MAGUIRE ENERGY INSTITUTE

THE OUTLOOK FOR ENERGY PRODUCTION IN THE U.S. GULF OF MEXICO:

HOW THE REGULATORY RISK PREMIUM IS RESTRAINING PRODUCTION

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INTRODUCTION

In President Obama's March 22 speech embracing an "all-of-the-above" energy strategy for the United States, he touted a two-pronged plan to pursue renewable, next-generation energy sources while simultaneously ramping up production of traditional fossil fuels to ensure the necessary energy for U.S. economic growth while helping to reduce the country's reliance on foreign suppliers.

Its pro-energy signals notwithstanding, the Administration has done little to make needed improvements to the regulatory governance of one of the nation's most important sources for fossil fuel production: the Gulf of Mexico. The Gulf is responsible for some 28% of total U.S. energy production. Yet it is governed by a regulatory regime that was largely retooled after the Macondo blowout of April 2010, creating a complex system of oversight for offshore activity that regulators to this day struggle to implement in a transparent and predictable fashion.

Rather than streamlining the system in favor of needed efficiency, the rules only continue to proliferate. On May 1, 2012, for example, the Interior Department's Bureau of Safety and Environmental Enforcement (BSEE) announced that new rules on drilling safety and environmental management systems will be issued in 2012, as well as new proposed rules to heighten requirements regarding blowout preventers and production safety systems.

Clearly, the rules and programs governing offshore operations need to keep pace with ever-evolving offshore exploration and production techniques. However, regulations must be implemented efficiently to avoid constricting the very industry they govern. Today's federal offshore regulatory regime largely falls short of that threshold test.

As discussed below, recent incremental decreases in the price of gasoline in the U.S. belie substantial shortcomings in Gulf of Mexico exploration and production activities – shortcomings that will likely be felt over the medium and long term. These shortcomings are often masked by other data. Rather than focusing on the number of rigs in the Gulf, for example, it is important to know what specific activities Gulf-based rigs are currently conducting. In addition, rather than merely looking at the total number of permits being issued at present, one must understand what those permits are for and how long it takes for them to be finally processed, including the time period required before they are officially deemed "submitted", at which point the U.S. Department of the Interior officially begins to track their progress. Finally, it is also important to consider the amount of revenue that offshore operations generate for the U.S. Treasury – a figure that dips markedly during periods of relatively lower activity.

These factors directly influence how much confidence companies, shareholders and investors have in the future of Gulf-based operations. If the U.S. is to generate the optimal level of energy production from this critical basin, the regulatory regime must provide an accommodating climate for investment in safe and environmentally sound operations rather than hinder the operators' ability to bring these highly sophisticated, capital-intensive, multi-year projects to fruition. America's energy independence and economic health depend on it.

UNDERSTANDING GASOLINE PRICE FLUCTUATIONS

The ups and downs of gasoline prices are primarily a reflection of changes in the price of petroleum. Not surprisingly, as oil prices have jumped about 25 percent over the past year, gasoline, diesel and jet fuel prices have increased by about the same percentage.

How are fuel prices determined? Though basic economics would suggests the simple interplay of global supply and demand, the underlying reality of the pricing process is more complicated. In practice, there are many prices for crude oil of a particular grade. For instance, on April 30, 2012, the “cash” price for a physical barrel of West Texas Intermediate was $104.87. But the “futures” price for delivery of a similar barrel in December 2012 was $106.21. What this suggests is that buyers and sellers of petroleum on April 30 believed prices would be higher at the end of this year than they are today, either because demand will increase or supply will be tighter. At the same time, on April 30, 2012 oil for delivery in December 2013 was trading at $102.56. This tells us traders on that day expected supply to be greater and/or demand to be lower 19 months into the future.

Global political uncertainty can be another influence on oil prices. Unrest during the Arab Spring pushed prices above $113 in April of 2011 on expectations of a major disruption of oil supplies. When that didn’t happen, prices fell to under $100 by June and were back in the $80 range by fall. Similarly, the current spike in oil and gasoline prices is due in part to the growing embargo on Iranian oil and that country’s threat to close the Strait of Hormuz.

