Aeon Petroleum Consultants Quarterly Newsletter

Aeon Petroleum Consultants is a professional engineering firm registered in the State of Texas. We specialize in estimating resources and reserves. Our intent on publishing this newsletter is to highlight topics of interest to those involved in estimating, reviewing, or reporting oil and gas resources and reserves.

In this issue, we will discuss the following:

- Aeon Petroleum Consultants website
- Material Balance Equation
    - Basic form
- How to calculate drive indices Relative Value
    - Various reserves categories
    - Various resource categories

We hope to make this quarterly newsletter informative and useful. If there are any topics you would like us to discuss in future newsletters, please contact us on our website and let us know.

Aeon Petroleum Consultants Website

The website for Aeon Petroleum Consultants can be found at:

www.aeon-petro.com

The website contains topics and items that should be of interest to those estimating, reviewing or reporting oil and gas resources and reserves. Besides listing the services that Aeon Petroleum Consultants can provide to the oil and gas industry, there are items available for download, software created by Aeon Petroleum Consultants available for download or demo, videos, and resource and reserve guidelines for viewing and download.

Check out our offerings here:

https://aeon-petro.com/supplement/shop/

Please feel free to contact us regarding our services, software, or items you would like us to discuss in these newsletters.

Determining Drive Mechanisms of Oil Reservoirs Using the Material Balance Equation

In an oil reservoir with multiple drive mechanisms, how does one determine the effect of each drive mechanism on the recovery of oil? What percent of the total expected recoverable oil is attributable to each drive mechanism?

The answers to each of these questions can be easily answered using the material balance equation. The material balance equation (MBE) is usually written in a form to solve for original oil in place (OOIP, or N in the MBE) as follows:

$$N = \frac{N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right] - \left(W_e - W_p B_w\right)}{\left(B_t - B_{ti}\right) + mB_{ti}\left(\frac{B_g}{B_{gi}} - 1\right) + B_{ti}(1+m)\left[\frac{S_{wi}c_w + c_f}{1 + S_{wi}}\right]\left(P_i - P\right)}$$

Where B_t is the total formation volume factor calculated as follows:

$$B_t = B_o + \left(R_{si} + R_s\right)B_g$$

Although this appears to be a simple calculation, most of the time it is difficult to use with the data available. Also, this form isn't too helpful if one wants to solve for the drive mechanisms responsible for cumulative oil production at any point in time. If one solves the equation for oil production at a given point in time (N_p), we get:

$$N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right] = N\left(B_t - B_{ti}\right) + \frac{NmB_{ti}\left(B_g - B_{gi}\right)}{B_{gi}} + \left(W_e - W_p B_w\right) + NB_{oi}(1+m)\left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right]\left(P_i - P\right)$$

If we make the following substitution and divide through, we get:

$$\alpha = N_p\left[B_t + \left(R_p + R_{si}\right)B_g\right.$$

$$\frac{N\left(B_t - B_{ti}\right)}{\alpha} + \frac{NmB_{ti}\left(B_g - B_{gi}\right)/B_{gi}}{\alpha} + \frac{\left(W_e - W_p B_w\right)}{\alpha} + \frac{NB_{oi}(1+m)\left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right]\left(P_i - P\right)}{\alpha} = 1$$

where the ratio of the drive due to solution gas to the total is:

$$\frac{N(B_t - B_{ti})}{\alpha}$$

where the ratio of the drive due to gas cap expansion to the total is:

$$\frac{NmB_{ti}(B_g - B_{gi})/B_{gi}}{\alpha}$$

where the ratio of the drive due to water influx to the total is:

$$\frac{(W_e - W_p B_w)}{\alpha}$$

and the ratio of the drive due to rock compressibility to the total is:

$$\frac{NB_{oi}(1+m)[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}](P_i - P)}{\alpha}$$

Here are the definitions of the various parameters and units:

