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The perfect well ratio: defining and using the theoretically minimum well duration to improve drilling performance

J. Ford Brett, Oil and Gas Consultants International (OGCI)

Abstract

One difficult part in evaluating drilling performance is comparing the performance of wells in different situations (e.g. different business units, depths, Lithology, complexity, etc). This paper describes a "Perfect Well Ratio" concept that can simply compare drilling performance in different business units and conditions, and can identify where to most effectively apply drilling engineering or operational resources. The "Perfect Well Time" described here is the minimum time that a well could possible be drilled, and is based on clearly defined physical factors that constrain the drilling time (e.g. rock specific energy, operational limits, number of casing strings, hole size, etc). The paper presents a simple spreadsheet technique that can estimate the "Perfect Well Ratio", a dimensionless parameter calculated as the ratio of the actual time to the perfect time. The parameter honors differences in well configuration, Lithology, and allows for meaningful performance comparisons across different well types.

Just what should a well cost?

One difficult part of assessing drilling performance is comparing wells in different situations - different depths, lithology, complexity, hole programs, business units, etc. When a driller says he "saved" 10%, it is difficult to know if there were legitimate savings or if the original AFE was just too conservative. The difficulty in nailing down what wells should really cost sometimes creates unproductive tension between Drilling Organizations and their Internal Customers. Concepts such as unscheduled events, benchmarking, drilling learning curves and more recently the technical limit(1,2) have helped to clear up the situation, but still leaves open grounds for debate - this is particularly true in areas without readily comparable industry benchmarks.

The basic idea is that, when you can identify the gap between current drilling performance and what is possible, you are able to quantify the benefits of improvement, and implement measures to capture those improvements. If you know what's possible, you're more likely find ways to save capital dollars.

What is the Perfect Well?

The "Perfect Well Time" described here is the minimum time that a well could possibly be drilled, and is calculated from clearly defined physical factors that constrain the drilling time - the rock's strength, operational limits, number of casing strings, hole size, etc.. The Appendix to this paper describes the process in more detail. But briefly, the perfect well time isn't the "Best Observed time", the "Best of the Best" time, the P90 time, the "Best Offset" time or even the "Technical Limit" (see nomenclature section of this paper for suggested definitions of those terms). It is the Physical Limit that represents how fast the well could possibly be drilled limited by the physics of the drilling process.

Given a geologic sequence, a hole-size program, mud weight, and a particular rig, physics limits how fast drilling operations can possibly be conducted. It takes energy to cause rock to fail, so given 100 horsepower to apply to the bottom of a well, you will be able to break a certain strength rock only so fast – even with a perfectly sharp bit, and perfect hole cleaning. Perfect well analysis uses such physical limits to find a close approximation to the minimum time a well could possibly be drilled. It assumes one bit per hole section, with penetration rate limited by the horse power available from the rig, the rock strength, perfect trip times, perfect casing and cementing operations, etc, to closely estimate the minimum time physics would let a particular well be drilled.

The only inputs needed for this analysis are the hole-size program, an estimate of the rock strength (accurately derived from a sonic log or seismic travel times in the area), pore pressure, and a few parameters about the drilling rig to be used. The idea becomes practical through use of a simple spreadsheet technique that can estimate the perfect well time in just a few minutes or as an automatic parameter output of a typical drilling data base.

The "Perfect Well Ratio" (PWR) - a dimensionless parameter calculated as the ratio of the actual time to the perfect time – allows comparison of wells in different conditions to a common benchmark of perfection. For example, Perfect Well Ratio of 2.1 means that the subject well took 2.1 times longer than the Perfect Well to drill. As will be discussed below, the parameters honor differences in well configuration, lithology, and allows for comparison across different well types.

The Perfect Well as a benchmark

Just like building a 100% mechanical efficiency engine, it's impossible to drill the Perfect Well. As will be shown below, the PWR approach can gauge a particular drilling operation's efficiency just as comparing the efficiency of a particular engine to what is theoretically possible can tell you how the engine performs.

The Perfect Well concept is not meant to replace a rigorous technical limit process. The Perfect Well identifies a performance level and infers opportunities to improve - not how to improve. A properly conducted technical limit process can identify how to improve. Even though it should not replace other performance analysis techniques, Perfect Well Analysis can improve these techniques because it is easy to determine and provides a quantitative benchmark that is not open to human interpretation. Most importantly, it puts the performance conversation on a completely quantitative footing – it sets an objective "stake in the ground".

