Addendum of April 2007 to the
Benefit-Cost/Small Business and Regulatory Flexibility Economic Analysis of January 2004

PROGRAMMATIC EFFECTS OF THE DEEP GAS INCENTIVES IN THE ENERGY POLICY ACT OF 2005

MMS published a rule in January 2004, that offered royalty relief incentives for deep gas drilling and production. Also, MMS prepared a detailed economic analysis of the benefits and costs expected from those incentives (DGEA04). The Energy Policy Act of 2005 (EPact05) mandates a change in some important provisions in that original deep gas rule. This paper delineates these changes and related decisions by MMS that follow the structure of the current incentive. It also updates portions of DGEA04 to help evaluate some options MMS has for implementing parts of the new deep gas incentives not dictated by EPact05. This update is founded on actual observations, rather than theoretical assumptions, about deep gas drilling under the influence of a royalty relief incentive.

Base Program and 4 Kinds of Changes Due to EPact05

The original deep gas royalty relief rule (30 CFR 203.40-203.48) created a 2-tier incentive program to increase and accelerate deep gas production from leases in water depths up to 200 meters in the Gulf of Mexico (GOM). The incentive is in the form of a royalty suspension volume (RSV) of 15 billion cubic feet (BCF) per lease for a new producing well between 15,000 and 18,000 feet subsea. The incentive for wells drilled 18,000 feet or more subsea is an RSV of 25 BCF per lease for a new producing well, or a royalty suspension supplement (RSS) of 5 billion cubic feet of gas equivalent (BCFE) for up to two unsuccessful wells on leases where no deep well has produced. Deep sidetracks and new deep wells drilled to the deeper zone on leases that already have produced from a deep well in the less-deep zone earn smaller RSV's under § 203.41(c). A subsequent deep well drilled on the same lease may share the RSV on the lease when it meets the conditions to be a qualified well. A qualified deep well must start production before May 3, 2009 to earn or share an RSV, or must start drilling before May 3, 2009 to a target depth below 18,000 feet subsea to earn an RSS. Provisions in 30 CFR 203.47 discontinue the RSV and RSS in years when the average NYMEX gas price exceeds a price threshold of $9.88/million British thermal units (MMBtu), adjusted for inflation after 2006.[1]

Section 344 of EPact05 mandates changes to some provisions in the existing program (e.g., the size of the RSV for certain ultra-deep wells, and the water depths in which the incentive is available). There are other issues with respect to which the statute is silent (e.g., period for which the ultra-deep RSV must be offered). Other regulatory adjustments are needed as a consequence of the requirement in section 344 to extend royalty relief to leases in a deeper water depth interval using the same methodology provided for in existing rules (e.g., the availability of an RSS in deeper water). For still other statutory provisions, MMS has broader policy discretion. For some of those discretionary provisions, MMS has chosen an implementation option that has the new incentive conform to the structure of the existing program (e.g., allowing all qualified deep wells to share an RSV earned by an ultra-deep well on the same lease). For some other discretionary provisions, MMS has selected an option that minimizes the fiscal cost of the new program (e.g., for some vintage of leases, no added relief is provided for drilling an ultra-deep well if the lease has previously produced from a deep well).

[1] The price threshold in the current CFR ($9/34/MMBtu) is expressed in 2004 dollars and escalated annually for inflation. Updating the price threshold to 2006 dollars is necessary because of the way inflation adjustments calculated by the Department of Commerce, Bureau of Economic Analysis (BEA) must be handled by MMS. BEA continues to revise its inflation series (GDP implicit price deflator) for several years after it publishes initial estimates. MMS, however, must make the call about what inflation rate to use to adjust the price threshold within 3 months of the end of a year (e.g., 2005). Therefore, MMS locks in the BEA estimate for a year (2005) by March of the next year (2006) and ignores subsequent revisions BEA may make in that estimate. This process means that the price threshold cannot be updated over a 2 year period (e.g., 2004 to 2006) using the most current BEA inflation series (e.g., the one available in March 2007). Rather, the price threshold for 2004 must be updated to 2005 using the BEA inflation estimate for 2005 available in March 2006 and then the resulting 2005 price threshold updated to 2006 using the BEA inflation estimate for 2006 available in March 2007.

