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Publication Date
2015-02-18

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A NextSTEPS white paper by: Kenneth B. Medlock III, Ph.D.

NextSTEPS
(Sustainable Transportation Energy Pathways) Program

UC Davis Institute of Transportation Studies

February 18, 2015
Final Version

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SUSTAINABLE TRANSPORTATION ENERGY PATHWAYS
of the Institute of Transportation Studies

Acknowledgements

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NORTH AMERICAN RESOURCES AND NATURAL GAS SUPPLY TO THE STATE OF CALIFORNIA

BY

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FEBRUARY 18, 2015

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Medlock is currently the vice president for conferences for the United States Association for Energy Economics (USAEE), and previously served as vice president for academic affairs. In 2001, he won (joint with Ron Soligo) the International Association for Energy Economics Award for Best Paper of the Year in the Energy Journal. In 2011, he was given the USAEE's Senior Fellow Award and in 2013 he accepted on behalf of the Center for Energy Studies the USAEE's Adelman-Frankel Award. In 2012, Medlock received the prestigious Haydn Williams Fellowship at Curtin University in Perth, Australia. He is also an active member of the American Economic Association and the Association of Environmental and Resource Economists, and is an academic member of the National Petroleum Council (NPC). Medlock has served as an advisor to the U.S. Department of Energy and the California Energy Commission in their respective energy modeling efforts. He was the lead modeler of the Modeling Subgroup of the 2003 NPC study of long-term natural gas markets in North America, and was a contributing author to the recent NPC study "North American Resource Development."

Medlock received his Ph.D. in economics from Rice in 2000.

Natural Gas Supply to California: Policy, Resources, Demand Pull and Infrastructure

Introduction

The last decade has been witness to an incredible transformation in the US energy fortune. The combination of hydraulic fracturing and horizontal drilling in upstream operations targeting ultra-low porosity, ultra-low permeability hydrocarbon bearing shale formations has unlocked a bounty of natural gas and crude oil resource. This transformative innovation has literally turned the US energy market on its head. Fewer than ten years ago a number of large capital players were developing liquefied natural gas (LNG) regasification terminals with an eye toward *importing* large volumes of natural gas to the US from distant locations. Today, there is a prevailing expectation that the US will soon be an *exporter* of LNG, largely due to the rapid growth in natural gas production from shale that has occurred in the last 8 years (see Figure 1). In fact, US gross natural gas production has risen from an annual average rate of 64.3 billion cubic feet per day (bcfd) in 2005 to 82.7 bcfd in 2013, driven primarily by growth in production from shale from less than 4 bcfd to over 31 bcfd.

Figure 1. US Gross Natural Gas Production (2000-2013)
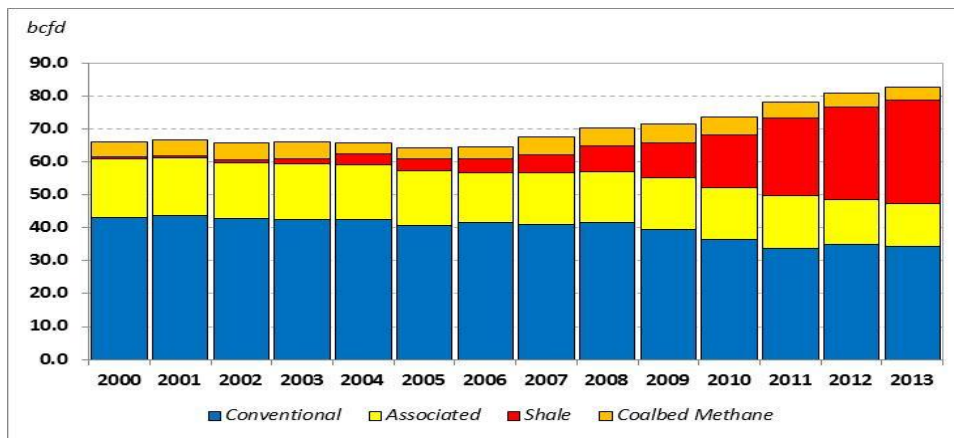
Source: Energy Information Administration

What Made the US Energy Renaissance Possible?

We begin by addressing the factors that made the upstream successes witnessed in the US during the past decade possible. This is also detailed in Medlock (2014).[1] First, we note that geology matters, but while the right geology is a *necessary* condition, it is not *sufficient* to ensure that profitable resource development will occur. *Sufficiency* requires a number of above-ground factors to be aligned. This thesis is upheld by the fact that shale resources outside the US are assessed to be significant, yet shale oil and gas production on a global scale is still limited primarily to the US. As detailed in Medlock (2014), the factors include:

- A regulatory and legal apparatus in which upstream firms can negotiate directly with landowners for access to mineral rights on privately-owned lands.
- A market in which liquid pricing locations, or hubs, are easily accessed due to liberalized transportation services that dictate pipeline *capacity* is unbundled from pipeline *ownership*.
- A well-developed pipeline network that can facilitate new production volumes.
- A market in which pipeline development is relatively seamless due to a well-established governing body, for example the Federal Energy Regulatory Commission (FERC) in the US, and a comparatively straightforward regulatory approval process.
- A market in which demand pull is sufficient to provide the opportunity for new supplies to compete for market share in the energy complex.
- A market where a well-developed service sector already exists that can facilitate fast-paced drilling activity and provide rapid response to demands in the field.
- A service sector that strives to lower costs and advance technologies in order to gain a competitive advantage.
- A sizeable rig fleet that is capable of responding to upstream demands without constraint.
- A deep set of upstream actors, such as the independent producers in the US, that can behave as the "entrepreneur" in the upstream thereby facilitating a flow of capital into the field toward smaller scale ventures than those usually engaged by vertically integrated majors.

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[1] Cite Goldman Paper here

If any of the above features is absent, a potential barrier to market entry and upstream development is presented, usually in the form of higher costs. Moreover, some of the above listed conditions can be co-dependent on others. For example, a well-developed service sector relies on a large set of upstream players to create significant demands for its products and services, just as the population of upstream actors in the upstream, for example the thousands of independent producers in the US, might not be so large absent a well-developed service sector. In short, the interdependence of the conditions listed above speaks to the notion that well-designed market institutions and regulatory frameworks can be self-reinforcing.

What is the Recoverable Shale Gas Resource in North America?

So, just how much recoverable natural gas is locked up in shale? To answer this question, we must recognize that the US market is part of an integrated North American market. Canada in particular is highly integrated with the US, meaning shale resources in Canada can compete with other sources of gas supply throughout North America, albeit at a disadvantage given the distance from market outlets and the cost of transporting gas via pipeline long distances.

