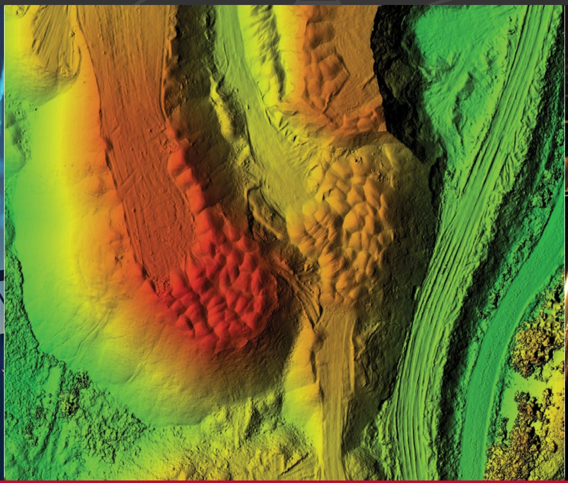
HAAS & COBB
PETROLEUM CONSULTANTS

THE CONFIDENT BID RECIPE

HAAS & COBB PETROLEUM CONSULTANT'S TECHNICAL GUIDE
FOR OIL & GAS ACQUISITIONS

JULY 2024



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A TRUSTED PARTNER

Haas & Cobb's reports are relied upon throughout the oil and gas space by a diverse clientele. Our confident bid recipe can help you to make the right choice when it comes to selecting and purchasing oil and gas assets.

Use this guide to ***proceed with confidence***.

STOP OVERPAYING FOR ASSETS

The table is set for an active Acquisition and Divestiture season in the Oil and Gas industry. Unfortunately, many buyers, including sophisticated evaluators, will often overpay for these assets because they overlook some key value drivers in their engineering analysis.

Stakes are getting higher in the oil patch these days. Companies need to make returns, not just grow reserves Capital sources have dried up due to a combination of the ESG movement and a decade long track record of overpromising and underdelivering returns.

"In this next round of acquisitions, companies MUST get the right valuation, or many could end up out of business."

Thad Toups
President of Haas & Cobb Petroleum Consultants

PROBLEM	PROBLEM	PROBLEM
Evaluators tend to use optimistic decline curves because they aren't considering changes in producing conditions.	Seller's revenue and expense models misrepresent long term cash flows.	Base Case evaluations will likely not be high enough to win the assets.
SOLUTION	**SOLUTION**	**SOLUTION**
Our Confident Bid Recipe shares some simple diagnostics to identify flow regimes, adds insight to the appropriate B Factor selection, and presents forecasting best practices.	Our Confident Bid Recipe sheds light on some of the seller's tricks used to inflate value and provides a recommendation to estimate expense and revenue inputs.	Our Confident Bid Recipe delivers an approach for arriving at your final bid, grounded in sound engineering.

Thankfully, Haas & Cobb Petroleum Consultants has formulated a simple 3-part recipe to arrive at a confident bid that's grounded in sound engineering. In this guide, we will walk through the biggest drivers in value and present a workflow for arriving at your final bids.

INGREDIENT #1:

ACCURATE PRODUCING WELL FORECASTS

The first ingredient in the recipe for a confident bid is accurate well forecasting; however, many evaluators will tend to be overly optimistic, caused by three common mistakes:

1. **Ignoring flow regimes**
2. **Fitting the entire production history**
3. **Not characterizing new wells**

Let's take a deeper dive.

Forecasting Mistake #1: Ignoring Flow Regimes Resulting in Incorrect B Factors

What is a flow regime, and why does it matter?

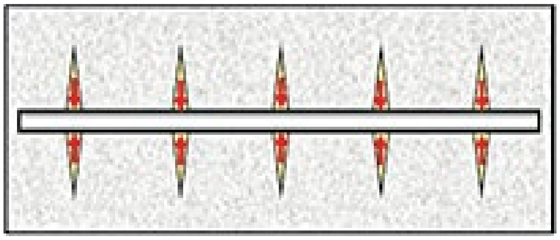
When a well first begins to produce, the fractures (natural and hydraulically induced are drained. This flow regime is called Linear or "Infinite Acting" because the well feels no boundaries. At this point in the well's life it thinks it can drain the universe.

The End of Linear Flow occurs when the well feels its first boundary. In conventional wells and older vintage completions, this first sign of a boundary may be associated with a fault block or an offset well's depletion. In horizontal multistage completions, the End of Linear Flow typically occurs when the individual stages begin to compete for fluid molecules.

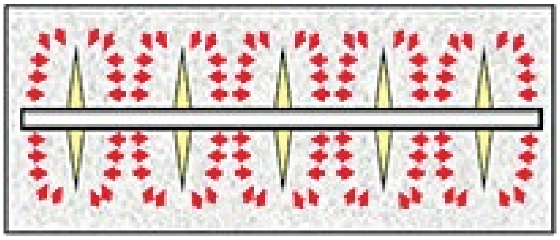
Once all the boundaries are fully realized, the well is in Boundary Dominated Flow Regime.

The Arps B Factor will change over the well's life as it matures, so identifying these flow regimes is critical to accurate forecasting.

Linear Flow



Transition, or end of Linear Flow



Boundary Dominated Flow (BDF)

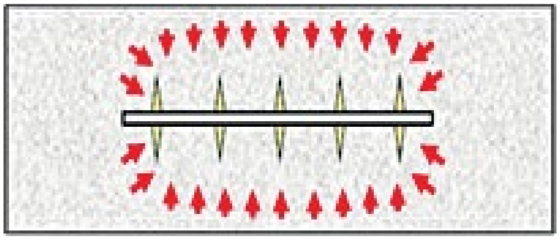


Figure 1: Illustration of Flow Regimes, SPE #188071-MS

FLOW REGIMES CAN BE OBSERVED BY CREATING SOME SIMPLE DIAGNOSTIC PLOTS

The dashboard shown in Figure 2 can be created using data visualization tools like Spotfire, Tableau, and Power BI. The initial Linear Flow regime in this sample well has been identified in blue to illustrate how short this period can be (observed to be 3–12 months for most modern horizontal shale wells).