The next section reviews the legal or policy reasons behind the mandatory and conforming provisions added to the deep gas incentive program. The following section explains choices MMS made about other implementation decisions raised by EPact05 (i.e., duration of the deep gas incentive, and continuation of the RSS component of the incentive). The final section updates parts of DGEA04 to compare options for one explicit discretionary provision (price threshold level) for application to EPact05 incentives.

Required Changes to Base Program

Section 344(a) of EPact05 mandates a third RSV tier of at least 35 BCF for certain ultra-deep wells, i.e., wells producing from 20,000 feet or more subsea. Unlike the existing regulations, EPact05 does not mention expiration or sunset of the ultra-deep gas incentive, and MMS therefore has not included a sunset for the ultra-deep incentive in this proposed rule. Section 344(b) extends the new 3-tier drilling depth incentive to leases in water depths from 200 to less than 400 meters in the GOM. Section 344(b) also stipulates use of "the same methodology" as in shallower waters of the GOM but resulting in no smaller RSV. MMS therefore has proposed use of the complete program currently applicable to leases in less than 200 meters of water for approximately 6 years for leases in 200-400 meters, the same eligibility period for deep wells under the current rule. Section 344(c) explicitly gives the agency the discretion to "place limitations on the royalty relief granted under this section based on market price", which allows MMS to apply a reasonable price threshold consistent with program objectives and scope. Also, like the existing regulations, section 344(c) excludes leases that have deep water royalty relief from this expanded deep gas incentive.

EPact05 language allows for agency discretion on several features of this expanded incentive. Specifically, the agency "may" rather than "shall" grant an RSV of not less than 35 BCF in two situations – to an ultra-deep sidetrack and to an ultra-deep well on a lease that already has produced from a deep well. Given this all-or-none choice, MMS has chosen, with one exception, to grant no RSV in these situations. The exception occurs when the first ultra-deep well is a sidetrack and that sidetrack is essentially equivalent to an original ultra-deep well. A sidetrack is essentially equivalent to an original well when the distance it is drilled is at least 20,000 feet from the old well from which it departs. This formulation avoids unintended relief for significantly shorter and thus less costly ultra-deep wells.

Provisions of the current regulation that allow an increase in RSV for a deeper well no longer apply to ultra-deep wells owing to the all-or-none statutory situation.[2] Thus, while an incentive to explore a deeper zone in the 18,000 to 20,000 feet subsea zone remains even after a lease has produced from a deep well in a less deep zone, this incentive is eliminated for ultra-deep wells drilled in the same circumstances.[3]

MMS has chosen to continue the current provision of allowing another deep well on the same lease to share the RSV when it meets the conditions to be a qualified well. This provision maximizes the value of the ultra-deep RSV and avoids any unintended discouragement of drilling multiple wells where needed to properly produce one or more deep reservoirs on the same lease.

Optional Changes to Base Program

EPact05 is silent about deep but not ultra-deep wells on leases in less than 200 meters of water and about the RSS. Because EPact05 implicitly extended the duration of the deep gas incentive program by adding leases in 200-400 meters of water and was silent regarding a sunset provision for ultra-deep wells, MMS considered extending the duration of the original

[2] Leases issued in 2004 and before EPact05 became law in 2005 retain the provision to increase the lease's RSV for a deep well to a deeper depth, including ultra-deep wells, because that right was granted in the lease instrument rather than through regulation.

[3] Deep and ultra-deep wells producing on the same lease at the same time is not typical, as the MMS data base indicates that only 1 of 12 current leases with a producing ultra-deep well also have a deep well that is producing.

2-tier incentive for leases in up to 200 meters of water. MMS also considered continuing the RSS for ultra-deep wells beyond the expiration date consistent with application of the current program. In this section, we draw upon the experience to date with the original deep gas incentive to explain why neither of those options was adopted. The next section looks at the alternatives for setting the price threshold for all elements of the incentive explicitly touched by the EPact05.

