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Unconventional Gas is the Fuel of the Future for Jordan

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Article Info

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Abstract

Comparable to conventional hydrocarbon systems, unconventional gas reservoirs are characterized by complex geological and petrophysical systems as well as heterogeneities at all scales. Unlike conventional reservoirs, unconventional gas reservoirs exhibit unique gas storage capacity and exceptional producing characteristics. Unconventional gas resources (tight and shale gas) are now a core business of many large gas producers compared to being an emerging source two decades ago. This is due to the significant improvement in understanding of these resources and advancement in technology used to target unconventional resources. Also, cost and operating efficiencies allow aggressive commercial development of such gas plays.

This paper focuses on unconventional gas development, resources, basin-centered gas accumulations, comparison between conventional and unconventional resources, challenges facing unconventional reservoirs development. Case histories of tight and shale gas plays in Jordan are discussed.

Keywords: conventional reservoirs; coalbed methane; shale gas; natural gas

Introduction

The International Energy Agency (IEA) predicted that oil supplies could rise as high as 120m barrels a day by 2030 [1]. The 120m figure is debatable and can be influenced by too many unseen factors. According to IEA there is a clear decline of 'currently producing fields', the clear oil peak took place right about 2004-2008, after which a massive increase in 'fields yet to be developed' followed by another big portion of 'fields yet to be found.' An increase in 'non-conventional oil' and 'natural gas liquids' encompasses out the supply picture to meet the 120m figure. Based on this scenario the global oil production in total is not expected to peak before 2030, production of conventional oil - crude oil is projected to level off and become steady within the coming couple of years. Conventional crude oil production alone increases only modestly over 2010-2030 – by a bit less than 5 mb/d - as almost all the additional capacity from new oilfields is offset by declines in output at existing fields.

The bulk of the net increase in total oil production comes from NGLs (driven by the relatively rapid expansion in gas supply) and from unconventional resources and technologies. Unconventional resources/reservoirs are defined as: tight gas; heavy oil; shale gas; gas hydrate and coalbed methane reservoirs. These resources became a core business of many large producers and a growing number of the majors.

A tight gas reservoir is one that cannot be produced at economic flow rates or recover economic volumes of gas unless the well is stimulated by a large hydraulic fracture treatment and/or produced using horizontal wellbores [2] [3]. This definition also applies to coalbed methane, shale gas, and tight carbonate reservoirs. There is no typical tight gas reservoir, it can be: deep or shallow; high pressure or low pressure; high temperature or low temperature; homogeneous or naturally fractured (heterogeneous);

single or multilayered; high transient decline rates; comingled production; require fracturing jobs and/or horizontal well. In other words, tight gas is gas that is 'trapped' in a very tight formation underground, stored within low porosity and low permeability rock formations. A great deal of effort has to be put into extracting this gas from a tight formation, such as fracturing and acidizing.

In many basins, e.g. Rocky Mountain basins in the Western US, gas accumulations in low permeability sandstones are associated with widespread gas shows while drilling and a lack of associated water production where the productivity of wells drilled in these settings varied dramatically [4]. This suggested having localized areas with more favorable rock properties, sweet spots, or the variations in drilling and completion technology account for the productivity variability.

Tight Gas Sands Development

The development of many tight gas sand fields that are productive today began in the Western United States San Juan Basin. By 1970s, around 1 Tcf/year were produced nationwide from the TGS. Then different fields were discovered including fields in East Texas (Dew-Mimms Creek), the Piceance Basin of northwestern Colorado (Rulison, Mamm Creek), the Green River Basin of Wyoming (Jonah, Pinedale, Wamsutter), and the Denver-Julesberg Basin of Colorado (Wattenberg). Tight gas is predominantly a cost-effective issue. Production is relative to technology development, well cost, stimulation cost and existing gas price. As technology has developed, the permeability threshold in North America has changed from less than 0.1mD in the 1970s to less than 0.01mD in the 1980s to less than 0.001mD (ultra-tight) today [2] [4] [5] [6]. As a result, tight gas now makes a substantial contribution (about 30% of produced gas) to USA gas supply. This figure was obtained based on the 70% contribution of unconventional gas that accounts for 43% of the USA gas production. The technologies that have allowed this are the ability to drill long horizontal wells, effective fracture stimulation and reservoir characterization including developments in 3D seismic, special core analysis, electric log data, and diagenetic and structural analysis.

In Europe, the higher cost base and ready access to "cheap" imported gas means that tight gas development has been largely neglected, except in Germany where financial incentives for tight gas exist. In Germany, tight reservoirs include reservoirs with effective gas permeability less than 0.6 mD [7]. The potential resources of undiscovered and tight gas in Germany are in the range of 50 to 150 billion cubic meters. Tight gas developments are currently underway in Germany, offshore Holland and the UK, and efforts are being made to develop basin centered gas accumulations in Central Europe. Unconventional gas extracted from European territory is not expected to come to market for at least a decade.