The state of knowledge of economically recoverable shale gas has changed considerably over the last decade. While geologists have long known about the existence of shale resources, their technical and economic feasibility were long thought to be severely limited. As recently as 2003, the National Petroleum Council estimated about 38 trillion cubic feet (tcf) of technically recoverable resources were spread across multiple basins in North America.[2] But, on the heels of the early exploration and development successes in the Barnett shale, in 2008 Navigant Consulting, Inc. performed a two part assessment that estimated a mean of 280 tcf of technically recoverable resources from the geology literature, while a survey of producers indicated up to 840 tcf.[3] From that point forward, the assessments began to progress rapidly, both in scale and in timing. In 2009, the Potential Gas Committee put its mean estimate at just over 680 tcf. In 2011, Advanced Resources International (ARI) reported an estimate of about 1,930 tcf of technically recoverable resource for North America and 6,622 tcf globally, with over 860 tcf in U.S. gas

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[2] NPC study reference
[3] Navigant study reference.

shales alone.[4] Most recently, the EIA commissioned assessments from Intek in 2011 and another assessment from ARI in 2013, with the former indicating 750 tcf of recoverable shale gas resources in the US Lower 48 and the latter, which was aimed at assessing *global* shale resources, indicating 7,299 tcf, with US shales totaling 1,161 tcf.[5] A striking pattern emerges when these independent assessments are taken together. Namely, as drilling activity, along with field experiences and downhole innovations, progresses, the scale of the assessments grows. This is a strong indication of the "learning-by-doing" that continues to occur in shale developments. So, while there remains disagreement about the exact size of the shale gas resource base, the disagreement is over magnitudes that are all substantially larger than our state of knowledge even just a decade ago. Moreover, betting the over on the range of assessments has thus far proved to be the smart play.

Figure 2. Shale Resources in North America
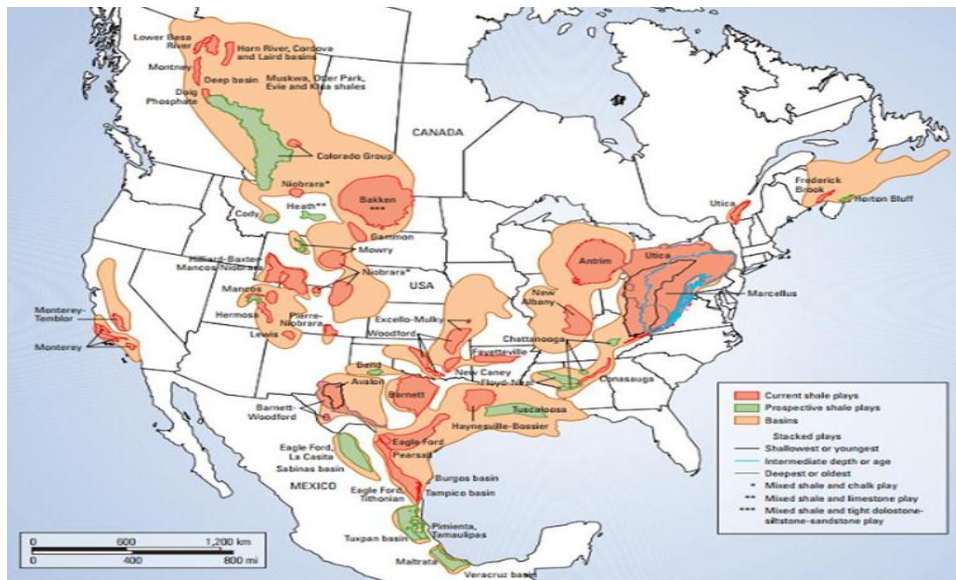
Source: Gallery of World Hydrocarbon Endowment & Shale Gas Resources, Al Fin Energy blog at
http://alfin2300.blogspot.com/2012/03/gallery-of-world-hydrocarbon-endowment.html

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[4] PGC 2009 study reference.

[5] Cite EIA assessments.

As previously mentioned, geologists have long known about the existence of shale formations, but the feasibility of technical and commercial access to those resources is relatively new. This raises an important point. In particular, it is important to understand the differences between resource *in-place*, *technically* recoverable resources, *economically* recoverable resources, and *proved* reserves; they are not synonymous, as each refers to a very different characterization of the resource base. Figure 3 highlights the resource characterization in a simple qualitative illustration. Specifically, we can think of resource in-place as the entire box; technically recoverable resource as everything that is "discovered and identified" including resource that is sub-economic; economically recoverable resource as anything that is proved, probable or possible; and then, of course, proved reserves is the smallest box in the upper left of the figure.

Figure 3. Resources and Reserves
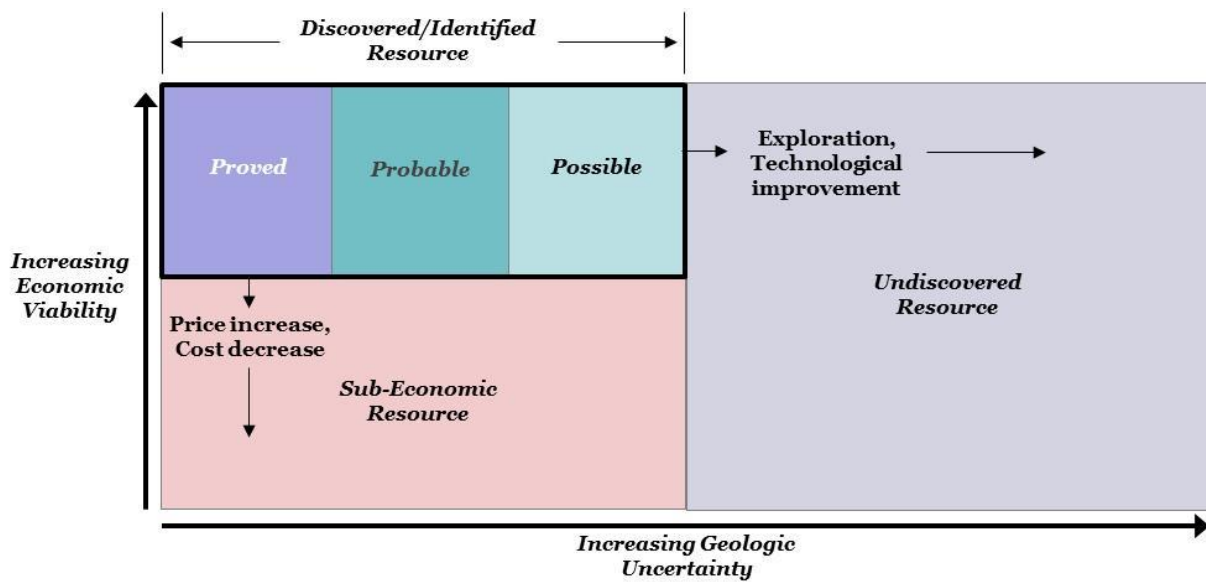
In the 1990s, before the shale renaissance in the US, Rogner estimated over 16,000 tcf of shale gas resources in-place globally with just under 4,000 tcf of that total estimated to be in North

America.[6] Importantly, the fraction of this resource that was thought to be *technically* recoverable was very small (<10 percent). But, the success realized in upstream shale production has triggered a reassessment of what is technically recoverable. For instance, the International Energy Agency (IEA) estimated that about 40 percent of Rogner's estimated resource in-place will ultimately be technically recoverable.[7] As noted above, in more recent work commissioned by the US EIA, ARI assessed a global technically recoverable shale gas resource of 7,299 tcf, with 2,279 tcf in North America and 1,161 tcf in the US alone, and the global assessment did not include shale potential in the Former Soviet Union or Middle East, both regions with long histories of significant oil and gas production.[8] However, large assessments of technically recoverable resources do not necessarily imply substantial production is forthcoming. Rather, commercial viability, or *economic* recoverability, requires not only that the cost of drilling and completing wells be low enough relative to the market price; it also requires the litany of above-ground factors discussed in the previous section also be present.

