Mr. Pawlowski,

You asked for a rundown on a hypothetical $15 million gas well in Cook Inlet from a tax/credit perspective.

As you know, the specifics for this hypothetical well will vary considerably based on the assumptions used. For example:

1) Are we solely looking at the economics of the well or looking at the big picture effects?
2) Is this a company that already has production? If so, how much?
3) How do the $15 million in well costs break out? Are they all capital costs? Are they all qualifying expenses for the various credits (e.g. distance from a unit or well for EICs - 43.55.025 credits)
4) Is the well productive or a dry hole?

These are just a couple of questions that will affect the results.

Tax Rate

Given the caveats, the tax rate in Cook Inlet is the lower of the rate under ACES or the rate under ELF.[1] The ELF rate is a fixed rate of $0.177/Mcf.[2] This analysis does not consider petroleum property taxes or state corporate income taxes.

AS 43.55.023 Credits

Credits under AS 43.55.023(a)(1) are 20% of qualifying expenses, spread over two years.
Credits under AS 43.55.023(b) are 25% of qualifying expenses.
Credits under AS 43.55.023(a)(1) and (b) can be combined for the same qualifying expenses but may neither credit may be combined with AS 43.55.025 credit for the same expenses.

AS 43.55.025 Credits

Credits under AS 43.55.025 range from 30%-40% depending on the details of the expenditure. These credits may not be taken for the same expenses as credits under AS 43.55.023. In essence, a company may apply for either .023 credits or .025 credits for a particular qualifying expense.

AS 43.55.024 Credits

Credits under AS 43.55.024 are commonly referred to as the “small producer credits.” The credit for production in Cook Inlet can be up to $12 million annually based on production volumes.[3] If the producer had commercial oil or gas production from a lease in Alaska before April 1, 2006 they can only receive the credit until 2016. If the producer did not have commercial production of oil or gas in Alaska before April 1, 2006 they may claim this credit for nine years following the first year of commercial production. While these are not strictly well-related credits they could be earned as a direct result of drilling a single productive well for a new explorer.

[1] See AS 43.55.011(j)(2)
[2] See 15 AAC 55.440 for the specifics of the calculation.
[3] See AS 43.55.024(c)

AS 38.05.180(i) Credits

AS 38.05.180(i) provide for exploration incentive credits of up to 50% of qualified expenses.

Scenario 1: New explorer, only well, no existing production, all costs qualify.

Assume we're looking at the economics for the well only, that the well is the only one drilled by this company, and that 100% of the well costs are qualifying capital expenses under AS 43.55.023(a)(1) and under AS 43.55.023(b) as a loss (assumes no production income).

Under this scenario the tax credits could be up to 45% of the qualifying expense of $15 million.[4] In this case the credits would be equal to $6.75 million spread over two years.[5] Production tax would be zero until production begins. When production commences the tax would be the lower of ACES or ELF rate of $0.177/Mcf. Credits under AS 43.55.023(a)(1) are currently required to be spread over two years which explains the split over two years referenced above.

Assume the well begins to produce at a rate of 6Bcf/year in the second year. Six Bcf/year is slightly above the national average for well productivity, but is consistent with publicly available data for a currently producing gas well in Cook Inlet randomly selected from AOGCC .[6] We also assume a 1% annual production decline. Lease expenses and sales price are estimated to be $1/Mcf and $5/Mcf and each are escalated annually.

Given the assumptions mentioned above, the results of a Monte Caro analysis are produced below.