Unlike DGEA04, actual observations on deep gas drilling incentives now can be used to guide estimates of the efficiency of potential deep gas incentive options. DGEA04 estimates were based largely on theoretical assumptions about how responsive operators would be to the new incentives, given the cost of drilling, the value of production, and the estimated distribution of deep gas reservoirs. In contrast, Table A shows the drilling intensity observed in two different periods – from 1998 to 2002 (just before deep gas relief was offered to existing leases) and from April 2003 to June 2005 (period for which data are available on activities potentially influenced by that relief). The table reports the average number of deep wells spudded (i.e., that began drilling) in a year during each period.[4]

Table A – Average Number of Deep Wells Spudded Per Year
on Leases in 0 to 200 meters of Water in the GOM

Time Interval	**15,000 – 18,000 ft subsea**	**≥ 18,000 ft subsea**
1998 – 2002	42.6	12.0
4/2003 – 6/2005	63.6	17.3

Coincident with onset of the widespread deep gas incentives has been a steep increase in the market price of gas. From 1998 to 2002 the EIA wellhead gas price averaged \$2.96/ thousand cubic feet (MCF). From April 2003 to June 2005 the EIA wellhead price averaged

[4] A review of more recent data indicates the results of this analysis are still sound. From mid-2005 through mid-2006 fewer deep wells were drilled than the annual average during the first 2 years of the incentive, despite even higher gas prices than prevailed during the previous two-year period. The disruptions from hurricanes Katrina and Rita undoubtedly depressed drilling in the later period, but these findings suggest that there is no basis to revise the existing analysis.

$5.32. The later period coincides with the deep gas incentive period, so drilling in that period reflects the combined effects of a higher gas price and the availability of royalty relief.

Royalty relief affects the price net of royalty received by the operator. We separate the effects of the price increase from the effects of royalty relief by assuming that the change in net price received by the operator explains all of the change in drilling intensity between the two periods. This assumption omits other factors, such as constraints on deep drilling capacity and a ramp-up period for full appreciation of the incentive, which may have delayed early drilling response to the new incentive.[5] While the wellhead price over the incentive period increased by $2.36 ($5.32/MCF - $2.96/MCF), the net price that an operator would have received, assuming a royalty rate of 1/6 and no royalty relief increased by $1.96/MCF {from $2.47/MCF [(1 – 1/6) * $2.96] to $4.43/MCF [(1 – 1/6) * $5.32]}. With royalty relief in the later period, the net price that the operator actually received increased by $2.85/MCF ($5.32/MCF - $2.47/MCF). Therefore, 69 percent ($1.96/$2.85) of the increase in drilling can be attributed to the price increase with the residual 31 percent attributed to royalty relief.[6]

Using this finding, we split the last row in Table A into those deep wells that would have been spudded in the absence of any deep gas incentive and those deep wells that were spudded in response to the existing incentive. Table B displays the results. For example, the estimate of 57.1 wells consists of the 42.6 wells per year which history indicates would have been drilled with no royalty relief had the gas price stayed around $2.96/MCF, plus 69

[5] MMS data as of the end of November 2005 showed 52 deep wells drilled in the last 6 months of 2003, compared to 43 in the first 6 months of 2005. That does not support the notion that a response of deep drilling to the introduction of the incentive experiences a ramp-up period. Perhaps there was a backlog of deep wells delayed in anticipation of the incentive in early 2003 or the lags in MMS data coverage exceed 5 months so early 2005 data are not yet complete.

[6] This is a different approach than we used in DGEA04 to update incremental deep gas drilling between the proposed rule (March 26, 2003) and the final rule (January 26, 2004). Analysis for the proposed rule was based on a fixed gas price of $3.50/MCF while analysis for the final rule updated the original analysis based on the AEO 2003 price path which averaged $4.11/MCF over the 2004 to 2019 period. For that update, we assumed the price threshold, set at $5/MMBtu in the proposed rule, served as a measure of the market conditions absent royalty relief that would provide similar incentive effects as royalty relief. That assumption is plausible only when the price threshold is close to the royalty-equivalent price, which we estimated as $4.91/MCF.

percent of the additional 21 (63.6 – 42.6) wells drilled which we attribute to the higher gas prices rather than to the royalty relief incentive program.