Recognizing the need to distinguish between technically and economically recoverable resources, we first require an estimate of the technically recoverable resource base in the US and Canada. Then, we can incorporate information on the costs associated with developing these resources, which allows an assessment of economically recoverable resources. Technically recoverable shale resource (*TRR*) can be derived from the average expected ultimate recovery (*EUR*) for a well drilled in play *i*, the aerial extent (*AE*) of play *i*, and the number of wells that will be drilled per acre (*SP*) in play *i*. However, *EUR* in particular is generally unknown in frontier resource plays, and the feasible well-spacing is also uncertain prior to production activity. As a result, this approach can be fraught with uncertainty, especially when there is a paucity of data.

Nevertheless, an estimate of *TRR* is the first step in defining the potential extent of future production, but we must also address the cost of development if we want a clearer picture of the *economically* viable production potential. As such, we must understand the costs associated with things such as acreage acquisition, pad site development and well completion in addition to the

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[6] Rogner cite.
[7] IEA cite.
[8] ARI cite.

production profile and estimated recoverability of each well. This enables a ranking of wells on a cost per mcf basis and allows one to distill the tremendous heterogeneity across wells drilled in a single shale play, with some wells profitable at relatively low prices and others at much higher prices, meaning some wells drilled may be *ex post* uneconomic. However, the producer's decision to develop acreage is typically based on a *portfolio* of wells, not a single well, and even uneconomic wells are useful to in inform future development decisions in that they reveal information about the acreage being developed.

The Barnett shale in northeast Texas, where the venture into shale began in earnest a little over a decade ago, is a good case study for understanding how to rank economic viability. Medlock and Seitlheko (2014) examined the production histories of more than 12,000 horizontal wells drilled into the Barnett shale. This exercise was done to better characterize performance of wells drilled into shale formation, particularly because the use of Arps equations does not fit production data very well, indicating the physical system of fluid flow in ultra-low permeability, ultra-low porosity shale is different than the system described by Arps equations.[9] The work by Male and Patzek (2013) allowed a more accurate characterization of decline profiles for shale gas wells, which then informs EUR. This subsequently allows type curves for wells drilled in the Barnett shale to be generated, and the distribution of EUR within the Barnett shale to be better understood. Combining this data with development costs, we can then construct the distribution of per unit costs for wells drilled in the Barnett. Figure 3 indicates the fitted decline curves for production in the Barnett shale for a p90, p50 and p10 well along with the associated breakeven costs and *EURs*.

We have estimated the breakeven price needed for an average type well in each of the identified shale plays. A distribution that characterizes EUR within each shale play is used along with the drilling and completion cost to derive a range of *per unit* costs associated with developing a given amount of resource in each shale formation. This procedure highlights two inter-related points. One, there is a substantial resource endowment recoverable at relatively low prices. And, two, which is relevant to understanding market dynamics, if developers can identify so-called "sweet spots", then prices, at least for a short period of time, can be relatively low without severely compromising profitability. This follows because as price falls, producers will, to the

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[9] See Male and Patzek (2013)

extent possible, lay down rigs in less productive acreage. In turn, rig counts are not reasonable proxies for production because a reduction in activity in lower productivity acreage (that typically needs higher prices to be profitable) may not compromise overall production in a major way. Importantly, this only speaks to *short run* dynamics. In the long run, price should reflect the central tendency of a distribution such as that in Figure 4 if production is to be stable within a shale play; if it does not, then acreage may become distressed, which will lead to asset sales and lower near term production.

Figure 4. Fitted production profiles for wells drilled in the Barnett shale
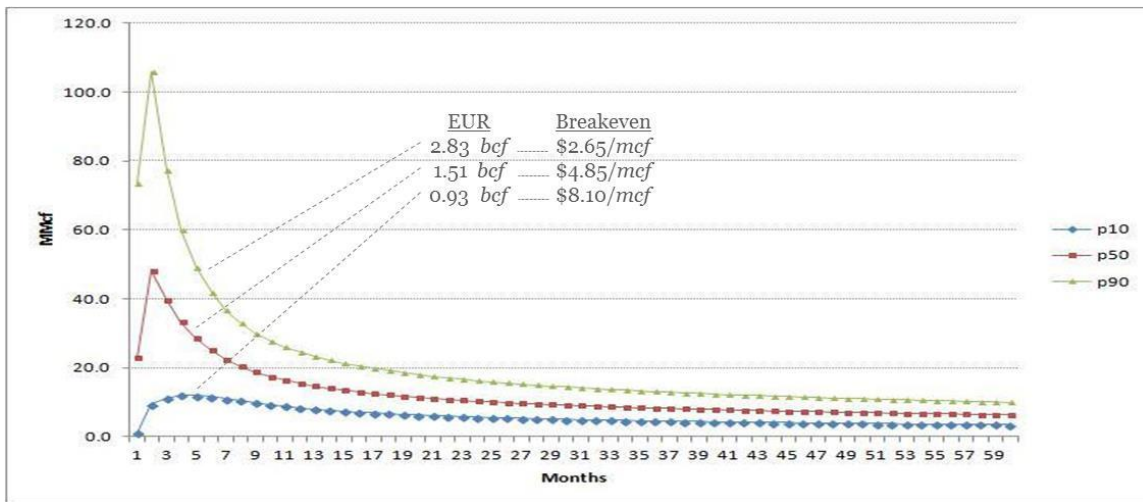
*Source: Reproduced from Medlock and Seitlheko (2014)*

The assessments of technically recoverable resources in North America are taken from a number of different sources.[10] The geophysical data available in the ARI and Intek reports are critical inputs to generating finding and development cost curves. Once average *EURs* are determined for each shale play, the resources are segmented into tiers by sampling at decile intervals from a distribution around the estimated mean *EUR*.[11] The distribution for plays where there is sufficient well performance data is determined by fitting the data, but where there is a lack of

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[10] Cite UT-BEG work, work at Rice, Intek and ARI.
[11] Note, sampling at these p-values is arbitrary, and we only do so herein for the sake of illustrating the methodology.

observed well data, the distribution is determined by econometrically fitting an exponential function that is a function of the average *EUR*. Then, along with drilling costs, where cost is fitted to average drilling depth and pressure, this is used to construct the cost per thousand cubic feet ($/mcf) for development in each of the tiers. Figure 5 illustrates the concept with sample p-values indicated for illustrative purposes only.