In short, oil prices—and by extension gasoline prices—are determined not just by current levels of supply and demand but by expectations of future changes in supply and demand due to global political uncertainty, technology, or domestic energy policies and regulations. In the case of the United States, oil and gasoline prices also incorporate a “regulatory risk premium”. In other words, if the market is not confident that the federal government will remove obstacles to oil and gas production in the Gulf of Mexico and elsewhere, energy traders will incorporate this risk, coupled with prospective cost estimates for regulatory compliance, into current thinking and future price structures.

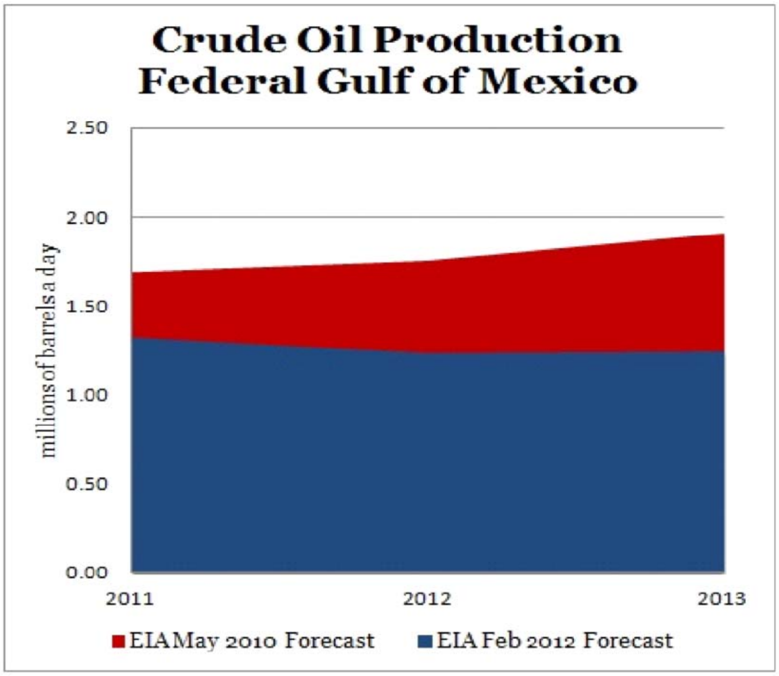
HOW OFFSHORE REGULATIONS AFFECT PRODUCTION AND PRICES

Output from the Gulf of Mexico looms large in terms of total U.S. oil production, in turn impacting the broader price of crude. Prior to the Macondo blowout in the spring of 2010, the Gulf of Mexico accounted for about 29% of the nation's domestic oil production. As a result of the deep water drilling moratorium imposed following the blowout, output from the Gulf dropped sharply. But since the economy was in recession and the total amount of oil spilled was equivalent to about nine days worth of consumption, there was a negligible impact on the prices of crude oil and gasoline.

Regulatory decisions, however, can have profound impacts on oil prices. When President George W. Bush lifted the drilling moratorium on the Outer Continental Shelf (OCS) off America's coasts in 2008, the price of oil immediately dropped more than $9 per barrel as analysts and traders factored in the potential new supplies, eventually hitting a 45-day price average for crude that was down 12 percent, or $16 per barrel.