Recent developments in the gas sector caused by the application of new technology have made unconventional gas resources available at competitive cost. A boom in unconventional gas would also have considerable implications for different countries' energy policy. Unconventional gas can play significant role in transforming any country's energy supply situation, but this is accompanied by an extra cost of addressing the technological and economic challenges unconventional gas faces as well as the questions of public acceptance.

Resources

The world natural gas reserves by geographic region are shown in Figure 1 [8]. From this figure one can see that the largest resources of natural gas exist in the Middle East.

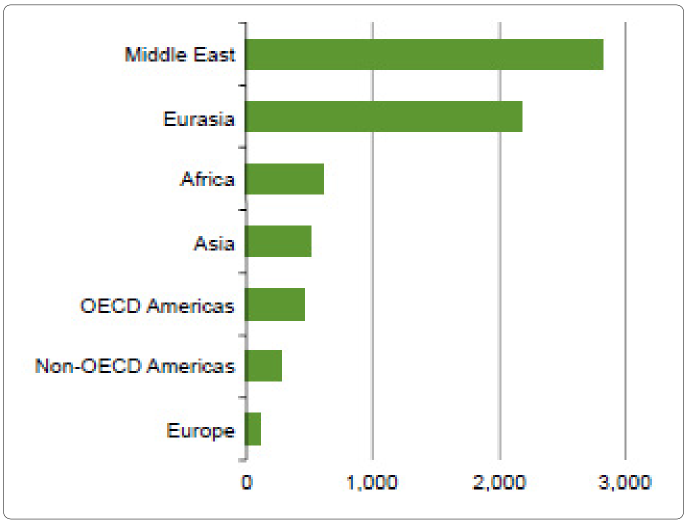

Figure 1. World Proved Natural Gas Reserves by Region as of January 1, 2016 (trillion cubic feet: Tcf)

The total scope of gas resources was viewed as a triangle for the first time by Master [9] as shown in Figure 2. This figure shows that the natural gas resources are distributed log-normally in nature with respect to formation permeability of tight gas sands. The triangle peak represents the conventional gas, which is relatively easy to extract, with a small available supply. There is much larger supply of unconventional gas, which makes up the base of the triangle, but it is more difficult to extract. As development of gas continues, oil and gas industries are moving down the triangle and developing more unconventional gas resources that are difficult to be exploit but they are large in size.

The tight gas resources in USA were estimated by the Gas Technology Institute (2001) and shown in Figure 3. The tight sand gas reserves distribution is well-matched with the scheme of the resource triangle shown in Figure 2 and confirms the fact that significant improvement in technology or changes in the gas market are required before the gas in the resources category can be produces at an economic level. Tight sands produce about 6 Tcf of gas per year in the United States which is 27-30% of the total gas produced. As of January, 2009, the U. S. Energy Information Administration (EIA) estimates that 310 Tcf of technically recoverable tight gas exists within the U.S, representing over 17% of the total recoverable gas. Worldwide, more than 7,400 TCF of natural gas is estimated to be contained within tight sands [10] with some estimates as large as 30,000 TcF.

According to Holditch et. al. [3], large resources of unconventional gas reservoirs exists worldwide. In Table 1, Kawata and Fujita [11] summarized the work of Rogner [10], who estimated the worldwide unconventional gas resource. As shown in Table 1, the largest resources exist in North America. Middle East and North Africa became number 6 in the world with total unconventional resources of 32,560 Tcf, and in the fourth place in terms of tight sand gas reserves (823 Tcf).

