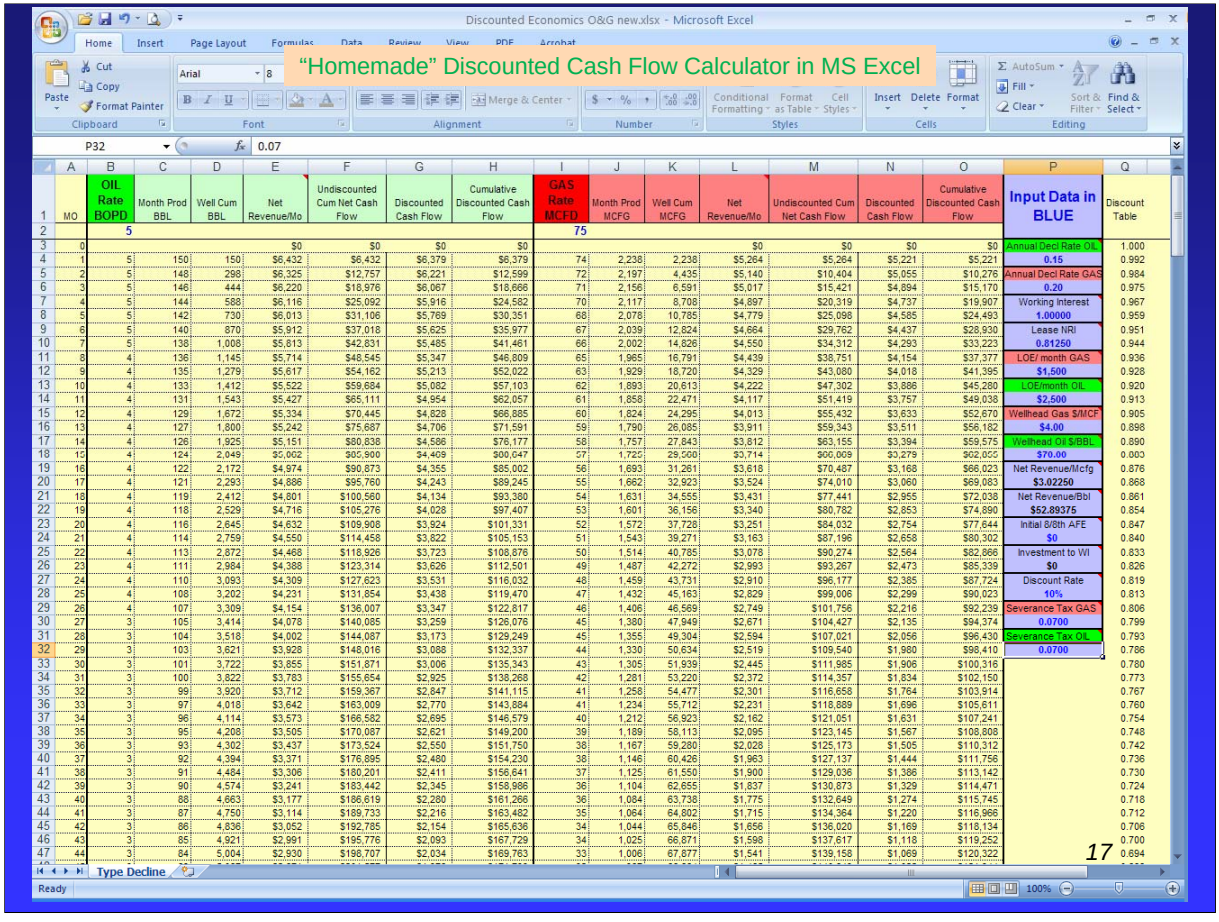


Presenter’s Notes: This graph shows the Present Value Profile from the DCF analysis and a “pseudo-present value profile” from the informal cash flow multiple method. You can see that the cash flow multiple is linear. Similarly the DCF present value profile is non-linear because it is based on a non-linear production decline curve and the exponential parameter in the present value equation (the inverse of compounding interest).

Sledge "B" Present Value
CFX vs. DCF



Presenter's Notes: Compare PRESENT VALUE by CFX and DCF. BROADLY SPEAKING, this analysis shows that a CF multiple valuation of 36 to 72 months equates to a PV of between 15% to 30%. Stated differently, it shows that if you could purchase a property for one of the multiples, then you could yield a return on your investment between 15% and 30%. This would hold IF your future production, expenses, and price are as you forecast!