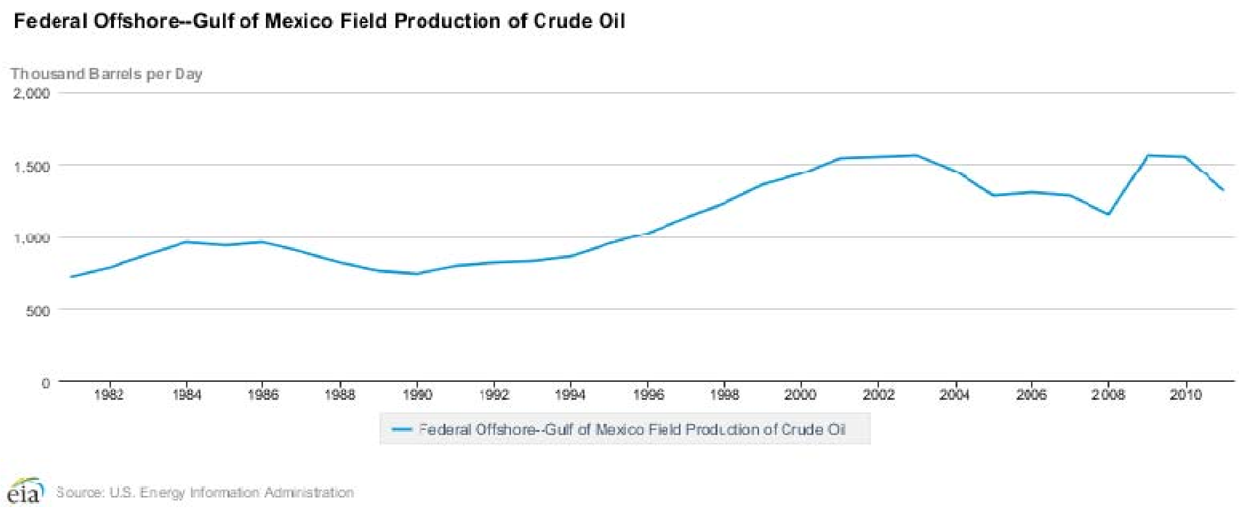
In contrast, when President Obama ended the deep-water drilling moratorium on October 13, 2010, price drops similar to those following the end of the 2008 OCS moratorium did <u>not</u> occur. The lack of change was due largely to the President's accompanying declaration of new safety rules to govern Gulf activity. Though these new regulations were not detailed at the time, the market foresaw a drawn-out period of clarification and uneven implementation, with the potential to negatively impact Gulf of Mexico deep-water operations. The U.S. "regulatory risk premium", in other words, had become significant, reflecting a lack of confidence in the overall ability of regulators to allow drilling and production to return quickly to pre-Macondo levels.

The aftermath of the moratorium – in which regulatory constraints continue to stifle optimal production levels – is indeed having a measurable impact on output from the Gulf of Mexico as well as on oil and gasoline prices. According to the Energy Information Administration (EIA), Gulf production fell from 1.55 million barrels per day (mb/d) in 2010 to 1.32 mb/d in 2011. This year, the EIA estimates Gulf output will fall further to 1.23 mb/d. But two years ago, before the moratorium, the EIA predicted that production would reach 1.76 mb/d this year. That means ***the difference between projected and actual production in the Gulf of Mexico is close to 30 percent*** (see chart). Had production from the Gulf of Mexico been 30 percent higher this year, the recent rise in oil and gasoline prices would likely have been more limited.



What went wrong? Once the moratorium was technically lifted, it was replaced by a *de facto* "permitorium" in which the number of deep- and shallow-water drilling permits issued dropped dramatically. It wasn't until February 28, 2011 (314 days after Macondo) that the

Interior Department approved the first new permit for an oil company to drill in more than 500 feet of water. Not surprisingly, while domestic crude oil production increased overall in 2011, production in federal waters in the Gulf of Mexico continued to fall through 2011, declining by 230,000 barrels per day (see chart).



A CLOSER LOOK AT GULF DRILLING AND PRODUCTION TODAY

At first blush, a number of indicators seem to suggest that exploration and production activity in the Gulf of Mexico is returning to pre-moratorium levels, and the administration has eagerly taken credit in recent months for increases in domestic oil and gas production.

One indicator often cited to bolster contentions of robust Gulf energy activity is the number of rigs operating in the basin. At the time of Macondo, 33 deep-water drilling rigs were operating in the U.S. Gulf of Mexico. Twenty-four were subsequently idled by the moratorium. Prior to the moratorium, deep-water rigs were leased out for $250,000 to $500,000 a day. Absent that revenue stream, many rigs departed the Gulf to drill in more welcoming overseas prospects governed by more predictable regulation. By one count, in January 2011, only eight floating rigs remained in the Gulf.

In recent months, however, more rigs have been spotted in the Gulf than has been the case for the past few years. Reuters recently reported that eight deep-water drilling rigs are expected to join the fleet in the Gulf of Mexico this year. If true, this would bring the total number of rigs in the basin just short of where it was before the Macondo blowout. According to one recent count, there were 30 deep-water mobile offshore drilling units (MODUs) in the Gulf of Mexico as of early May 2012, compared to 33 prior to the moratorium. Energy industry observers also expect to see 10 or more additional deep-water MODUs added to the Gulf in 2012.

But what are rigs in the Gulf of Mexico doing these days? According to the Baker Hughes count of active rigs, in the two months prior to the deep-water moratorium, there was an average of 27 "active" rigs in the Gulf, with "active" defined as rigs engaged in drilling-related activities, as opposed to maintenance, completions, workovers, etc. As of May 1, the Baker Hughes count indicated a total of 18 active rigs in the Gulf, a level that falls far short of pre-moratorium numbers. In other words, the activities rigs are engaged in today are considerably less productive than was the case prior to the moratorium.

