

Drilling an exploration prospect downdip: Quantifying the trade-offs between chance of success and associated resource potential

Mark Schneider, Gary P. Citron, Paul Haryott, and David Cook

ABSTRACT

A common method for choosing an exploration prospect drilling location is to drill the crest of the structure. This tends to maximize the chance of discovering a conventional hydrocarbon accumulation. However, the discovered resource volumes may not justify development due to a limited proven area and thus require additional downdip appraisal drilling, adding appraisal costs and delaying possible development. An alternative approach is to drill downdip, where a discovery has a high chance of exceeding the minimum commercial field size needed to justify development. In practice, the prospect should be assessed using its full probabilistic resource distribution before selecting the drilling location. A downdip discovery smaller than the minimum commercial field size may lead a decision maker to drill another well further downdip. A dry hole drilled downdip with a thick, porous reservoir may lead a decision maker to sidetrack updip. This paper describes the reduction in the chance of success as the well location moves downdip and quantifies the resource distributions for the updip and downdip volumes relative to the drilling location. Although the overlap of updip and downdip resource distributions may be significant, using this approach allows the technical team to present an optimal location that maximizes value and quantifies the trade-off between a lower chance of success and increased resource potential.

AUTHORS

MARK SCHNEIDER ~ *Rose & Associates, Houston, Texas; markschneider@roseassoc.com*

Mark Schneider is a partner with Rose & Associates. He is active in consulting, training, and software focusing on risk analysis and uncertainty characterization of upstream opportunities. He received a B.S. degree in chemical engineering and a B.S. degree in natural gas engineering from Texas A&I University in 1981. He received an M.S. degree in petroleum engineering from the University of Houston in 1991.

GARY P. CITRON ~ *Rose & Associates, Houston, Texas; garycitron@roseassoc.com*

Gary P. Citron is a senior associate with Rose & Associates and served as managing partner from 2003 to 2014. In 2008, he co-founded the Risk Coordinators Workshop, which continues today. From 1994 to 1998 he served on Amoco's assurance team. He received his B.S. degree in geology from the University at Buffalo and his Ph.D. in geology from Cornell University. He is the corresponding author of this paper.

PAUL HARYOTT ~ *Rose & Associates, Houston, Texas; paulharyott@roseassoc.com*

Paul Haryott is a principal consultant with Rose & Associates. He has led assurance teams and been a senior manager in major oil companies and has a special interest in new opportunity development and exploration management. He received his B.Sc. degree in geology from Liverpool University in 1996 and his M.Sc. degree in petroleum exploration studies from Aberdeen University in 1997.

DAVID COOK ~ *Rose & Associates, Houston, Texas; davidcook@roseassoc.com*

David Cook is a partner at Rose & Associates and the manager of their software company. He has led the development of prospect, play, and portfolio risk analysis tools since 2004 and implemented the *Pwell* functionality in the RoseRA prospect

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assessment software. He received his B.S. degree in geophysics from Texas A&M University in 1978 and worked at Mobil Oil until 2000.

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INTRODUCTION

Reliable exploration portfolio management begins with a consistent, systematic determination of a success case resource distribution and the associated probability (chance) of geologic success. These key elements can become calibrated from performance tracking through time. The techniques for determining an unbiased assessment of these parameters are well documented (Capen, 1976; Otis and Schneidermann, 1997; Rose, 2001; Quirk and Ruthrauff, 2008; Otis and Haryott, 2010; Milkov, 2015; Citron et al., 2018), so there is no need to delve further into this space.

As the prospect resource size and chance characterizations evolve to a drill-ready state, many millions of predrill dollars may have been invested. Furthermore, given that exploration well costs can exceed tens of millions of dollars, which clearly eclipse characterization-related investments, a valid determination of the optimal exploration well location becomes paramount. The critical questions that assessors should be ready to address in their location-specific characterization include the following.

1. What is the impact of a downdip well location on the chance of geologic and commercial success?
2. If a successful crestal well cannot prove sufficient resource volumes for commercial development, then are we prepared to drill appraisal wells and possibly defer development?
3. What is the deepest downdip well location that ensures, if a dry hole occurs, that there will be no business case for drilling a sidetrack well updip to access potential left-behind resources?

Schneider and Cook (2017) began to address these questions with a poster presentation at the centennial AAPG annual convention. Milkov (2021) addressed multiple zone aggregation when drilling downdip and noted that the literature is remarkably devoid of any quantification on this topic. This paper serves to fill that void, expanding the concepts in the Schneider and Cook (2017) poster and providing a workflow to calculate, for any downdip location, the probability that well location is geologically successful, and to quantify the range of success case resources both updip and downdip from the selected location. Critically, iterations of this process permit the determination of an optimal area of the prospect that contains a location that maximizes expected monetary value. A clearly quantified characterization of probability, resource size, and value of potential downdip locations will improve decision quality.

Definitions

This paper uses the “greater than or equal to” convention of percentile description. A percentile is a cumulative percentage,

represented throughout the paper by a capital P followed by a number. For example, the P10 is greater than or equal to 10% of the values of each particular continuous distribution. In this convention, the P10 is greater than the P90.

Estimated ultimate recovery (*EUR*) represents the volumes of hydrocarbons, at standard conditions, that ultimately will be recovered from a reservoir before abandonment. At any point in time, *EUR* is the sum of cumulative production and recoverable resources to be produced. All of the *EUR* values in this paper have units of millions of barrels of oil. In this paper, all *EUR* values have been determined volumetrically (as opposed to production decline or material balance methods) because the methodology addresses positioning an exploration well before any discovery. The *EUR* can be defined as

$$EUR = GRV \times \frac{N}{G} \times \left[\text{avg } \Phi \times \text{avg } (1 - S_w) \times RE \times \left(\frac{1}{FVF} \right) \right] \quad (1)$$

where *GRV*=gross rock volume, the product of the reservoir area \times gross thickness; *N/G*=net-to-gross; Φ =effective porosity; *S_w*=water saturation; *RE*=recovery efficiency, the percentage of the in-place hydrocarbons ultimately recovered; and *FVF*=formation volume change factor for the hydrocarbons between reservoir and surface conditions. Oil shrinks, whereas gas expands.

The porosity, saturation, recovery efficiency, and *1/FVF* can be multiplied to generate a recovery yield (*RY*). Therefore, the *EUR* equation can be simplified in two forms, each with three main components:

$$\begin{aligned} EUR &= GRV \times N/G \times RY \text{ or} \\ EUR &= Area \times \text{avg net pay} \times RY \end{aligned} \quad (2)$$

To provide clarity and consistency within an organization, the prospect's *EUR* distribution represents success cases and should be determined before the assessment of the probability of geologic success (*P_g*).

The *P_g* is the chance of making a discovery equal to or exceeding the P99 *EUR* that would sustainably flow into the well from the penetrated target (Rose, 2001). That P99 can be approximated by the product of P90 values from each of the three main *EUR* input components noted above. Hence, Rose (2001) suggested that the chance of trap be assessed as the

confidence that trap exists with at least the P90 area extent. Traditionally, the prospect *P_g* assumes a near-crestal well location such that the area updip of the location is less than the P90 of the productive area distribution. When determining the *P_g*, there is no consideration of commerciality of the resource—only the presence of hydrocarbons. The *P_g* equals the product of defined chance factors related to the petroleum system. Synonymous with chance of success *P_{well}* and probability of success, *P_g* is expressed here as a percentage.

Minimum commercial field size (*MCFS*) is the field size that contributes to a discounted net present value (*NPV*) equal to zero, when burdened only with future development and operating costs, treating all prior investments as sunk. Ideally, a decision maker would approve the development of any discovery greater than the *MCFS*.

The probability of commercial success (*P_c*) = *P_g* \times *PMCFS*, where *PMCFS* is, given a discovery, the chance of finding an *EUR* greater than or equal to the *MCFS*.

Next, *P_{trap @ well}* is the percentile location on the area distribution that the area updip of the well location is found; it is synonymous with the phrase "area percentile."

For *P_{well}* = *P_g* \times [(*P_{trap @ well}*)/90%], *P_{well}* is the chance that the downdip location will be a discovery. The denominator of 90% reflects the common standard that the trap chance factor is assessed as the chance of exceeding the P90 of the productive area distribution. For a well drilled at any location within the P90 productive area, the *P_{trap @ well}* stays at 90%, so a prospect with a *P_g* = 50% has *P_{well}* = 50% \times [90%/90%] = 50%. For a prospect with a *P_g* = 50% but drilled at a location associated with P50 of the area distribution, *P_{well}* = 50% \times [50%/90%] = 28%.

The probability of commercial success for a well drilled downdip (*P_{well}* (comm)) = *P_{well}* \times *PMCFS* (well) is the *P_c* for a well drilled downdip, where *PMCFS* (well) is the chance that a discovery at that downdip location will find an *EUR* greater than or equal to the *MCFS*.