Figure 5. Estimating the Range of Shale Development Costs
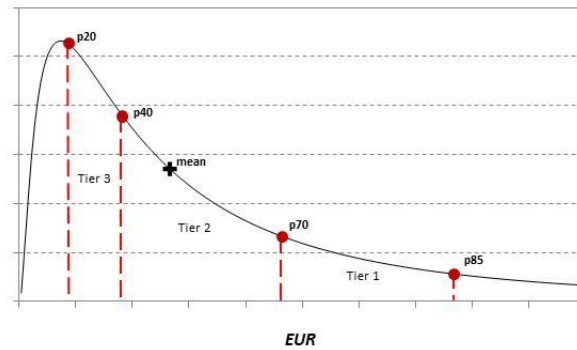
Use *EUR* for the selected tiers and well costs to generate costs (see discussion in text).
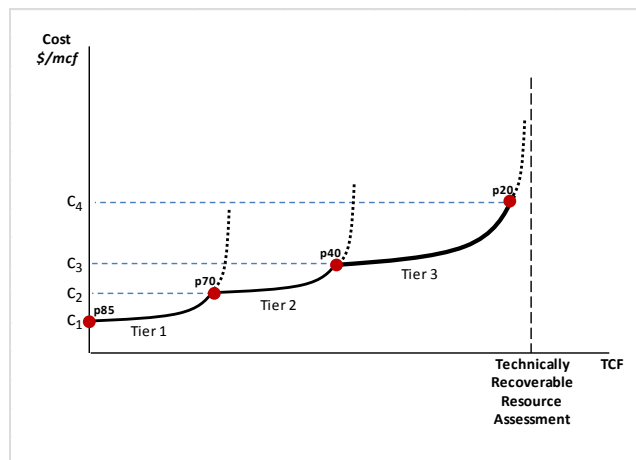
Many factors influence development cost. For example, shale that is clay-rich is generally not prone to yield high production rates, which in turn tends to reduce its attractiveness commercially, even if the technically recoverable resource assessment is large. Other factors – such as total organic carbon, natural fracturation, isopach, permeability, porosity, and other

features – are also critical. To be sure, the degree of complexity involved in developing cost curves for shale is high and involves a significant degree of uncertainty.

In addition, there is significant heterogeneity in well performance within each shale play, so it is important to characterize that how such variation will ultimately impact the breakeven prices within the play. Simply referencing an "average" well, or any other type well, to represent any entire shale play will not reflect such variation. This is precisely why we fit a distribution from available well production data that describes the possible *EURs* in each shale formation. Then, we sample from the distribution at each decile (10 percent intervals) to construct tiers within the resource.

Some caveats are worth mentioning here. For one, it is very possible that observed *EURs* will change over time, especially as practices in the field evolve. Technical and commercial recoverability is largely an issue of technology, not geology, as geologists have long studied the properties of shale. Indeed, innovations continue to raise the initial production rates (*IP*) and *EURs*, on average, of wells drilled every year. This, in turn, drives down per unit costs of development, making a greater amount of resources economically viable at a given price. Assessments of technically and economically recoverable shale gas could also increase as technologies and processes are developed – largely through experience – to improve recovery rates and lower costs.

The *EURs*, along with drilling and completion costs, are used to construct per unit costs for resource development. Much like *EUR*, however, a complete set of drilling and completion costs are not known for all shale plays. Accordingly, we estimate drilling costs to be a function of total vertical depth and formation pressure. This yields

$$WellCost_i \;=\; \underset{(0.8941)}{0.8616} \;+\; \underset{\left(9.0041\times10^{-5}\right)}{3.6605\times10^{-4}}\,TVD_i + \underset{(1.8606)}{3.2192}\,Pressure_i \tag{1}$$

with $R^2 = 0.9016$.

The parameter estimates in equation (1), along with the distribution of *EURs* within each play, allow us to construct estimates of per unit costs. For example, a horizontal well with an average total drilling depth of 12,000 feet and pressure gradient of 0.95 psi/ft^2 is estimated according to

(1) to cost $8.64 million. If the *EUR* for a p50 well is 6.1 bcf/well, then the per unit drilling and completion cost is estimated to be $1.42/mcf. Of course, a return to capital must be earned, taxes and royalties must be paid, and operating costs must be covered, which is how we would arrive at a breakeven cost for the well in this example. Assuming a weighted average cost of capital of 12%, using the current US corporate income tax rate, a royalty rate of 20%, and all other current finance and tax parameters, the breakeven price for the shale gas well in this particular example comes in at $5.27/mcf.[12]

Of course, as discussed in the Barnett shale example illustrated in Figure 4, there is tremendous heterogeneity among wells in any particular shale play. As referenced above, the resource costs are "tiered" by sampling from the distribution of *EURs*. To do this, the density function describing *EUR* within a shale play is estimated from *EURs* that are inferred from existing well production histories. Using the example in the previous paragraph, if the wellhead breakeven of $4.69/mcf is consistent with the p50 *EUR* for the play, then a tier 1 wellhead breakeven, where tier 1 is defined here as a well in the top quartile of *EUR* in the play at 12.0 bcf/well, would be about $3.53/mcf. This is consistent with the so-called "sweet spot" in the play. On the other end of the spectrum, we have lower performing wells in the bottom quartile of the *EUR* distribution that would see an average recovery of 3.1 bcf/well at a breakeven cost of $8.69/mcf. Of course, this example is meant to be illustrative only. Figure 6 illustrates the estimated p10 to p90 range of *EURs* for the plays assessed herein, with the mean illustrated as the point at which colors change, and Figure 7 depicts the estimated average breakeven prices by tier in each tier.

We read Figure 7 not as a supply curve; rather, it is a curve depicting the amount of resource available at a particular price in the long run. We make this distinction because there is no guarantee that Figure 7 will help indicate the price of gas at any given point in time. To begin, Figure 7 only captures shale deposits and is thus not fully representative of all gas production opportunities. In addition, there are short term constraints on the pace of drilling and completion activity at any given point in time, there are uncertainties within each play and across plays about the EUR for any well drilled, and demand can fluctuate at any moment in time thus stressing short term deliverability. Finally, Figure 7 represents a collection of wellhead breakeven prices, so it does not capture transportation differentials to Henry Hub, or any liquid market hub for that

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[12] The example in this paragraph is representative of a p50 well in the core area of the Haynesville shale.

matter. Now, having listed all such caveats, what Figure 7 does indicate. Specifically, there is an estimated 1060 tcf of shale gas resource recoverable across North America at prices below $6/mcf, and almost 1450 tcf at prices below $10. This latter point highlights the elasticity of long run supply, which is relevant for long term prices, in particular if, for example, the US begins exporting LNG to Asian markets where prices have recently been over $11/mcf.