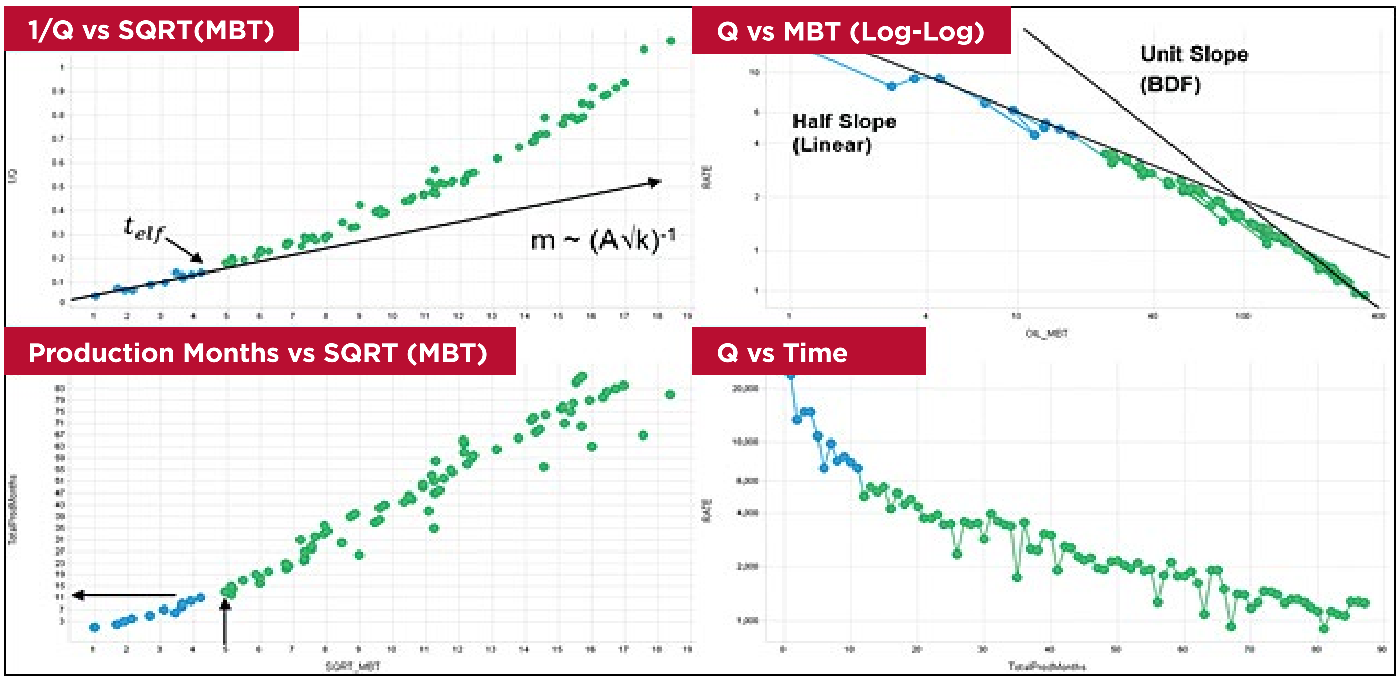


Figure 2: Example Flow Regime Diagnostic Plots, Haas & Cobb Petroleum Consultants.

Utilizing the diagnostics in Figure 2, Time to End of Linear Flow (t_{elf}) can be detected by:

- Deviation from straight line behavior on Cartesian (1/Q) vs. Sqrt(MBT) where MBT ≈ Np/Q
- Deviation from -1/2 slope on log-log Q vs. MBT

These diagnostics also work for daily data. Accuracy will improve when normalizing rates by bottom hole pressures. Sometimes it may be necessary to clean up your data to remove erroneous production months.

Ideally, the Arps inputs (Decline Curve Parameters) used to predict well behavior should be derived on a well by well basis to match producing conditions. As presented in the Society of Petroleum Evaluation Engineers (SPEE) Monograph IV, appropriate B Factors for a given flow regime generally trend as outlined in Table 1.

Current Flow Regime	Recommended B Factor
Linear	>1**
Transition	0.5 - 1.0
BDF	0.3 - 0.5

Table 1: Flow Regime B Factor Recommendations

** Linear Flow period will vary based on completion, spacing, and other factors. See section on "Characterizing New Wells" for more discussion on selecting a B Factor for early time wells in still in Linear Flow.

Forecasting Mistake #2: Fitting the Entire Production History

It is easy to overestimate remaining reserves and inflate value with a projection that is a "great fit." You'll see a lot of this in the data room:

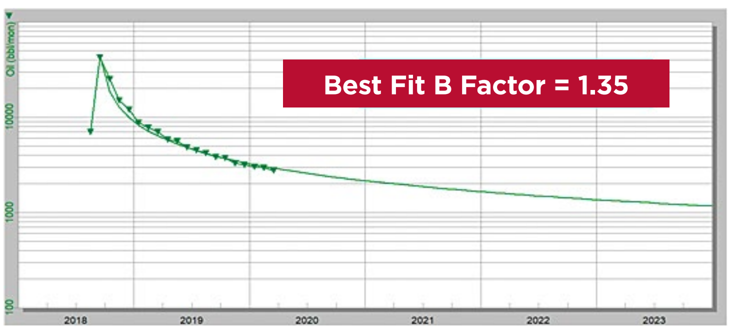


Figure 3: Example Optimistic Forecast

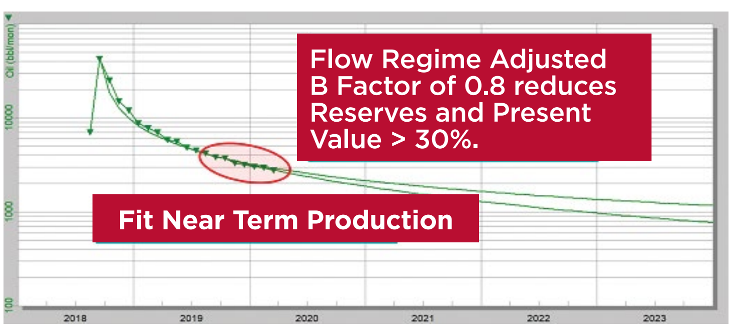


Figure 4: Fitting Near Term Production, a Better Approach

While this projection fits the historic production data in a very reasonable manner, this well has been overvalued by at least 30%! **Fitting an Arps projection through the full history, or relying too heavily on early time production, will almost ALWAYS OVERESTIMATE volumes and value.** The main issue is the well will continue to feel more and more of its boundaries, and the B-Factor will trend downwards as the well approaches its terminal decline.

In addition to honoring the well's current flow regime, another reason to avoid fitting the full production history relates to well events that take place and change the current operating conditions. Common occurrences that will influence the production trends include a well reaching bubble point, implementation of artificial lift, choke adjustments, changes in tubing sizes, etc. These changes can alter the decline profile of the well, and fitting the whole trend may persuade the evaluator to incorrectly shallow the decline. **The evaluator should do their best to identify these events and fit the projection to the most recent period.**

Forecasting Mistake #3: Not Characterizing New Wells

New wells without material production trends, sometimes referred to as "unseasoned", lend themselves to wide ranges of interpretations.

Often, decline curve analysis is not reliable until the well has reached a constant bottom hole pressure. These early time wells can be especially tricky if the evaluator does not have daily production rates or pressure data. See example unseasoned PDP well in Figure 5.

These wells are often some of the most valuable wells in the asset you are evaluating, so being wrong can be very costly.

Take the following example in Figure 5 below:

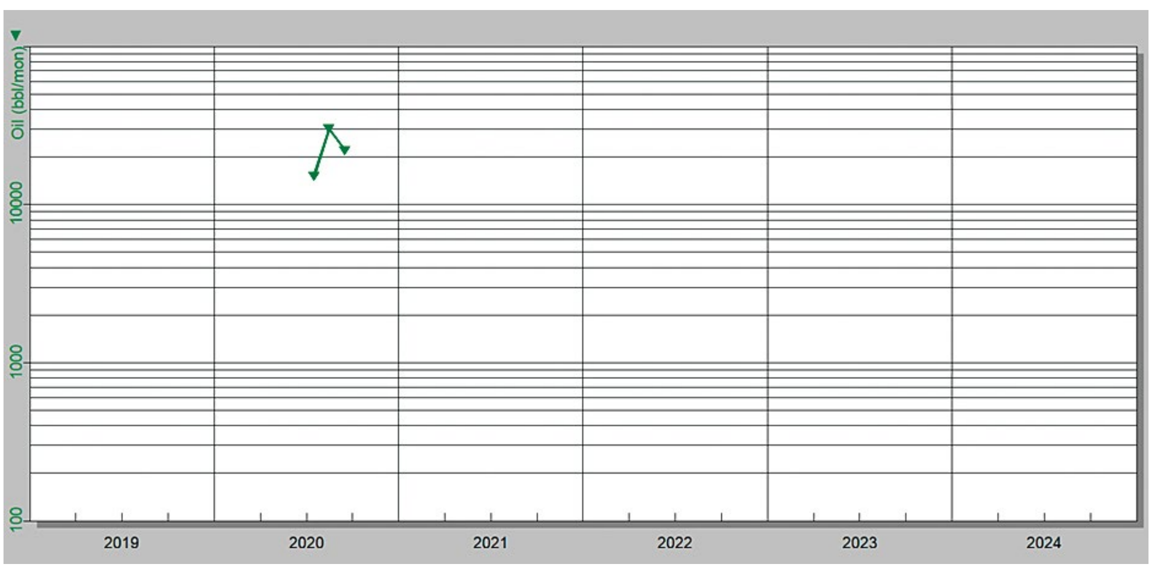


Figure 5: Example Unseasoned PDP Well

"In God we trust, all others must bring data."