Expected monetary value (*EMV*) is the sum of the probability-weighted *NPVs* (after tax) of commercial success and failure (where the *NPV* of commercial failure is negative). For any given commercial *EUR* case, the *NPV* is the discounted sum of each year's net cash flow (income minus investment minus

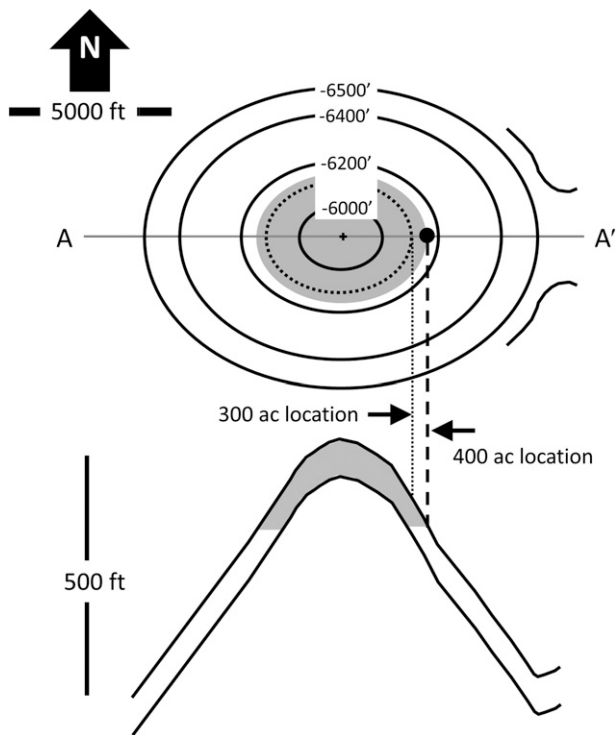


Figure 1. Example prospect and schematic cross section used for prospect assessment. The prospect has a probability of geological success of 50%, which incorporates a trap chance of 80%. The dotted contour encloses 300 ac, which is the 90th percentile of the productive area distribution. The vertical dashed line represents a well drilled with 400 ac updip from the location to the -5950-ft crest. The vertical dotted line represents a well location with 300 ac updip. Note how a discovery drilled at the 300-ac location could actually have a productive area closer to 400 ac due to the lower oil-water contact.

expense). Income is the revenue from producing the *EUR*. See the Appendix for more detail.

Example Prospect Details

Figure 1 illustrates a simple map and cross section for an example prospect used in the workflow. Before the application of the *Pwell* workflow, the prospect had its *GRV* generated from standard area versus depth plotting techniques (Frick and Taylor, 1962). Because this approach accurately captures the geometry of the trap, any correlation of the average net pay to the productive area is accounted for.

The area–depth pairs are plotted in Figure 2 for a simulation trial in which the gross reservoir thickness was 115 ft and the area was 400 ac. The oil-saturated *GRV* for this trial is the shaded closed polygon. The prospect has P90 and P10 gross reservoir thicknesses

of 45 and 210 ft, respectively. For any trial, multiplication of the *GRV* by the *N/G* provides the net rock volume (*NRV*) and the average net pay is that *NRV* divided by the associated area.

The *EUR* distribution resulted from standard Monte Carlo techniques, in which each trial samples the input variable distributions and then multiplies them to create an *EUR*. The workflow used 20,000 trials. Ideally, all of the input parameters have undergone a reality checking process for distribution type and range. Figure 3 tabulates the prospect input parameter distributions summarized at the productive area, average net pay, and hydrocarbon recovery yield level, and tabulates and plots the output geologic and commercial *EUR* distributions on a log-probit plot.

The vertical line represents the *MCFS* of 9.4 million bbl of oil (see the Appendix for determination details). The *MCFS* projects to P66 on the y axis, so 66% of the *EUR* outcomes exceed that threshold (*PMCFS*). Those outcomes have been redistributed to convey that only commercial outcomes would enable the project to move forward. This prospect has a $P_g = 50\%$, and the probability of commercial success, $P_c = P_g \times PMCFS = 50\% \times 66\% = 33\%$.

Traditionally, exploration prospects have been drilled at or near the crest; therefore, the numbers above would be appropriate for consideration. However, often there are business reasons to drill downdip of the P90 productive area on a trap. The following methodology is designed to quantify the response to important business-related questions pertinent to a noncrestal drill decision, in a clear and systematic fashion.

Methodology to Quantify Potential Downdip Locations

1. From the map, determine the area associated with the well location (*AAWL*). On the map in Figure 1, the potential location at the perimeter of the shaded area has an *AAWL* of 400 ac. The 400 ac plotted on the area distribution chart determines $P_{trap} @$ well when projected to the vertical axis and is used to calculate *Pwell* (Figure 4).
2. For each trial:
 - a. If the sampled area is less than the *AAWL*, then place that *EUR* value in the updip group. This assumes a dry hole at the well location.

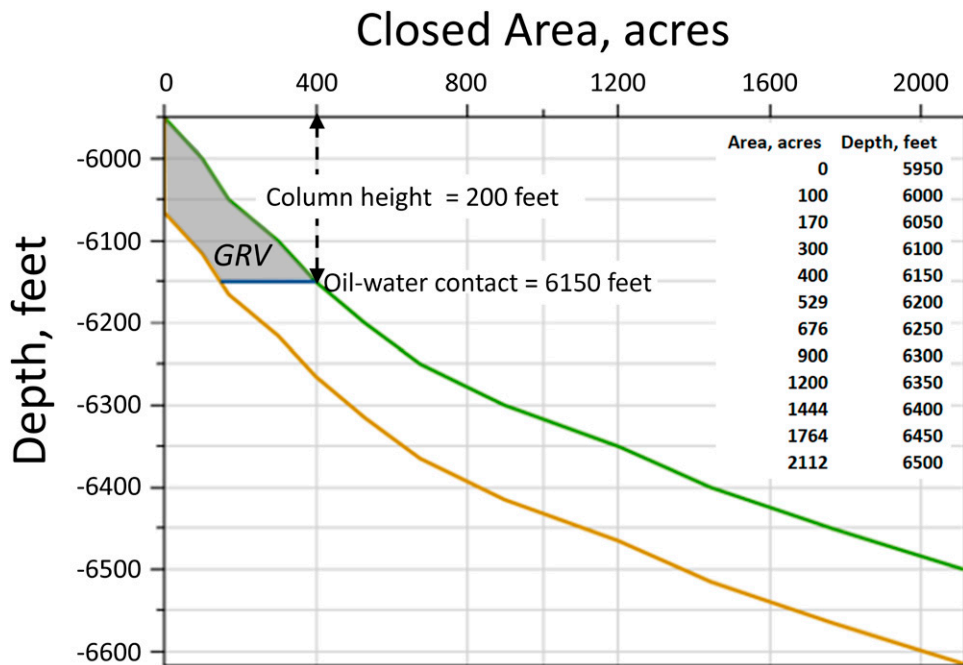


Figure 2. Area versus depth below sea level plot for the example prospect used to generate the gross rock volume (*GRV*) (shaded polygon). In this trial, the *GRV* (31,844 ac-ft) includes a vertical reservoir gross thickness of 115 ft and an oil-water contact at -6150 ft such that the area equals the 400 ac discussed in Figure 1, with an associated hydrocarbon column height of 200 ft down from the crest.

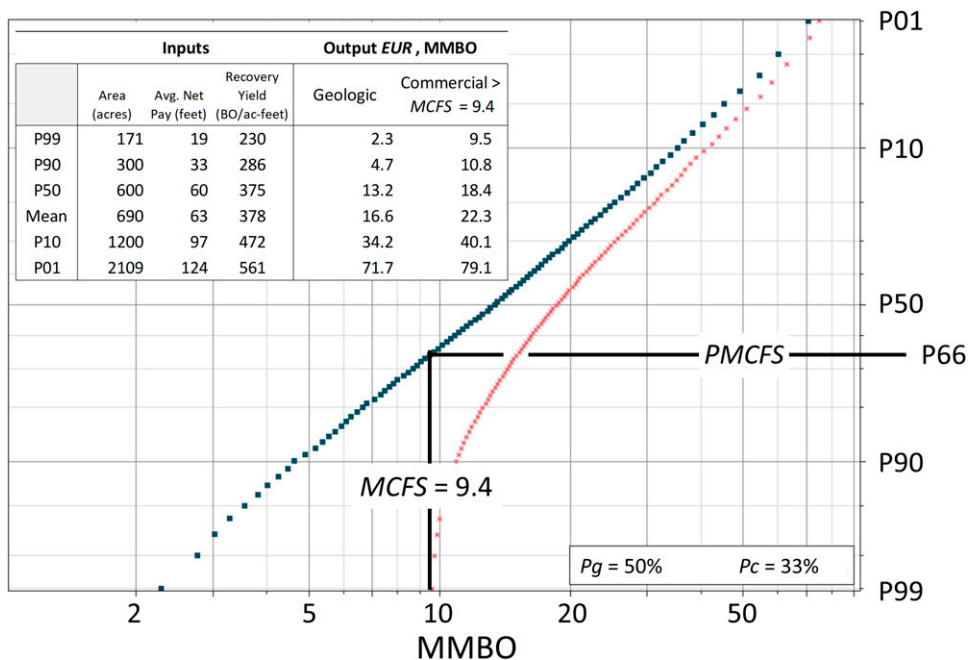


Figure 3. Example prospect estimated ultimate recovery (*EUR*) distribution plotted in a log-probit coordinate system. Percentile values (*P*) for key inputs and output values shown in upper left corner. Recovery yield is defined in the text as the product of the volumetric parameters excluding the net rock volume. A minimum commercial field size (*MCFS*) of 9.4 million bbl of oil (MMBO) was applied to redistribute *EUR* values in excess of the *MCFS* as the curved “commercial distribution.” With a probability of geological success of 50% and the *MCFS* of 9.4 million bbl of oil that posts at P66, the probability of commercial success is $66\% \times 50\% = 33\%$. Avg. = average; BO = barrels of oil; *P_c* = probability of commercial success; *P_g* = probability of geologic success; *PMCFs* = given a discovery, the chance of finding an *EUR* greater than or equal to the *MCFS*.