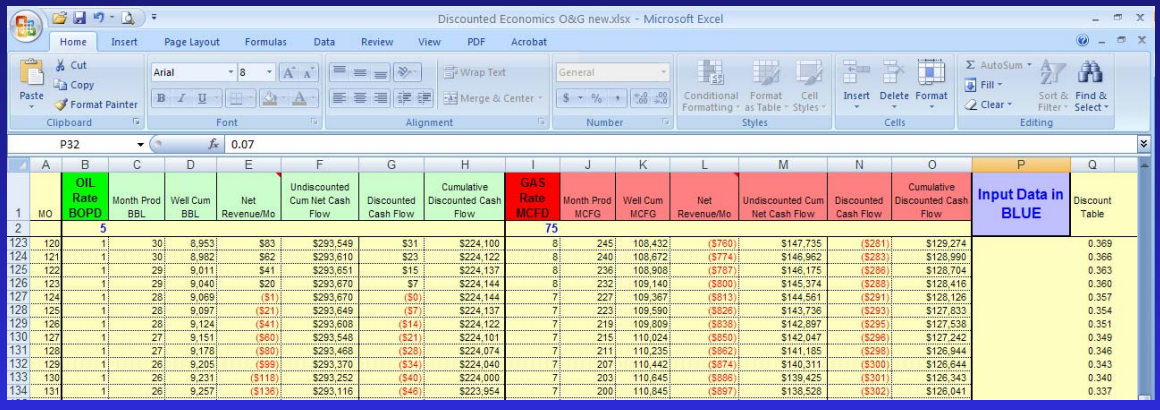


	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	MO	OIL Rate BOPD	Month Prod BBL	Well Cum BBL	Net Revenue/Mo	Undiscounted Cum Net Cash Flow	Discounted Cash Flow	Cumulative Discounted Cash Flow	GAS Rate MCFD	Month Prod MCFG	Well Cum MCFG	Net Revenue/Mo	Undiscounted Cum Net Cash Flow	Discounted Cash Flow	Cumulative Discounted Cash Flow	Input Data in BLUE	Discount Table
2		5							75								
3	0				$0	$0	$0	$0				$0	$0	$0	$0	Annual Decl Rate OIL	1.000
4	1	5	150	150	$6,432	$6,432	$6,379	$6,379	74	2,238	2,238	$5,264	$5,264	$5,221	$5,221	0.15	0.992
5	2	5	148	298	$6,325	$12,757	$6,221	$12,599	72	2,197	4,435	$5,140	$10,404	$5,055	$10,276	Annual Decl Rate GAS	0.984
6	3	5	146	444	$6,220	$18,976	$6,067	$18,666	71	2,156	6,591	$5,017	$15,421	$4,894	$15,170	0.20	0.975
7	4	5	144	588	$6,116	$25,092	$5,916	$24,582	70	2,117	8,708	$4,897	$20,319	$4,737	$19,907	Working Interest	0.967
8	5	5	142	730	$6,013	$31,106	$5,769	$30,351	68	2,078	10,785	$4,779	$25,098	$4,585	$24,493	1.00000	0.959
9	6	5	140	870	$5,912	$37,018	$5,625	$35,977	67	2,039	12,824	$4,664	$29,762	$4,437	$28,930	Lease NRI	0.951
10	7	5	138	1,008	$5,813	$42,831	$5,485	$41,461	66	2,002	14,826	$4,550	$34,312	$4,293	$33,223	0.81250	0.944
11	8	4	136	1,145	$5,714	$48,545	$5,347	$46,809	65	1,965	16,791	$4,439	$38,751	$4,154	$37,377	LOE/ month GAS	0.936
12	9	4	135	1,279	$5,617	$54,162	$5,213	$52,022	63	1,929	18,720	$4,329	$43,080	$4,018	$41,395	$1,500	0.928
13	10	4	133	1,412	$5,522	$59,684	$5,082	$57,103	62	1,893	20,613	$4,222	$47,302	$3,886	$45,280	LOE/month OIL	0.920
14	11	4	131	1,543	$5,427	$65,111	$4,954	$62,057	61	1,858	22,471	$4,117	$51,419	$3,757	$49,038	$2,500	0.913
15	12	4	129	1,672	$5,334	$70,445	$4,828	$66,885	60	1,824	24,295	$4,013	$55,432	$3,633	$52,670	Wellhead Gas $/MCF	0.905
16	13	4	127	1,800	$5,242	$75,687	$4,706	$71,591	59	1,790	26,085	$3,911	$59,343	$3,511	$56,182	$4.00	0.898
17	14	4	126	1,925	$5,151	$80,838	$4,586	$76,177	58	1,757	27,843	$3,812	$63,155	$3,394	$59,575	Wellhead Oil $/BBL	0.890
18	15	4	124	2,049	$5,062	$85,900	$4,469	$80,647	57	1,725	29,568	$3,714	$66,869	$3,279	$62,855	$70.00	0.883
19	16	4	122	2,172	$4,974	$90,873	$4,355	$85,002	56	1,693	31,261	$3,618	$70,487	$3,168	$66,023	Net Revenue/Mcfg	0.876
20	17	4	121	2,293	$4,886	$95,760	$4,243	$89,245	55	1,662	32,923	$3,524	$74,010	$3,060	$69,083	$3.02250	0.868
21	18	4	119	2,412	$4,801	$100,560	$4,134	$93,380	54	1,631	34,555	$3,431	$77,441	$2,955	$72,038	Net Revenue/Bbl	0.861
22	19	4	118	2,529	$4,716	$105,276	$4,028	$97,407	53	1,601	36,156	$3,340	$80,782	$2,853	$74,890	$52.89375	0.854
23	20	4	116	2,645	$4,632	$109,908	$3,924	$101,331	52	1,572	37,728	$3,251	$84,032	$2,754	$77,644	Initial 8/8th AFE	0.847
24	21	4	114	2,759	$4,550	$114,458	$3,822	$105,153	51	1,543	39,271	$3,163	$87,196	$2,658	$80,302	$0	0.840
25	22	4	113	2,872	$4,468	$118,926	$3,723	$108,876	50	1,514	40,785	$3,078	$90,274	$2,564	$82,866	Investment to WI	0.833
26	23	4	111	2,984	$4,388	$123,314	$3,626	$112,501	49	1,487	42,272	$2,993	$93,267	$2,473	$85,339	$0	0.826
27	24	4	110	3,093	$4,309	$127,623	$3,531	$116,032	48	1,459	43,731	$2,910	$96,177	$2,385	$87,724	Discount Rate	0.819
28	25	4	108	3,202	$4,231	$131,854	$3,438	$119,470	47	1,432	45,163	$2,829	$99,006	$2,299	$90,023	10%	0.813
29	26	4	107	3,309	$4,154	$136,007	$3,347	$122,817	46	1,406	46,569	$2,749	$101,756	$2,216	$92,239	Severance Tax GAS	0.806
30	27	3	105	3,414	$4,078	$140,085	$3,259	$126,076	45	1,380	47,949	$2,671	$104,427	$2,135	$94,374	0.0700	0.799
31	28	3	104	3,518	$4,002	$144,087	$3,173	$129,249	45	1,355	49,304	$2,594	$107,021	$2,056	$96,430	Severance Tax OIL	0.793
32	29	3	103	3,621	$3,928	$148,016	$3,088	$132,337	44	1,330	50,634	$2,519	$109,540	$1,980	$98,410	0.0700	0.786
33	30	3	101	3,722	$3,855	$151,871	$3,006	$135,343	43	1,305	51,939	$2,445	$111,985	$1,906	$100,316		0.780
34	31	3	100	3,822	$3,783	$155,654	$2,925	$138,268	42	1,281	53,220	$2,372	$114,357	$1,834	$102,150		0.773
35	32	3	99	3,920	$3,712	$159,367	$2,847	$141,115	41	1,258	54,477	$2,301	$116,658	$1,764	$103,914		0.767
36	33	3	97	4,018	$3,642	$163,009	$2,770	$143,884	41	1,234	55,712	$2,231	$118,889	$1,696	$105,611		0.760
37	34	3	96	4,114	$3,573	$166,582	$2,695	$146,579	40	1,212	56,923	$2,162	$121,051	$1,631	$107,241		0.754
38	35	3	95	4,208	$3,505	$170,087	$2,621	$149,200	39	1,189	58,113	$2,095	$123,145	$1,567	$108,808		0.748
39	36	3	93	4,302	$3,437	$173,524	$2,550	$151,750	38	1,167	59,280	$2,028	$125,173	$1,505	$110,312		0.742
40	37	3	92	4,394	$3,371	$176,895	$2,480	$154,230	38	1,146	60,426	$1,963	$127,137	$1,444	$111,756		0.736
41	38	3	91	4,484	$3,306	$180,201	$2,411	$156,641	37	1,125	61,550	$1,900	$129,036	$1,386	$113,142		0.730
42	39	3	90	4,574	$3,241	$183,442	$2,345	$158,986	36	1,104	62,655	$1,837	$130,873	$1,329	$114,471		0.724
43	40	3	88	4,663	$3,177	$186,619	$2,280	$161,266	36	1,084	63,738	$1,775	$132,649	$1,274	$115,745		0.718
44	41	3	87	4,750	$3,114	$189,733	$2,216	$163,482	35	1,064	64,802	$1,715	$134,364	$1,220	$116,966		0.712
45	42	3	86	4,836	$3,052	$192,785	$2,154	$165,636	34	1,044	65,846	$1,656	$136,020	$1,169	$118,134		0.706
46	43	3	85	4,921	$2,991	$195,776	$2,093	$167,729	34	1,025	66,871	$1,598	$137,617	$1,118	$119,252		0.700
47	44	3	84	5,004	$2,930	$198,707	$2,034	$169,763	33	1,006	67,877	$1,541	$139,158	$1,069	$120,322		0.694

See notes following

Presenter's Notes:
Homemade Cash Flow spreadsheet, with discounted present value. The formulas for exponential decline and discounting a cash flow stream are not difficult to find or understand. The author built this spreadsheet in Microsoft Excel. Input parameters are shown in blue. It will calculate present value of both an oil and a gas production forecast. It only handles Exponential Decline. (Hyperbolic decline could be modeled as segments of different exponential decline.) LOE is fixed, as is Price. You can input different severance tax rates and PV discount factors. It is relatively unsophisticated, but comparing results to IHS PowerTools ©, for example, shows excellent order-of-magnitude agreement.
This example is for a stripper oil or gas well starting at either 5 BOPD or 25 MCFD. Each row is one month. The fourth column from the left for either oil or gas shows the net income for the month. The right-hand most column under oil and gas shows the cumulative discounted Present Value. When the net income per month becomes negative, then you have reached the economic limit. At that point, you can read the value of the cumulative Present Value and there is your answer for PV. The next slide shows this for the oil side of the spreadsheet.