W. Edwards Deming

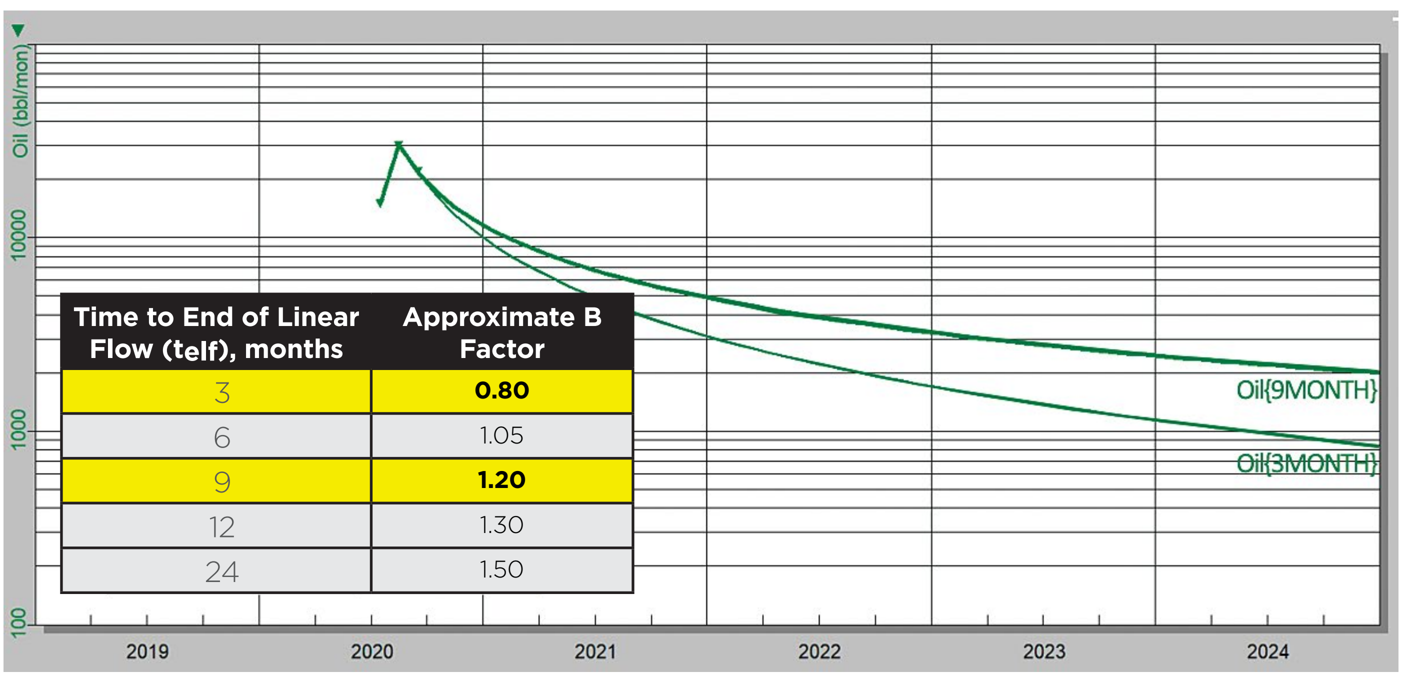
How does one approach forecasting new wells with limited production history?

These wells are often still in the Linear Flow regime and can be projected with a large range of EURs. A novice evaluator may be inclined to apply a regional type well projection adjusted to the IP of the immature producer. Warning: if the type well profile has been created as the average well in the area, this decline curve may not be representative of the well in question. Our recommendation is to characterize the immature producing well.

Understanding the attributes highlighted above helps the evaluator find analog wells to estimate how the unseasoned producing well will behave. Figure 6 demonstrates the impact of the Linear Flow period on B Factor and Reserves on early time estimates. In this example, the difference between a 3-month and 9-month Linear Flow period can result in an EUR difference of > 40%.

KEY ATTRIBUTES TO CONSIDER:

- Completion Design
- Stage Spacing
- Horizontal Lateral Spacing
- Well Type: Parent/Child/ Co-Completed
- Offset Well Cumulative Production



Time to End of Linear Flow (telf), months	Approximate B Factor
3	**0.80**
6	1.05
9	**1.20**
12	1.30
24	1.50

Figure 6: Example New Well Forecast

INGREDIENT #2:

ACCURATE ACCOUNTING INPUTS

The next ingredient in the recipe for a confident bid is expenses and revenue models.

Brokers and sellers can overstate value by using "creative" accounting inputs that tie reasonably well with the Lease Operating Statements (LOS).

Let's look at some common "Tricks" sellers will use in their accounting models to mask the true value of the assets.

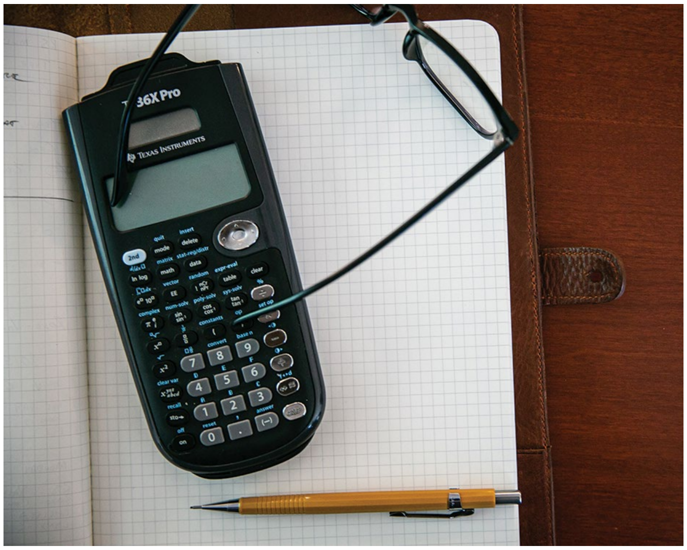
According to a recent @Thoupster X poll, accounting input discrepancies are the largest component of value disconnect in about 30% of the deals evaluated.

Operating Expenses

The monthly lease operating expense (LOE) of a well is a double-edged sword in that it impacts near term cash flow as well as controls the economic life of the property. Therefore, it is important to accurately estimate current expenses and understand how these costs may change over a well's life.

Some common practices that sellers use to inflate value by misrepresenting expenses include:

1. **Using field averages**
2. **Using highly variable expenses**
3. **Excluding "non-recurring" expenses from the models**



"Creativity is great, but not in accounting."
Charles Scott

Seller Trick #1: Using Field Level Operating Expense Models Resulting in Overvaluing Newer Wells

In a typical data room, the seller will provide a company level LOS in a spreadsheet format. The seller may even be polite enough to show you how the fixed expense models in the matching database have been calculated. Table 2 shows an example field level LOS with average $/well fixed costs:

	MONTH 7	MONTH 8	MONTH 9	MONTH 10	MONTH 11	MONTH 12	6 Mo Avg	12 Mo Avg
FIXED LOE								
Total Fixed Costs ($/Month)	756,372	764,631	799,224	1,156,617	934,842	945,050	892,789	865,339
Well Count	65	65	65	65	65	65	65	65
$/Well/Month	11.636	11,764	12,296	17,794	14,382	14,539	13,735	13,313

Table 2: Sample Fixed Expense Calculation from Seller

Rather than using an average expense computed from field or company total LOS, Haas & Cobb Petroleum Consultants recommends calculating the 6 and 12 month average expense on a well level, as operating expenses can vary substantially from well to well.