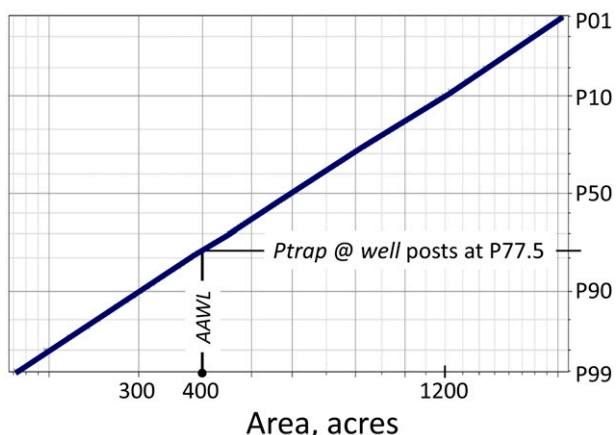


Figure 4. Example prospect productive area distribution plotted in a log-probit coordinate system. The vertical line represents a 400-ac area associated with the well location (AAWL). This area posts at the 77.5th percentile (P77.5), which is used to generate the chance that the downdip location will be a discovery (P_{well}) by applying the formula defined in the text. $P_{trap @ well} =$ percentile location on the area distribution that the area updip of the well location is found.

- b. If the sampled area is greater than or equal to the AAWL, then place that EUR value in the downdip group. This assumes a discovery at the well location, which includes the discovered updip volume.
3. Repeat for n trials, sort by AAWL, record the percentiles, and calculate the mean for both EUR groups.
4. Calculate:
 - a. P_{well} (at AAWL) = $P_g \times [(\% \text{ trials} > \text{AAWL}) / 90\%]$. The percentage of trials greater than or equal to the AAWL = $P_{trap @ well}$.
 - b. The percentage of trials in which EUR is greater than or equal to the MCFS for each of the updip and downdip groups.
5. Repeat these steps for other potential well locations to generate data for comparative valuation.

Figure 5 shows the unique workflow design for the methodology. Iterations of the workflow began at a well location 200 ac downdip from the prospect crest, then continued in increments of 100 ac, down to 1200 ac. These form the data set used for analysis, valuation, and discussion. Of note, for a discovery at any downdip location, the downdip EUR distribution represents the range of EUR from the prospect crest to the base of hydrocarbons in the well, plus the remaining EUR distribution from the base of the hydrocarbons in the well to the hydrocarbon water contact.

Additional complexity—for example, incorporating a range of column heights—can be assessed using the techniques discussed in this paper.

RESULTS

The workflow in Figure 5 generated a set of P_{well} and EUR results (Table 1). No commercial truncation has been applied. The trade-off between increasing EUR by drilling downdip and a lower chance of a discovery is displayed in Figure 6. As defined earlier, $P_{well} = P_g$ for locations within the P90 of the area distribution.

A decision maker may ask, “Why not drill at the downdip area that generates the EUR of the MCFS?” Although this is a worthwhile question, the EUR is a function of many parameters, not just the area. Figure 7 plots the output EUR from 5000 of the 20,000-trial simulation against the input area. For example, although the 700-ac location is associated with a mean updip EUR just above the MCFS

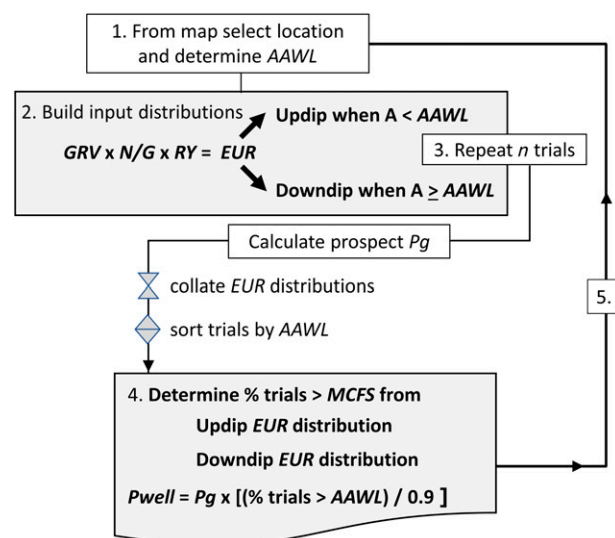


Figure 5. Workflow map used to generate the chance the downdip location will be a discovery (P_{well}) and updip and downdip estimated ultimate recovery (EUR) distributions. Gross rock volume (GRV), net-to-gross (N/G), and recovery yield (RY) represent the input distributions (GRV, N/G, and RY) defined in the text, which when multiplied generate the EUR distribution. In this simulation, $n = 20,000$ trials were computed for each specific downdip well location selected. $A =$ productive area sampled in the simulation; $AAWL =$ area associated with the well location; $MCFS =$ minimum commercial field size; $P_g =$ probability of geologic success.

Table 1. Probability Metrics and Associated Mean Resource Size for Each Location Evaluated

Area Updip from Location, ac	<i>P</i> _{trap @ well Location}	Calculation of <i>P</i> _{well} , %			Mean <i>EUR</i> , Million Barrels of Oil	
		<i>P</i> _g ×	$\frac{P_{trap@well}}{90\%}$	= <i>P</i> _{well}	Updip with Dry Hole at Location	Downdip with Discovery at Location
200	P97.8	50	100.0	50.0	3.06	17.53
300	P90.0	50	100.0	50.0	4.17	18.66
400	P77.3	50	85.8	42.9	6.00	20.51
500	P63.2	50	70.3	35.1	7.66	22.76
600	P50.0	50	55.5	27.8	9.25	25.18
700	P38.9	50	43.2	21.6	10.53	27.71
800	P29.7	50	33.0	16.5	11.61	30.46
900	P22.7	50	25.2	12.6	12.51	33.23
1000	P17.1	50	19.0	9.5	13.31	36.11
1100	P13.0	50	14.5	7.2	13.91	39.19
1200	P9.9	50	11.0	5.5	14.46	42.28

For each well location, the calculation of the chance that the downdip location will be a discovery (*P*_{well}) from probability of geologic success (*P*_g) is shown. Also shown is the associated mean estimated ultimate recovery (*EUR*), in millions of barrels of oil from the updip distribution, assuming a dry hole at the location, and the mean *EUR* of the downdip distribution (crest to spill), assuming a discovery at the location. As chance of trap is assessed against the 90th percentile (P90) of the productive area distribution, *P*_{well} = *P*_g for all well locations, with area associated with the well location (AAWL) ≤ P90 area of 300 ac.

(Table 1), note the scatter of *EUR* values, with many less than the *MCFS*. A wide range of areal uncertainty can contribute to the *MCFS*, between 300 and 1200 ac. Large or small values for average net pay or the average porosity or recovery efficiency can contribute, often significantly, to the wide *EUR* range.

Note that whenever 200 or 300 ac was selected in a trial, the resulting updip *EUR* was always less than the *MCFS*. Thus, a discovery at a location 200 or 300 ac downdip from the crest would likely require a downdip appraisal well to determine commerciality—hence, the importance of considering the full range of a location’s updip and downdip resources along with the associated chances of success in the decision-making process.

Table 2 illustrates the P99–P01 range of *EUR* values for the considered locations, and the associated probability metrics computed from the workflow and standard commercial truncation algebra.

Figure 8 illustrates the splitting process that generates the updip and downdip *EUR* distributions for a well location with 400 ac updip. The *MCFS* of 9.4 million bbl of oil intersects the downdip *EUR* distribution, then projects to the y axis at P82. From Table 2, *P*_{well} is 43%, so the *P*_{well} (comm) = 82% × 43% = 35%.