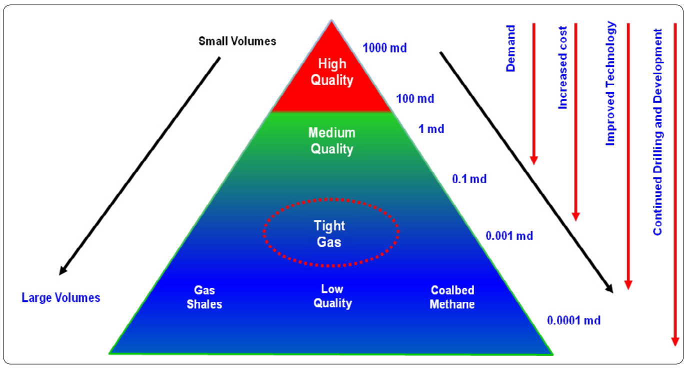

Figure 2. Resource Triangle

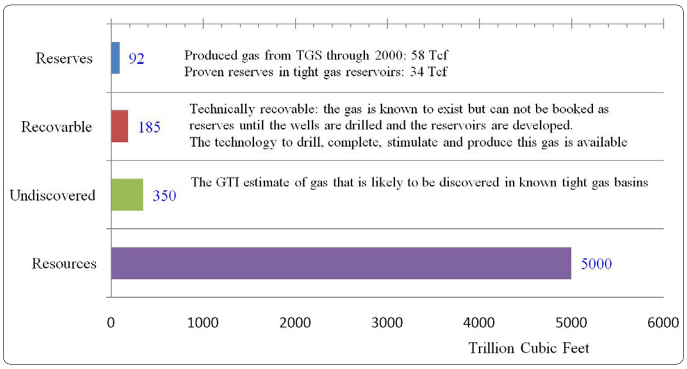

Figure 3. Tight Gas Resources in USA [26]

Using the United States as an analogy, there is good reason to expect that unconventional gas production will increase significantly around the world in the coming decades for the following reasons [3] [6] [10]:

- Exploitation of the estimated resources
- A large number of geologic basins around the world contain unconventional gas reservoirs.
- Utilization of reasonable recovery efficiency to develop unconventional gas worldwide.
- Tight gas sands development in the United States is critical to future U.S. gas supply and has to be over 4 Tcf/year and is supported by ongoing technological development.
- The related developed technology in the United States over the past 3 to 4 decades will be available for application around the world.
- New technology is rapidly becoming a worldwide commodity through efforts of major service companies
- The global need for energy, particularly natural gas, will continue to be an incentive for worldwide unconventional gas resource development.
- Tight gas sands, gas shales, and coalbed methane are already critical to North America today and will be an important energy source worldwide during the 21st Century.
- Unconventional resources exploitation governmental incentives.
- Conventional gas is mature and declining so the future of the gas industry is Unconventional, consequently unconventional gas production has no other choice but to grow.
- Higher oil and gas prices are driving the development of unconventional oil and gas resources.

Table 1: Worldwide Unconventional Gas Resources

Region	Coalbed Methane	Shale Gas	TSG	Total
North America	3,017	3,842	1,371	8,228
Former Soviet Union	3,957	627	901	5,485
Centrally Planned Asia and China	1,215	3,528	353	5,094
Pacific (OECD)	470	2,313	705	3,487
Latin America	39	2,117	1,293	3,448
Middle East and North Africa	0	2,548	823	3,370
Sub-Saharan Africa	39	274	784	1,097
Western Europe	157	510	353	1,019
Other Asia Pacific	0	314	549	862
Central and Eastern Europe	118	39	78	235
South Asia	39	0	196	235
Total	9,051	16,112	7,406	32,560

The petrographic observation of the tight sand porous media revealed that the pore geometry of sandstone can be broken down into three categories [6] [12] [13]: 1) grain-supported pores, 2) narrow intergranular slots connecting solution pores, and 3) matrix-supported grains.

Basin-Centered Gas Accumulations

The commercial production of gas from BCGAs is generally associated with areas that have improved permeability. These areas are known as "sweet spots". Sweet spots are "those reservoir rocks that are characterized by porosity and permeability values greater than the average values for tight gas sands at a specific depth interval" [14]. Holditch [2] reported that "the commercial production from BCGAs is strongly dependent on the presence of open natural fractures and the ability to connect these natural fracture systems through hydraulic fracture stimulation".

Conventional Versus Unconventional Reservoirs

Many papers in the petroleum literature provide information on the differences between conventional and low permeability reservoirs in terms of petrophysical attributes and trapping mechanisms, most of these papers refer to the materials published by Naik [15]. These differences lie in the:

- low-permeability structure itself
- response to overburden stress

- impact of the low-permeability structure on effective permeability relationships under conditions of multiphase saturation, or
- understanding of multi-phase, effective permeability to gas at varying degrees of water saturation under conditions of overburden stress

A comparison of conventional reservoir behavior with unconventional reservoir behavior is shown in Figure 4 [15] [16]. In a conventional reservoir, it is clear that there is relative permeability in excess of 2% to one or both fluid phases across a wide range of water saturation. In traditional reservoirs, critical water saturation and irreducible water saturation occur at similar water saturation values. Under these conditions, the absence of common water production usually implies that a reservoir system is at, or near, irreducible water saturation. In low-permeability reservoirs, however, one can find that over a wide range of water saturation, there is less than 2% relative permeability to either fluid phase, and critical water saturation and irreducible water saturation occur at very different water saturation values. In these reservoirs, the lack of water production cannot be used to infer irreducible water saturation. In traditional reservoir, there is a wide range of water saturations at which both water and gas can flow. In low-permeability reservoir, there is a broad range of water saturations in which neither gas nor water can flow. In some very low-permeability reservoir, there is virtually no mobile water phase even at very high water saturations. The term 'permeability jail' describes the saturation region across which there is negligible effective permeability to either water or gas. Failure to fully understand these relationships leads to widespread misunderstanding as to how hydrocarbon systems are marked in low-permeability reservoirs.