Figure 6. Estimated Expected Ultimate Recovery by Shale Play
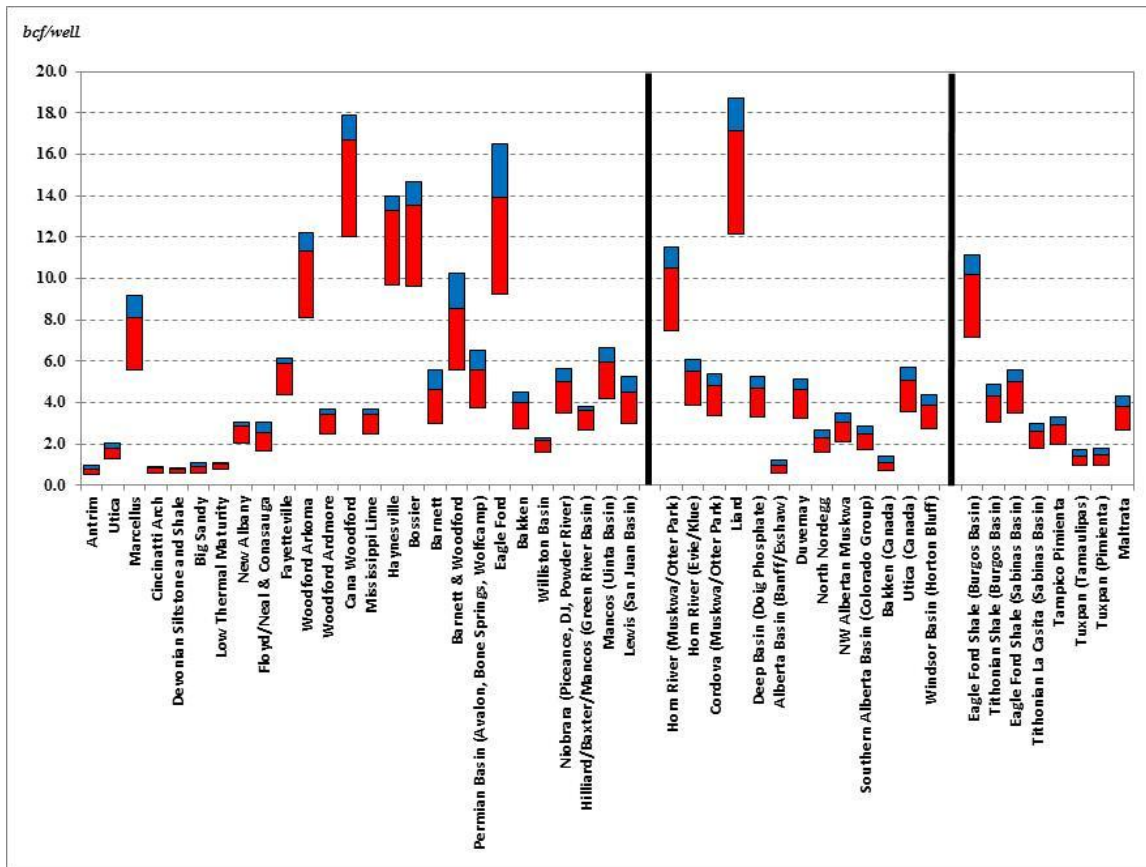
Regarding the resources represented Figure 7, about 246 tcf of the available resource under $6/mcf is in Canada, 111 tcf is in Mexico, and the remaining 656 tcf is in the US. At prices under $10/mcf, 358 tcf is in Canada, 215 tcf is in Mexico, and 874 tcf is in the US. Finally, we note that the total *technically* recoverable resource associated with Figure 7 is 1,844 tcf, where almost 400 tcf of the technically recoverable resource is commercially viable only if prices are at a minimum of $10/mcf.

Figure 7. North American Shale Gas Resource and Average Breakeven Price by Play
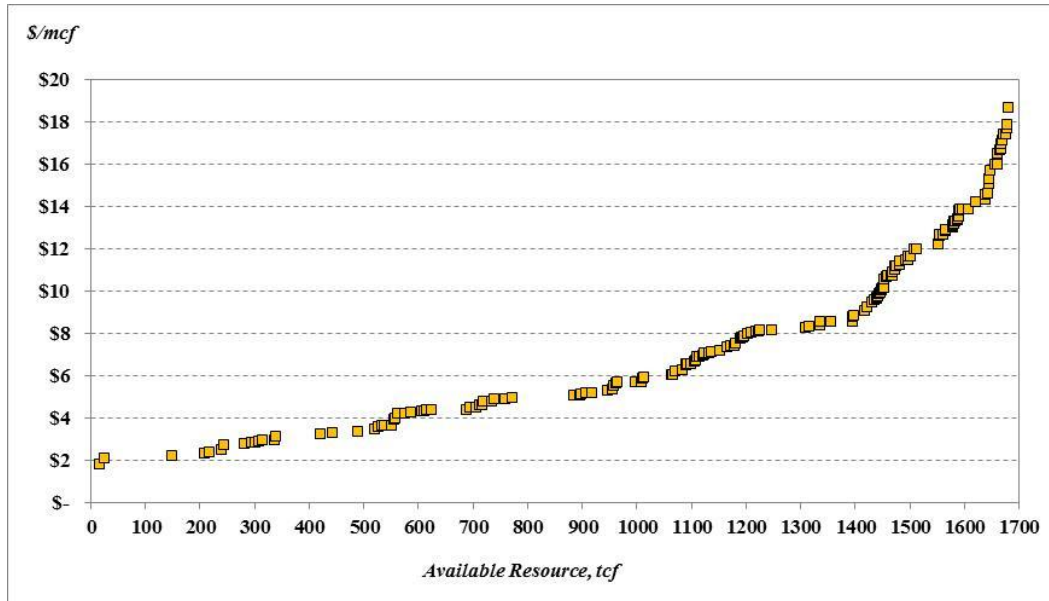
A notable area of uncertainty is in Mexico, where ongoing energy reform efforts have the potential to radically transform the upstream sector. This, in particular, could have significant ramifications for development costs as the domestic upstream industry develops, along with all the associated procurement channels. Specifically, if a deeper set of upstream actors, and hence greater competition, emerges in Mexico, and if the existing service industry already active in the US is allowed to move easily across the border, then development costs could fall. Of course, local content requirements, fiscal terms and security concerns will each affect supply chain economics.

Finally, we note that the Montney formation in Western Canada is not included in the data discussed above. While often discussed in the context of shale due to the drilling and completion process required for production, the Montney is a siltstone and sandstone tight gas formation. The Montney resource is particularly relevant for gas production in and flows away from Western Canada, which has bearing on California. Canada's National Energy Board (NEB) estimates there are 449 tcf of recoverable natural gas in the Montney formation.[13] This is a

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[13] See NEB website for more detail (http://www.neb-one.gc.ca/clf-nsi/rthnb/nws/nwsrls/2013/nwsrls30-eng.html).

sizeable resource that has the potential to support Canadian natural gas exports, by either pipeline or LNG, for years to come.

Natural Gas to California

What does the North American shale gas resource base mean for gas flows to California, and the delivered wholesale price over the next 20 years? To begin, we must consider the demand pull for natural gas in California if we are to assess the sources of supply to the state. Importantly, we must recognize that the current and pending regulations can have significant effects on end-user choice in energy demand, industrial facility and power plant siting, and pipeline development. The state of California is no different, and, in fact, fuel choice and infrastructure investment is being shaped heavily by policy. Currently policies are in place to increase renewables' share in power generation to 33% by the end of decade and curb statewide carbon dioxide emissions. These policies will impact natural gas use, although the direction of the influence is not entirely clear. The renewables targets, which do not include large hydroelectric sources as renewable, could constrain natural gas consumption. In addition, carbon dioxide emissions abatement policies are an emphasis in Assembly Bill 32, the Global Warming Solutions Act (AB32), and the recent rulings of the US EPA have reinforced this priority.[14] AB32 orders that greenhouse gas emissions be no larger than 1990 levels by 2020, and that the Air Resources Board establish a market-based mechanism for tradable permits. The social benefit of such policies is beyond the scope herein, but adoption will impact the composition fuel use.