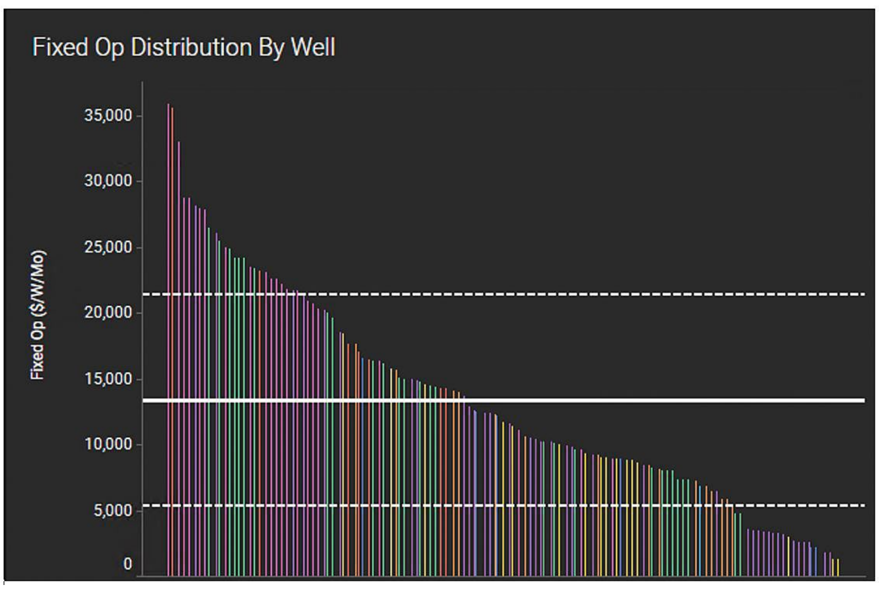


Figure 7: Sample Distribution of Fixed LOE by Well

Figure 7 illustrates the same $13,313 field average LOE as a distribution of wells. The individual well's expenses range from less than $5,000/month to over $30,000/month.

Why is this important? While applying the field average cost to all wells will produce a good initial tie out to the LOS, this method will underrepresent total field expenses by causing marginal wells to become sub-commercial too quickly while inflating value on high volume producers that are carrying too little LOE.

Seller Trick #2: Using Highly Variable Operating Expense Models

Another trick that sellers will use to inflate value is modeling too much of the LOE as "variable" (changing over time with production rates).

As you are deciding how to split your expenses between fixed and variable, keep in mind that a higher variable percentage will typically extend the life of the well, increasing reserves and present value. Consider a mature shale well producing 200 bbls/day. Using 2/3 variable expenses and 1/3 fixed expenses could inflate the well's present value by ~10%, versus using 1/3 variable and 2/3 fixed.

Sellers like this trick because they can still illustrate a "good tie out" when comparing the LOS to the database models.

What should be considered variable?

Each asset has its unique solution, but generally the following itemized expenses can be modeled as variable costs to some degree. In our experience, other categories of expenses should be modeled as largely fixed (>75%).

Example Variable Expenses	% Variable	% Fixed
Gathering, Marketing, Transportation	100	0
Processing	100	0
Salt Water Disposal	100	0
Contract Compression	50	50
Chemicals	50	50
Electricity, Fuel, Power	50	50

Table 3: Example Variable Expenses and Recommended Allocations

Seller Trick #3: Removing All “Non-Recurring” Operating Expenses (e.g. Workovers)

In many data rooms, the costs associated with workover or non-routine maintenance is classified as “non-recurring” and removed from any expense models applied to the wells. Depending on the assets, this can often be a significant portion of the costs and should be considered. x

While it may be too conservative to keep all recent workover costs in the go-forward expense models, we recommend including a workover program as part of the field level expenses.

One method is to estimate the frequency and cost for a workover for a typical well and allocate these to the well level as shown:

$$\frac{\textit{Estimated Workover Cost Per Well (\$)}}{\textit{Estimated Workover Frequency (months)}} = \textit{\$/well/month}$$

Due to the Spring 2020 price crash, nearly all E&P companies significantly cut spending especially on workovers and other well maintenance programs. If your lease operating statements cover anomalous events such as this, it is important to disregard historic data that doesn’t represent “normal” operating conditions.

Revenue Models

The revenue component of your evaluation is likely the most uncertain variable, as commodity price and market conditions are always changing.

While we may not be able to control commodity pricing, evaluators can use these revenue modeling tips to avoid making aggressive mistakes.

Tip #1: Avoid Using Short Term Averages or Improving Conditions

"Waha gas will a premium to Henry Hub next year!"

These famous last words were common in 2016 when it was projected that the West Texas hub was to have supply shortage in the coming years. Unfortunately, many buyers built these premiums into their bids; meanwhile, the Permian Basin associated gas caused the contracts tied to Waha pricing to end up in the dumps.