Table B – Average Number of Deep Wells Spudded Per Year
From April 2003 through June 2005

Stimulus	**15,000 – 18,000 ft subsea**	**≥ 18,000 ft subsea**
Higher price alone	57.1	15.7
Higher price plus Royalty Relief	63.6	17.3
Residual Attributed to Royalty Relief	6.53	1.65

From this analysis, we observe that available empirical evidence for the relatively short time since we implemented deep gas drilling incentives in late March 2003 suggests the assumptions used in DGEA04 might have been overly optimistic. After accounting for price effects, only a 10 to 12 percent increase in deep drilling appears associated with the current incentive, a range well below the original increases projected for both the deep and deeper drilling depths. As such, the empirical results to date do not provide strong support for extending the duration of the current deep gas incentive program, and MMS proposes not to do so. MMS proposes only to continue indefinitely the statutorily-mandated ultra-deep category, with respect to which Congress was silent. Given this program formulation, the efficiency of the ultra-deep well part of the program could potentially benefit from lower price thresholds than applies to the current program.

Price Threshold Analysis

In this analysis we estimate the incremental production and fiscal costs associated with 6 price threshold (PT) options between \$9.88 and \$3.70/MMBtu (expressed in 2006 dollars)[7]. In addition to the end points of this range, we consider price thresholds of \$7.76, \$6.88,

[7] These price thresholds are equivalent to \$9.34 and \$3.50/MMBtu, respectively, expressed in 2004 dollars.

$5.65, and $4.47/MMBtu (all expressed in 2006 dollars)[8]. This new PT would apply to the following RSVs and RSSs: (1) the extra 10 BCF for ultra-deep wells until the sunset of the current incentive in 0-200 meters of water, (2) the 35 BCF earned by ultra-deep wells in 0-200 meters of water after sunset of the current incentive, and (3) all RSVs and RSSs earned by the deep and ultra-deep wells in 200-400 meters of water.

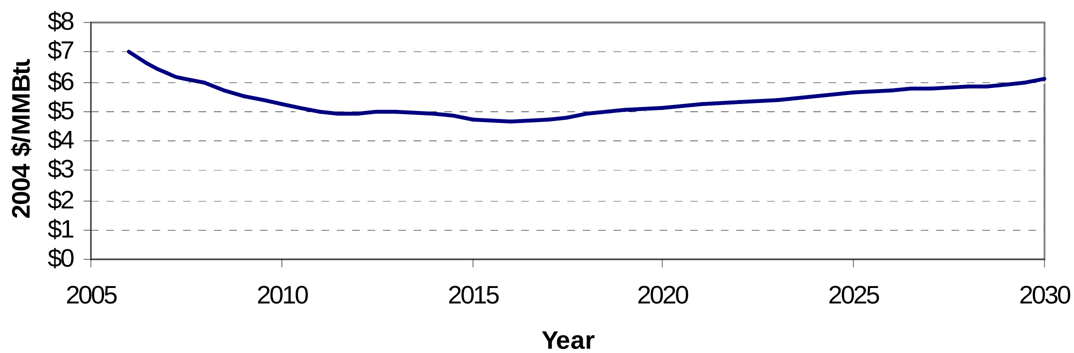
We consider only PT's at and below the one in current regulations for several reasons. The level of the PT in current regulations was set when acceleration of deep depth drilling was considered extremely important and results from the incentive program were expected to be robust. Moreover, even though the PT parameters were set when gas prices and expectations were lower than they are in early 2006, they were chosen within the context of a program that has a fixed expiration date. The lack of an expiration date makes it administratively difficult to end a program should performance not meet expectations or market conditions change significantly, e.g., higher prices and expectations mean operators need to rely less heavily on the benefits from deep gas royalty relief to justify future drilling to ultra-deep depths. Thus not having an expiration date makes it more important to estimate and highlight the consequences of applying alternatives PT's in connection with the new statutory incentive and the current expected path of future gas prices.