The *EUR* of the updip distribution has a P01 of approximately 14 million bbl of oil, a value that falls

at approximately the P60 of the downdip geologic *EUR* distribution. The P99 *EUR* of the downdip distribution occurs at the P72 of the updip distribution. The degree of overlap of the updip and downdip distributions, which could be surprising to many, indicates the prevailing uncertainty. The amount of *EUR* overlap between the updip and downdip distributions will be a function of trap geometry, column height, and thickness variability. For example, for a stratigraphic trap wedge that thins to zero at the

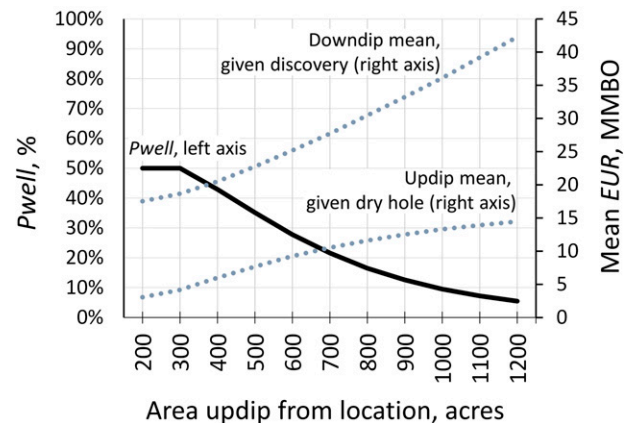


Figure 6. Plot of chance the downdip location will be a discovery (*P*_{well}), on the left y axis for each downdip location shown decreasing, whereas the mean of the associated downdip and updip estimated ultimate recovery (*EUR*) distributions (right y axis) increase. MMBO = million barrels of oil.

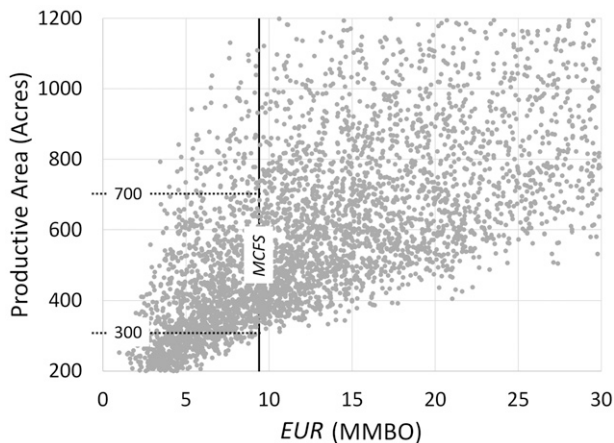


Figure 7. Crossplot of productive area (acres) and resulting estimated ultimate recovery (*EUR*, millions of barrels of oil [MMBO]) for 5000 trials randomly selected from the 20,000-trial simulation. The vertical line is the minimum commercial field size (*MCFS*). Analysis of the 300- and 700-ac locations is described in the text.

updip edge but thickens downdip, one would expect more separation between the downdip *EUR* distributions from the updip *EUR* distributions. In our example prospect, the *RY* parameters are the same for the updip and downdip trials so that only the *GRV* affects the *EUR* overlap.

Figure 9 plots the P99, P90, P50, P10, and P01 from the *EUR* distributions for the family of updip geologic distributions and the family of downdip geologic distributions for the locations considered. In the updip distributions, the upward deviation from (and above) perfectly straight lines (i.e., a lognormal distribution) results from the truncation effect that does not allow any areas greater than the location area. Once the *MCFS* is imposed on an *EUR* distribution, additional metrics related more to decision-making arise. Figure 10 shows how the commercial chance values can be further quantified and communicated for more informed decision-making. Curve 1 shows *Pwell* (comm) begins at 34% for the 200-ac location, increases slightly to a maximum value for the location associated with 300 ac, and then declines steadily. The peak at 300 ac is not seen on the *Pwell* curve (Figure 6) because the location is not beyond the P90 area, so the parameter *Ptrap* @ well is fixed at 100% and does not impact the calculation. However, the *Pwell* (comm) is derived from the *Pwell* times the percentage of downdip *EUR* outcomes greater than or equal to the *MCFS* (which steadily increases as the location moves downdip).

Figure 10 includes two other location-dependent metrics. First, given a dry hole, the chance that an updip discovery will exceed the *MCFS* (curve 2) is derived from the percentage of the trials that achieve that level when the oil column is limited to the well location (Table 2). This forms the bottom boundary of the shaded envelope, beginning at 0 for 200 ac and increases up to approximately 60% at 1200 ac downdip. For the 400-ac location detailed in Figure 8, note how the intersection of the *MCFS* with the updip *EUR* distribution is projected to approximately P13, contributing to the bottom part of the shaded envelope crossing 400 ac at 13%.

Second, given a discovery, the percentage of trials that generate an *EUR* greater than or equal to the *MCFS* (curve 3 in Figure 10) is the top of the shaded envelope, beginning at 68% for drilling 200 ac downdip. Figure 8 showed the *MCFS* intersection with the 400-ac location downdip *EUR* distribution projected to P82; hence, the upper part of the shaded envelope crosses 400 ac at 82%. Figure 9 showed that approximately 99% of the downdip *EUR* distribution associated with the most downdip (1200-ac) location exceeded the *MCFS*. This is corroborated by the area versus *EUR* crossplot (Figure 7), where at 1200 ac, all of the associated *EUR* values exceed the *MCFS*.

Third, the vertical arrow (4 in Figure 10) illustrates that the 300-ac location has the widest part of the shaded chance envelope. For a “perfect” well location, a discovery would have 100% chance of exceeding the *MCFS*, and a dry hole would leave the updip accumulation with 0% chance of exceeding the *MCFS*. In other words, a “perfect” well location would show no overlap of the updip and downdip *EUR* distributions. Thus, wider ranges in the shaded envelope between the “given discovery” and “given dry hole” chance curves are desired for the drilling well location. This maximum chance width at 300 ac coincides with the maximum *Pwell* (comm), can be considered the least ambiguous location, and deserves consideration in the valuation for the optimal location.

The rigorous workflow allows an exploration team to not only calculate the *Pwell* and *Pwell* (comm) as the well location moves downdip but also to probabilistically modify the prospect *EUR* distribution of a discovery to that well location as well as the updip “attic” resource potential. However, the valuation of the resources includes other parameters such

Table 2. Location-Specific Resource Distribution and Probability Attributes, Based on the Area Updip from the Location

Area Updip from Location, ac	Given Discovery at Location										Given Dry Hole at Location												
	Downdip Geological					Downdip Commercial					Updip Geological					Updip Commercial							
	P_{well} , %		EUR, Million Barrels of Oil			P_{well} , %		EUR, Million Barrels of Oil			P_{well} , %		EUR, Million Barrels of Oil			P_c at PMCFs, Crest, %		EUR, Million Barrels of Oil					
		P99	Mean	P01		PMCFs, %		P99	Mean	P01		PMCFs, %		P99	Mean	P01		PMCFs, %		P99	Mean	P01	
200	50.0	2.51	17.53	72.42	67.8	33.9	9.54	22.93	81.32	1.22	3.06	5.53	0.0	0.0	0.00	0.00	0.0	0.0	0.00	0.00	0.00	0.00	0.00
300	50.0	3.22	18.66	73.41	73.7	36.8	9.54	22.93	81.32	1.41	4.17	8.45	0.2	0.1	9.48	9.71	0.2	0.1	9.48	9.71	9.71	9.99	9.99
400	42.9	3.94	20.51	78.03	82.0	35.2	9.58	23.48	82.54	1.61	6.00	13.87	13.1	6.6	9.41	11.29	13.1	6.6	9.41	11.29	11.29	16.69	16.69
500	35.1	4.80	22.76	82.57	87.8	30.8	9.67	24.92	84.43	1.76	7.66	19.12	29.4	14.7	9.43	12.73	29.4	14.7	9.43	12.73	12.73	21.49	21.49
600	27.8	5.49	25.18	85.80	91.2	25.3	9.74	26.90	86.84	1.90	9.25	24.68	41.5	20.7	9.46	14.22	41.5	20.7	9.46	14.22	14.22	27.21	27.21
700	21.6	6.05	27.71	89.62	93.9	20.3	9.89	29.01	90.33	2.01	10.53	29.56	48.7	24.4	9.47	15.47	48.7	24.4	9.47	15.47	15.47	32.10	32.10
800	16.5	6.87	30.46	94.46	95.7	15.8	10.05	31.49	95.42	2.09	11.61	33.96	53.9	27.0	9.48	16.51	53.9	27.0	9.48	16.51	16.51	36.77	36.77
900	12.6	7.64	33.23	100.94	97.1	12.2	10.23	33.98	101.41	2.13	12.51	37.61	57.3	28.6	9.49	17.44	57.3	28.6	9.49	17.44	17.44	40.06	40.06
1000	9.5	8.14	36.11	106.55	97.9	9.3	10.41	36.71	106.99	2.20	13.31	40.83	59.8	29.9	9.50	18.28	59.8	29.9	9.50	18.28	18.28	43.92	43.92
1100	7.2	8.62	39.19	110.26	98.5	7.1	10.99	39.66	110.40	2.22	13.91	43.70	61.5	30.7	9.50	18.91	61.5	30.7	9.50	18.91	18.91	46.13	46.13
1200	5.5	9.75	42.28	115.46	99.1	5.4	11.86	42.59	115.52	2.23	14.46	46.71	62.7	31.4	9.51	19.53	62.7	31.4	9.51	19.53	19.53	50.70	50.70

