Will the Operational Success of U.S Gas Producers Be a Financial Fizzle? Shale Gas and the Future of the U.S. Gas Market

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For the past thirty-five years, the U.S. natural gas industry has been haunted by a spectre – the spectre of resource depletion.

This spectre was not a product of childish imagining – the stereotypical ghosts under the bed. The spectre of resource depletion continuously confronted the industry. Natural gas reserves in the contiguous 48 states plummeted 47% from 289 Tcf in 1967 to only 153 Tcf in 1993. Natural gas production declined 32% from its peak of 22.5 Tcf in 1973 to 15.3 Tcf in 1986. Production subsequently managed to increase modestly during the 1990's, but only because the reserve-to-production ratio was also plummeting from 15.7 in 1967 to a highly uncomfortable 8.3 by 1999.

After looming large for a quarter of a century, the spectre of resource depletion has begun to fade during the past decade. Following three decades of annual production exceeding annual reserve additions by an average of 4.4 Tcf per year, annual reserve additions have consistently exceeded production beginning in 1999.

From 1998 to 2006, average annual reserve additions were 24.5 Tcf, 44% higher than the 17.0 Tcf average additions from 1990 to 1998. Because reserve additions consistently exceeded annual production during this period by an average of 5.85 Tcf per year, what appeared to be an inexorable trend of declining reserves has been decisively reversed. The year 2006 saw natural gas reserves in the contiguous 48 states reach 201 Tcf, a level last seen in 1976.

This reversal was entirely the result of the emergence of unconventional gas as the dominant source of U.S. natural gas reserve additions. From 1998 to 2006, reserve additions from tight sandstones, coalbed methane, shale gas, and tight carbonates averaged 13.0 Tcf per year, a 124% increase over the 5.8 Tcf per year they contributed from 1990 to 1998 (Figure 1). Of the 7.5 Tcf overall increment to reserve additions, these four unconventional sources contributed 7.2 Tcf, 96% of the total.

Unconventional gas reserve additions from 1998 to 2006 were dominated by additions from tight sandstones. Reserve additions in tight sandstone resource plays averaged 7.8 Tcf per year, 60% of all unconventional gas reserve additions. Reserve additions from coalbed methane plays, the second most important unconventional source during this period, averaged 2.6 Tcf per year, another 20% of unconventional additions.

Despite the substantial recent contributions of tight sandstone and coalbed methane plays to domestic gas reserves, these additions have failed to have any appreciable effect on natural gas production. From 1996 to 2006, dry gas production in the contiguous 48 states actually decreased slightly from 18.4 Tcf to 18.1 Tcf (the lower production in 2006 being wholly attributable to the consequences of hurricanes Katrina and Rita).

The lack of any effect on production is in part explained by the growing proportion of reserves that are classified as proved undeveloped or proved non-producing. By definition, these reserves do not contribute to current production. More importantly, this lack of effect is explained by the overall size of both the tight sandstone and coalbed methane resource and the distribution of these resources by play.

Traditionally in the evaluation of oil and gas resources, the focus is on field and reservoir numbers and sizes. Unconventional resource plays do not lend themselves well to such an approach. They are usually **continuous** accumulations; thus traditional field and reservoir designations, designed for **discrete** accumulations, do not work when applied to resource plays.

However, resource plays in their entirety can be classified by size. Table 1 proposes such a classification. Four size categories are suggested: **Minor**, **Significant**, **Major**, and **Mega**. Two complementary measures are used to classify plays by size: daily production and estimated ultimate recovery. The minimum level of production for a major play is set at approximately 1% of 1996-2006 production. The minimum level of ultimate recovery for mega play is set at 30 Tcf, the threshold size for a super-giant gas field.