We take as the current expected price path the projection in EIA's Annual Energy Outlook 2006 adjusted to a basis directly comparable to the PT. Briefly, that price path is the AEO projection for the average U.S. wellhead value stated in 2004 dollars. We add $0.32/MCF to account for the average long term difference between the national wellhead and the Gulf coast prices reported by EIA. We then match the NYMEX Henry-Hub price by dividing that value by 1.025 to convert the MCF value to a MMBtu value using the typical

[8] These price thresholds are equivalent to $7.34, $6.50, $5.34, and $4.19/MMBtu expressed in 2004 dollars.

thermal content of gas (1.025 MMBtu/MCF) from the Gulf coast. As shown in Figure A, this composite price path has a "U" shape over time and averages $5.15/MMBtu ($5.28/MCF) in 2004 dollars for the 2007 to 2022 period.[9] The price path used in DGEA04 also had a "U" shape and averaged $4.11/MCF (2003$) for the 2004 to 2019 period.

Figure A - Most Likely Gas Price Path, AEO 2006 Adjusted to Landed Gulf Coast Btu Value



We estimate the effect of the additional RSV of 10 BCF for ultra-deep wells (35 BCF under EPact05 less 25 BCF under current regulations) by assuming drilling increases in the same proportion as the expected value of the relief. Before sunset of the current deep gas incentive program, we value this added incentive somewhat less than 10 BCF since it has a present value less than 10 BCF because it is claimed only after the already existing incentive is exhausted.

We then estimate the tempering effect of a given PT based on the frequency with which volatile gas prices are expected to exceed the PT. For the tempering effect on drilling, we assume a PT reduces drilling in the same proportion it reduces the expected value of the

[9] The average of this gas price forecast is close to the average price over the 2003-2005 period used to establish the price-induced increase in drilling, so the baseline drilling shown in Table B should be a valid baseline for the forecast period.

royalty relief.[10] The expected value of the royalty relief depends on the likelihood of drilling a successful well and the royalty costs saved due to the RSV. For example, assume a 20 percent chance of drilling success and that gas prices never exceed the PT. Then, the expected value of relief for drilling an ultra-deep well while the RSS remains available would be 11 BCF (35 * 0.2 + 5 * 0.8). If volatile prices are expected to exceed the PT 23 percent of the time, the expected value of the incentive is reduced by 2 factors. First, the incentive is realized only 77 percent of the time. Second, the royalty value when relief is not suspended is calculated at that subset of volatile prices that are less than the PT. If gas prices in this 77 percent-subset average 85 percent of the mean price over the whole period (low-side average price), the expected value of the incentive is 7.2 BCF (11 BCF * 0.85 * 0.77). In this case we assume incremental drilling and production are only about 65 percent (7.2 BCF/11 BCF) of what they would have been had there been no PT or no chance prices would exceed the given PT.[11]

To estimate the frequency of price above a given PT and the low-side average price, we use a mean-reverting price-process model to simulate typical gas price fluctuations. Like the one for DGEA04, this model uses a volatility factor of 30 percent (standard deviation of the price distribution in year T) and a reversion factor of 75 percent. The reversion factor sets the mean of the price distribution in year T by closing that portion of the gap between the observation in year T - 1 and the mean to which it was reverting. These volatility and reversion factors were derived from an analysis of EIA quarterly gas price data for the period

[10] Because the price threshold level is not firm until the final rule, we assume that between the proposed and final rule operators will act as though each of the price threshold options shown here have an equal chance of applying. That means the incremental drilling for the one year we assume between proposed and final rule is the same for each price threshold option.

[11] Because the $9.34 ('04$) PT was in effect, the incentive response observed in the 2003-2005 period includes the influence of that PT. We have ignored this nuance in this analysis because it was almost certainly very small and we don't have a reliable estimate for this tiny effect. This approach is tantamount to assuming operators did not believe the PT of $9.34 ('04$) would be exceeded when making deep drilling decisions between the end of March 2003 and mid-year 2005 (when NYMEX gas prices averaged about $6/MMBtu).