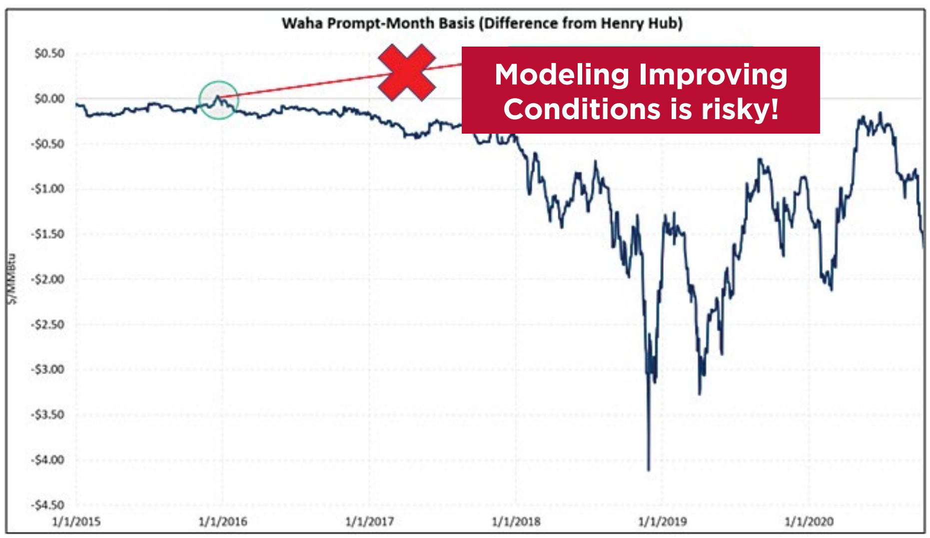


Figure 8: Waha Basis Differential to NYMEX (Source EIA)

A good number of buyers from this time frame did not survive this fatal mistake.

While it may be important to examine improving conditions as part of your evaluation (we will address this topic in the Bid Case section), we recommend grounding your base case evaluation in historic averages. Typically, a 6- or 12-month average should represent current conditions for key inputs such as commodity price differentials, Natural Gas Liquids yield, and gas shrinkage.

Deviations from the historic LOS data should be supported by new contractual agreements.

Generally, these revenue calculations do not need to be made on a well by well level (unlike the expenses). If the fluid types are similar and marketed the same, the stream properties shouldn't deviate greatly from well to well. Haas & Cobb Petroleum Consultants recommends creating revenue models using a spreadsheet similar to Table 4. If time permits, evaluators should inspect the averages on an 8/8ths and a net basis, as many times they can yield different calculations (e.g. cost-free leases).

	MONTH 6	MONTH 7	MONTH 8	MONTH 9	MONTH 10	MONTH 11	MONTH 12	6 Mo Avg	12 Mo Avg
Production Volumes (from Economic Database)									
Oil Production Volume	56,533	52,734	54,239	48,717	47,510	49,500	47,680	50,063	55,939
Gas Production Volume	43,035	37,179	44,972	43,019	39,558	34,000	33,541	38,711	40,237
Sales Volumes (From LOS)									
Oil Sales Volume	57,098	52,734	54,239	50,179	46,560	49,500	47,680	50,149	55,826
Gas Sales Volume	27,112	22,307	26,265	25,398	21,465	21,420	20,460	22,886	24,686
Product Sales Volume	189,696	199,653	212,541	197,444	199,847	187,987	155,847	192,220	187,471
Sales Revenues (After Deductions)									
Oil Sales Revenue	3,227,241	2,636,995	1,555,465	649,402	1,213,880	1,806,750	1,864,288	1,621,130	2,523,622
Gas Sales Revenue	21,681	2,423	(9,597)	1,453	18,890	21,511	22,199	9,480	15,872
Product Sales Revenue	125,444	122,555	68,484	33,555	68,078	67,881	67,000	71,259	84,155
INDEX PRICES (Source from EIA)									
WTI Index Price ($/bbl)	57.52	50.54	29.21	16.55	28.56	38.31	40.71	33.98	45.34
HH Index Prices ($/Mcf)	2.02	1.91	1.79	1.74	1.75	1.63	1.77	1.77	2.05
DIFFERENTIALS (Calculated)									
Received Oil Price ($/bbl)	56.51	50.00	28.67	12.94	26.07	36.49	39.09	32.21	44.06
Oil Differential $/bbl	-1.01	-0.54	-0.54	-3.61	-2.49	-1.82	-1.62	(1.77)	(1.28)
Oil Differential %	-2%	-1%	-2%	-22%	-9%	-5%	-4%	-7%	-4%
Received Gas Price ($/Mcf)	0.80	0.11	-0.37	0.06	0.88	1.00	1.08	0.46	0.66
Gas Differential ($/Mcf)	-1.22	-1.80	-2.16	-1.68	-0.87	-0.63	-0.69	(1.30)	(1.39)
Gas Differential %	-60%	-94%	-120%	-97%	-50%	-38%	-39%	-73%	-68%
Received NGL Price ($/bbl)	24.58	23.64	11.95	7.12	14.29	15.15	18.04	15.03	17.96
NGL Differential %	-57%	-53%	-59%	-57%	-50%	-60%	-56%	-56%	-60%
SHRINK & YIELD (Calculated)									
Oil Shrink %	-1.0%	0.0%	0.0%	-3.0%	2.0%	0.0%	0.0%	-1%	0%
Gas Shrink %	37%	40%	42%	41%	46%	37%	39%	41%	39%
NGL Yield (bbl/MMcf)	104.95	127.86	112.53	109.28	120.29	131.64	110.63	118.70	111.59

Table 4: Sample Revenue Accounting Workup

Tip #2: Include Flat Pricing in Your Scenarios

Most assets are presented in a data room using a current strip price deck. As none of us are certain what commodity prices are going to be in the next year, Haas Engineering recommends also running your economics on a flat price deck that represents current conditions. This is a good way to normalize all your acquisition opportunities, as well as get comfortable with your bid strength should nothing materially change in the commodity price space.