Under current California policy, efficiency and conservation is encouraged and the use of low carbon fuels is prioritized. This, along with aggressive renewable portfolio standards (RPS) policies and AB32, should minimize growth in energy demand, raise the share of renewables in the energy mix, and, therefore, limit increases in (and perhaps even reduce) demand for fossil fuels in the state. This, in turn, stands to, at the very least, limit the growth of natural gas demand in California. As seen in Figure 8, demand for natural gas in power generation is expected to decline through the early 2020s.

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[14] For more detail see the California Air Resources Board website at http://www.arb.ca.gov/cc/ab32/ab32.htm.

Figure 8. California Natural Gas Demand by Sector, 2000-2030
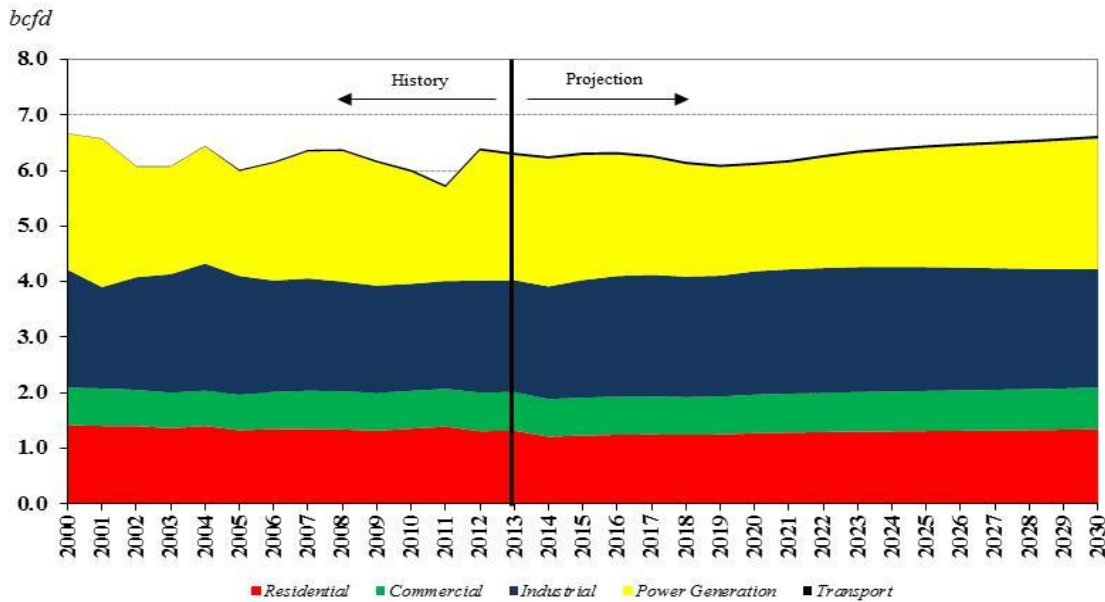
Source: U.S. EIA (history) and CES Energy Demand Projection Model (projection), Medlock (2014)

As noted above, of note in Figure 8 is the relatively modest growth in demand from the power generation sector, which is largely the result of aggressive renewables and energy efficiency policies. In particular, the projected demand in power generation in 2015 is 2.25 bcfd, falling to 1.91 bcfd in 2020, then steadily increasing to 2.15 bcfd in 2025 and 2.35 bcfd in 2030. Note, to the extent economic growth is slower or policies are adopted beyond 2020 to further increase renewables or enhance end-use efficiency, the forecasted demand could be lower. Similarly, if economic growth is more rapid, or the current policy direction is abated, then the demand in power generation could be higher.

Also of note in Figure 8 is the relatively small presence of natural gas in transportation. However, scale is relevant. Specifically, the growth rate of demand in transportation through 2030 is projected at 3.75%, with demand rising from 432 mmcfd in 2013 to a total of 778 mmcfd in 2030. This compares to a national average annual growth rate of 2.41%. Moreover, California

accounts for 61% of national demand for natural gas in transportation in 2030, which is up from just under half currently.

Demand side policies such as those in California, which are motivated primarily by environmental objectives, will have ripple effects back through the entire energy value chain. Specifically, if the prospects for demand growth are as modest as illustrated in Figure 9, then the infrastructure requirements to transport natural gas to California are reduced, and existing infrastructure is sufficient to handle the state's natural gas requirements, absent any significant shift in the sources of supply to California. Given the size of the California market relative to the rest of the US west of the Rockies, this has implications for natural gas production in West Texas, New Mexico, Wyoming, and Western Canada, all regions with significant current upstream activity and/or sizeable shale gas potential.

In the upstream and midstream, the US and Canada are characterized by regulatory institutions that facilitate relatively rapid expansion of production and infrastructure, especially when compared to other regions around the world. Indeed, in the US and Canada, existing regulatory and market institutions present very little in the way of obstructing the production, which has been very important in explaining why natural gas production from shale in the US has grown so rapidly in the last several years. Moreover, the density of the pipeline network has provided tremendous access for producers to access markets. Even in situations where short-term deliverability constraints have arisen, either in a newly emerging producing region or farther downstream, the regulatory and market institutions governing the construction of interstate pipeline capacity are relatively seamless, which generally results in rapid expansion of pipeline infrastructure and a relaxation of the constraint.

A great example of this was seen recently with the resolution of the constraints that developed in 2008-09 on pipeline capacity exiting the state of Texas as a result of the growth in production from the Barnett, Fayetteville, and Haynesville shales. In fact, gross production from these three shale basins alone rose from 3.6 bcfd in 2007 to 12.5 bcfd in 2010, and prices in Texas fell to well in excess of $1.50/mcf below the price at Henry Hub in neighboring Louisiana as a result of the developing bottlenecks. The price signals triggered a subsequent wave of investment activity and significant pipeline capacity was added between Texas and Mississippi. This point highlights

the fact that, due to the nature of regulations in the US market, the greatest risks to profitable natural gas development are commercial, not regulatory, notwithstanding certain regions where environmental concerns have led to outright bans on development activity. This point is salient because as new production regions mature that can serve the western US, there are few impediments to developing interstate pipeline capacity to move natural gas to California.