1995 to 2003.[12] Simulations with this model help estimate the chance each year that the gas price will exceed a given PT.[13]

There is one technical difference between the current price process model and the one used for DGEA04. To facilitate interpretation and use of the low-side and the high-side average prices, we now simulate the price process with distributions of the level rather than the log of prices.[14] For that reason, the annual probabilities with which price exceeds a given PT in this study are not comparable to those reported in DGEA04.

Associated with the tempering effect of a PT on drilling is a tempering effect on forgone royalty, that is, royalty that would have been collected in the absence of royalty relief. Net forgone royalty consists of 4 elements; (1) royalty lost from RSV's on production that would have occurred in the absence of royalty relief; (2) added revenue from royalty paid by liquids produced along with the incremental gas; (3) added revenue from royalty paid by incremental gas after exhaustion of RSV's; and (4) added revenue from royalty paid by incremental gas production in periods when market price exceeds the PT.[15] The added royalty in the 4th element is calculated with the converse subset of average prices used in the incremental drilling estimate, that is, a high-side price that averages only gas prices that exceed the PT. In our earlier example, the high-side price would be the average price in the 23 percent of the time that the price sampled from the price path exceeds the PT.

[12] This more recent period better represents the future state of gas markets than a longer and potentially outdated back-cast period. Quarterly rather than annual observations were used to obtain enough data points to reliably characterize the volatility in this period.
[13] Even when the expected value each year of the price path remains below a given PT, anticipated fluctuations in the gas price around the long term trend line can occasionally result in the actual price spiking above the threshold for one or more years.
[14] The mean of a series of distributions of the level of annual prices is close to the base price path shown in Figure A while the mean of a series of distributions of the log of annual prices will be systematically above that base price path. This explains why we switched procedures for simulating the price path.
[15] The royalty not paid due to the RSV on incremental production is not part of forgone royalty since that production would not have occurred and generated royalty without the incentive.

Table C summarizes estimates of the effects of the EPact05 incentive for ultra-deep gas for a range of possible PT's through 2022. Extending the assessment period for additional years has no meaningful effects on the results or findings, as incremental production ceases to increase after 2022. Table D shows comparable estimates for the EPact05 extension of the current incentive to deep wells on leases in water 200-400 meters deep. The second column in each table shows the average annual chance that future gas prices will exceed different PT's indexed to 2006, as calculated by our price process simulation model. The third and fifth columns show the associated incremental production and net forgone royalty. As a base, the same model finds that from 2007-2022 the existing incentives, which expire in 2009, will add 328 BCF of deep gas and result in net forgone royalties of -$1,416 million ('06$) on the shelf ($4.31/added MCF).[16]

Table C – Cumulative Incremental Production and Forgone Royalty 2007-2022 from Ultra-deep Wells in 0 to 400 meters of water under Various Price Threshold Levels*

Price Threshold Policy (2006$)	**Probability Gas P > PT**	**Added Gas (BCF)**	**Increase from Base Production (%)**	**Net Forgone Royalty MM$**	**Decrease in Royalty (%)**	**Royalty Cost/ Added MCF**
$9.88/MMBtu '06$	1%	197	14%	-$989	-72%	-$5.01
$7.76/MMBtu '06$	10%	174	12%	-$855	-62%	-$4.92
$6.88/MMBtu '06$	21%	148	10%	-$702	-51%	-$4.75
$5.65/MMBtu '06$	45%	95	7%	-$410	-30%	-$4.32
$4.47/MMBtu '06$	72%	49	3%	-$160	-12%	-$3.27
$3.70/MMBtu '06$	85%	30	2%	-$61	-4%	-$2.05

* Does not include production and royalty associated with the RSV of 25 BCF already available until May 2009 to ultra-deep wells in water 0-200 meters deep.

[16] Beyond the much less robust than predicted response, the existing policy now looks less attractive than when it was issued. First, the new higher price path means relatively more base production and thus more forgone royalty. Second, the higher chance of violating the PT results in less incremental drilling associated with the incentive provided.