For each well location, given a discovery at that location, the downdip geological and commercial 99th percentile (P99), mean, and P01 estimated ultimate recovery (EUR) values, in millions of barrels of oil. Also reported are the chance that the location will be a discovery (P_{well}); the chance of finding an EUR greater than or equal to the minimum commercial field size (MCFs), given a discovery (PMCFs); and the probability of commercial success for a well drilled downdip (P_{well} (comm)). Given a dry hole at the location, the updip geological and commercial P99, mean, and P01 EUR values are shown. Also included are the PMCFs read off the updip geological distribution and resulting probability of commercial success (P_c) at the crest for an updip sidetrack well. These distributions are plotted in Figure 9.

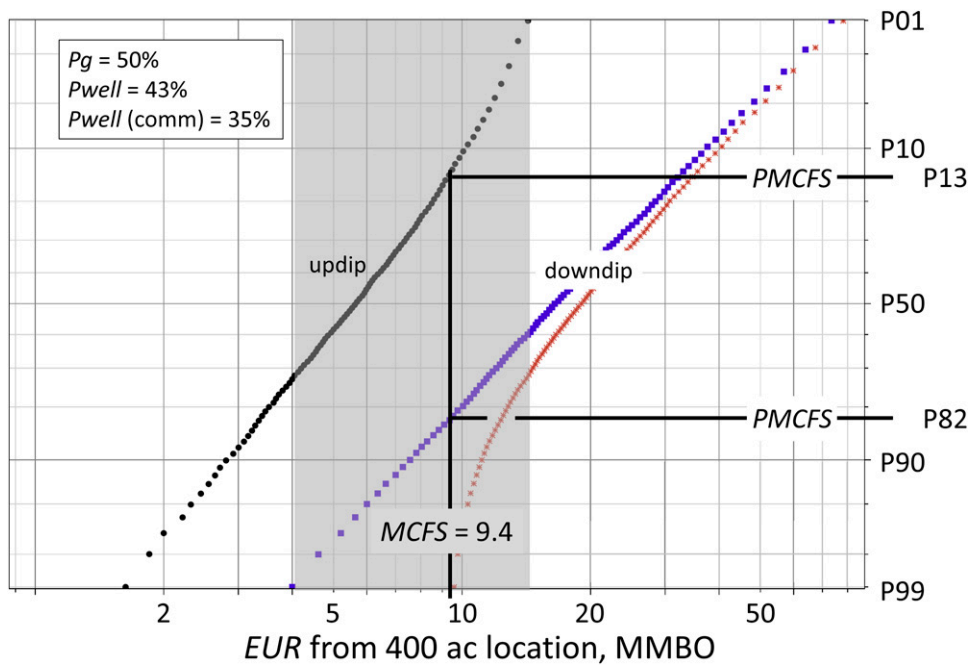


Figure 8. Estimated ultimate recovery (*EUR*) distributions updip and downdip of a well location with 400 ac updip, plotted on a log-probit coordinate system, with the prospect probability of geologic success (P_g) = 50% and the chance the downdip location will be a discovery (P_{well}) = 43%. The P_{well} (comm) is the chance the downdip resources will be commercially successful, given the minimum commercial field size ($MCFS$) posts at the 82nd percentile (P82), such that P_{well} (comm) = 82% × 43% = 35%. The commercial distribution associated with that is redistributed as the curved line. If the well location is a dry hole, then the $MCFS$ can be projected to the updip resource distribution and projects at P13. Thus, given a dry hole, the probability of commercial success for a crestal well updip = 13% × P_g = 13% × 50% = 6.5%. The shaded rectangle represents the overlap of the updip and downdip distributions. MMBO = million barrels of oil; $PMCFs$ = given a discovery, the chance of finding an *EUR* greater than or equal to the $MCFS$.

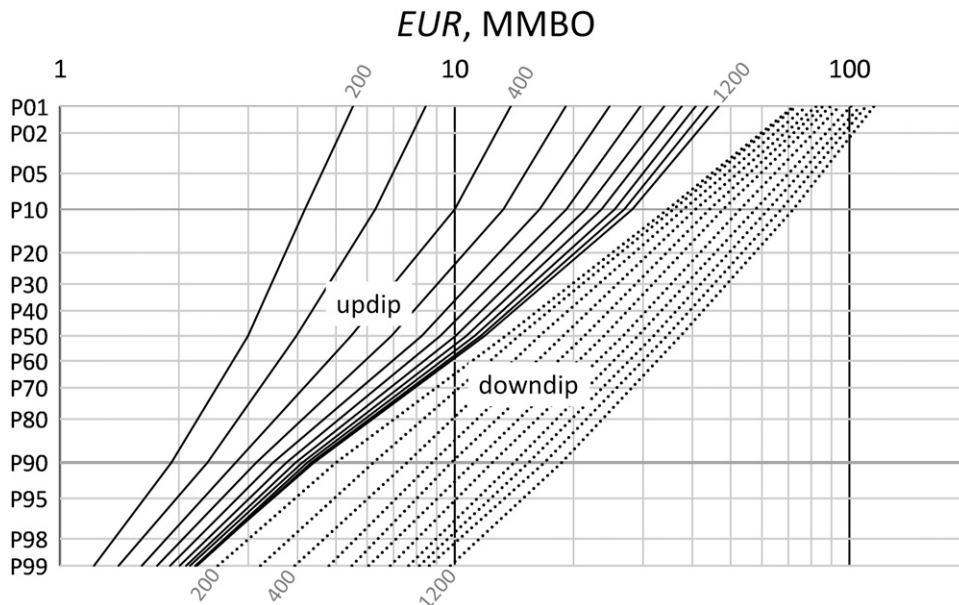


Figure 9. Updip and downdip (dotted) estimated ultimate recovery (*EUR*) distributions for the 11 well locations assessed in 100-ac increments between 200 and 1200 ac. Each curve connects the 99th percentile (P99), P90, P50, P10, and P01 values of the distribution. See Table 2 for the P99, P01, and mean of each distribution. The downdip distributions represent the prospect crest to the base of hydrocarbons in the well, plus the remaining *EUR* distribution from the base of the hydrocarbons in the well to the hydrocarbon water contact, rather than being limited to that portion downdip of the location. MMBO = million barrels of oil.

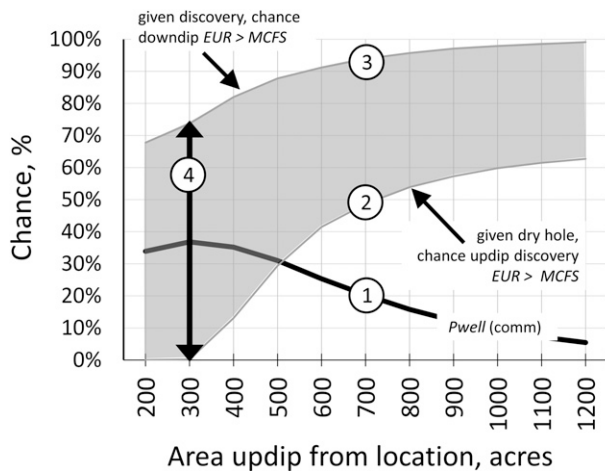


Figure 10. The solid curve (1) represents the chance the potential well location will be a commercial discovery (*Pwell* (comm)). The shaded envelope has a lower bound (2) that represents for each location the chance, given a dry hole at that location, that there will be an updip commercial discovery. The upper bound (3) represents for each location, given a discovery there, the percent of the downdip estimated ultimate recovery (*EUR*) outcomes that exceed the minimum commercial field size (*MCFS*). Figure 8 shows those boundary values from the 400-ac location to be 13% and 82%, respectively. From a probability perspective, the larger the width of the shaded chance envelope, which reaches a maximum at 300 ac (4), the less ambiguous the well location decision is.

as cost, timing, and productive rates. These factors lead to success case *NPV* values that can be probability weighted by commercial chance metrics to calculate which location generates the maximum *EMV*.