"Homemade" Discounted Cash Flow Calculator in MS Excel



	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	MO	OIL Rate BOPD	Month Prod BBL	Well Cum BBL	Net Revenue/Mo	Undiscounted Cum Net Cash Flow	Discounted Cash Flow	Cumulative Discounted Cash Flow	GAS Rate MCFD	Month Prod MCFG	Well Cum MCFG	Net Revenue/Mo	Undiscounted Cum Net Cash Flow	Discounted Cash Flow	Cumulative Discounted Cash Flow	Input Data in BLUE	Discount Table
2		5							75								
123	120	1	30	8,953	$83	$293,549	$31	$224,100	8	245	108,432	($760)	$147,735	($281)	$129,274		0.369
124	121	1	30	8,982	$62	$293,610	$23	$224,122	8	240	108,672	($774)	$146,962	($283)	$128,990		0.366
125	122	1	29	9,011	$41	$293,651	$15	$224,137	8	236	108,908	($787)	$146,175	($286)	$128,704		0.363
126	123	1	29	9,040	$20	$293,670	$7	$224,144	8	232	109,140	($800)	$145,374	($288)	$128,416		0.360
127	124	1	28	9,069	($1)	$293,670	($0)	$224,144	7	227	109,367	($813)	$144,561	($291)	$128,126		0.357
128	125	1	28	9,097	($21)	$293,649	($7)	$224,137	7	223	109,590	($826)	$143,736	($293)	$127,833		0.354
129	126	1	28	9,124	($41)	$293,608	($14)	$224,122	7	219	109,809	($838)	$142,897	($295)	$127,538		0.351
130	127	1	27	9,151	($60)	$293,548	($21)	$224,101	7	215	110,024	($850)	$142,047	($296)	$127,242		0.349
131	128	1	27	9,178	($80)	$293,468	($28)	$224,074	7	211	110,235	($862)	$141,185	($298)	$126,944		0.346
132	129	1	26	9,205	($99)	$293,370	($34)	$224,040	7	207	110,442	($874)	$140,311	($300)	$126,644		0.343
133	130	1	26	9,231	($118)	$293,252	($40)	$224,000	7	203	110,645	($886)	$139,425	($301)	$126,343		0.340
134	131	1	26	9,257	($136)	$293,116	($46)	$223,954	7	200	110,845	($897)	$138,528	($302)	$126,041		0.337

Note the oil Net Revenue per month has gone negative in month 124 or about 10.4 years into the forecast. The accompanying cumulative discounted cash flow at this point is about $224,000 which would be the PV10 value since we used a 10% discount factor.

Presenter's Notes: This shows how the oil production went negative in month 124 (10.4 years). The actual oil production at this point was less than 1 BOPD, but it was still rounded to 1 BOPD; we might choose to truncate the cash flow earlier. However, it shows that the PV10. for 5 BOPD at 15% decline and the price and LOE forecast would be about $224M. Note that the gas cash flow has already gone negative at this time. The cash flow for a 25 MCFD gas well declining at 20% suggests a PV10 of about $136M at 16 Mcfd.

Discounted Cash Flow
vs.
Cash Flow Multiple

So which method is better?

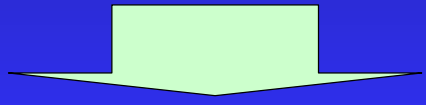
- Bank Debt? or Your money?
- One well? or 350 wells?
- High value? or Low value?
- Stable production? Early life production?

It's a question of "Appropriate Analysis":
Use the analytical technique most suited to the requirements of the evaluation at hand.

Presenter's Notes: WHICH ONE SHOULD I USE? This is a question of appropriate analysis. For almost any sort of financing, you will need to calculate a formal discounted cash flow PV. For quick order of magnitude estimates, the cash flow multiple is very helpful. If you are using your own money, you may be entirely satisfied with a cash flow multiple analysis. The CFX is a very useful method for quick evaluations if all pertinent data are known, and the property is in a stable mode of decline.

Steps to Evaluate a Producing Oil & Gas Property for Acquisition

Calculate Value of current production
Calculate Value of non-producing opportunities



$$ Bid or Make Offer $$

Presenter's Notes:

STEP 1 - VALUE THE EXISTING PRODUCTION – the Reservoir Engineering Group

STEP 2 - DEFINE AND VALUE THE "NON-PRODUCING OPPORTUNITIES - THE CLASSIC "UPSIDE"

NOTE: "NON-PRODUCING OPPORTUNITIES" the A&D word for "PROSPECTS"!

This is where the Geologist can really add value, BECAUSE…it is usually the buyer's UPSIDE evaluation of a property that creates the competitive edge when bidding. **However, h*ow do you translate a geological prospect or exploration idea into a NUMBER?***

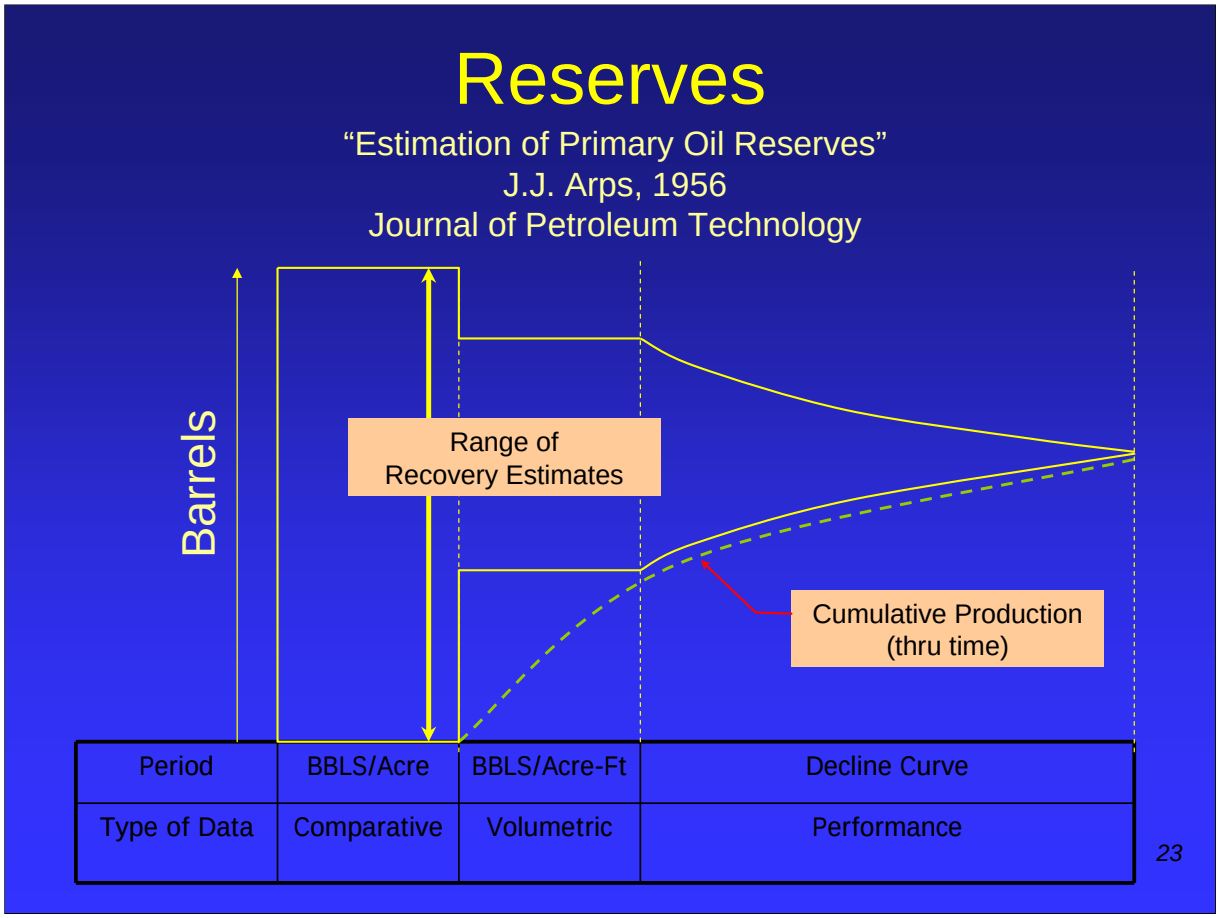
Value of Non-producing Opportunities (i.e., Prospects)