Figure 9. US Natural Gas Production: Shale and All Other (2007-2030)[15]
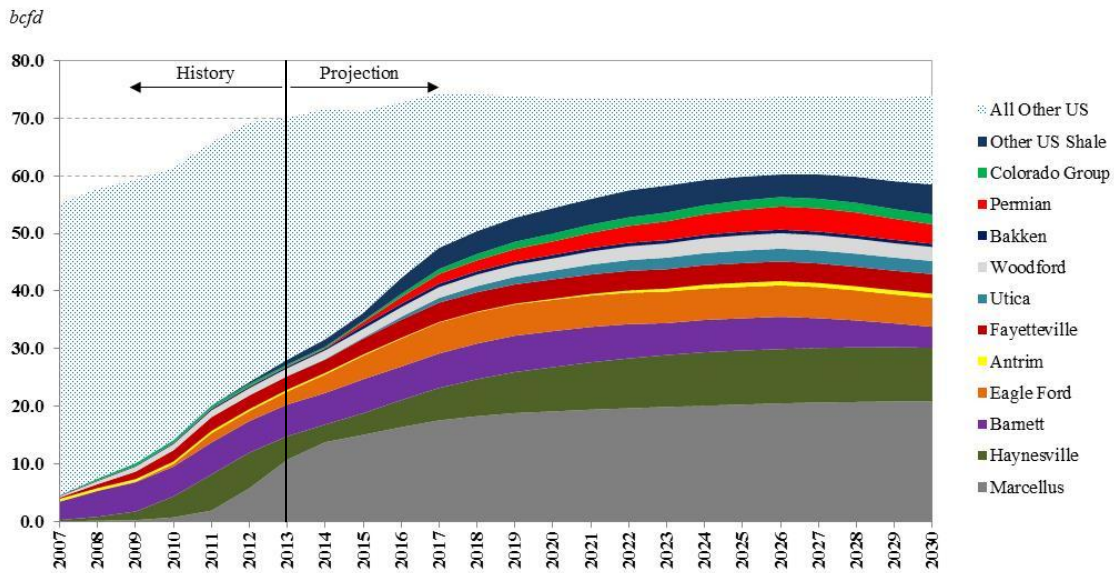
Source: Baker Institute CES Rice World Gas Trade Model, vApr14 (Medlock)

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[15] The projections are generated using the Rice World Gas Trade Model (RWGTM). The Baker Institute's RWGTM was developed by Kenneth B. Medlock III and Peter Hartley at Rice University using the Marketbuilder software platform provided through a research license with Deloitte Marketpoint, Inc. The RWGTM is a dynamic spatial partial equilibrium model in which all spatial and temporal arbitrage opportunities are captured. As such, each point of infrastructure in the gas delivery value chain—field development, pipelines, LNG regasification, LNG shipping and LNG liquefaction—is modeled as an independent profit maximizing entity, where profits are maximized intertemporally. Thus, the optimal investment path is dependent on the price received for wellhead production in the case of field development and on the tariff collected for transportation infrastructure, as well as a host of other parameters such as the upfront fixed cost, interest rate on debt, required return on equity, debt-equity ratio, income tax rate, sales tax rate, and royalty. In this manner, the model is solving a classic intertemporal optimization problem for investment in fixed capital infrastructure. The architecture of the RWGTM, the data inputs, and modeled political dimensions are distinct to Rice and its researchers. The RWGTM is used to evaluate how different geopolitical pressures, domestic policy frameworks, and fundamental market developments can influence the long run evolution of regional and global gas markets and how those developments in turn influence geopolitics. More detail is available upon request.

Modeling at the Baker Institute's Center for Energy Studies (CES) indicates that US shale gas production could exceed 50 bcfd and account for well over half of US domestic natural gas production by the 2020s (see Figure 9). The prices associated with the projection indicated in Figure 9 rise from the mid $4's to the low $6's between now and 2030 at Henry Hub (see Figure 10), which is consistent with the long run costs of developing shale resources as depicted in Figure 7. There is still a clear opportunity for LNG exports from North America, particularly given the pricing disparity that exists between the US and European and Asian markets, although market response to export volumes from the US in Asia and Europe will ultimately determine the volume of exports.[16]

As seen Figure 9, expected US shale production growth is very strong. It is worth noting, however, the plateau in overall US production that is projected to emerge later this decade arises not for lack of resource, but because Canadian natural gas production begins to grow (not pictured) and international market rebalancing limits the commercial opportunity for LNG exports from the US. LNG exports from the US approach 6 bcfd by the mid-2020s, making it the third-largest LNG exporter in the world.

Natural gas supplies to the state of California shift over the next couple of decades to reflect a greater production from the Permian Basin in West Texas and from the various production opportunities in Western Canada. As indicated in Figure 11, production growth in Canada ultimately pushes gas into northern California along the PGT system through Malin. This is augmented by increased flow of natural gas from the Rockies along the Ruby system. Production growth in the Permian Basin finds its way into southern California along the El Paso north and south lines. Interestingly, the volumetric increase into California from Permian Basin production is not as large because demand growth in Arizona is sufficient to absorb much of the volume. This stands in contrast to Canadian production volumes, which do not reach significant demands until reaching California.

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[16] For much more detail on this see the CES working papers "U.S. LNG Exports: Truth and Consequence," 2012, available at http://bakerinstitute.org/research/us-lng-exports-truth-and-consequence; and "Natural Gas Price in Asia: What to Expect and What it Means," 2014, available at http://bakerinstitute.org/research/natural-gas-price-asia-what-expect-and-what-it-means. Both are authored by Ken Medlock.