Figure 1: Probability Distribution of NPV for Scenario 1

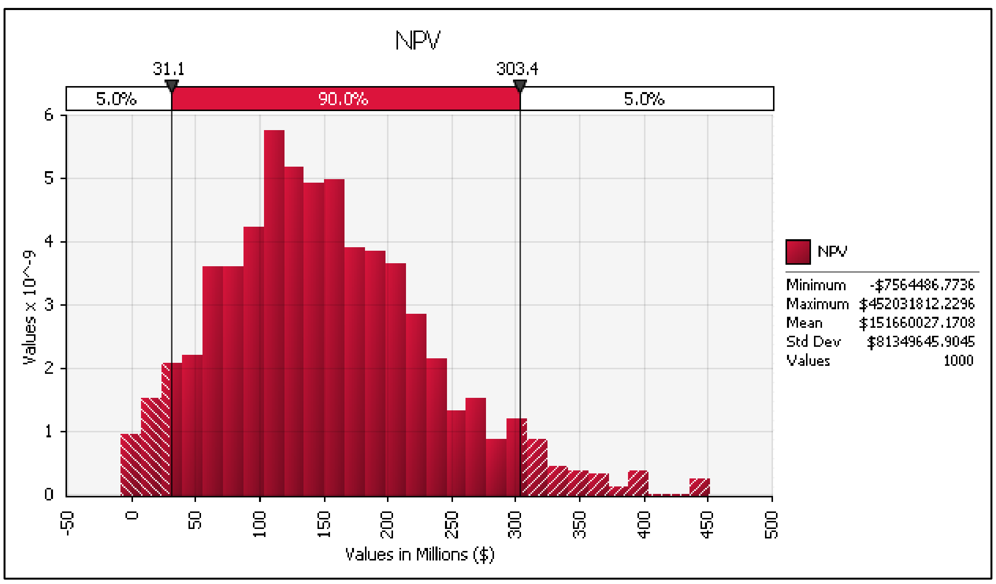


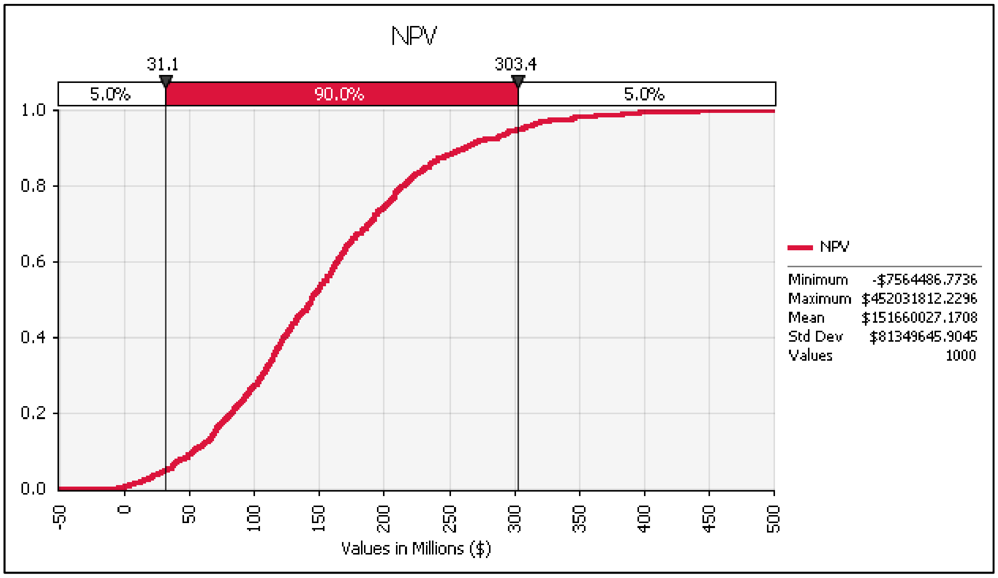
Figure 2: Cumulative Probability of NPV for Scenario 1

---

[4] 20% under AS 43.55.023(a)(1) over two years and 25% under AS 43.55.023(b)

[5] $5.25M in year one and $1.5M in year two.

[6] http://pubs.usgs.gov/fs/fs-0113-01/fs-0113-01.pdf



Scenario 2: New explorer, only well, no existing production, all costs qualify for EIC and .023 credit

Assume that we are still looking at the economics for the well only, the well is new exploration for a small producer with no existing production and all costs qualify for the maximum rate under AS 43.55.025 and for a Net Operating Loss (NOL) credit under AS 43.55.023(b).

Under this scenario, the tax credit could be up to 65% of the qualifying expense of $15 million or $9.75 million.7

Depending on production volumes, this producer may also qualify for a credit of up to $12 million against production taxes under AS 43.55.024(c) for up to ten years.

Assume the well begins to produce at a rate of 6Bcf/year in the second year. Six Bcf/year is slightly above the national average for well productivity, but is consistent with publicly available data for a currently producing gas well in Cook Inlet randomly selected from AOGCC .8 We also assume a 1% annual production decline. Lease expenses and sales price are estimated to be $1/Mcf and $5/Mcf and each are escalated annually.

Given the base case assumptions for Scenario 2 mentioned above, the results of a Monte Caro analysis are produced below.