Reserves Entities & Reserves Categories

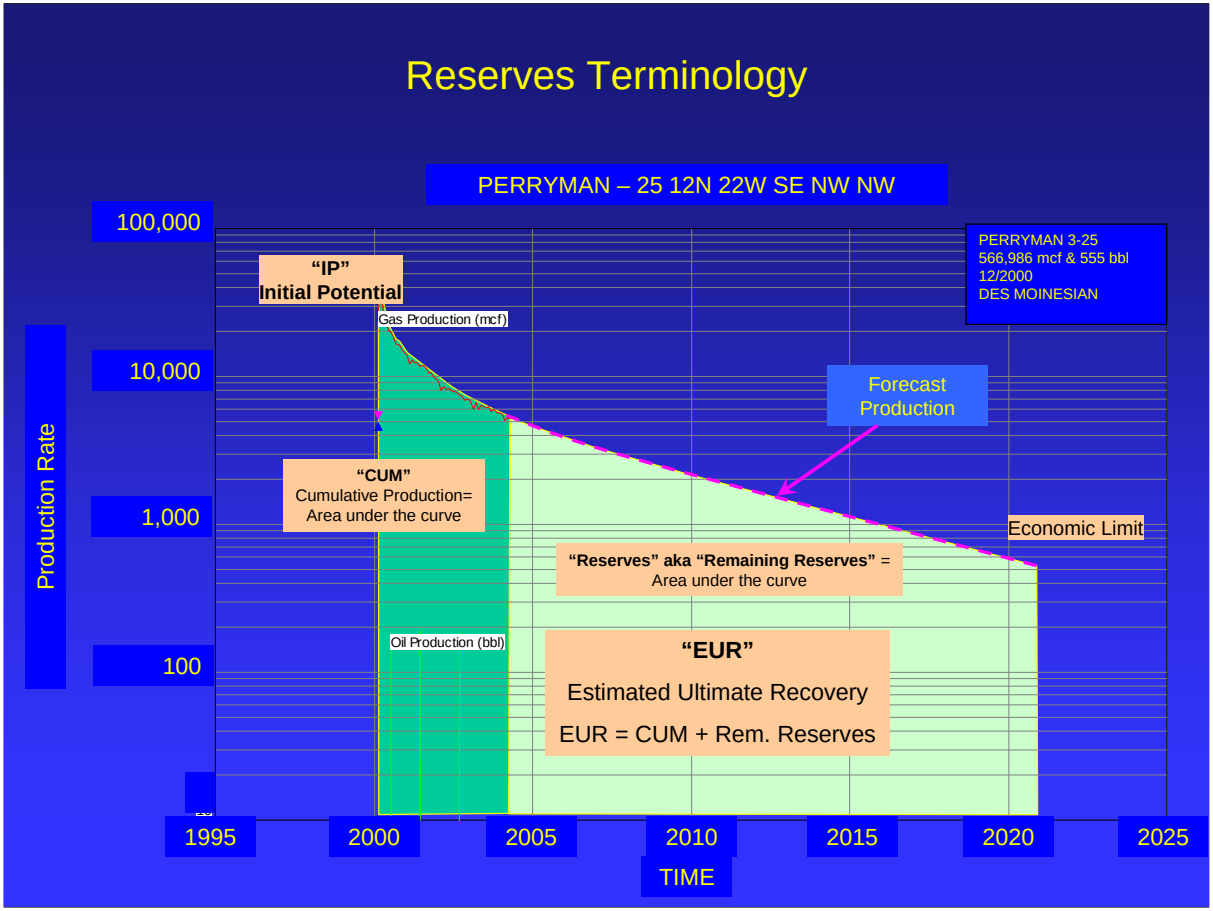
Presenter's Notes: Think of things this way: When you define a prospect or **Non-Producing Opportunity,** consider it a "**Reserves Entity"** to which you have to assign a dollar value. By assigning your Reserves Entity to a **Reserves Categories,** you can account for, and keep track of, them and attach a value. Reserves categories carry implied risk and uncertainty attributes.

"Reserves may be defined as the amount of oil or gas remaining to be produced (recovered) under current economic and operating conditions"

Presenter's Notes: A BRIEF REMINDER OF "RESERVES; This is a classic definition of "Reserves" for producing oil and gas properties, but it doesn't cover the non-producing potential of the property, and it is really unsuitable for prospect ideas – the non-producing upside!



Presenter's Notes: This diagram has been quoted time and time again, for it is an excellent graphic representation of the range of reserves estimates for producing properties and prospects at different stages. Recall the value of a property is the current value of the reserves (the PV). The most appropriate method of estimating reserves will change through time and with the nature of the production. Note that in the pre-drill time there may be a broad range of estimates of how much oil or gas will be recovered, but as wells are drilled and reservoir data becomes known, and as production performance is plotted (decline curve), the range becomes narrower. Finally the point at which all parties agree is when production has ceased and the well is plugged. At least this is true until new drilling and production technology comes along!!



Presenter's Notes: RESERVES TERMINOLGY:

Initial Production Rate "IP": usually expressed in BBLS/Day or MCF/Day. With certain exceptions, this is the highest rate at which a well will ever produce.

Cumulative production: This is the "area under the curve". How much oil or gas has been produced at any given date.

Forecast Production = the incremental production yet to occur = "Reserves". "Remaining Reserves" is equal to "Reserves."

Economics is based on the total amount of oil or gas a well can produce. Prior to drilling or completing a zone, this is simply called a well's "Reserves" or "Reserves Potential". The sum of Cumulative Production and Remaining Reserves = "Estimated Ultimate Recovery" or "EUR".

Reserves

Proved: there is reasonable certainty (P90) of recovery under current economic conditions and technology.

Unproved: geologic & engineering data delineate reserves at less than p90; economic and technological conditions are insufficient to categorize as “proved”.

Probable or Possible

Developed or Producing

Undeveloped or Non-producing

The concepts above are combined and sorted into Reserves Categories…

Presenter’s Notes: Proved – P90, and Unproved, less than P90, where P90 is denotes a statistical confidence in the number, OR “Certainty”.

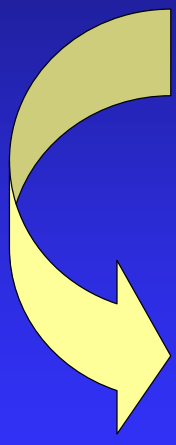
Proved reserves may be categorized as either Producing or Non-Producing.

Developed and Undeveloped. Simply stated, “Developed” means a well has been drilled and exists. “Undeveloped” means one will have to drill a well.

For more clarity of message, we combine these definitions into certain RESERVES CATEGORIES.

Reserves Categories

Proved
Unproved
Probable
Possible
Developed or Producing
Undeveloped or Non-producing



Common Reserves Categories

Proved Developed Producing - **PDP**
Proved Developed Non-Producing – **PDNP**
Proved Undeveloped – **PUD**
Probable – **PROB**
Possible - **POSS**

Presenter's Notes: TRANSFORM RESERVES DEFINITIONS INTO "CATEGORIES"

The terms here are the most common categories used in property evaluation. They are very useful for developing the present value of an acquisition because each contains an implied element of risk and uncertainty.

DEVELOPED MEANS THERE IS A WELL.

UNDEVELOPED MEANS A WELL MUST BE DRILLED

The **PDP** category is usually addressed by the Reservoir Engineers, aided by Geology if geologic data is critical to the determination of Ultimate Reserves.

The "**Behind Pipe**" category (**PDNP),** is often delineated by Engineers, but Geologists should always screen data for by-passed pay zones.

The geologist's **Prospects are Reserves Entities** that can be sorted into the Undeveloped Categories based on risk and uncertainty.

PUD, PROB, POSS--EACH IMPLIES A GREATER DEGREE OF RISK AND UNCERTAINTY.

PDP: the Value of Current Production starts with Calculating Reserves for Current Production

Methods of Reserves Calculation
- Volumetric
- Material Balance – BHP/Z (gas)
- Decline Curve (performance)

Types of Decline Curves
- Exponential
- Hyperbolic
- Harmonic

Exponential Decline Curves
- Decline Rate is Constant
- Rate-Time is linear on semi-log plot