Compared to the Technical Limit, one benefit of the Perfect Well is that it is not open to human judgment. There are numerous examples where the technical limit – supposedly the 'best' a well could practically be drilled – has been beaten, and beaten badly. In those cases, faulty human judgment created a technical limit that did not actually reflect a real limit. (Note: The next article in this series shows that in one case the PWR correlated with a much more difficult to produce Technical limit with a correlation coefficient of .98).

Knowing the "Perfect Well Time" is a bit like knowing the "irreducible oil saturation" of a reservoir. Just as comparing the oil in place with the irreducible saturation identifies opportunities for improved production, the PWR can identify opportunities for improved drilling performance. Operations relatively close to their perfect well will be difficult to improve, and those farther away should be easier to improve. The PWR can also, be used to identify situations where application of drilling technology, engineering or operational expertise could yield performance improvements, can quickly and easily compare drilling performance across different well types and operators, validate estimates and performance in non-operated situations, and check the objectivity of various other drilling performance metrics (such as the technical limit).

Using the Perfect Well Ratio to Analyze Drilling Performance of a Portfolio

One inherent difficulty in analyzing performance in is accounting for all the differences between the various types of wells (well depth, rock strength, pressure regime, hole size program, vertical, directional, horizontal or multilateral, rank wildcat vs. routine development, etc.). PWR Analysis was developed as a method to assess these diverse operations.

Figure 1 summarizes PWR for over 500 wells in twenty-four different actual drilling programs worldwide. The programs varied from 4.2k ft to 19.8k ft in depth, from deserts to jungles, from rank wildcats to routine developments, on and offshore, on four continents. The programs included drilling activities performed by various operators along with two program operations were managed by an integrated project management provider. Detailed analysis of each program, described in detail in the next article in this series, confirms more difficult to produce findings from Technical Limit, Learning Curve Analysis, and Benchmark studies, and shows how the PWR can be used as an easy key performance indicator of drilling performance.

The operations in Figure 1 are numbered in rough order of technical difficulty from left to right ('1' being the most difficult and '24' being the technically easiest). The x-axis shows the type of operation, and the well depth. Additionally, some of the programs had industry 'best in class' offsets and/or rigorously defined Technical Limits. Where available they are also shown in the figure.

Figure 1 – PWR Worldwide Performance

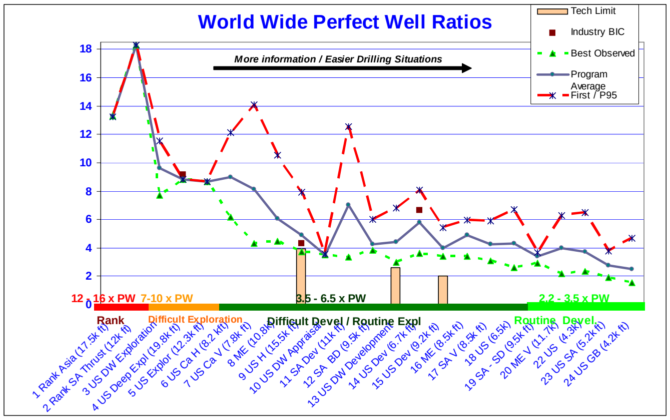


Figure 1 shows results for Perfect Well Ratio Analysis of the 24 different programs. The more rank exploration data is on the left with by progressively easier drilling operations shown to the right. The three lines represent the first or worst well in a program (red), the average (blue) and best observed (green). For single exploration wells the lines converge. Programs/wells have a regional designation (Asia, SA –South America, US-United States, ME –Middle East, along with Horizontal wells designated with an H. Other abbreviations are associated with hole diameter or a regional producing formation in order to aid 'generic' identification.

Using the PWR to create Performance Standards

Figure 1 shows a powerful use of the PWR concept. By classifying different types of wells/programs into different groups (e.g. Rank Exploration, Difficult

Exploration, Difficult Development/Routine Exploration, and Routine Development), one can use the PWR as a key performance indicator to identify operations that are not performing as well as they might or have demonstrated best results that could be shared with other areas of the company. Detailed investigation of programs with the best PWR performance yielded insight into best practices in project management discipline, well planning, and program design.

Before the PWR, differences in hole size, rock strength, operational objectives, made it difficult to assess a particular operation's efficiency in an absolute sense. With the perfect well concept, drilling organizations that thought performance was 'good' clearly have opportunities for improvement.