Beginning in early 2012, the administration also began touting the number of permit approvals that had been issued for unique wells in the deep waters of the Gulf, meaning wells for which containment plans are required under post-Macondo regulations to provide live interventions or contain leakage as the result of a well-control incident. By early March, the administration claimed to have approved permits for 94 unique wells requiring containment since the Macondo blowout. However, closer scrutiny reveals that only 32 of the 94 permits approved were for unique new wells specifically permitted to reach hydrocarbons. The other 62 permits applied either to pre-moratorium wells (meaning revised plans companies were required to submit to meet the changed regulatory requirements) or included permits that only allow shallow batch set depths, meaning additional permits are required to reach total depth for hydrocarbons. This finding echoes a 2011 IHS CERA report, *Restarting the Engine*, that revealed, "In the six-month period following the lifting of the moratorium, almost 90 percent of deepwater exploration plan approvals and more than 80 percent of the deepwater development plan approvals were re-approvals of previously approved plans."

THE OPAQUE PATH TO "DEEMED SUBMITTED" STATUS

Offshore exploration and drilling begins many years before crude oil is reliably tapped from a well and prepared for transport to shore. Prospects come to life as the result of a lengthy, technologically sophisticated process in which potential oil and gas reservoirs are identified and then subjected to a gradually intensifying battery of tests to gauge the likelihood and potential size of a new discovery. These efforts require enormous amounts of time, capital investment, and patience to overcome the numerous instances of negative results, false positives and the overall uncertainty that accompany any large-scale investment. This process cannot proceed in advance of federal approval.

The initial phase of the exploration and development plan approval process – which itself precedes the point at which actual applications for permits to drill (APDs) are submitted – has traditionally been a bit of a black hole. This initial period of review begins when an operator first submits a plan to a regulator who determines whether the plan meets all the initial criteria that must be covered before it is considered complete and ready for formal review. During this period, the plan can be sent back to the operator as many times as the regulator decides necessary before deeming it "submitted". No official tracking mechanism exists to gauge progress during this initial phase. Though rules do exist mandating that initial reviews of plans take place within 30 or 120 days, depending upon the specifics of the submission, industry observers note that these policies are generally viewed as guidelines. There is no true accountability compelling authorities to adhere to the timeframe for reviewing this first step in the permitting process.

While companies have experienced this "slow walking" for some time, the amount of time required before exploration and development plans are deemed submitted has, since Macondo, risen sharply. As of May 15 2012, according to Interior Department data tracking regulatory actions on plans after Macondo, the average number of days to obtain approval for a plan is 207 days. The average number of days from original submission to deemed submitted status is 160 days. Prior to the moratorium, the average approval time for a plan from original submission to final approval was 50 days total.

Only when regulators finally deem the application submitted does the official Bureau of Ocean Energy Management (BOEM) clock actually start to tick. It is this part of the application process – which can be followed through online tracking tools on the BOEM website – that Administration officials often refer to in arguing that the revised plan approval mechanism is working under a timeframe similar to pre-Macondo days. In fact, though the time period from deemed submitted to "final approval" is limited under statute, industry observers note that the agency will sometimes request additional information during the deemed submitted phase. This has the effect of restarting the clock on an individual plan approval, causing the mandated 30- or 120-day time clock to wind back to the beginning. The Administration may be technically correct in claiming the waiting period *after* a permit has been deemed submitted has returned to pre-Macondo levels. But in reality, the claim masks significant underlying delays that need to be addressed.

"JUST IN TIME" PERMITTING STIFLES RIG ACTIVITY

After an operator obtains approval for an exploration or development plan, it then submits an Application for a Permit to Drill ("drilling permit" or APD). Historically, operators were able to obtain a new drilling permit in a timeframe that roughly corresponded to the number of days required to drill one well. In other words, while a rig is drilling one well, the operator could obtain approval to drill another. This structure provides the company with the ability to plan for the next job. Given the substantial daily costs inherent in maintaining a single drilling rig in the Gulf of Mexico, it is critical to know from an operational standpoint where and when future work will occur. Currently, however, drilling permit approvals are being issued on a "just in time" basis, which sharply hinders the operator's ability to plan for the next job. This trend has become a major industry concern since a predictable backlog of approved drilling permits is required in order to secure long-term rig contracts.