Table D – Cumulative Incremental Production and Forgone Royalty 2007-2022 from Deep Wells in 200-400 meters of water under Various Price Threshold Levels*

Price Threshold Policy (2006$)	Probability P > PT	Added Gas (BCF)	Increase from Base Production (%)	Net Forgone Royalty MM$	Decrease in Royalty (%)	Royalty Cost/ Added MCF
$9.88/MMBtu '06$	1%	26	5%	-$150	-32%	-$5.77
$7.76/MMBtu '06$	10%	20	4%	-$129	-28%	-$6.33
$6.88/MMBtu '06$	21%	16	3%	-$105	-22%	-$6.63
$5.65/MMBtu '06$	45%	10	2%	-$62	-13%	-$6.39
$4.47/MMBtu ’06$	72%	5	1%	-$24	-5%	-$4.54
$3.70/MMBtu '06$	85%	4	1%	-$9	-2%	-$2.53

* Does not include production and royalty associated with ultra-deep wells in 200-400 meters of water.

The incremental production and forgone royalty amounts shown in the third and fifth columns were estimated using the same basic model as for DGEA04, but with updated assumptions. Briefly, that model calculates flows of royalty-free and royalty-bearing production associated with baseline drilling (which would occur anyway) and incremental drilling attributed to the royalty relief incentive. In addition to the drilling intensity calculation explained in the previous section, the update assumes the expected price path averages $5.61/MCF (‘06$) and the most recent MMS resource assessment for natural gas from ultra-deep depths in the GOM in 0 to 400 meters of water. That assessment anticipates from 11.4 to 29.4 TCF of gas is undiscovered but technically recoverable. Appendix A summarizes the main assumptions in these calculations. Appendix B describes the spreadsheets that perform the calculations.

Table D shows the full estimated production and fiscal effects of EPact05 incentives on deep wells in 200-400 meters of water because of the sunset date for those incentives and the completion of the assumed production profile for incremental wells. Table C does not show the full estimated effects of EPact05 incentives on ultra-deep wells because there is no sunset date to wind down the effects of those incentives. The decision on the final price threshold value should concentrate mostly on the ultra-deep production and fiscal effects for 2 reasons. The amounts shown in Table C far exceed those in Table D. Also, the PT choice is more critical for limiting fiscal waste where no sunset date exists.

Price Threshold Options

Six options for the final PT have been evaluated. The PT of $9.88 matches the PT in the existing deep gas regulations and promises the largest increment to ultra-deep production (adding 15% to forecast ultra-deep production). However, according to projections based on the so far tepid response to the existing incentive it is the most fiscally expensive PT option (sacrificing 70% of forecast royalties from ultra-deep gas) and the least cost-effective in terms of forgone royalty per unit of added production ($4.18/added MCF).

At the other extreme, we evaluated a PT of $3.50 in '04$ ($3.70 in '06$) because it is the nominal value the original Deep Water Royalty Relief Act (DWRRA) set for the gas PT a decade earlier. Similarly based estimates indicate it is the least fiscally costly and most cost-effective of the options being considered, but those advantages are offset by the virtual absence of an incremental production effect. Since we believe Congress intended for MMS to grant at least some modest level of additional relief to ultra-deep wells and to deep wells on the slope, the least fiscal cost alternative is not considered practical. Given the generally anticipated future gas price path, a PT this low could be viewed by some as effectively canceling the deep gas royalty relief enacted in EPact05.

Two other options have the simplifying administrative advantage of being the same as ones now used in deepwater relief programs. Inflation over a decade lifted the original DWRRA gas PT value from $3.50/MMBtu in 1994$ to $4.47/MMBtu by 2006. This PT applies to leases issued under the mandatory incentives of the DWRRA and to older deepwater leases that qualified for royalty relief. As such, this relatively restrictive PT pertains to leases that have the largest RSV's that MMS offers. Because Congress considered this a reasonable PT level in connection with the RSV's it mandated to promote development in the deepwater frontier, it is not an unreasonable choice for MMS to make in connection with the RSV's Congress mandated to promote drilling in the ultra deep depth frontier and in other shallow water, deep gas areas.

In 2004, MMS raised the PT for newly issued deepwater leases to $6.50/MMBtu (which is equivalent to $6.88/MMBtu in 2006 dollars). This higher PT was adopted, in part, because it had become clear that gas prices had risen to a new plateau and were unlikely to return to the average level expected when the now $4.47 PT was set in the early 1990's.