PWR Standards for different types and complexity of operations can then be defined to classify wells by different degrees of difficulty. This can improve new venture/project capital estimates that may now be made with demonstrated worldwide knowledge of like drilling performance, organizational learning rates, and regional understanding of drilling costs. For example, this broad set of data show that a perfect well ratio of more than about 3.5 for routine development drilling operations would indicate an opportunity for improvement compared with what is commonly achieved elsewhere.

Perfect Well analysis complements the Technical Limit approach

The Technical Limit approach (1) has proven to often improve drilling performance. This section provides some examples of how the Perfect Well approach can complement the technical limit approach by providing an unambiguous benchmark. Appendix II shows how the Perfect Well Concept very closely correlates with the much harder to predict technical limit.

"Human Created" Technical Limits don't necessarily define the best possible performance.

Operation #9 in Figure 1 (US 15.5k ft development) clearly shows the need for the perfect well methodology to complement standard industry practice. A competitor had recently defined a 'technical limit' for the area. But that limit was not the actual limit, because clearly the best observed well in operation #9 beat the estimated technical limit.

Technical limits are estimated by a drilling team and therefore may not necessarily be an objective standard measurement. The example also shows that use of a perfect well ratio technique would have suggested that in this case the technical limit (with a PWR=4.0) was achievable. Many similar type wells have subsequently demonstrated Perfect Well Ratios of 3.5 or better. In this case, the PWR serves the organization well by creating an unambiguous performance benchmark showing much more room for improvement than a technical limit estimate indicates.

The Technical Limits defined for developments #13 and #15 as well as actual best observed performance on routine developments (see developments #20, #21, #22, #23, and #24 in Figure 1) show that an accurate Technical Limit for operations is in the range of 1.8 to 2 times the perfect well. For more complex wells with multiple logging runs and extensive data gathering, the Technical limit will be a slightly higher multiple of the perfect well. Performance evaluation on these complex wells should focus more on the need and value of complexity and not necessarily on overall drilling performance time.

'Best in class' offsets aren't necessarily the best possible

Development #14 in Figure 1 shows the possible harm in just "looking over the fence" and comparing to the industry's 'best' in an area. The average for the Operator's development beat the best competitor well so it would be easy to infer and claim outstanding performance. The overall performance averages a PWR of 6 indicating about 50% more improvement is necessary to get to excellent performance (4 or better PWR). In this case at least, the Perfect Well Ratio is a better gauge than the industry best in class, and shows that sometimes saying "our performance is just as good as the best in class" could be a dangerous cause of complacency.

Perfect Well Analysis complements conventional Learning Curve Analysis

Besides improving the Technical Limit approach, Perfect Well Analysis can also improve application of Learning Curve Analysis(2). The following example shows how the PWR can help clear up this ambiguity. The Development #11 in Figure 1 was 'touted' by the integrated services provider as an example of excellent improvement. Indeed the learning on the project was significant. The initial well was some three times longer than the final well. One problem with conventional Learning Curve Analysis is that it is difficult to distinguish between good learning and poor preparation. Both can show similar results.

In Development #11, the initially very high PWR of 12x indicates that it may not be an example of 'very fast learning', but rather an example of 'poor preparation'. Clearly the best time observed in the development was quite good (PWR = 3.5), but the initial wells – and the average PWR for the entire development – was too high to be considered an unqualified success. In this way, the PWR can be used to calibrate the learning curve analysis.

Perfect Well Approach improves cost estimating and targeting

Complementing the Technical Limit and Learning

Curve approaches are important benefits of the Perfect Well Approach. Of course, time matters only as it relates to costs. The Perfect Well approach can be used as the primary component for a key performance indicator that calibrates well costs.

The Perfect Well Ratio is an effective exploration drilling performance estimating tool

Because they often lack good offsets, it's often difficult to create meaningful cost targets for exploration wells. The PWR approach can improve cost targets because it controls for differences in depth, hole program, pore pressure, and Lithology.

Programs #4 and #5, and #6 and #7 in Figure 1 show the performance of deep exploration wells drilled in an area offset to shallower difficult development drilling. The perfect well ratio for the two exploration wells equals the average for the shallower drilling. This tie supports use of the rock hardness approach and the value of using shallow drilling data in an area to assess riskier deeper drilling performance. The wide range for the development drilling would intuitively imply a wide range of risk in subsequent deeper exploration drilling. This data is useful in also testing the P10 and P90 cost estimates in exploration economic analysis often developed by 'what if' scenarios.