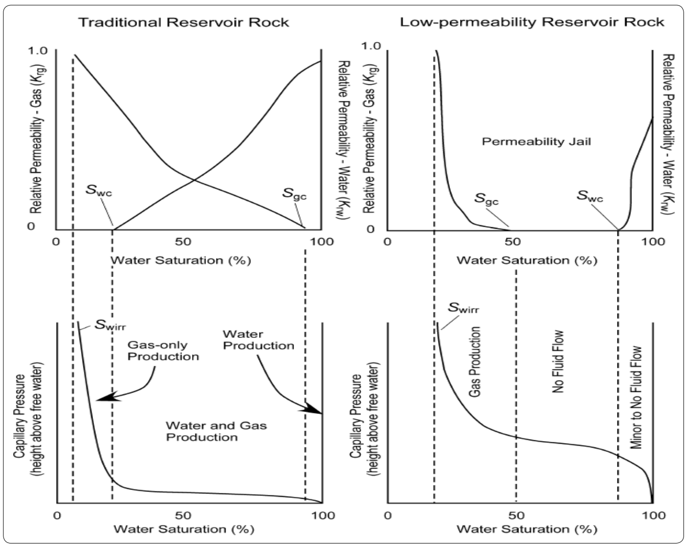

Figure 4. Representation of capillary pressure and relative permeability relationships in traditional and low-permeability reservoir rocks (S_{wc}- Critical water saturation, S_{gc} -critical gas saturation, and S_{wirr} - irreducible water saturation)

Low-permeability reservoirs are usually characterized by high to very high capillary pressures at relatively moderate wetting-phase saturations (Figure 5). In many cases, wetting-phase saturations of 50% (close to S_{gc}) are associated with capillary pressures in excess of 1000 psia, suggesting that a large number of pore throats are less than 0.1 micrometer in diameter and are of the micro- to nanoscale. In many low-permeability sandstone reservoirs, wetting-phase saturation continues to decrease with increasing capillary pressure [6].

The relationships between relative permeability, capillary pressure, and position within a trap in traditional and low permeability reservoirs are shown in Figures 5 and 6, respectively as represented by map and cross section views [16]. These two figures illustrate the differences encountered in drilling a low-permeability reservoir versus a more traditional one. In both cases, the map shows a reservoir body that thins and pinches out in a structurally up dip direction. In conventional reservoirs (Figure 5), water production extends down dip to a free-water level (FWL). In the middle part of the reservoir, both gas and water are produced, with water decreasing up dip. The up dip portion of the reservoir is characterized by water free production of gas.

Figure 6 illustrates relationships found for a reservoir with low-permeability reservoir properties. In low permeability reservoirs, significant water production is restricted to very low structural positions near the FWL. In many cases, the effective permeability to water is so low that there is little to no fluid flow at or below the FWL. Above the FWL, a wide region of little to no fluid flow exists. Farther up dip, water-free gas production is found. Because of the wide region with little to no fluid flow, once drilling encounters the wide transition zone with virtually no fluid production, drilling uncommonly extends down dip to a true FWL.

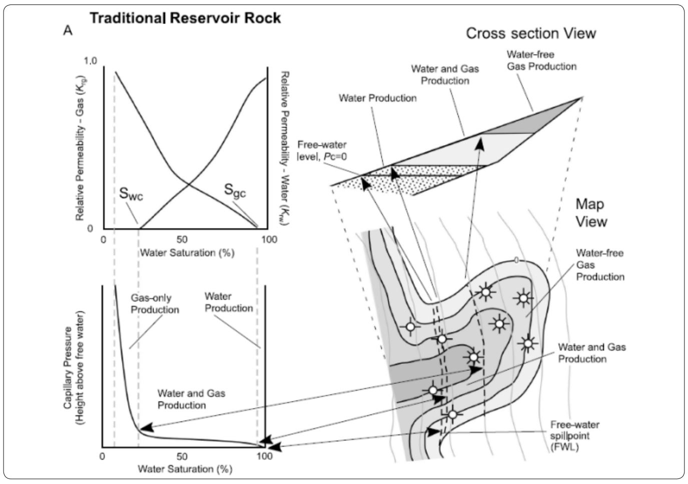

Figure 5. Representation of the relationships between capillary pressure, relative permeability, and position within a trap of a conventional reservoir