[7] 40% for the credit under AS 43.55.025 and 25% for a net operating loss credit under AS 43.55.023(b)
[8] http://pubs.usgs.gov/fs/fs-0113-01/fs-0113-01.pdf Page 2

Figure 3: Probability Distribution of NPV for Scenario 2

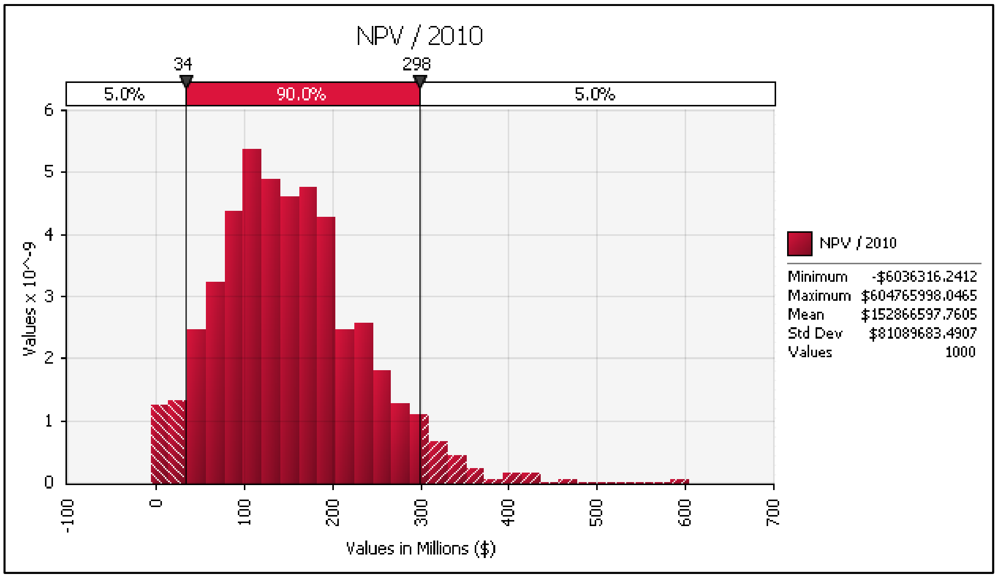
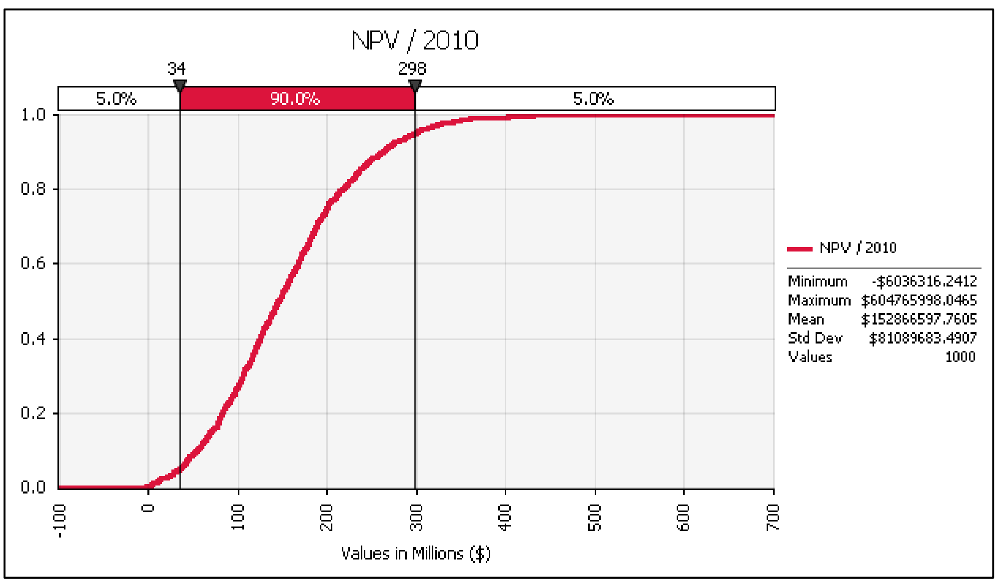


Figure 4: Cumulative Probability of NPV for Scenario 2



These scenarios both assume the well is not a dry-hole, although production values were allowed to vary as low as zero in the analysis.

Please feel free to contact me if you have any further questions.