N = original oil in place (stock tank barrels – STB)
N_p = produced oil (STB)
B_t = total formation volume factor (bbl/STB)
B_o = instantaneous oil formation volume factor (bbl/STB)
B_{oi} =initial oil formation volume factor (bbl/STB)
B_g = gas formation volume factor (bbl/scf)
R_p = cumulative gas-oil-ratio (scf/STB)
R_s = instantaneous gas-oil-ratio (scf/STB)
R_{si} = initial gas-oil-ratio (scf/STB)
W_e=water influx (bbl)
W_p=produced water (STB)
B_w=water formation volume factor (bbl/STB)
m=ratio of gas cap pore volume to oil reservoir pore volume
c_w=compressibility of water (vol/vol/psi)

cf=compressibility of rock matrix (vol/vol/psi)
S_{wi}=initial water saturation (decimal)
P_i=initial reservoir pressure (psi)
P=instantaneous reservoir pressure (psi)

Relative Value of Reserves and Resources

To properly estimate reserves, a cash flow projection of each project (well or field for example) must be done. The reason for this is that in order to be classified as reserves, a project must be economic. In many cases we will also make a pro-forma cash flow projection for contingent and prospective resources. When making cash flow projections for behind-pipe or undeveloped reserves and resources a capital cost must be included to bring the reserve or resource to producing status.

In a reserve report it is common to calculate sub-totals for each reserve category and sum to a grand total. For example, sub-totals would be calculated for proved reserves cash flow projections as proved developed producing (PDP), proved developed non-producing (PDNP), and proved undeveloped (PUD). From these sub-totals a grand total cash flow is summarized as a total proved reserve cash flow. Likewise, the net present values are summarized.

For a reserve report this type of calculation is fine, but is this a good basis of value for a sale or purchase of oil and gas properties? We would say “no”. The value of the reserves (and resources) must be adjusted to take into account the value of the various categories. The is not a risk adjustment, but a value adjustment. There are various metrics used in the purchase and sale of oil and gas properties such as cash flow multiples, payout, dollar per barrel-of-oil equivalent per day, rate-of-return, and net present value. All of these can be adjusted to account for the various reserves and resource categories.

As an example, let us say the metric used for the sale and purchase of an oil field is net present value at a 20-percent discount rate (NPV20). In this case, two wells are for sale; a proved developed producing (PDP) well and an offset proved undeveloped (PUD) location. The proved developed well has a behind pipe proved developed non-producing (PDNP) reserve associated with it. The cash flow projection at the anticipated timing of the non-producing and undeveloped reserves shows the NPV20 for all three reserves of $1 million each. In the eyes of a buyer, is a PDP NPV20 of $1 million equal to a PDNP NPV20 of $1 million equal to a PUD NPV20 of $1 million? Think about that for a moment. The NPV20 for the PDNP and PUD are based on the timing in the reserve report, while the NPV20 for the PDP well is from the start date of the report. Any delay in moving the PDNP and PUD to a PDP status will reduce the NPV20 as stated in the reserve report. There is little risk in a change of the NPV20 from the PDP well, but what about a possible casing leak or poor cement job on the PDNP or offset drainage for the PUD reserve? It should be immediately apparent that although the NPV20 for each is the same, the values of each are different.

Listed in the table below are adjustment factors that can be used to calculate value based on the various reserve and resource classes and categories.

Reserve/Resource Class and Category	Adjustment Factor
Proved Developed Producing	1.000
Proved Developed Non-Producing	0.900
Proved Undeveloped	0.750
Probable	0.500
Possible	0.100
Contingent Resources	0.010
Prospective Resources	0.001

These adjustment factors are not written in stone, but guidelines as starting points. We will state that adjustment of values is a debatable subject, as a sale and purchase of oil and gas properties involves more than just the assessment of value. These types of transactions must take into account the cost of capital, whether the properties include operations or are non-operated, contract obligations, gathering systems, equipment and buildings, and land.

Using these factors and applying them to the example above is shown in the table below:

Well	Reserve Category	NPV20 ($MM)	Adjustment Factor	Adjusted NPV20 ($MM)
1	PDP	1.000	1.000	1.000
1	PDNP	1.000	0.900	0.900
2	PUD	1.000	0.750	0.750
Total				**2.650**

As shown in the table above, the value for the properties has been adjusted to a total of $2.65 million.

This is a continually evolving subject and we would like to hear from you regarding the methods you use to adjust value for sale and purchase transactions. You can email you methods and comments to:

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