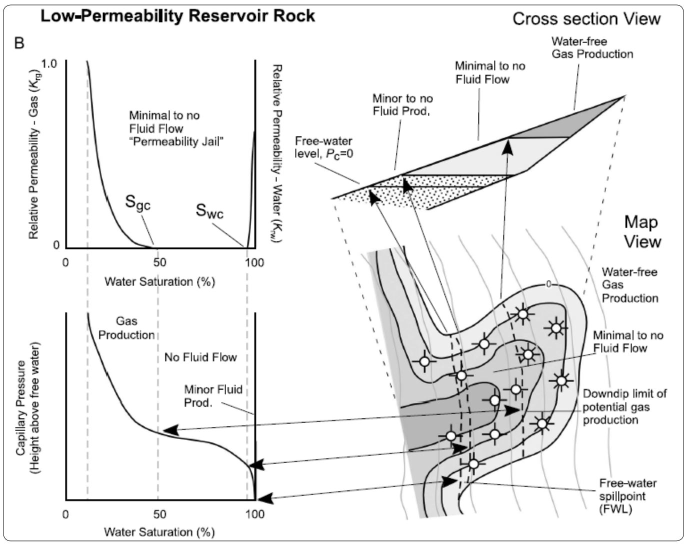

Figure 6. Representation of the relationships between capillary pressure, relative permeability, and position within a trap of a low-permeability reservoir

Challenges

Production from unconventional tight gas reservoirs is expected to rise in the next decades. Developing the tight gas sands is a huge challenge to geoscientists faced with understanding the depositional setting, stratigraphy, structure, geochemistry, geomechanics, seismic character, and petrophysical properties controlling production. Some of the greatest challenges include: 1) understanding how and where these rocks are charged with gas; 2) what controls the location of highly-productive "sweetspots"; and 3) what factors, such as sand body size and heterogeneity, account for the large variations in well drainage areas. To address these challenges oil and gas industry has to focus on the needed technologies to continue development of gas from unconventional reservoirs. Economic production from TGS depends on the used methods and technologies that address the following challenges:

- Geomechanical, petrophysical and geological characteristics
- Formation evaluation
- Reservoir engineering studies (field/well modeling & simulation)
- Massive hydraulic-fracturing treatments.
- Advanced drilling: Horizontal, multilateral and UBD
- Special completion methods.

Understanding of the geomechanical, petrophysical and geological properties: formation strength and in-situ stresses; lithofacies associations; facies distribution in-situ porosity; effective gas permeabilities at reservoir conditions; capillary pressure; pore size and its distribution; etc, is essential for understanding gas production from TGS reservoirs. Because most logging tools were developed to evaluate formations with high porosity, they often lose their sensitivity in low-permeability, low-porosity reservoirs. If technology can be developed well enough to provide a better estimate of formation permeability, porosity and water saturation, the development of unconventional reservoirs can be improved substantially.

Proper formation evaluation is essential for the development of TGS reservoir. Not all methods (volumetric, material balance, decline curves and reservoir models) used to estimate the reserves of conventional reservoirs work to evaluate the unconventional reservoirs reserves. Usually, volumetric methods do not work in tight gas sands because the proper drainage area to use in the computation is hardly ever known. One of the most difficult parameters to evaluate in tight gas reservoirs is the drainage-area size and shape. In tight reservoirs, months or years of production normally are required before the pressure transients are affected by reservoir boundaries or well-to-well interference. Thus, the engineer often has to estimate the drainage-area size and shape for a typical well to estimate reserves. It is required to know the depositional system and the effects of diagenesis (caused by increased pressure and temperature) on the rock to estimate the drainage area size and shape for a specific well. Egg-shaped drainage volumes are likely caused by depositional or fracture trends and the orientation of hydraulic fractures. Also, material balance seldom works in tight gas sands because it is almost impossible to shut in wells long enough to determine the current average reservoir pressure. Therefore, the best method to determine reserves in tight gas reservoirs is to analyze production data by use of either decline curves (production versus time: hyperbolically decreasing flow rate) or reservoir simulation.

Most TGS reservoirs are not isotropic and homogeneous. Some reservoirs are naturally fractured, layered with anisotropic permeabilities. The reservoir-engineering analysis methods must be tailored to better analyze the processes that occur in TGS reservoirs. A common characteristic of TGS reservoirs is that the formations can be very thin and/or several hundreds or even thousands of feet thick. Well completion cost and recovery maximization can be achieved if these reservoirs are produced with multizone completions, oriented perforating, massive hydraulic fracturing, and proper logging methods.