Valuation

The trade-offs of increased resource potential downdip with a lower *Pwell* assist in the optimization of a well location through a decision tree analysis that can be solved for *EMV*. Haskett (2003) addressed building decision trees to assess appraisal drilling, focusing on how that information can ultimately reduce resource uncertainty. This current paper acknowledges the inevitable uncertainty for the decision maker and addresses comparative *NPV* (*NPV@10%*) of the mean commercial *EUR* associated with specific locations. The cash flow model of various development cases related to size, with associated salient details, are described in the Appendix. Table 3 summarizes key metrics from previous figures and tables with the *NPV@10%* for the commercial mean *EUR* to build a decision tree branch for valuation at each location. When the *NPVs* are properly probability weighted, the resulting *EMV* serves as valuable input to identify where unnecessary appraisal costs can be avoided.

Table 3. Location-Specific Probability, Mean Estimated Ultimate Recovery, and Associated Net Present Value Metrics

Acres Updip from Location	<i>Pwell</i> Geological, %	$\times PMCFs,$ %	$= Pwell$ (comm), %	Given Discovery, Downdip		Given Dry Hole at Location, Updip				
				Commercial Mean <i>EUR</i>	<i>NPV@10%</i> , Million Dollars	Comm Mean Updip <i>EUR</i>	<i>NPV@10%</i> , Million Dollars	<i>Pg</i> ×, %	<i>PMCFs</i> Updip, %	$= Pc$ at Crest, %
Crest 0	50.0	66.3	33.2	22.93	81.30					
200	50.0	67.8	33.9	22.93	85.86	0.00	0.0	50	0.0	0.0
300	50.0	73.7	36.8	22.93	85.9	9.71	2.4	50	0.2	0.1
400	42.9	82.0	35.2	23.48	89.78	11.29	11.23	50	13.1	6.6
500	35.1	87.8	30.8	24.92	100.3	12.73	19.5	50	29.4	14.7
600	27.8	91.2	25.3	26.90	115.0	14.22	28.4	50	41.5	20.7
700	21.6	93.9	20.3	29.01	131.3	15.47	36.0	50	48.7	24.4
800	16.5	95.7	15.8	31.49	150.9	16.51	42.6	50	53.9	27.0
900	12.6	97.1	12.2	33.98	171.2	17.44	48.5	50	57.3	28.6
1000	9.5	97.9	9.3	36.71	194.2	18.28	54.0	50	59.8	29.9
1100	7.2	98.5	7.1	39.66	219.8	18.91	58.2	50	61.5	30.7
1200	5.5	99.1	5.4	42.59	245.9	19.53	62.3	50	62.7	31.4

From left to right, for each location, the calculation of chance that the downdip location will be a discovery (*Pwell*) and the probability of a commercial success (*Pc*) for a well drilled downdip (*Pwell* (comm)) is shown. Also shown for each location, given a discovery, is the commercial mean for the downdip estimated ultimate recovery (*EUR*) distribution (in millions of barrels of oil), and the comparative net present value (*NPV@10%*) for that value. Given a dry hole at the well location, the commercial mean of the updip *EUR* distribution and the *NPV@10%* for that value is shown. Because a dry hole at most downdip locations has not totally condemned the prospect, the calculation of the *Pc* for an updip crestal well is also shown. Numbers in boldface type are used in the decision tree calculations in Figure 11 and described in the text. The *NPVs* are from the Appendix. *PMCFs* = given a discovery, the chance of finding an *EUR* greater than or equal to the minimum commercial field size.

For each case, the exploration well cost is \$10 million. If required, an appraisal well costs \$10 million and has an accompanying production delay of 0.5 yr, which further decreases the *NPV*. Different producing environments or supply conditions may dictate longer delays, which could be modeled easily and would further emphasize the benefit of identifying a well location that could eliminate the need for an appraisal well. As Figure 7 indicates, there is no unique productive area associated with the *MCFS*; consequently, a stepwise approach follows beginning with a base case drill location at the crest.

For each decision branch shown in Figure 11, the horizontal line at the far left is a primary branch and the number in the lower right corner (shaded box) is the *EMV* calculated. A circle represents a chance node, where the probabilities assigned to the adjacent branches must sum to 100%. The black squares after a discovery indicate the option to drill an appraisal well before development.

The major decision branches that emanate from Figure 11A (crestal location) and continue with options for the 400-ac location (Figure 11B–D) are meant to assist in the decision-making process. The case with the highest *EMV* may not be pursued because management may not give approval for development if the *EUR* discovered with a lowest known oil in a reservoir is less than the *MCFS*. The risk tolerance of the decision maker is not addressed here, but it could alter the decision paths from the ones discussed below.

DISCUSSION

Figure 11A shows the tree for the crestal location, where a discovery is followed by a downdip appraisal well, readily justified because Figure 7 illustrates that there were no *EUR* values exceeding the *MCFS* until well locations had updip productive areas of 400 ac or more.

The prospect *Pg* is 50% and the *PMCFS* is 66.3%, generating a *Pc* = 33.2% (which becomes the probability weighting for the success branch); the resource valued is the mean commercial *EUR*, 22.3 million bbl of oil. The discounted cash flow model (with a 10% discount rate) generates a success case development *NPV@10%* of \$81.3 million (see the Appendix). The *NPV@10%* for the success case outcome

branch in Figure 11A is the development *NPV@10%*, including the exploration and appraisal costs and the startup delay of 0.5 yr due to the appraisal program. This adjustment is made using the standard time value of money equation ($n=0.5$ yr appraisal delay; i = discount rate) less the exploration and appraisal well costs. As a result, the success case *NPV@10%* in millions of dollars is equal to

$$\begin{aligned} & [\text{Development } NPV@10\% / (1+i)^n] \\ & - \text{exploration well cost} - \text{appraisal well cost} \\ & = [81.3 / (1.10)^{0.5}] - 10 - 10 = 57.52 \end{aligned} \quad (3)$$

This generates an *EMV* (adding all probability weighted adjusted *NPV@10%* values from each end node) of \$10.7 million, to which the other location (primary branch) valuations can be compared.

For each alternative downdip case, the approach is replicated with the appropriate size, chance, and *NPVs* from Table 3 to build a representative primary branch. Incorporated in the overall assessment is the fact that each branch can have specific options. For example, if the location results in a discovery less than *MCFS*, there is an option to drill a downdip appraisal well that burdens the discovery branch with appraisal capital and production time delay. If the location is a dry hole, then there is the option to drill an updip appraisal well, with the same burdens but applied to the valuation of the updip *EUR* distribution. The primary branch with the highest *EMV* suggests the path forward, but may not represent the best decision. Figure 11B–D illustrates some representative options for the 400-ac primary branch case.

Figure 11B shows the primary branch that models the decision of no appraisal well following either a discovery or a dry hole. With *Pwell* equal to 42.9% and *PMCFS* equal to 82% of the downdip *EUR* distribution, the *Pwell* (comm) is the branch probability of $43\% \times 82\% = 35.2\%$. The downdip commercial mean *EUR* has increased to 23.5 million bbl of oil and generates a success case *NPV@10%* = \$79.8 million and results in an *EMV* of \$21.6 million.

Figure 11C illustrates executing the option to drill a downdip appraisal well in the event of a location discovery, but not to drill an updip appraisal well if the location is a dry hole. The success case *NPV@10%* = \$65.62 million, which incorporates the exploration and appraisal wells and the associated