Tip #3: Always Confirm your Models Using Tie Out Plots

After completing accurate forecasts and creating defendable expense and revenue models, the final step in your Base case evaluation is to create some tie out plots. A tie out plot is made by comparing a company total net LOS to the Loss OK cash flow projections from the database. These exhibits as shown in Figure 9 allow the evaluator to get confident that the mechanics of the models are in sync with the provided financials.

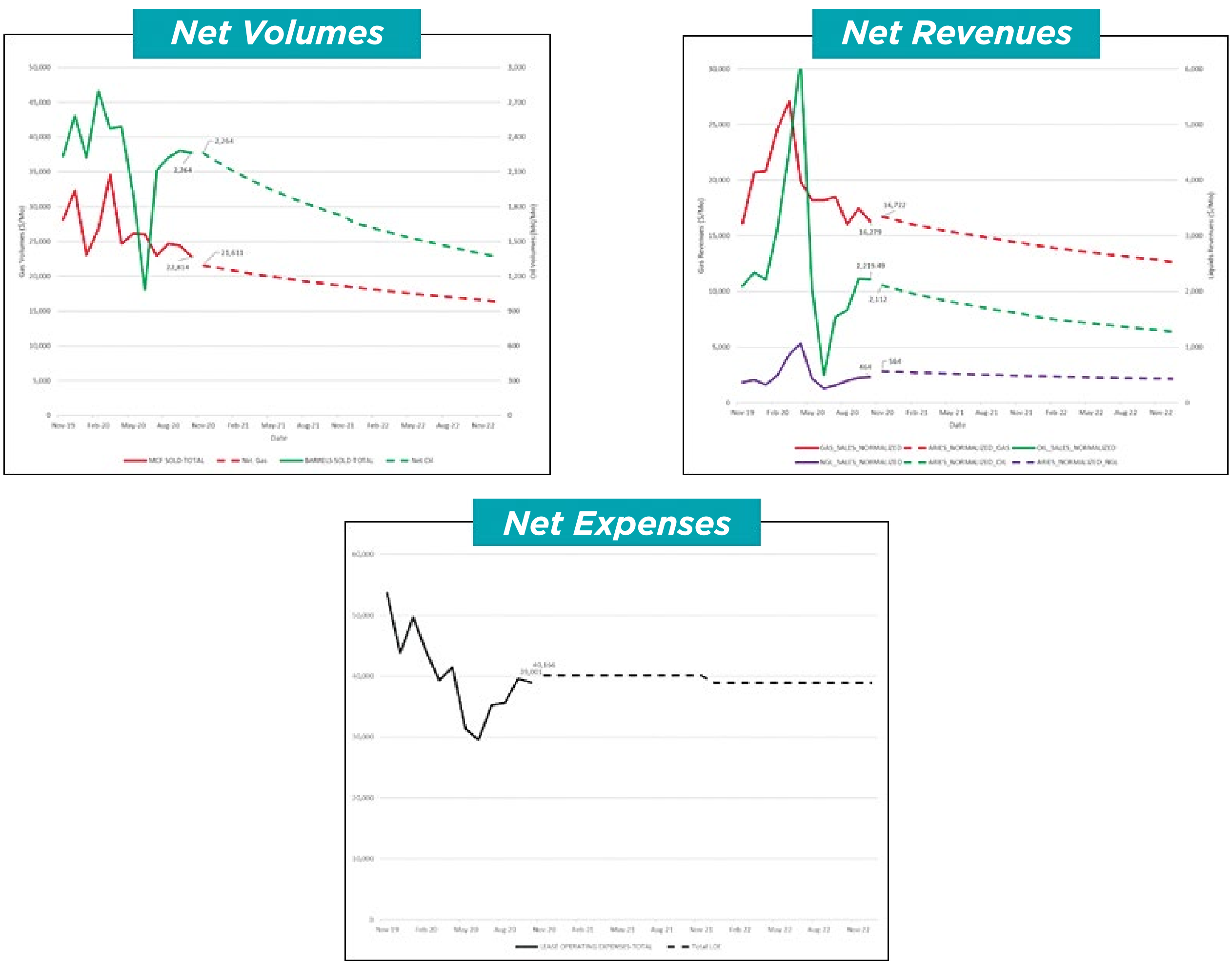


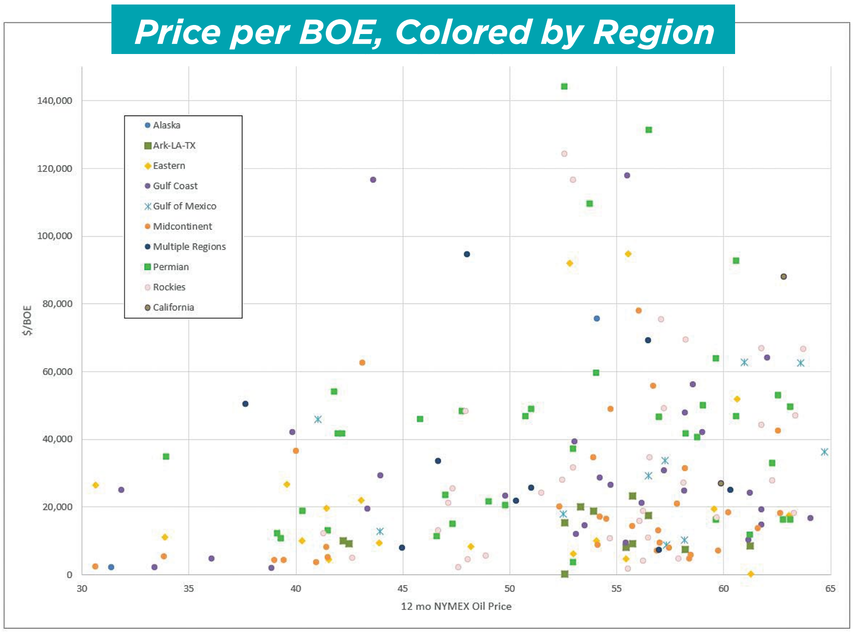
Figure 9: Example Tie Out Plots

INGREDIENT #3:

TAKING YOUR BASE CASE TO A BID CASE

Many teams will make bids based on $/flowing barrel or # of months of cash flow. As you can see in Figure 10, the range of these metrics can be very large. Haas Engineering recommends avoiding these "rules of thumb" when finalizing your bids.