Usually gas production from TGS reservoirs requires some form of artificial stimulation, such as hydraulic fracturing. Wells completed in tight reservoir rocks have to be stimulated by one or several hydraulic fracs in order to achieve an economically adequate production rate. Compared with conventional reservoirs, TGS often show a much weaker response to the frac treatments, resulting in low production rates and a high economic risk. It is known that natural rock fractures are an important factor in the economic recovery of gas from tight reservoirs. Advanced methods of gas production in these environments are taking advantage of gas flow from natural fractures in the reservoir rock. The distribution, orientation, and density of these fractures is key to proper planning and well scheduling in tight gas reservoirs. In addition to these physical attributes, reservoir engineers also need detailed analyses of the effects of interstitial clays and fluids. The nature of the natural fractures and other characteristics of the reservoir were sufficiently well-determined that drilling could be accurately directed.

Advancements in drilling methods reduce drilling and field development costs and substantially improve the economics of developing TGS reservoirs. Further modern technologies for the production of TGS reservoirs are horizontal and multilateral wells, as well as underbalanced drilling. Application of advanced techniques like horizontal drilling and technologies that permit efficient fracturing of multiple zones per well allow gas to migrate a shorter distance to reach a location where it can enter a well and be produced with minimum driving force. When these reservoirs extend vertically for several thousand feet, new fracturing techniques are required. To create better solutions adapted for gas, industry researchers will need to understand underlying flow physics in greater detail.

Gas production from a TGS well will be low on a per-well basis compared with gas production from conventional gas reservoirs. A lot of wells have to be drilled to get most of the gas out of the ground in TGS reservoirs. Geologists, engineers, log analysts, and other professionals have to come to the common table with a need to better understand and predict reservoir properties in low-permeability reservoirs and use that information in resource evaluation, reservoir characterization and management.

Case History – Jordan

I.Tight Gas: Risha Gas Field in Eastern Jordan

Jordan has no conventional oil resources of its own and relies fully on imports. The country's known oil reserves are only one million barrels and that of natural gas is 213 billion cubic feet [7]. Production of gas in Jordan began in May 1989 from the Ordovician Formation of Risha gas field that was discovered in September 1986 (see Figure 7). Initially the production was from the Northern Area, from the main Risha area and from the Risha 8 reservoir. Risha basin exploration began with seismic shooting (9,057 km) and exploratory drilling by Jordan's Natural Resources Authority. Seismic images showed horst and graben structures in the Paleozoic section [18]. The Paleozoic sediments (Figure 8) dip and thicken eastward while the overlying Mesozoic sediments thicken toward west and dip under the Basalt Plateau. The total sedimentary thickness in the Risha basin exceeds 7,000 m [18]. Risha-1 (3177 m TD) and Risha-2 (3314 m) were drilled in 1984 followed by Risha-3 (4204 m) which discovered gas in Ordovician sandstones. Since then, dozens of wells have been drilled; many are dry but some wells produce gas (see figure 7). Reservoir geology of the producing Risha Formation is quite complex with varying production capacity between wells due to original poor porosity (2-10%) and permeability (less than 10 md, in most wells less than 0.01 md) locally improved by natural fracturing and minimum water saturation of 28%. The Risha field described to be 1500 sq. km in area produces from Ordovician tight sandstone at different depths with thin beds (2-12 m each) in faulted glacio-fluvial channels. Its proven gas reserves are 180 billion cubic feet (Bcf) (equivalent of 34.2 MMbo) [19]. Nevertheless, estimates of total gas reserves in the field range from 400 bcf [27] to 2-3 Tcf [20]. The decline analysis was used for reserve estimation in Risha formation with a result of 604 BSCF. However the estimation represents the minimum recoverable amount of gas from the existing producers only [20].

Figure 9 shows Jordan natural gas consumption and production from Risha field [21]. The gas production, from Risha field, since 1989 and up to the end of 2006 has totaled 0.1598 Tcf (~160 BCF). Current daily production is around 22 MMSCF or 8.03 Bcf per year (0.00803 Tcf/year). The current yearly production has decreased by about 73% compared to 2006. Six out of 20 producing wells are produced irregularly through gas compression. Treated gas is sold to Risha power plant to generate around 70 Mw. The produced gas consists mainly of methane (91%), carbon dioxide (7.5%) and other traces (1.5%) with a gross calorific value of 940 Btu/SCF (sales gas heating value varies from 920 to 980 Btu/SCF). The high content of carbon dioxide makes the gas sour.