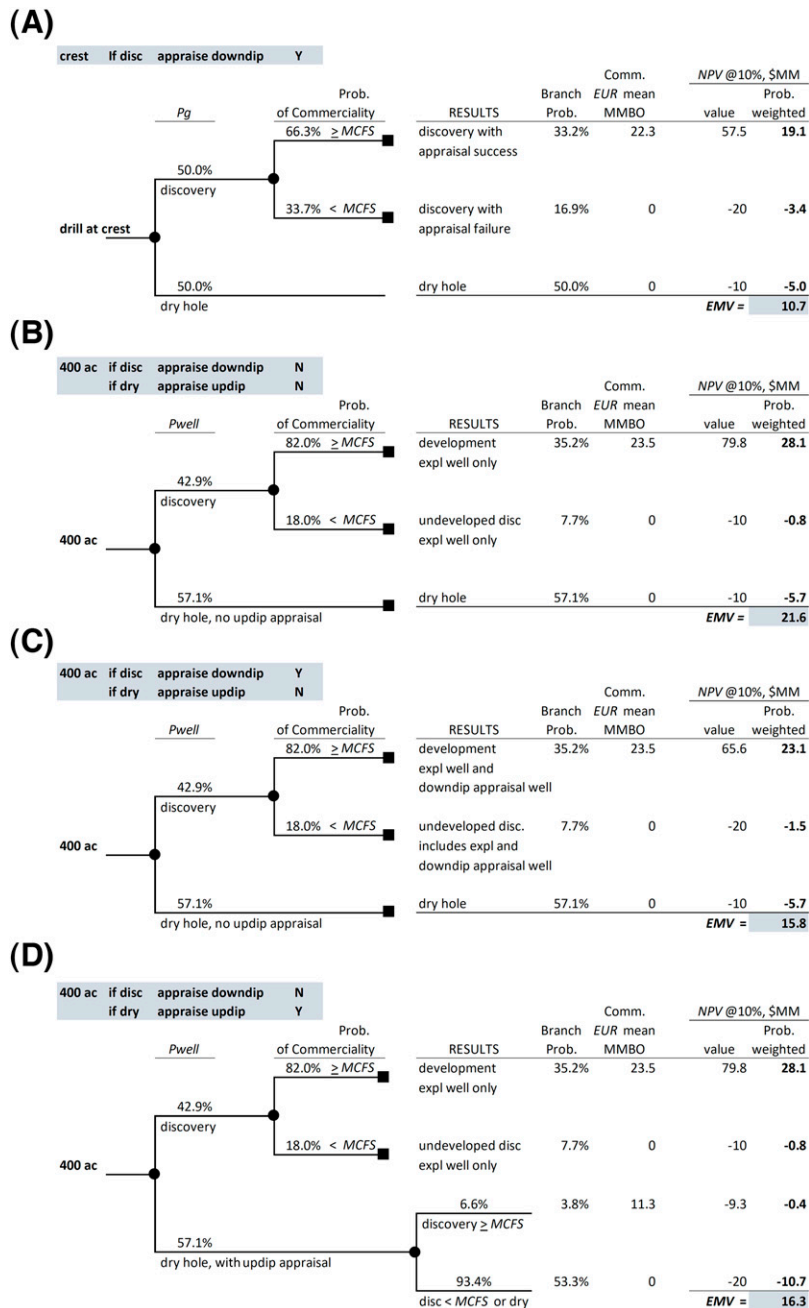


Figure 11. (A) Decision tree showing the expected monetary value (EMV) of drilling at the crest. The two black squares show that there is an option to drill a downdip appraisal well if there is a discovery (disc), which is pursued here. Note that this evaluation does not have a physical well location. The probabilities (Prob.) of the branches are based on the percent of the total number of simulation trials that exceed the minimum commercial field size (MCFS). (B) Decision tree for a location 400 ac downdip. The upper two black squares show that there is an option to drill a downdip appraisal well if there is a discovery, which is not pursued here. The lower black square indicates the option to drill an updip appraisal well if the location is a dry hole, but this is not pursued here. Estimated ultimate recovery (EUR), Prob., and net present value (NPV) from Table 3. (C) Decision tree for a location 400 ac downdip, where a discovery is followed by a downdip appraisal well, but a dry hole is not appraised with an updip appraisal well. The EUR, Prob., and NPV from Table 3. (D) Decision tree for a location 400 ac downdip, where a discovery is not followed by a downdip appraisal well. However, if the exploration well is a dry hole, then the circle represents the chance node an updip appraisal well will either succeed or fail. Comm. = commercial; expl = exploration; \$MM = million dollars; MMBO = million barrels of oil; N = no; Pg = probability of geologic success; $Pwell$ = chance that the downdip location will be a discovery; Y = yes.

production time delay. Notice that the appraisal well has a 18% chance of having *EUR* less than the *MCFS*, resulting in branch outcome with a \$20 million loss. The options in this decision tree result in an *EMV* of \$15.8 million, less than the \$21.6 million *EMV* when the decision is to proceed directly to development. In other words, for this location, drilling an appraisal well predevelopment destroys value.

A third option models the decision not to drill a downdip appraisal well in the event of a discovery, but to include an updip appraisal well after a dry hole (Figure 11D). The end of the dry hole branch becomes a chance node to indicate the appraisal well will either be a discovery exceeding *MCFS* or a commercial failure, which could be a dry hole or discovery less than *MCFS*.

The discovery branch probability with *EUR* greater than or equal to the *MCFS* for the updip appraisal well is 6.6%, which after a dry hole is derived from *Pg* multiplied by *PMCFS*, or $50\% \times 13.1\% = 6.6\%$ (see Figure 8, in which the *MCFS* is applied to the updip *EUR* distribution). The original prospect *Pg* is used after a downdip dry hole (and would likely never increase, even assuming the reservoir and seal remain) because the *Pg* is designed to be associated with the P90 area, or smaller. Note that the branch with updip appraisal discovery with

EUR greater than or equal to the *MCFS* has $NPV@10\% = -\$9.3$ million. This is because the development $NPV@10\%$ of \$10.7 million did not cover the \$20 million cost of drilling an exploration and appraisal well. However, it is developed because losing \$9.3 million is better than losing \$20 million if you do not develop it. The option in this decision tree result in *EMV* is \$16.3 million. This value is preferable to the result of Figure 11C, but not the optimal case (Figure 11B), which avoids any appraisal drilling.

A fourth option (not shown in Figure 11) is to drill an appraisal well downdip in the event of a discovery and an appraisal well updip in the event of a dry hole. This path has the most cost burdens and thus the lowest *EMV*. Such an approach illustrates the importance of analyzing drilling options before the decision, and was applied to every location, with the results displayed in Figure 12. The gray curves in Figure 12 show the results of the four main options for appraisal wells applied uniformly to each location. The solid black curve represents the decision strategy by *Pwell* location from the available valid options. The letters A–D post the results from Figure 11A–D, respectively.

Figure 7 demonstrates that no *EUR* values greater than the *MCFS* were generated from locations with 300 ac or less updip; therefore, a discovery at one of these locations should prompt a downdip appraisal well (option path 3). This is tantamount to saying that discoveries at these locations likely confirm only very small column heights relative to the 550-ft maximum column available.

For locations from 400 to 700 ac downdip, discoveries indicate a larger column with progressively larger amounts of *EUR* in excess of the *MCFS*, so no appraisal is required (Figure 12, option path 1), saving costs and maximizing *EMV* without the previous concerns of a minimal resource. Option path 2, where there would be an updip appraisal well given a dry hole at those locations, represents the second-best option; therefore, the shaded area highlights the incremental value created from the optimizing strategy.

For locations 800 ac downdip to the spill point, any discoveries would document an extensive column relative to the maximum possible column so that no further downdip appraisal would be needed. A dry hole at any of these locations should warrant consideration for an updip appraisal well (option

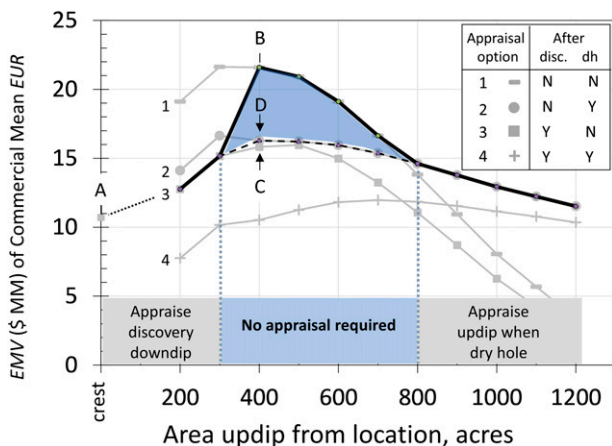


Figure 12. The expected monetary value (*EMV*) versus well location area, with the cases indicated by letter (Figure 11A–D). Each of the gray curves represent whether a downdip appraisal is drilled after a discovery (*disc.*), and whether an updip appraisal is drilled after a dry hole (*dh*). The shaded polygon represents location areas with enhancement of *EMV* by saving appraisal costs. *EUR* = estimated ultimate recovery; \$MM = million dollars.

path 2) because there could be large attic resources available. However, a decision maker may consider these locations to be far too downdip for the initial exploration well because P_{well} values are less than 20% (Figure 6).

In summary, this workflow demonstrated that the 400-ac location with no appraisal wells was the optimal case based on a key decision metric (EMV). Other critical factors for the locations, moving downdip are as follows.

1. Locations encompassing 200 and 300 ac, given a dry hole, cannot support an updip appraisal well because the updip EUR distributions are entirely below the $MCFS$ of 9.4 million bbl of oil (Figures 7, 9).
2. A well location between 400 and 500 ac downdip decreases P_{well} from 50% to 40%, with P_{well} (comm) decreasing from 35% to 30% (Figures 6, 10). This same location range is associated with a 20%–30% chance of leaving behind updip commercial resources. The trade-off is that a discovery at these locations provides an 80%–90% chance of a commercial accumulation (Figure 10).
3. For well locations 400–600 ac downdip, the P90 downdip resources for a discovery are close to or greater than the $MCFS$ (Figure 9). Given a dry hole, the P_c for a sidetrack to test the crest from the 400-ac location would be 7% (and 21% from the 600-ac location). If that updip test is a discovery, then the mean resources would be 6.0 million bbl of oil at 400 ac and 9.2 million bbl of oil at 600 ac, each below the $MCFS$ of 9.4 million bbl of oil.