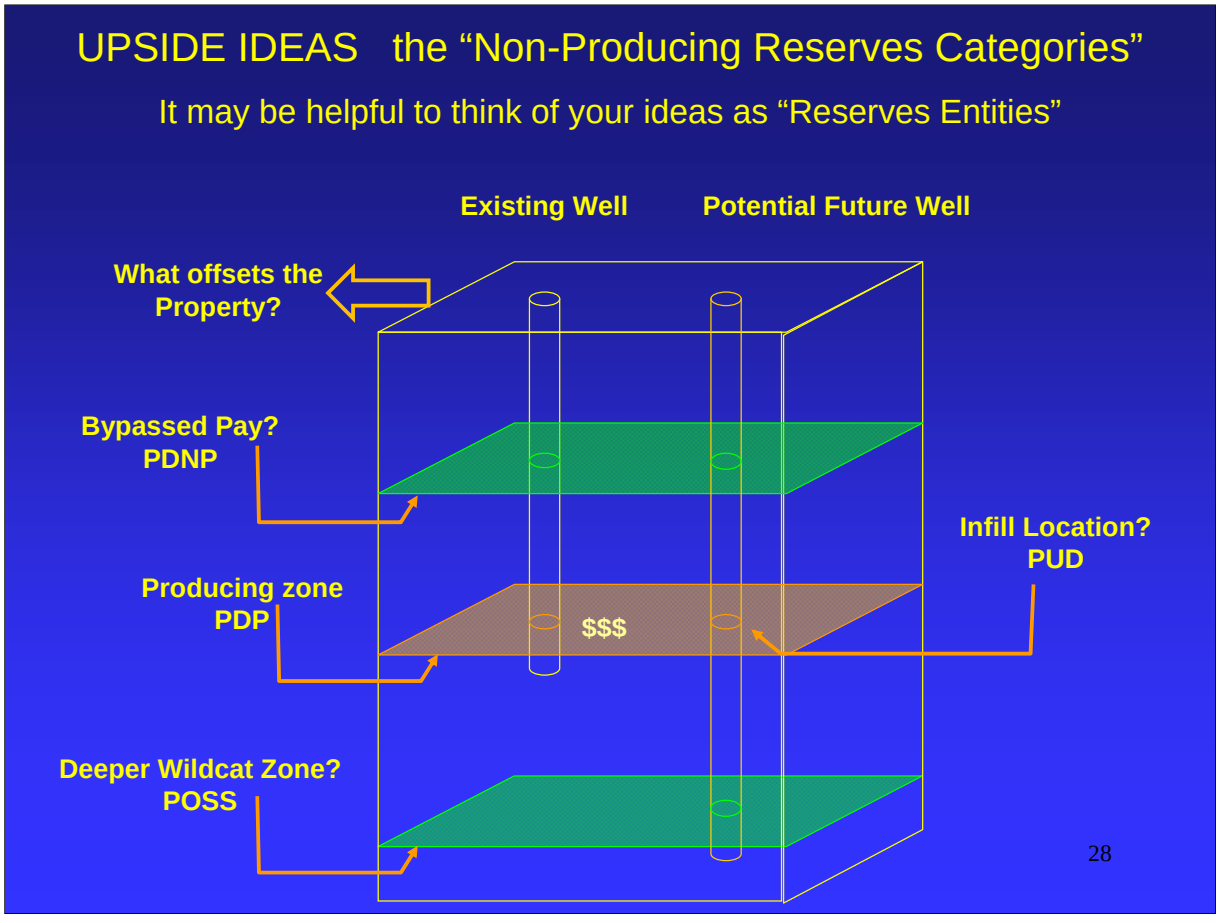
Presenter's Notes:

Calculate Reserves

Methods of Calculation

Focus on Decline

Focus on Exponential Decline



Presenter's Notes: EXAMPLE OF WHAT YOU MIGHT DELINEATE. When charged with exploiting a producing oil and gas property, the geologist must think of the entire "earth cube". What is deeper? What is shallower and possibly bypassed? Are the reservoir characteristics of porosity and permeability suitable for increased density (infill) drilling? Does the depositional model for the reservoir lend itself to a high or low degree of heterogeneity, and with the former, limiting one well's capability to effectively drain a given area? In this example I point to:

1 – interesting zone behind pipe that may be productive

2 – potential infill location to drill for the current producing zone.

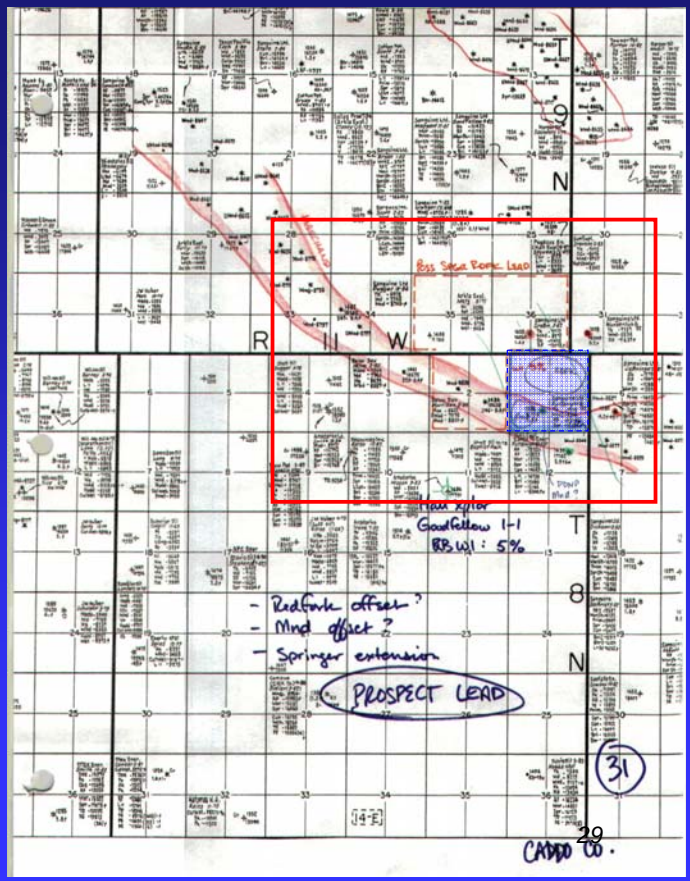
3 – possiblility of finding the same uphole zone in your infill location?

Each Idea becomes a Reserves Entity that may be assigned a Reserves Category, valued and risk-weighted.

Case Study: "Herndon's" Map Idea Prospecting Sec 1-T8N-R11W Caddo Co., OK

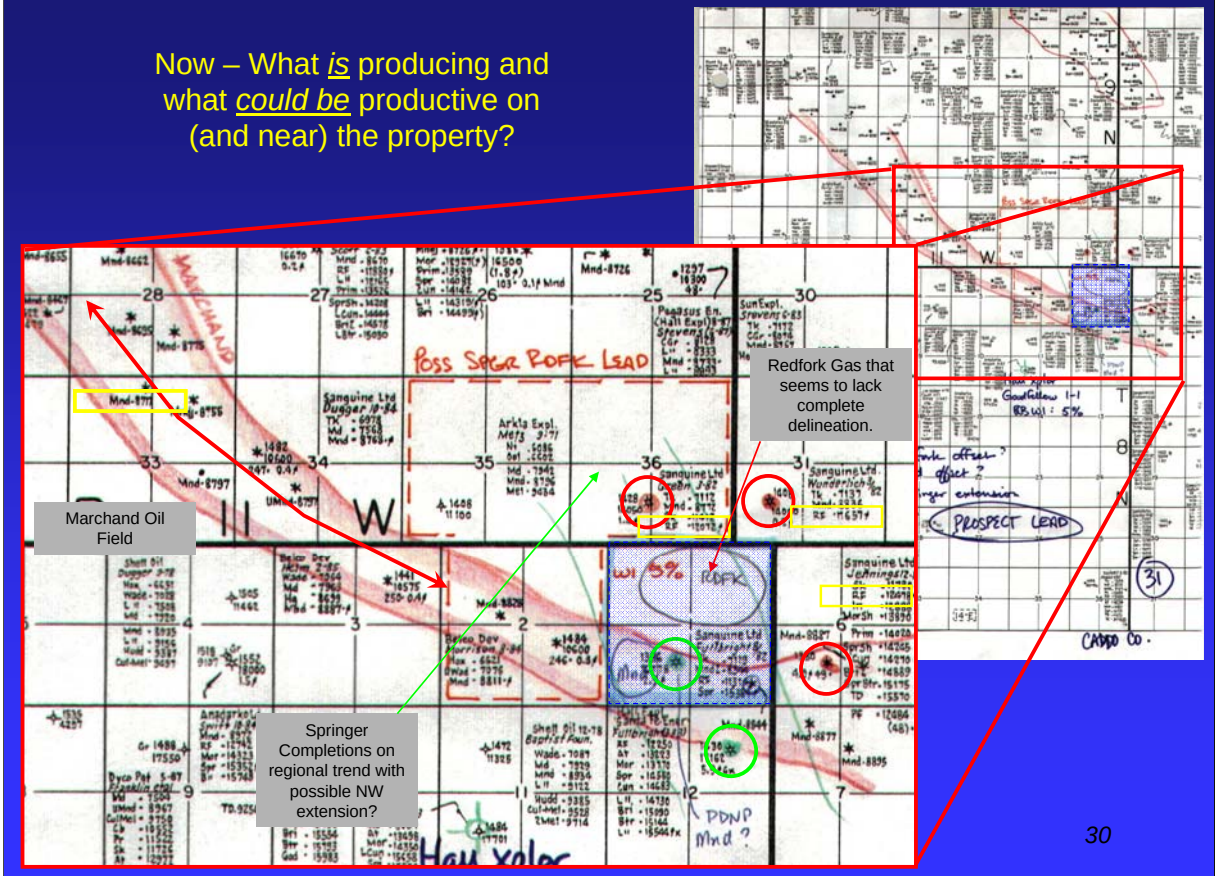
Interpret the Commercial Data – "Herndon's Maps"
(or your in-house data in GeoGraphix or Petra)