Table 1. Resource Play Size Categories

Size Category	Minor	Significant	Major	Mega
Daily Production (Bcf)	<0.2	0.2-0.5	0.5-3.0	>3.0
Ultimate Recovery (Tcf)	<2	2-5	5-30	>30

Tight sandstone and coalbed methane plays have made major contributions to U.S. gas reserve additions. But that level of contribution is also their limitation. The largest tight gas sandstone plays and the largest coalbed methane plays are only **major** plays; none are **mega** plays (though one coalbed methane play, the Fruitland coalbeds of the San Juan Basin, could ultimately become a marginal mega play). Even though each resource type has a substantial number of major plays (16-18 tight sandstone and 4-6 coalbed methane plays), their ultimate resource is still limited to an estimated 215-325 Tcf for tight sandstones and 65-110 Tcf for coalbed methane.

These major plays are thus essentially only **sustaining** plays. Their development has been essential to maintaining U.S. gas production and reserves. Given the scale of U.S. gas production, their ultimate resources are insufficient to transform U.S. gas supply.

Unlike tight sandstones and coalbed methane, the third largest component of unconventional gas resources, shale gas, does promise to transform U.S. gas supply. Signs of this transformation are already occurring. Following a decade of essentially stable production, U.S. gas production leapt up 13.4% in just twenty months from 50.7 Bcf/day in December 2006 to 57.5 Bcf/day in August 2008. The majority of the increase came from shale gas plays, most notably the Barnett shale in the Fort Worth Basin and the Fayetteville shale in the eastern Arkoma basin. If this rate of increase could be maintained, U.S. gas production would easily exceed its previous 1973 peak as early as 2010.

The rate of gross reserve additions also reached new heights in 2007, exceeding 44 Tcf. This level of additions, which has no historical precedent in the long history of U.S. gas exploration and development, was nearly double the 24.5 Tcf average of 1999-2006, previously the highest level of reserve additions ever achieved on a sustained basis in the United States. The composition of these 2007 reserve additions by source is not yet precisely determined. But from their geographic locations, it is obvious that the vast majority came from the three major unconventional sources: tight sandstones, shale gas, and coalbed methane.

Shale gas promises to transform U.S. gas supply because it is potentially an immense resource. Following the successful development of the Barnett shale, more than twenty other shale gas plays have been identified in the contiguous U.S. Most are areally large, exceeding one million acres (and ranging upwards to the thirty million acres for the Marcellus shale in the Appalachian Basin). Most are thick, with net thicknesses averaging 100 to 500 feet or more. Thus many have massive reservoir volumes, exceeding a billion acre-feet. Unlike the tight sandstone and coalbed methane plays, the largest of which are only large **major** plays, five to ten of the shale gas plays have the potential to be **mega** plays, each with an ultimate recoverable resource exceeding 30 Tcf. At least two of the shale gas plays have the potential of ultimate resources considerably over 100 Tcf. Another five plays could be major plays. Thus, at this very early stage of evaluation, recoverable shale gas potential ranges from 300 to 1200 Tcf.

The development of mega oil and gas deposits, such as shale gas, is almost always **disruptive** to oil and gas markets. Their development results in the rapid addition of large new increments to supply, more than can be readily absorbed by slowly growing demand. The principal effect of their development is thus to drive down prices.

The classic, if extreme, example of the effects of development of a mega deposit is the development of the East Texas field in 1930-1933 (Table 2). The East Texas field, discovered in October 1930, was the first super-giant oil field discovered in North America. Its development occurred both when U.S. production dominated the world oil market and when world oil demand was declining at the beginning of the Great Depression. Within three years after its discovery, East Texas field production rose to 15% of world oil production. This increase drove the oil price down nearly 75% by June

1933 before production controls stabilized the market at a price 35% below the 1930 price.

Table 2. Production and Price: The Early Development of the East Texas Field

	Oil Production (million bbls)			
Year	**East Texas Field**	**Rest of U.S.**	**World Total**	**Price/Bbl (2006$)**
1930	*	**1012**	**1412**	**$12.63**
1931	**122**	**941**	**1374**	**7.05**
1932	**148**	**867**	**1311**	**11.15**
1933	**216**	**971**	**1441**	**8.16***

*Low of $3.29 ($0.25 nominal) in June
Sources: American Petroleum Institute, Texas Bureau of Economic Geology

Formal production controls, usually politically enforced, such as those applied to U.S. oil production until 1971 and by OPEC to the present day, are unavailable to the U.S. gas industry today. Thus the only meaningful limit on production will be set by production cost. Development of shale gas will drive the price of natural gas down to a level where substantial proportions of unconventional gas resources will be uneconomic to develop.