Figure 10. Henry Hub Price, 2000-2030 (Real 2010$)
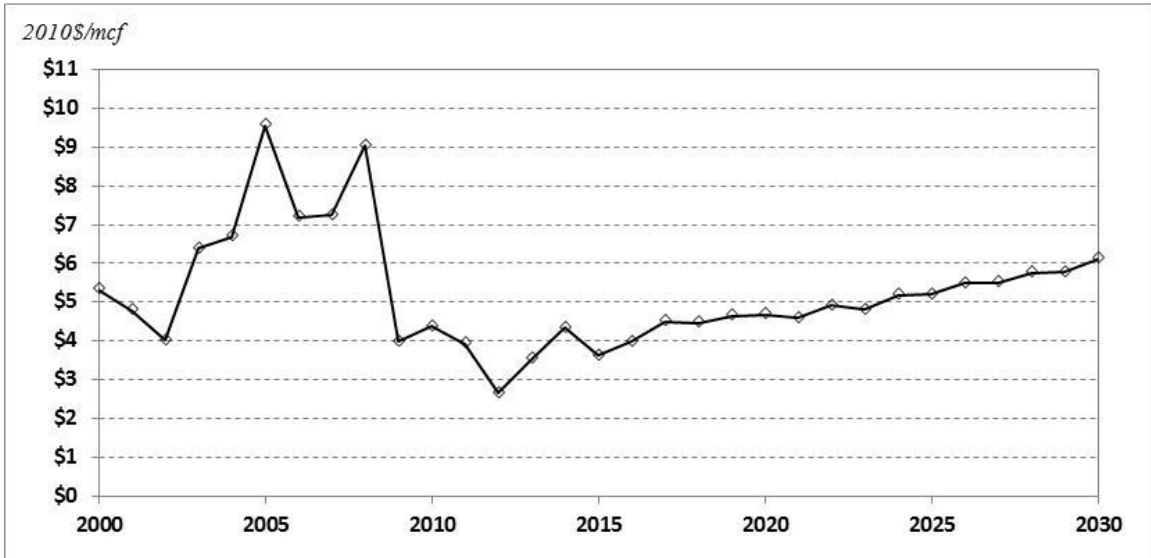
Figure 11. Sources of Supply into California, 2013-2030
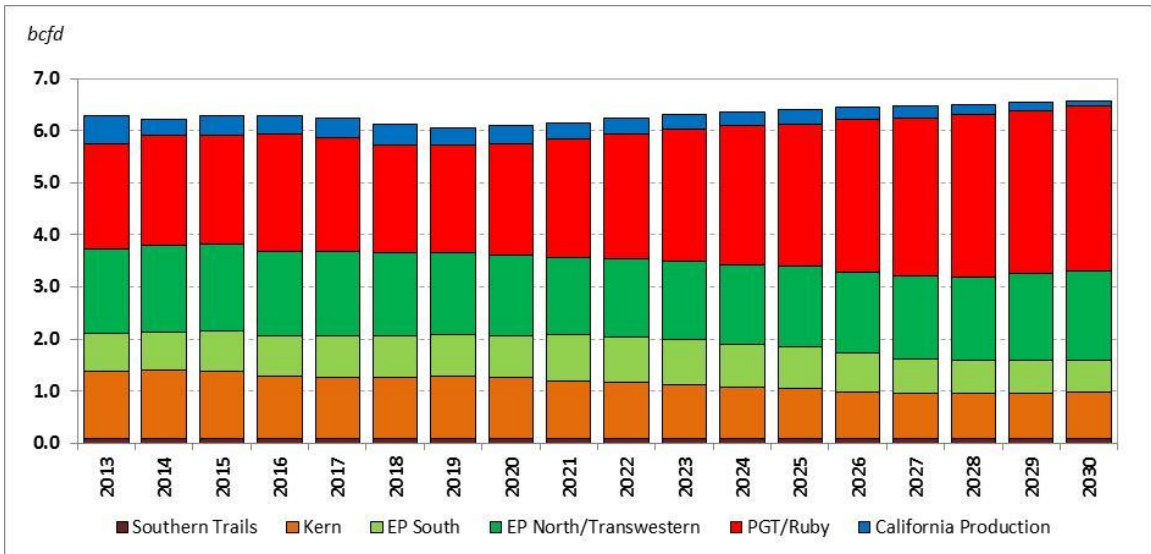
As can be gleaned from Figure 11, natural gas flows from Canada and the northern Rockies (PGT/Northwest PL/Ruby) are projected to increase substantially from 2013 to 2030. Volumes on the Kern River pipeline drop by about 30%, and production in California declines much more dramatically, by about 80%.[17] The El Paso system plus Transwestern and Southern Trails see relatively stable throughput through 2030, which reflects strong production growth in Texas. In sum, we see that California imports grow as indigenous production declines and demand grows modestly. Moreover, production growth in Texas and Canada tend to squeeze out exports from the Rockies via the Kern River pipeline. However, this should be taken to imply that Rockies production declines. Indeed, it does not. Rather, demand growth in other western states, particularly in power generation, is projected to be sufficient to absorb production in the region. Finally, with regard to California specifically, we see that northern sources of supply are projected to increase their share of the California market longer term.

The strong growth in Canadian natural gas flows to California through 2030 bears some discussion. To begin, as noted above, there is an abundance of resource assessed to be technically recoverable in Canada. The Canadian NEB and US Geological Survey estimate almost 1100 tcf of resource, split amongst shale, tight, coal bed, and conventional formations, with shale and tight gas resources representing the vast majority.[18] This highlights the need for an outlet for Canadian gas—as LNG, pipeline, or local demand—if production activity is to continue expanding.

According to analysis at the Baker Institute CES, LNG exports from Canada are commercially challenged due to high capital costs and a long-term international price environment that softens considerably relative to very recent history.[19] The capital cost of a greenfield LNG export facility in the environmentally sensitive region of British Columbia is two to three times greater than the

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[17] Notably, this is indicative of the lack of production growth from the Monterrey shale formation. This follows due to the nature of the play – specifically, it is an oil play that is geologically, and hence commercially, challenged. Since this particular study is focused primarily on natural gas, the longer term prospect for oil-directed development of the Monterrey shale is out of scope herein.

[18] See Canadian Gas Association, "Natural Gas Resource Base–Canada," at http://www.cga.ca/wp-content/uploads/2011/02/Chart-9-Natural-Gas-Resources-Canada.pdf.

[19] For much more detail on this see the CES working papers "U.S. LNG Exports: Truth and Consequence," 2012, available at http://bakerinstitute.org/research/us-lng-exports-truth-and-consequence; and "Natural Gas Price in Asia: What to Expect and What it Means," 2014, available at http://bakerinstitute.org/research/natural-gas-price-asia-what-expect-and-what-it-means. Both are authored by Kenneth B Medlock III.

capital outlay required to reverse an existing LNG import facility on the US Gulf Coast. Therefore, despite a sizeable transportation cost savings to the Asian market, the fixed cost burden is prohibitive. In fact, modeling indicates Canadian gas production will continue to decline through 2016, but re-surge when US LNG exports commence and domestic US demands rise. At that point, Canadian natural gas will utilize existing pipeline infrastructure and rights-of-way to access a strengthening US market.

Of course, a major caveat here is the extent to which demand in California actually grows. Natural gas is currently exported to the Western US via pipeline from production originating in both Alberta and British Columbia. But if demand growth is minimal, then the shale and tight gas resources in basins such as the Horn River and Montney are not likely to find enough demand in the Western US to be absorbed, which will curb upstream activity and put downward pressure on prices.

Concluding Remarks

The upstream regulatory framework in North America creates an investment environment that is generally attractive to capital. The sheer scale of the shale gas revolution over the past decade is a testament to this. Capital is capable of moving into the market with relative ease, and there is little in the way of impediment to capturing arbitrage opportunities when they exist. Expansion of interstate pipelines is generally fairly easy (notwithstanding the current debate surrounding the Keystone XL pipeline), and access to liquid pricing points, which reduce market risk associated with a venture, is readily available. Securing mineral rights is also relatively unencumbered since firms can negotiate directly with landowners on privately held lands. All of this sets the stage for continued strong domestic production of natural gas, and has implications for the manner in which California receives natural gas supplies.

Although beyond the scope of this analysis, energy reform in Mexico bear mention. In particular, reform of the energy sector in Mexico has the potential to be yet another game changing stimulus to the North American production outlook. Moreover, this has direct implications for the state of California. But, uncertainty prevails with regard to the future of energy production in Mexico

and the degree to which the Mexican energy sector integrates with the rest of North America. Thus, while ongoing reforms indicate a very promising future, much remains to be determined regarding the parameters that will ultimately define success. Nevertheless, the potential opportunities in Mexico are sizable, and full realization of the potential will contribute to even greater changes in the North American natural gas market, California included.

In the longer term, largely due to policies that are preferential to renewables and greater efficiency in end-use, natural gas demand prospects in California are relatively meager, especially when compared to the rest of the US. Regardless, the source of supply into California will increasingly shift toward Canada, while production within the state is likely to steadily decline. Strong growth of associated gas production in Texas, and the Permian basin specifically, which is driven by oil-directed drilling activity, will primarily serve growing loads in the Gulf Coast region, but flows into California from the region are likely to stabilize as production activity there strengthens.