- ❖Post the property on your map
- ❖Review the producing zones
- ❖Place this info in the stratigraphic framework
- ❖Are the producing fields fully delineated?
- ❖Are there any intersecting production trends that could generate untested wellbore zones?



Presenter's Notes: Here is an actual example from an evaluation of the upside potential for a property in a large acquisition package. This technique utilized the commercial Oklahoma "Herndon's Maps" which show all wells drilled, the producing zone and depths, and commonly oil and/or gas shows from other formations. The property of interest is a 640 acre lease highlighted in blue. The exploitation geologist who is familiar with the area's stratigraphic section and producing reservoirs in the region can highlight the map (as shown) regarding the known production and, then in the mind's eye, visualize other possibilities based on the data shown.

Now – What *is* producing and what *could be* productive on (and near) the property?

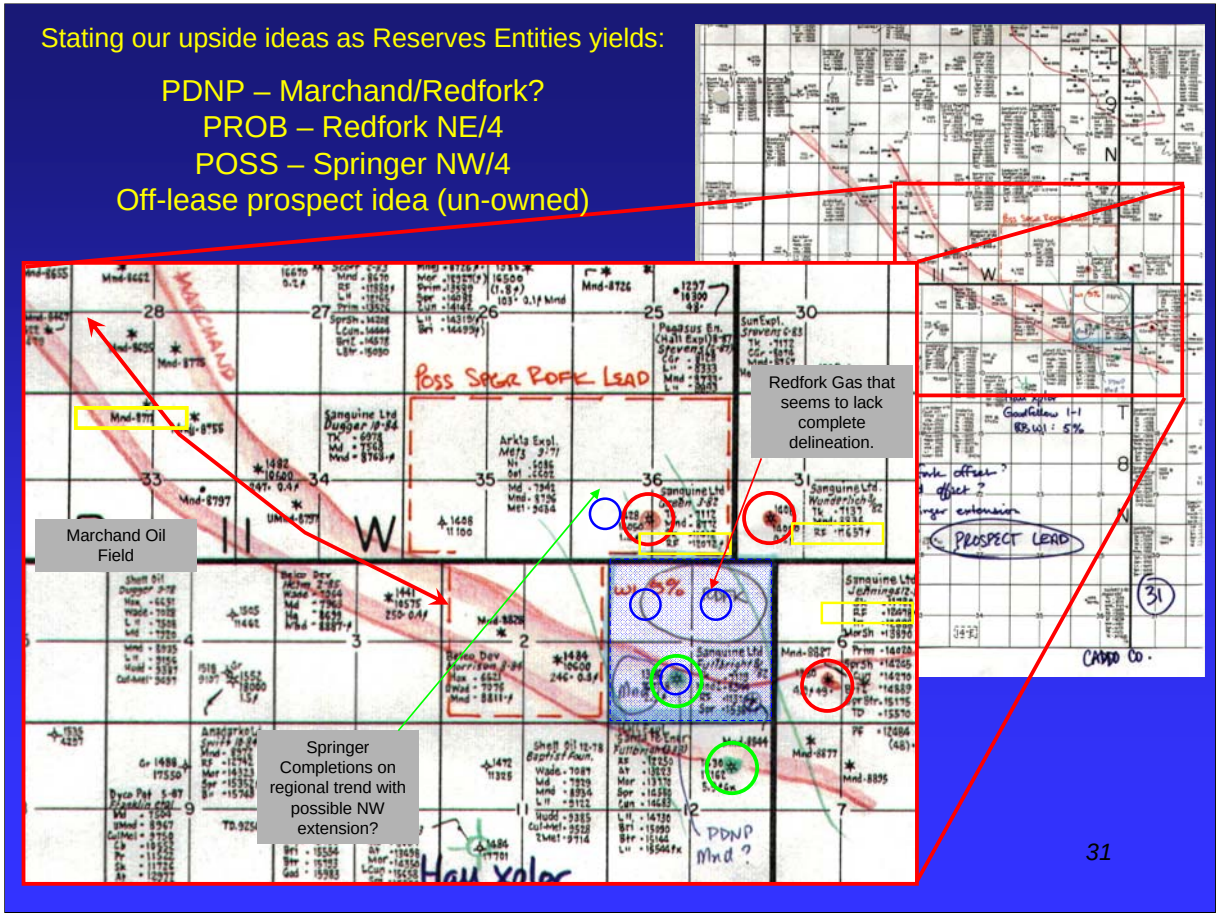


See notes following

Presenter's Notes:

The exploitation geologist has highlighted the completions and their distribution. First, examination shows a Marchand oil field (red outline) that trends across the southern portion of the section. There is a Marchand completion in the SE/4 of the section. Note that the development of the Marchand appears to be one well per 160 acres. That trend, which includes the Springer well in the SW/4, strongly suggests there could be Marchand sand in the Springer wellbore behind pipe. Second, there are three Redfork completions offsetting the section, and the limits of that development are not defined by dry holes. The geometry of the completions relative to known Redfork depositional environments suggests there may be a potential location for Redfork in the NE/4 of the section. Lastly, there is one well completed in the Springer in the SW/4 and in the 160-acre offset in the NE/4 of the section to the south. However, there are no wells deep enough to have penetrated the Springer to the north and west, and a typical basinal trend is the interpretation for Springer sands in this part of the basin. This suggests there is a potential Springer location in the NW/4 of the objective section, and perhaps the acreage to the NW is prospective for Springer or Redfork or both.

This analysis was done without even reviewing a log or preparing a map. Of course, one would not have a very high degree of confidence in each estimated non-producing upside entity (reserve entity) as herein defined, but the upside ideas have been identified pending further investigation.