CONCLUSIONS

Traditional consideration of a prospect for drilling requires the characterization of the full range of prospect EUR , associated chance of geologic success, and knowledge of a $MCFS$ for valuation metrics. However, when considering drilling potential downdip locations, additional analyses can illustrate the updip and downdip resources for each location, as well as the associated chance that the location will be geologically and commercially successful. The trade-offs of decreased chance associated with increased resources

can be illustrated and structured in a decision tree format. Such an approach quantifies the consequences of decisions before investment. Drilling a location where EMV is maximized, due to the ability to eliminate an appraisal well downdip to confirm commerciality or updip to chase potential left-behind resources, can now be clearly characterized and communicated for more informed decision making.

APPENDIX: CALCULATION OF NPVs

Using standard discounted cash flow analysis, multiple development cases were calculated to estimate the $MCFS$ and a range of $NPV@10\%$ that covered the EUR distribution. In addition to the $MCFS$ case of 9.4 million bbl of oil (the EUR generating $NPV@10\%=0$), this approach generated an $NPV@10\%$ for the following EUR (million bbl of oil): 3.5, 15.0, 22.3, 30.0, 50.0, and 72.1.

All of the development cases assumed that all of the wells were drilled in the first year, with production startup the following year. The number of producers were based on an 80-ac well spacing applied to the area that is representative of that EUR being developed. Initial well rates were based on a productivity index of approximately 14 BOPD/ft of average net pay. Production forecasts were based on an exponential production decline rate varying from 19%/yr for the smallest noncommercial case to 13%/yr for the

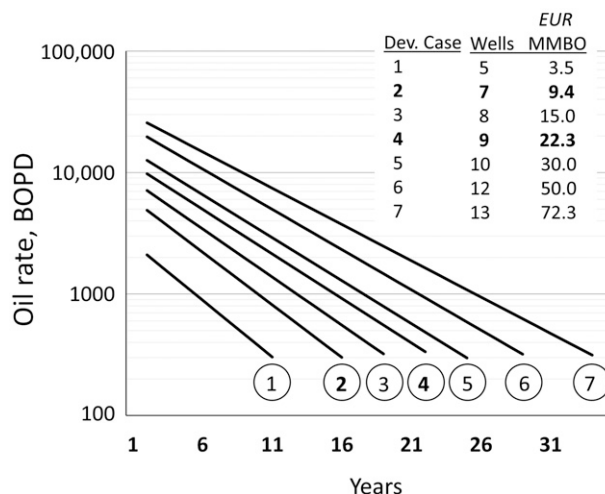


Figure 13. Production profiles (oil rate in BOPD versus year) that contribute to the income cash flow stream for the seven development cases. Development (Dev.) case 1, which produces 3.5 million bbl of oil (MMBO) from five wells, is below the minimum commercial field size of 9.4 MMBO shown by case 2 and deemed noncommercial. The cash flow details for cases 2 and 4 are shown in Figure 14. EUR = estimated ultimate recovery.

Table 4. Development Plan Inputs to the Discounted Cash Flow Model for the Seven Estimated Ultimate Recovery Cases Modeled

EUR, Million Barrels of Oil	Area, ac	Average Net Pay, ft	Number of Producers	Initial Rate, BOPD/Well	Maximum Field Rate, BOPD	Capex Development Well, Million Dollars	Capex Facilities, Million Dollars	Capex Total, Million Dollars	Opex Total, Million Dollars	NPV@10%, Million Dollars
3.5	404	30	5	420	2100	50	15	65	39	-29
9.4	549	49	7	700	4900	70	20	90	101	0
15.0	635	63	8	889	7112	80	28	108	154	33
22.3	718	76	9	1085	9765	90	37	127	217	82
30.0	787	89	10	1260	12,600	100	45	145	275	139
50.0	923	115	12	1638	19,656	120	64	184	383	315
72.1	1034	139	13	1974	25,662	130	83	213	433	539

Development plan inputs to the discounted cash flow model for the seven estimated ultimate recovery (EUR) cases modeled, resulting in the far-right column output of net present value discounted at 10% (NPV@10%), in millions of US dollars.

Abbreviations: Capex = capital expenditures; Opex = operational expenditures.

largest case. The production plot for all of the cases is shown in Figure 13.

Capital expenses of \$10 million per development well and facilities costs ranging from \$20 to \$83 million were applied in year 1. The operating expenses to support this production varied from \$11.10/bbl of oil for the smallest EUR case to \$6.00/bbl of oil for the largest EUR case. The price of oil was kept constant at \$50/bbl of oil. The cash flow streams were modeled to the economic limit, with producing life for the developed cases ranging from 16 to 34 years.

The resulting net cash flow stream with a 50% tax rate was discounted at a 10% discount rate using the mid-year discounting method to calculate the cumulative NPV (NPV@10%) for each development case. Salient information from each case is summarized in Table 4.

The annual cash flow streams for the 9.4 and 22.3 million bbl of oil cases are shown in Figure 14. The results from each NPV@10% calculation was plotted against the input EUR, and a polynomial curve was applied to best fit the data points. This enabled an accurate estimate of NPV@10% for any simulated commercial EUR output associated with the various downdip drilling locations (Figure 15). These development NPV@10% values were then adjusted to include the exploration well cost and the appraisal well cost, if any. If an appraisal well was drilled, then the production start-up was delayed 6 months, with the associated time value of money reduction applied. The success case NPV@10% values shown in the decision trees includes all of these adjustments, as appropriate, for each outcome branch.

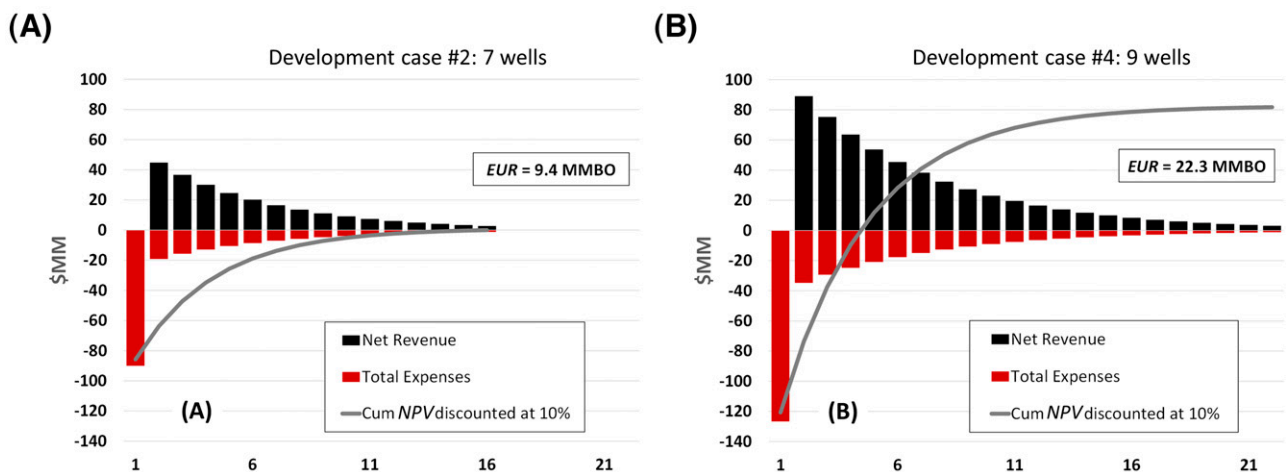


Figure 14. Annual net revenue, total expenses, and cumulative (Cum) net cash flow for (A) development case 2 (estimated ultimate recovery [EUR] = 9.4 million bbl of oil [MMBO]) and (B) development case 4 (EUR = 22.3 MMBO). The 9.4 MMBO produced in case 2 generates a comparative net present value (NPV@10%) = 0, defining the minimum commercial field size. \$MM = million dollars.

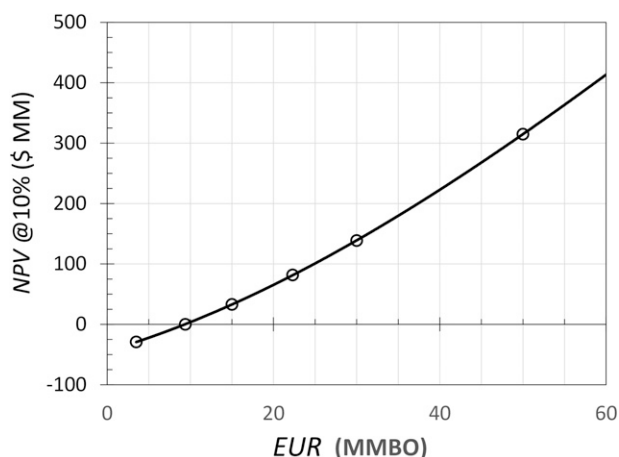


Figure 15. Development comparative net present value ($NPV@10\%$) versus estimated ultimate recovery (EUR) curve built as a polynomial best fit to seven cases shown in Figure 13 (only the six smallest cases shown). This curve is before the impact of exploration and appraisal costs, and the time value of production delay in the case of appraisal. \$MM = million dollars; MMBO = million barrels of oil.

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