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Shale vs. Conventional Asset Development

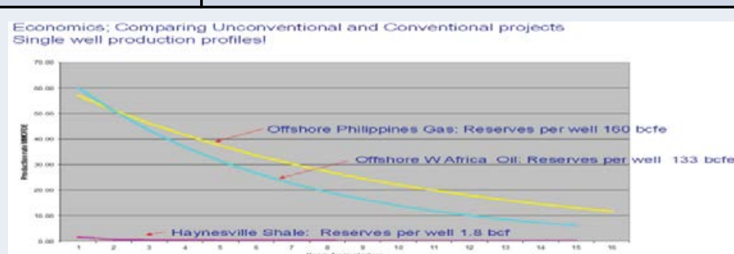
This paper compares the economics of shale gas and Light Tight Oil (LTO) with conventional (sandstone/carbonate reservoir) oil and gas development. It's a complex issue: this is a high level introduction to the different business risk considerations between the two assets: it is intended for anyone interested in the key exploration, appraisal and development risk factors leading up to Final Investment Decision (FID).

Overview of Shale and Conventional Asset Investment Considerations

Shale Resource, Onshore	**Conventional Reservoir, Offshore, major Onshore**
Exploration and Appraisal activities run together to estimate reserves, assessing geology, natural fractures, hydrocarbon content and amenability to hydraulic fracturing. Wells produce at very low rates compared to conventional wells. Hundreds are needed to exploit the shale rock. Most are drilled horizontally for thousands of metres through the rock and hydraulically fractured to produce commercially. At FID for development, reserves uncertainty is similar to conventional after exploration but before appraisal. Capturing the upside requires market access, infrastructure, acceptable fiscal terms, and the ability to handle high intensity development. The project can be adjusted, scaled up or down, as it proceeds, according to market conditions and new information.	Exploration seismic and drilling identifies a potential structure (trap), but "Appraisal" drilling (typically 3-10 wells) then takes place to reduce production rate, reserves and other uncertainties to an acceptable level before optimising the development for FID . Wells may be vertical, inclined, or horizontal in the reservoir but seldom exceed a few ten's of meters length in the reservoir itself and may or may not be hydraulically fractured. Following FID, capital is committed and spent to complete the development, including production wells and associated facilities. This capital cannot be recovered if market conditions change during production or if the downside uncertainties (reserves, costs, market access etc.) materialise. There is much less control over eventual profit once the project is developed.
• Reserves uncertainty is high as the resource covers a large, heterogeneous area. Many wells need to be drilled to establish average rate and recovery /well.	• Reserves are estimated using appraisal well test data.
• Well production decline rates are ~40% /yr. So the bulk of a well's production occurs in a few years, reducing exposure to market fluctuations when estimating probable returns.	• Well production declines at typically ~8%/yr and wells are drilled in a short time period. Therefore the project return is highly exposed to market changes over time.
• Financial performance measured by Internal Rate of Return (IRR) vary greatly. Some shale gas reservoirs are commercial at gas prices < $3/MMBTU. Others need significantly higher prices. Shale LTO requires oil prices across a range of $45-$65/Barrel (bbl).	• Financial performance of conventional reservoirs varies with size, accessibility (deep water, well depth, temperature/pressure, transportation to market), oil quality, etc. Viability ranges widely from below $10 to over $80bbl. Gas well economics depend on local market price or access to LNG projects.
• Economies of scale and continuous improvement are critical to success and need a manufacturing approach to drilling large numbers of similar wells, as well as close supply chain management.	• Economies of scale do not apply to the same extent as in shale oil or shale gas.
• A robust service sector is needed to sustain operations.	• Services are summoned for ad-hoc needs as required.
• Projects can be controversial with significant social/political factors due to work intensity, long duration, and perceived environmental impact.	• Environmental risk is usually lower than for shale oil and shale gas unless operating in pristine, fragile or challenging environments such as the Arctic.

Shale wells have low production and low reserves per well – 1.8 bcf/well vs. 133-160 bcfe/well for conventional hydrocarbons.

Bcf = billions cubic feet
Bcfe = billions cubic feet equivalent
Source: WBC Training



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