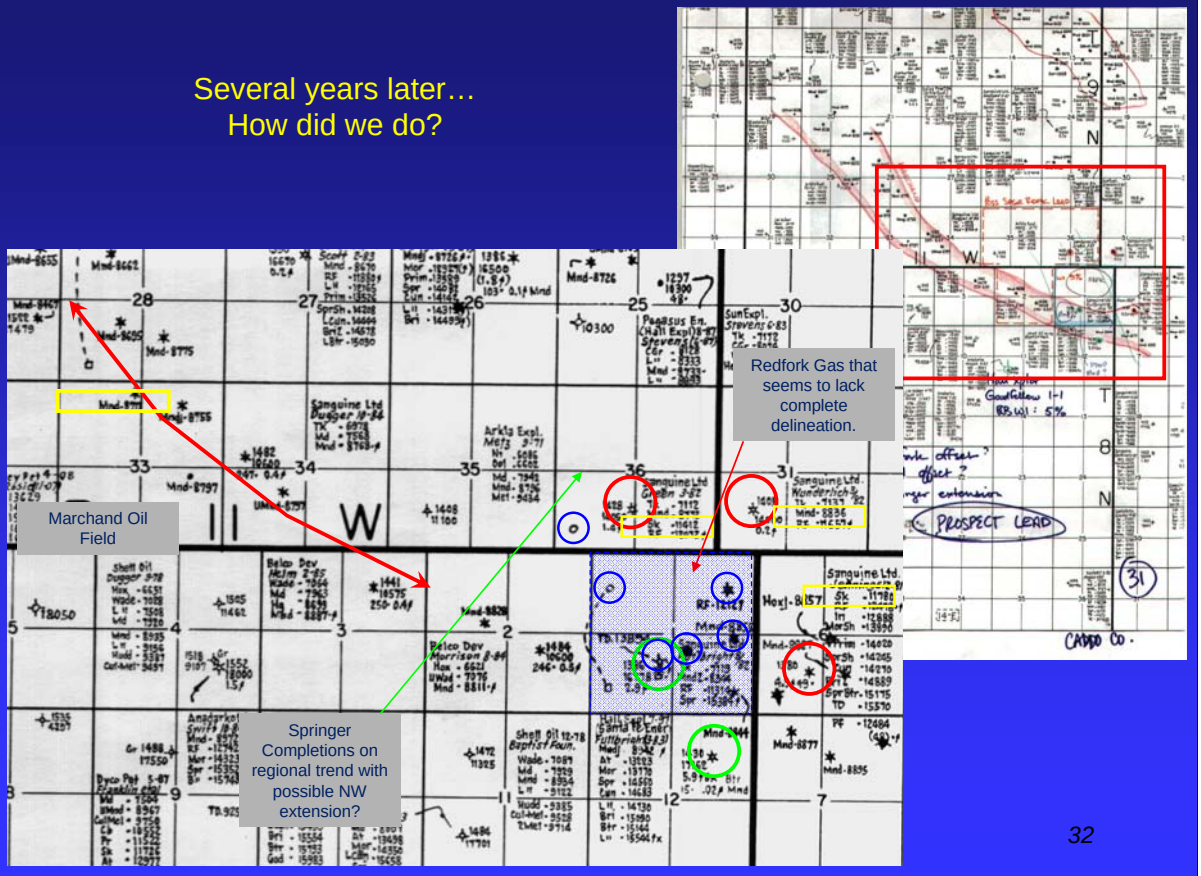
Presenter's Notes: By thinking of the prospect ideas given in the previous slide in terms of Reserves Entities, the different ideas may be accounted for as follows:

PDNP – possible Marchand behind pipe in the Springer well in the SW/4 – maybe even a Redfork sand behind pipe?

PROB – possible drilling location for Redfork (NE/4)
POSS – possible drilling location for Springer (NW/4)

Finally, we have also identified a possible off-lease prospect on the lands to the north and west.

Several years later…
How did we do?



See notes following

Presenter's Notes:

This is the Herndon's Map today. Note that indeed there was additional non-producing upside on this 640-acre lease, and it was not too different than the upside defined by simply applying geological expertise and earth-cube evaluation to the property.

1 - Two new Marchand oil wells have been completed in the SE/4.

2 – Unsuccessful twin to the Springer well in the SW/4 was drilled to the Redfork, but a new Redfork well was completed in the NE/4.

3 – A new well is being drilled in the NW/4 – possibly for Redfork and Springer (no TD available at this time).

4 – A new well has been staked in off-lease in the area deemed as "prospective" in the original evaluation.

In this case, one can see that the initial evaluation made only with this map, experience, and knowledge of the stratigraphy and depositional environments was are a reasonable one. The "PROB" reserve entity of the Redfork well in the NE/4 turned out to be exactly correct. The Marchand may still be behind pipe in the Springer completion; however, two new Marchand completions drilled in the SE/4 would have offset the value originally ascribed to the Marchand PDNP and possibly exceeded it. The Springer potential of a well in the NW/4 and possibly in the off-lease to the north and west is now being tested. In terms of potential non-producing upside value of the original property, the original reserves entity assessment would have been of the correct order of magnitude.

Value a Non-Producing Reserve Entity

DCF is the formal method:

- Model future production and Ultimate Reserves.
- Forecast price and expenses.
- Estimate the capital required to drill.
- Estimate when you will do this (timing of capital expense).
- Calculate a DCF PV based on your start date and forecasts.

Presenter's Notes: YOUR UPSIDE IDEA MUST BECOME A VALUED "RESERVE ENTITY."

In order to provide a "number" consistent with the delineation of non-producing upside reserve entities, one must apply a number. Using the formal methodology, one could model a future discounted cash flow of each reserve entity. You would need to estimate the values shown on this slide, and then calculate a PV value from your cash flow. One direct benefit of this methodology is it forces one to think critically about each entity and its PV, a useful process.

Value of Non-Producing Reserve Entity

Is there an informal method?

Yes.

Quantify your technical opinion into an

ORDER OF MAGNITUDE Estimate

and then risk it to reflect your confidence level

See notes following

Presenter's Notes:

WHAT IF YOU DON'T HAVE THE TIME OR RESOURCES TO CALCULATE A DISCOUNTED CASH FLOW ANALYSIS OF EVERY POSSIBLE UPSIDE IDEA? Very often, the time frame of the evaluation of non-producing upside of a property package is so compressed that formal calculation of DCF and PV for each idea is impractical or impossible. Plus, when the forecast cash flow will not begin for years in the future, then the estimates of price, capital, operating expenses and reserves may change significantly, and due to future changes in these estimates, today's PV could be much different than a PV a few years from now.

HOW CAN I STILL CONVERT MY GEOLOGICAL OPINION TO A NUMBER? As noted earlier, order of magnitude is a powerful tool. In the evaluation of producing oil and gas properties and the estimation of the value of non-producing upside, it is extremely helpful to know if the "upside" value is $1MM or $10MM or even $100MM. What is important is that you not pay $12MM for $3MM of upside for the lowest value, for example. I suggest the technique, described next, as one means of quantifying the potential value of the non-producing upside, as delineated by the evaluators.

Risked Order of Magnitude Estimate

1 - Judge the reserve potential of your idea based on your experience. Convert to BOE (e.g., 6mcf/bbl).

2 - Record the property's NRI. Estimate the net BOE's.

3 - Apply a fractional probability of success or confidence level (Ps). In other words – "risk" your number appropriately.

4 - Apply a purchase price per BOE to the risked BOE potential.

E.G.: BOE x NRI x Ps = Risked Net BOE

See notes following

Presenter's Notes:

FIND IT AND SIZE IT. In nearly every package of oil and gas producing properties for sale, the first information one seeks out is the leasehold footprint and the working and net revenue interests for sale. In the prior example, one such acreage footprint and the WI and NRI were posted to the Herndon's Map and used to delineate upside potential. I suggest the following thought process for the geologist and the evaluation team. Once the idea is delineated, apply an order of magnitude estimate of its reserve potential. If there is existing production in the delineated formations, such as Marchand, Redfork, and Springer, then a quick look at available production data will define this. In the example I used herein, we might have arrived at 40MBO for the Marchand Oil, maybe 1BCFG and 5MBO condensate for the Redfork and maybe 2.5 BCFG for the Springer idea. By the way, I have not checked the production data for these numbers, I am relying on my own experience with the region. Once you have defined the reserve potential, convert mcf into barrels of oil equivalent (BOE) or barrels of oil into mcf equivalent (MCFE). The "equivalent" term means that we have converted possible reserves of oil or gas into the other so that we may use one cash metric for a package. On a BTU basis a common equivalency is 6mcf/bbl. The other equivalency is based on price. In recent years, the price of oil versus gas has become de-coupled from the BTU basis. For example as of Fall 2010, with NYMEX oil at $80/bbl and gas at $4/mcf, the price equivalency is 20mcf/bbl. The industry has shifted between quoting deals on an MBOE and MCFE basis; in this discussion I have used BOE at a 6mcf/bbl equivalency.

MULTIPLY BY THE NET REVENUE – THIS IS HOW MUCH OF IT YOU WILL OWN: The amount of the estimated reserves that you will own is equal to your net revenue interest in the property. Therefore you multiply your estimate by the NRI.

RISK IT BY YOU CONFIDENCE ESTIMATE. In the method described here, I used Ps not as a formal estimate of Geologic Success, but used as a confidence/knowledge factor in the metrics of the particular reserve entity. For example, in the Marchand PDNP, one might assign a 50% (0.5) factor, due to the field trend extending on both sides of the acreage. The Redfork would have higher geologic risk and you might assign a 25% (0.25) Ps to it. Finally, knowing the risks of Springer sands and the fact that a geologic study was not complete, one might assign it a 10% (0.1) Ps. Were you able to actually "pull" some logs and map an idea, the Ps values might be higher. When you have applied these steps, you will have a "Risked Net BOE."