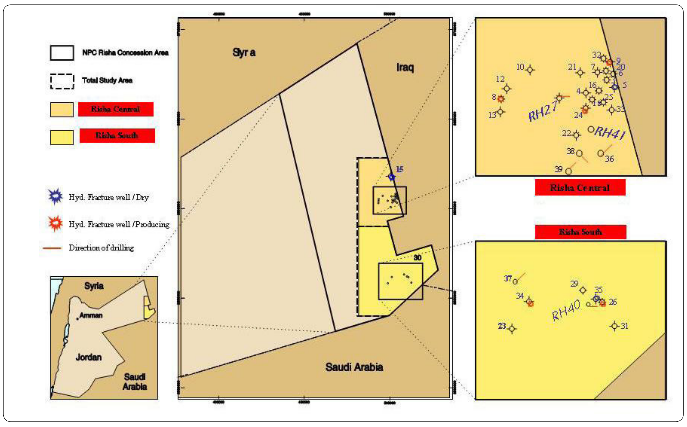

Figure 7. Location of Risha Gas Field in Jordan. NPC Concession [20]

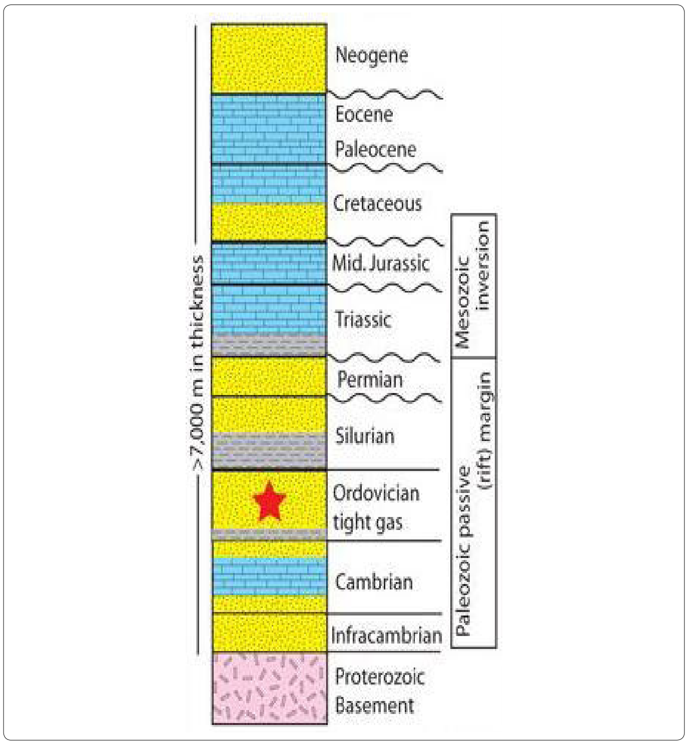

Figure 8. Risha Field Stratigraphic Column

Risha field is widely extended in both areal and vertical space and there are strong indications about the presence of large gas potential outside the drainage area of the existing wells [20], because of the following facts:

- The majority of the existing producers are concentrated in relatively small area (30 sq. km) out of the National Petroleum Company concession area of 7600 sq. km (Figure 7).
- The carried out field integrated studies were not successful due to a huge amount of gas required for history matching.
- The petrophysical data in deep wells indicate the possibility of the presence of huge amount of gas in deeper Ordovician formations.
- The tight fractured reservoirs are characterized by initial sharp decline in rate followed by gradual leveling off in production with time (Figure 9). Therefore the analytical methods would give increasing gas volume with time.
- The experience in Risha, compared to worldwide observations of analogous reservoirs, indicates that reservoir pressures near producing wells are close to their initial values. Thus, drilling more wells will improve the overall recovery.
- The importance of Risha field is strengthened by the fact that it shares a similar geologic history with the little-developed Akkas gas field, some 200 kilometers further east in Iraq. Indeed, the Paleozoic section thickens eastward up to 6,500 m. It appears that the deserts of eastern Jordan and western Iraq have a great potential for Paleozoic tight gas plays awaiting systematic exploration.
- Proper investment and application of modern technology for tight sand gas could result in increasing the production significantly from Risha field.