How far will the price decline and how long will this price decline persist? Future prices depend on the supply curve for all unconventional gas resources; shale gas, tight sandstones, and coalbed methane. The supply curve is essentially constructed by estimating how much of each resource will be available at a specified cost. This curve is not fixed; it changes over time as drilling and completion technology improves and thus reduces costs.

The effective gas **price** floor is likely to be in the $5.00 to $6.00 per Mcf range, corresponding to a **resource cost** of $3.50 to $4.25 per Mcf. At the lowest levels of shale gas potential, such prices are likely to persist into the latter half of the next decade. Shale gas resources at the higher levels could well result in such real prices persisting past 2025.

Proponents of expanded U.S. gas production predominantly perceive its effects as supplying new markets. The major immediate impacts of expanded shale gas production will however be felt in the composition of U.S. supply, not in rapidly expanding domestic demand.

The rapid recent growth in tight sand gas and coalbed methane production has fully **replaced** the decline in conventional gas production. Rapidly growing shale gas production is likely to **displace** higher cost sources of both domestic supply and imports.

This effect is already showing up in LNG imports. LNG imports, touted as a major source of future U.S. gas supplies as recently as 2007, are well on their way to becoming an inconsequential portion of U.S. supply for the next decade. After peaking at 3.07 Bcf/day in the second quarter of 2007, they plunged 65% to only 1.07 Bcf/day in the third quarter of 2008. Other markets - east and south Asia and Europe, where the gas price is tied more closely to the world oil price, pay substantially more for spot LNG cargoes than the U.S. market. With rapidly rising domestic gas production and consequent low domestic gas prices, LNG is no longer a competitively priced gas source for the U.S. market

The effect of shale gas development on imports from Canada will be less dramatic, but just as inexorable. Because natural gas markets in Canada and the U.S. are closely intertwined, low wellhead gas prices in the United States mean even lower gas prices in western Canada. Because a high proportion of the remaining gas resources of Canada are high cost, much of these resources will be uneconomic to develop in the immediate future. Thus western Canadian gas production will decline and Canadian gas exports to the United States will decline even faster. By 2020, western Canadian gas producers could find themselves competing with Appalachian shale gas producers for customers in Ontario and Quebec.

The other major effect of shale gas development on domestic natural gas supply is likely to be an indefinite postponement of a natural gas pipeline from the Arctic Slope of Alaska to the contiguous United States. At low gas prices, the high costs of transporting this gas make netbacks at the wellhead very low and hence highly unattractive to both Arctic Slope producers and the State of Alaska.

Although unconventional gas production, particularly shale gas, will be increasing steadily during the next decade, total domestic supply will grow more slowly as unconventional production displaces other sources of supply. Thus a rapid expansion of demand is unlikely. What is more likely is growth in selected demand sectors. With the development of a large shale gas resource in the Appalachian Basin, gas is likely to displace fuel oil for residential and commercial space-heating in the northeast United States. Demand for gas for electrical generation will also increase. Gas will fuel essential backup capacity for intermittent renewable sources of electricity such as solar and wind. Its low price and ready availability will also displace some development of these sources.

The development of major new markets for natural gas, such as a substantial role as a transportation fuel, is neither realistic nor desirable. Domestic gas production at 25 to 30 Tcf per year, an amount adequate to provide for expanded current demand sectors, still means production of a quadrillion cubic feet of natural gas over 35 years. Current unconventional sources can likely provide this amount. However, we do not know what will replace them once they are depleted. No subsequent major gas resources in the contiguous 48 states have been identified to replace currently known unconventional resources.

The spectre of resource depletion, though currently very faint, has not disappeared. By 2050, its presence will again be confronting us.

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