APPLY SOME NUMBER YOU MIGHT PAY PER BOE FOR NON-PRODUCING UPSIDE. It is important to note, that in the above valuation, no capital has been included for the expense of recompletion or drilling. Obviously this must be included in a non-producing PV estimate because we shall not recover those reserves for free! If we calculated a formal DCF and PV, we would include this. For the analysis and estimating purposes delineated here, I suggest another method. In the A&D segment of our industry, most companies utilize simple metrics to compare different packages of properties and, once again, compare them on an order of magnitude. Typical metrics would include what one might pay for a producing barrel of oil equivalent (BOE) or a producing mcf of gas equivalent (MCFE). The same numbers are applied to non-producing reserves of oil or gas. This latter metric is often cited as what a company might pay for reserves "in the ground." Obviously, the price paid for non-producing BOE's versus producing BOE's would be less because one must spend capital to recover the non-producing BOE's. Thus, a metric for price per non-producing barrel of oil has included a factor for future capital expense.

Value of Non-Producing Reserve Entities

Risked Order of Magnitude Estimates

R17

	A	B	F	G	H	I	J	N	O	P	Q	R
1	RSRV CTGY	LSE NAME	RSVR	OIL BBL	GAS MMCF	BOE	Ps	NET BOE	RISKED NET BOE	WI	NRI	PROJECT DESCRIPTION
2	PDNP	BILL	RDFK	5,000	500	88,333	0.20	27,626	5,525	38.8%	31.3%	CHECK LOG FOR RDFK PDNP
3	PDNP	GEORGE	MRRW		750	125,000	0.15	86,705	13,006	83.6%	69.4%	CHECK LOG FOR MRRW PDNP
4	PDNP	SWEETIE	SKNR	15,000	400	81,667	0.50	37,483	18,742	54.9%	45.9%	PROBABLE SKNR PDNP
5	PROB	ASHBY	SKNR	25,000	800	158,333	0.50	78,857	39,429	62.5%	49.8%	PROBABLE SKNR DENSITY LOCATION
6	PROB	MEANDER	SKNR	25,000	800	158,333	0.50	62,945	31,473	47.5%	39.8%	PROBABLE SKNR DENSITY LOCATION
7	PROB	CASHVILLE	MRRW		1,000	166,667	0.50	132,267	66,133	100.0%	79.4%	POSS DENSITY LOCATION. 480 AC UNDRILLED. SOME OFFSETS ON 160 AC
8	POSS	CHAMPION	MRRW		2,500	416,667	0.15	181,500	27,225	55.2%	43.6%	POSS MORROW LOC E/2
9	POSS	NOODLE	RDFK	10,000	1,500	260,000	0.35	90,017	31,506	43.2%	34.6%	PROBABLE RDFK DENSITY LOCATION
10	POSS	HARRY UT	ATOK-SPGR	20,000	3,000	520,000	0.10	119,792	11,979	28.6%	23.0%	POSSIBLE RDFK DENSITY AND ATOKA STEPOUT
11	POSS	JONES	ATOK-SPGR	10,000	3,500	593,333	0.15	434,551	65,183	90.1%	73.2%	POSSIBLE ATOK-SPGR STEPOUT
12	POSS	REMINGTON	SPGR		1,500	250,000	0.25	34,280	8,570	15.5%	13.7%	POSSIBLE SPRINGER PUD IN SE/4
13	POSS	SMITH	RDFK	15,000	1,000	181,667	0.20	56,816	11,363	38.8%	31.3%	POSS RDFK DENSITY LOCATION
14		**TOTALS:**		**125,000**	**17,250**	**3,000,000**		**1,342,841**	**330,134**			
15												

330,134 net BOE x $10/BOE = 3.3MM$

If you are willing to pay $10/net BOE for upside net reserves potential, then this estimate suggests your assessment of the upside value is on the order of 3.3MM$.

See notes following

Presenter's Notes:

This spreadsheet shows a portion of an actual evaluation performed on a relatively large (>100 properties) property set. The green columns show data that was given at the start. Some original data columns are hidden, such as legal location in order to fit this on a slide. The yellow columns show data and calculations resulting from the geological delineation and evaluation of upside reserves entities. The list is shown in a conventional order from PDNP to PUD, to PROB, to POSS reserve entities. There are no PUD's listed in this example.

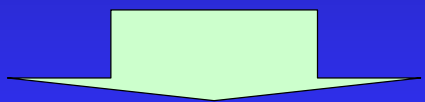
In this methodology, "Ps" is a broad statement of one's confidence level in the reserves entity and the amount of oil or gas attributed to it. Although this technique may be problematic to some reservoir engineers, I have found it to be a very effective way to quantify my geological opinion for describing the "upside" of a property set and its potential value. Based on my personal experience, and with no disrespect intended, some exploration geologists tend to be optimistic in their assessments of prospect size and overall success, and care needs to be taken in the application of the confidence factor. In fact if a multi-disciplinary team is defining the upside reserve entities, usually a better conclusion may be reached.

This example yields an estimated Risked Net BOE upside of about 330,000 barrels of oil equivalent. Using the methodology shown in this presentation, the geological evaluation has now been converted into an order of magnitude NUMBER. It is seriously useful to know that the upside is not 30MBOE or 3000MBOE, but it is 330MBOE. Because we still want to know "What would I pay for the upside potential?", we can, for example, apply a corporate metric of price paid for reserves in the ground. In this instance, I have shown $10/MBOE would be offered for the upside potential. Simple math shows that the amount to bid on the upside or non-producing reserve entities is around $3.3MM.

A cautionary statement: Because this is essentially a probabilistic methodology, it should not be applied to very small property sets. However, it remains a very effective tool to "size" the upside potential. Finally, one very good benefit about this methodology is that, if you end-up purchasing the property set, you then have a prospect inventory with various means of ranking the ideas. The spreadsheet contains gross unrisked BOE's, net BOEs, NRI, and a confidence estimate, all of which could be sorted to assist prioritization of potential recompletions or drilling locations. Having been responsible for incorporating relatively large acquisitions and "getting-up to speed" on new properties, this becomes a very valuable tool.

Steps to Evaluate a Producing Oil & Gas Property for Acquisition

Calculate Value of current production
Calculate Value of non-producing opportunities



$$ Bid or Make Offer $$

See notes following

Presenter's Notes:

Summary. The evaluation of oil and gas properties most simply is composed of two parts. First – evaluate the current production. Second, evaluate the non-producing potential. The geologist is primarily involved in the delineation and evaluation of the non-producing potential. This is usually called the "upside potential." In order to do this efficiently and effectively, the geologist should be familiar with the financial evaluation of oil and gas properties. The formal method is discounted cash flow (DCF) to yield a present value quoted at a certain discount rate (PV10). The plot of PV versus discount rate yields a present value profile (PVP). The informal method is to utilize a cash flow multiple (CFX), which is a fast and effective means of calculating a present value. Plotting the number of multiple years (or months) versus the resulting values gives a pseudo-present value profile that is shown to equate to certain DCF PV's.

It is also important that the evaluating geologist has a working knowledge of different reserves terminology. Reserves terminology yields reserves categories that are applied to oil and gas production and prospects. These are PDP, PDNP, PUD, PROB, and POSS with risk and uncertainty increasing, respectively. The exploitation geologist must think of a producing property in terms of the "earth cube" or in three dimensions when seeking non-producing ideas. Most geologists would call these "prospects". Once an idea is conceived, it is very useful to think of it not as a prospect necessarily, but, as a one of the listed reserves entities. A spreadsheet of each reserves entity may be created in which estimates of reserves and confidence are applied to the net revenue interest for sale. The resulting summary can define an order of magnitude of risked net BOE of upside potential. A corporate metric of purchase price per non-producing BOE may be applied; this may convert risked net BOE potential into a potential cash bid offer. In today's acquisitions and divestiture market, it is almost always the buyer's upside evaluation that creates the competitive edge when bidding. Happy hunting!

and they said there would be no math.....

Thanks for your attention!