Perfect Well method is useful for gauging deeper drilling in a region with shallow drilling experience.

The example below (Program #4 and #5 in Figure 1) illustrates how the perfect well approach can gauge performance expectations of deeper drilling in regions with shallow well data. The deeper wells as shown below match the overall Perfect Well Ratio though quite different in specific drilling results. The relationship seems to make sense in that the same rocks and corresponding rock hardness are drilled through in each well and the subsequent continuation through progressively deeper horizons might logically follow a similar trend.

Comparison of PWR of Exploration wells of dramatically different depths

	Exploration Well Depth	PW Ratio	Actual Days
Program #4 in Fig 1	12.3k ft	8.7	69
Program #5 in Fig 1	19.8k ft	8.8	261

The Perfect Well Ratio can distinguish between 'good' and 'bad' exploration wells even with few offsets

Exploration well #2 in Figure 1 shows clearly a failure for a rank drilling project (its detailed post audit indicated failure as well). Expected performance for similar rank wells and from competitor analysis suggested was in the 10-12x the perfect well while actual results were more than 18x. Exploration drilling in a rank environment always presents significant risks and is difficult to estimate. Work to date suggests that expectations of 12x to 14x are reasonable, but unlike the development operations, that recommendation is based on only a few wells. A larger database and more analysis and use of worldwide experience to set targets based on realistic expectations is warranted. Compare Exploration well #3 with Appraisal well #10 and subsequent development #13. The appraisal well #10 shows a comparison of appraisal drilling to subsequent development drilling. The appraisal program appears to be very efficient with a final PWR of less than 4.

Perfect Well Analysis can identify opportunities for improvement

Because the PWR is an unambiguous and quantitative performance indicator, it makes an excellent Key Performance Indicator for drilling performance. Detailed performance analysis confirmed the PWR findings that operations with abnormally high PWRs most likely could improve, and those with exceptional low PWRs could be used as sources of best practices.

The Perfect Well Ratio can identify well managed operations

Operations #9, #10, #12, #15, #19, #23 and #24 in Figure 1 show unambiguously excellent risk management and project performance as evidenced by a small spread in best to average well PWR and a very good average Perfect Well Ratio of less than 5 for difficult drilling and less than 4 for more routine drilling. The P(97.7) values for these programs show the spread required for analysis of risk, which is especially important for small program size (less than 5 development wells) or for appraisal drilling.

The Perfect Well Ratio identifies Opportunities

The PWR can find areas where increased application of drilling technical and operational effort might yield performance improvements. For example, Developments #6, #7, #11, #14, #15, #16, #18, #20 and #21 in Figure 1 show programs most likely to be targets for enhancement. PWR Analysis indicates that target improvements in the range of 50-100% are possible because they are so far from normal PWRs for similar type wells. Achieving such gains would create cost improvements in the range of 25-50% (assume 50% of drilling time savings results in cost savings-low end average from regression of historical day rate drilling performance). Further detailed analysis of these drilling operations did in fact show these operations could have benefited from fewer 'starts and stops', more drilling resources, more time to plan operations, and/or better communication with and coordination by the drilling organization's customers. The point is that in these cases Perfect Well Analysis would be sufficient to identify areas where the way the drilling operations are managed could be improved.

Summary

Perfect well analysis provides an objective method to measure drilling performance. Once limiting parameters are identified, one may evaluate a portfolio of drilling programs in terms of performance and identify areas to apply resources that most likely will result in improvement actions yielding better results. The perfect well method can help organizations:

- Analyze a diverse portfolio of drilling operations
- Validate other drilling performance methods
- Gauge organizational and technical performance
- Separate learning curve benefits from technical program changes to gauge change effectiveness
- Estimate cost improvement targets
- Allocate resources to improve drilling operations

But perhaps most importantly, the Perfect Well approach has proven to change the conversation between Drilling and their customer from 'explaining the differences between performance and self-created targets' to 'assessing the risk, costs, and rewards of closing the gap between current performance an appropriate expectations'.

Appendix I – Calculating the Perfect Well Time

The following describes a technique that allows one to consistently calculate the physical limit for a particular drilling operation (and thus create well cost estimates and identify opportunities for improvement) using a quick and simple technique that converts standard operational times and a specific energy to calculate the minimum time to drill an interval to a "perfect well time". The Perfect Well Time is a close approximation of the minimum time possible to drill a particular well, and can easily be calculated with a simple spreadsheet.