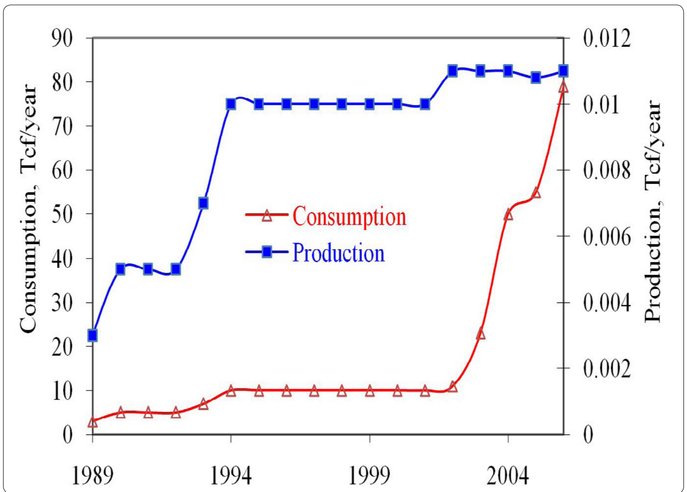

Figure 9. Jordan Natural Gas Consumption and Production from Risha Gas Field

Based on the production history shown in Figure 9, one can see that during the initial stage of production, gas productivity grows fast, mainly because more wells were brought in, and kept operating at high reservoir pressure. Risha wells yields gas with the content discussed earlier, and the reservoir pressure drops a little. The first steady gas production was reached in 1994 and lasted until the year 2001. In 2000, the NPC in collaboration with Geoquest (a division of Schlumberger) had conducted a detailed study of the Risha gas field. Consequently, and during the years 2002-2005, Weatherford had drilled one well using UBD technology and re-entered three other wells for production stimulation. This resulting in increasing the gas production and be shifted to a new steady state (see Figure 9).

Most of the wells drilled after 1986 penetrated only the Risha member (upper section) of the Dubeidib. The NPC has set itself an ambitious target to increase gas production from the field to 300 MMSCFD by 2015. Because the gas production from Risha field southern area (Figure 7) had begun in August 2003, with few wells drilled so far, and to slow down the decline in gas production, in October 2009, British Petroleum (BP) signed a deal with the government of Jordan to explore and develop the natural gas resources of the Risha Basin. During the first phase of the project, BP will explore the area totaling about 7,000 sq. km along the Jordanian-Iraqi border for 3-4 years at a cost of $237 million. If the exploration yields successful results, BP will then invest US$8-10 billion to produce 300-1,000 million cubic feet (mcf) per day. If all goes well, the Jordanian government will receive 50% of the produced gas, with the other half going to BP and NPC. This will significantly boost Jordan's natural gas and electricity production.

II-.Shale Gas

The most recent work about shale gas development was discussed by Khlaifat [22] and the most comprehensive study about shale gas resources in Jordan was carried out by Luning et al. [23]. In their study they have identified three lower hot shale depocenters in Jordan, which are located in the western Risha, eastern Wadi Sirhan, and Jafr areas. The eastern Risha area was part of a larger scale paleohigh covering northeast Jordan, most of Syria and Iraq, and north-central Saudi Arabia (Qusaiba area). At least in Jordan, the high coincides with the depocenter of the latest Ordovician glaciation.

Thermal maturity increases from immature in the Southern Desert outcrops to late or postmature in northern Jordan. Organic richness and pyrolysis data decline significantly with increasing thermal maturity caused by hydrocarbon generation. Prior to maturation, maximum organic richness was interpreted to have considerably exceeded 10% (TOC) with good S2 yields (up to 74 mg/g) as reflected in the values of the immature lower hot shale in two exploration wells in the Jafr and Southern Desert areas [23]. Konert et al. [24] estimated that Silurian sourced hydrocarbons in the range of about 1 trillion bbl of oil equivalent were initially reservoired on the Arabian plate. The oil and gas discoveries in the Risha and Wadi Sirhan areas demonstrate the existence of the Silurian hydrocarbon system in Jordan, however, with little exploration success so far. This may partly be caused by the low level of exploration in Jordan [25]. For further exploration of shale gas in Jordan, more efforts have to be put towards carrying out a proper workflow for Silurian plays shale gas resource development where Ordovician reservoir quality and timing of maturation are not overlooked.

Conclusion

The following conclusions can be drawn from the paper:

- There is an enormous volume of unconventional gas to supply world energy needs for many decades to come to be found and produced.
- Although TGS production is growing in more than 35 countries, gas production from a TGS well is low compared with gas production from conventional reservoirs on a per-well basis.
- A bundle of wells have to be drilled to get most of the gas out of the unconventional reservoirs.
- Small well spacing is required to deplete a low-permeability reservoir in a 20- to 30-year time frame.
- The capital cost of unconventional gas production is high because of the need for more rigs, equipment and people.
- The driving forces to bring much of unconventional TGS to market are: increased oil and gas prices; decline in conventional oil and gas production; and improvement in drilling, completion and hydraulic fracturing technologies.
- Understanding and predicting reservoir properties, needed for resource evaluation, reservoir characterization and management, in low-permeability reservoirs requires a team work of geoscientists, engineers and other professionals.
- The three considered cases show that tight and shale gas reservoirs have a huge future potential for production.

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