Don't make bids based on $/flowing barrel or # of months of cash flow!



Should YOU PAY FOR NON-PDP?

This e-book focuses on PDP valuations, though some opportunities require consideration of future development. Contact Haas & Cobb Petroleum Consultants to learn more about our type well workflow and valuing upside.

Figure 10: 2019-2021 Transaction Price/Flowing BOE. **Sources:** Stephens, Inc. & Enverus

So, how do you go from your Base Case, grounded in reasonable forecasts and historic data, to your Bid Case?

Odds are your Base Case evaluation will not be high enough to win the assets, so Haas Engineering recommends building out a Bid Case matrix. Maybe you're bullish on prices, or maybe you're confident you can lower operating expenses. Perhaps the assets are immature (and have more uncertainty), and there is room to increase your forecasts on some wells. Now is the time to build out those scenarios and inspect the impact to present value.

HAAS & COBB PETROLEUM CONSULTANTS RECOMMENDS RUNNING THE FOLLOWING 7 SCENARIOS BEFORE SUBMITTING YOUR FINAL BIDS:

1. **Forecasts increase x%**
2. **Expenses decrease x%**
3. **Prices increase x%**
4. **Forecasts increase + Expenses decrease**
5. **Forecasts increase + Prices increase**
6. **Prices increase + Expenses decrease**
7. **Forecasts increase + Expenses decrease + Prices increase**

At the end of the day, you should clearly understand how far you're leaning forward on your bid. Once you inspect the impacts of these key drivers, you can make your bid in accordance with your risk tolerance. We recommend checking the Bid Case against the Base Case to ensure you are still comfortable with the bid. For example, if a team decided to bid $125 MM$ (~PV15 if expenses and forecasts improve) for the sample assets above, this would equate to a PV8 on the Base Case.

Sample Base Case Value = 100mm$ PV 15

Bid Case Matrix, PV 15 mm $			
	Forecast +20%	Expense −20%	Price +20%
Forecast +20%	115	125	140
Expense −20%	125	110	127
Price +20%	140	127	120

Table 5*: Example Bid Case Matrix*

If this meets your hurdle rate, you can now bid with confidence!

"Most of the world will make decisions by either guessing or using their gut. They will either be lucky or wrong."

Suhail Doshi

Thank you for reading our eBook! Next time you are in a data room environment, we hope you'll consider our Confident Bid Recipe.

1 Use Accurate PDP Forecasts

- Select B Factors based on Flow Regimes
- Fit the Decline Curve Though Most Recent Trend
- Characterize New Wells

2 Model Accurate Accounting Inputs

- Avoid short Term Trends and/or Improving Conditions
- Run Various Price Scenarios including Flat Pricing
- Create Tie Out Plots to Ensure Good History Match

3 Create Bid Case from Base Case

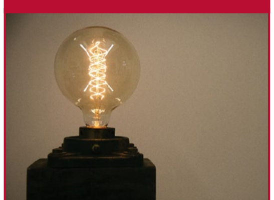
- Avoid Rules of Thumb Values
- Create Bid Case Matrix
- Bid with Confidence in Accordance to Risk Tolerance

ADD VALUE AT ALL STAGES OF THE ASSET LIFE CYCLE

PRE-ASSETS

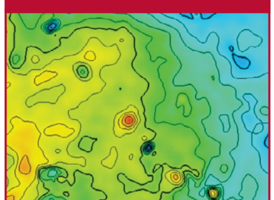
- Strategize
- Screen Opportunities
- Data Room Support
- Type Curves
- Bid Underwriting

EARLY ASSETS



- Strategic Asset Planning
- Production Enhancement
- Database Organization
- Commercial Optimization
- Technical Training

GROW



- Permit Navigation
- Drilling & Completion Support
- Reservoir Modeling & Simulation
- Field Extension & Behind Pipe Studies
- Pilot Studies & EOR Implementation

MONITOR & REPORT

- SEC & PRMS Reports & Audits
- RBL Bank Reports & Fair Market Valuations
- Regulatory Filings
- CCUS Surveillance Implementation
- Reservoir Surveillance

EXIT PLAN

- Upside Modeling
- Connect with Buyers
- Data Room Support
- Work with Brokers
- Bid Evaluation

SETTING THE STANDARD IN PETROLEUM ENGINEERING AND GEOLOGIC CONSULTING SERVICES

Our Core Values

- Service
- Results
- Integrity

Our Services

- Independent Reserves Reports and Audit Reports
- Technical Support and Evaluation Studies
- Subsurface Modeling
- Reservoir Simulation
- Enhanced Recovery and Waterflooding
- Gas Storage and CCUS
- Mineral Rich Brine Recovery
- Technical Courses and Training
- Expert Witness Testimony

Our Customers

- Public and Private E&P Companies
- Non-Operating Working Interest Owners
- Mineral Owners
- Banks and Financial Institutions
- Private Equity Firms
- Midstream Companies
- Buyers and Sellers
- Legal Teams
- Family Offices
- O&G Investors
- CCUS Companies
- Rare Earth Mineral Companies

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Proceed with Confidence