To define the perfect well each hole interval has the following process steps (Note: Some steps may be deleted if there is no logging or casing, etc.). The time required to accomplish each interval is then the sum of each 'perfect time' to accomplish each process step. The following table summarizes the process steps. The section that follows describes how the sonic travel time is converted using a specific energy concept into the fastest possible penetration rate.

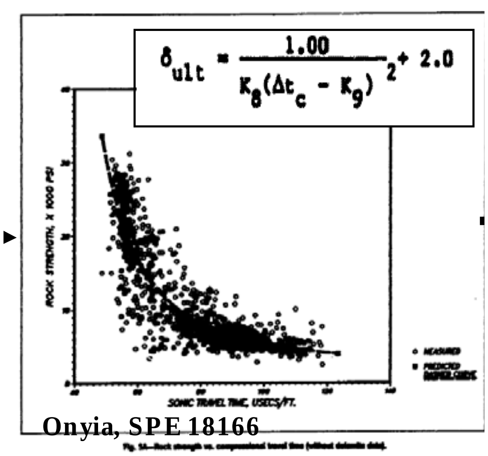
Perfect Well Assumptions – Operational Times

Process Step	Perfect Time
BOP Rig up / Test	3 hrs
Drillout / LOT	1 hr
Trip time - Cased Hole	5400 ft/hr
Trip Time - Open Hole	3400 ft/hr
Drilling Connections	982 ft/hr
Time to Cut the Rock	Depends on Sonic Log, Hole Size, & Mud Weight – see Below
Casing Running Time	2700 ft/hr
Mix and Pump Cement	15 min rig up / rig down 5 bbl/min mix 20 bbl/min pump
Logging	2000 ft/hr

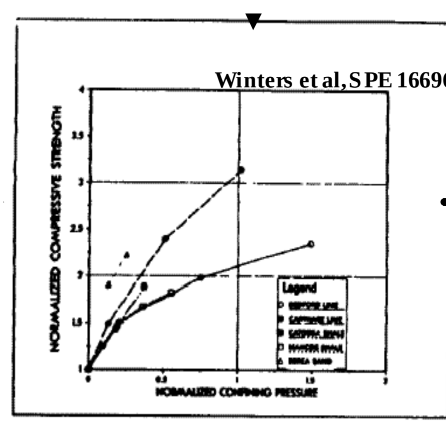
Perfect Well Assumptions – Time to cut the rock…

The Specific Energy concept assumes that it takes a minimum amount of energy to cut a certain volume of hole. The time that it takes to cut a specific interval of hole depends on the horsepower being applied to the bottom hole. Assuming a sharp bit and perfectly clean bottom of the hole there is a maximum rate that rock can be cut. To estimate the minimum time to cut an interval of rock, one needs to know the horsepower applied to the bottom, the compressive strength of the rock, and the area of the bottom of the hole.

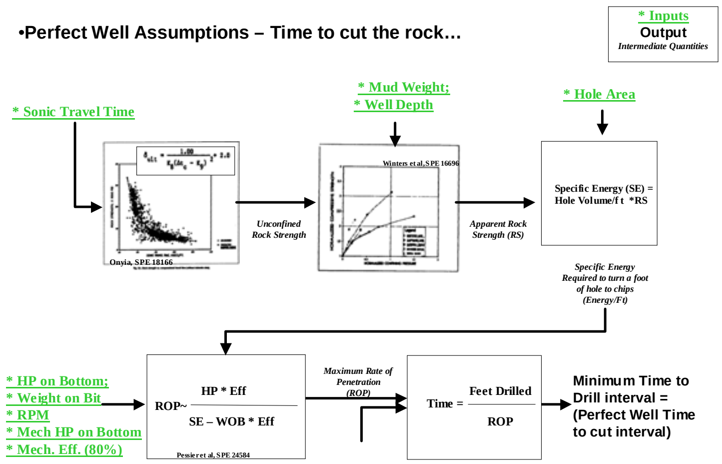
Onyia, et al and Winters et al, showed that compressive strength of a rock is a function of the unconfined compressive strength and the mud weight. There is also a reasonable correlation between Sonic Travel Time and unconfined Rock Strength (4).