The APD Inventory measures how many APDs have been approved and are waiting for drilling to commence (in industry parlance, for a well to be "spud"). Observers estimate that a minimum of three APDs are necessary in the inventory for each active rig in order to secure the long-term contracts necessary to sustain the industry. With the active deep-water rig count currently at 18, industry expectations call for an approved APD inventory of at least 54, meaning a backlog of 54 permitted wells that have not been spud should be available, thus ensuring that a rig can move to another well once its current job is completed.

As of March 31, however, there were only 6 approved drilling permits in the inventory for which the well was not yet spud. During February 2012, the APD inventory was also 6; in both January 2012 and December 2011, the APD inventory stood at 4. With eighteen active rigs currently in the Gulf of Mexico, this leads operators to question where the active rigs will be going next. In short, "just in time" permitting is resulting in sub-optimal use of oil and gas resources in the Gulf and may cause idle rigs to move to other locations around the globe.

LOST LEASE SALES: LOST PRODUCTION, LOST REVENUE

The effects of the Administration's marked ambivalence toward fostering energy production in the Gulf of Mexico are not limited to increasing the U.S. regulatory risk premium. Under the Administration, offshore lease sales have gradually declined each year, depriving the U.S. Treasury of a sorely needed and once relatively dependable source of revenue while dampening future output from the Gulf and other offshore reservoirs.

During 2008, for example, $9.4 billion was generated in new offshore lease bids. That figure has noticeably dropped each year, to $1.1 billion during the recessionary year of 2009, $979 million in 2010, and then a paltry $36 million in 2011 as the Administration managed only one lease sale during the entire year. In other words, as budgetary concerns have increasingly taken center stage in U.S. political discourse, the Administration has amassed a lackluster record of holding offshore lease sales, further exacerbating budget shortfalls.

The consequences of the Administration's record on lease sales will also be felt in the longer term, as lease sales provide the foundation for new exploration and development that leads to future oil and gas production. Each lease takes years and millions or billions of dollars to fully develop. Companies must undertake a lengthy and costly process involving geological mapping, testing, and drilling exploratory wells before production can begin. In short, these leases are the necessary prelude to developing a tract of land and bringing energy to market.

CONCLUSION: THE REGULATORY RISK PREMIUM IMPOSES A SURCHARGE ON U.S. OIL AND GASOLINE PRICES

While citing the benefits of an "all-of-the-above" energy strategy may serve short-term political imperatives for the Administration, more sophisticated industry observers, including analysts, investors, insurers, and the companies themselves, know better. The opacity of the offshore regulatory process serves to erode business confidence in future Gulf of Mexico production, adding significant upward pressure to the U.S. regulatory risk premium.

The recent drop in oil and gasoline prices can be explained by a slowing world economy, an easing of tensions with Iran, and increased production from Saudi Arabia and other OPEC countries. Most of Europe has slipped back into recession, U.S. economic recovery remains halting, and even fast-growing countries like China and India are recording lower rates of economic growth, thereby muting global energy demand. None of these developments, however, has affected the U.S. regulatory risk premium. Put differently, absent uncertainty about the cost and time-frame of acquiring regulatory approval for deep water drilling in the Gulf of Mexico, oil and gasoline prices would be even lower.

The outlook for oil and gas production in the Gulf of Mexico remains murky. Companies making massive investments of capital and time require predictability and confidence that production goals can be met. If companies find it increasingly difficult to tell their own executives and board members when projects are going to be approved, this uncertainty will affect decisions about where to place future capital investment. Investors need reasonable predictability or they will simply look elsewhere for more inviting opportunities. If Gulf production is to reach levels that equal its true potential in the months, years, and decades to come, the regulatory sphere must deliver on its obligation to provide a predictable review and approval process.

President Obama is on target when calling for an "all-of-the-above" energy strategy, both to enhance domestic production—with all the attendant benefits of jobs and revenue—and to ensure America's energy security. The Gulf of Mexico contains some of the world's largest reservoirs of recoverable crude oil and natural gas. Bringing reasonable speed and transparency to the permitting process for deep water drilling is a critical component of a meaningful all-of-the-above domestic energy strategy. Absent such actions, American households and businesses will continue to pay a hidden "surcharge" on oil and gasoline that reflects the current regulatory risk premium.