Onyia, SPE 18166



Both effects can be combined along with the hole size to determine the a minimum amount of energy it will take per volume of rock. The minimum energy assumes one perfectly sharp bit per hole section, perfect hole cleaning, and always exactly 100 psi overbalance. Knowing the horsepower applied to the bottom of the hole (which will depend on hole size and rig type), one can calculate the minimum time that a particular interval of rock could possibly be drilled. (3, 5)

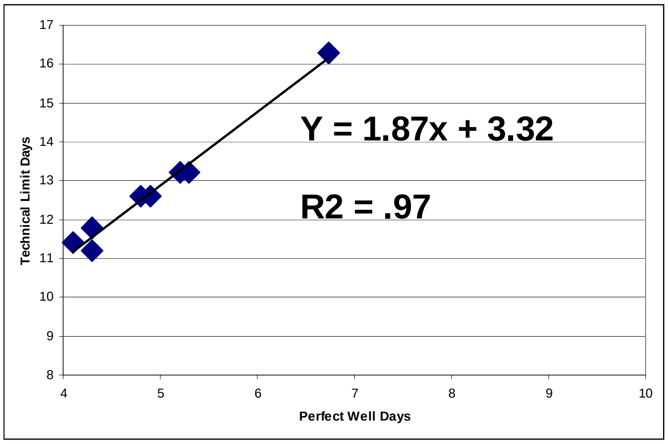


APPENDIX II – How does the Perfect Well compare with the technical limit?

On operation included in this PWR study routinely uses a Technical Limit process to improve drilling performance in its deepwater operations. The approach has helped drilling teams identify and implement valuable improvements. The Perfect Well concept is not meant to replace appropriately used the technical limit process, because the Prefect Well identifies opportunities to improve, not HOW to improve. An interesting question, however, is just how does an estimate of the perfect well compare with Technical Limit estimates created by well-disciplined technical limit estimates. The Figure below shows how the perfect well time – estimated in less than 2 hours – compares with that created through rigorous use of a technical limit process on nine wells drilled over the course of more than a year.

Variation in well depths and hole programs created significant differences in technical limit estimates. The Perfect well analysis correlated almost perfectly (R^2= 97%) with the technical limit estimates created by the team. Also, potentially significant, is that the 'slope' of the fit is 1.87, quite close to the best-observed perfect well ratio of 1.8. Essentially this means the technical limit process used by this operation very nearly creates the empirically observed best Perfect Well Ratio from the >500 wells in the study. Estimating the Perfect Well Time takes about an hour, following a technical limit process can take the entire team days.

Clearly, knowing the perfect well time is not the same as using a disciplined technical limit process to identify and take action on improvements. It is significant, however, that the perfect well time can quickly and easily create accurate estimates for technical limit drilling times.



Acknowledgments

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Nomenclature

Types of well durations:

Perfect Well – the fastest a particular well could possibly be drilled – is based on sonic logs, hole/casing size, and a set of parameters that describe the physical limit for a particular drilling operation.

Technical Limit – An estimated well duration generated by a group process whereby experts consider the best time observed on an operation and estimate the best possible time given the situation to be experienced on a particular type of well, with a particular set of equipment.

Best of Best – A fictitious well duration generated by combining the best observed time for each operation from a series of substantially similar wells (e.g. best rig up time plus best 17.5" hole section, plus best cement time, etc). Indicates what can actually be done.

Best In Class – the best time observed by any operator in a series of comparable wells.

Best Observed – the best time observed in particular operator's in a series of substantially similar wells.

Average well duration – the mean duration of a series of substantially similar wells.

P87.5 well duration – the mean duration plus two standard deviations of a series of more than 20 substantially similar wells.

Perfect Well Ratio (PWR) – the ratio of an actual well's duration to the Perfect Well time.

Types of Cost estimates:

<u>Perfect Well Cost estimate</u> – the cheapest a well could possible be – based on the perfect well time, and firm lowest quoted prices on equipment and services

<u>P10, P50, P90</u> – risk weighted cost estimates based on statistically based estimates of drilling times and firm quoted prices

<u>Scoping Well Cost Estimate</u> – cost estimate generated with low effort (say 1-2 hrs) and only general location/lithologic information.

<u>Budgetary Well Cost Estimate</u> – Cost estimate that taking about 1 day to produce that includes a specific time window and scope of work.

<u>AFE Well Cost</u> – Formally approved well cost estimate that includes a specific time window, specific scope of work and a specific lithologic column.

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