Also, this less restrictive PT of $6.88 is applied to deepwater leases issued with much smaller RSV's than those mandated by the DWRRA. A smaller RSV means that a larger portion of the RSV is likely to be produced in any one year.

Unlike the ultra-deep gas incentive in the EPact05, the 2 deepwater PT's of $4.47 and $6.88/MMBtu apply to incentives which have ended or can be administratively ended when they are no longer needed. That difference further strengthens the case for choosing a more conservative PT for the permanent ultra-deep gas relief resulting from EPact05 than for the transitory deepwater relief reconsidered with each lease sale.

The final 2 options ($7.76 and $5.65/MMBtu) represent choices that mirror the 2 deepwater PT's but at a somewhat higher price plane. Neither of these PT's is used in any other royalty relief program, so that administrative simplification benefit of the other choices is missing.

The lower PT in this set, \$5.65/MMBtu, is closest of the options evaluated to average gas prices over the long term according to the most recent projections (\$6.12/MMBtu for 2007-2022). As such its choice might be viewed as making the relief incentive an insurance policy to help operators who happen to produce their RSV at a time when the volatile gas price has temporarily ebbed below the long term average value to which it is expected to revert.

Projections indicate a higher PT of \$7.76 would yield almost twice as much incremental production, though at more than twice the forgone royalty cost as a \$5.65 PT. That tradeoff is not considered defensible. In fact, the 2 high PT options (\$9.88 and \$7.76) are estimated to be the least cost-effective of those considered and therefore least appropriate for the permanent ultra-deep drilling and production incentive. These two options are thus dropped from further consideration.

Costs and Benefits of Section 344

The cost of Section 344 of EPact05 is a transfer from taxpayers to OCS operators. We estimate this fiscal cost or transfer as the net forgone royalty from providing the incentive to deep drillers that would have had deep production even without the incentive. Table E provides annual estimates and the present value through 2022 of the net forgone royalty under the new incentive for the PTs of \$6.88, \$5.65, \$4.47, and \$3.70. The table combines the (undiscounted) effects from the EPact05 incentives for ultra deep wells (Table C) and for deep wells on leases in 200-400 meters of water (Table D). Against these fiscal costs, the royalty relief incentive should generate real benefits to the nation from increased exploration and production of deep gas resources.

Table E -- Annual Net Forgone Royalty and the Present Value 2007 through 2022 for Price Thresholds of $6.88, $5.65, $4.47 and $3.70 (Million '06$)

YEAR	$6.88/MMBTU	$5.65/MMBTU	$4.47/MMBTU	$3.70/MMBTU
2007	-$8	-$3	-$1	$0
2008	-$17	-$8	-$2	$0
2009	-$28	-$14	-$4	-$1
2010	-$45	-$25	-$9	-$3
2011	-$62	-$35	-$13	-$5
2012	-$69	-$42	-$16	-$7
2013	-$71	-$42	-$16	-$7
2014	-$71	-$43	-$17	-$6
2015	-$65	-$40	-$16	-$7
2016	-$60	-$39	-$16	-$7
2017	-$56	-$35	-$15	-$6
2018	-$55	-$33	-$14	-$5
2019	-$53	-$30	-$13	-$5
2020	-$50	-$29	-$11	-$4
2021	-$49	-$27	-$11	-$4
2022	-$49	-$27	-$11	-$4
Sum	-$807	-$472	-$184	-$71
NPV @ 7%	-$447	-$260	-$100	-$38

These calculations are based on the future natural gas demand, supply, and price path projected in the AEO of 2007. The incremental production assumes both the mandatory provisions (i.e., the size of the RSV for the first ultra-deep well on a lease, the water depths in which the incentive is available, and no sunset for the ultra-deep well incentive) and those proposed by MMS under the discretionary provisions (i.e., sunsets for the deep well incentive and the RSS, ineligibility of ultra-deep sidetracks less than 20,000 feet long or ultra-deep wells on leases that already have a deep well) of EPact05 Section 344. The period through 2022 is long enough both to exhaust the effects of the existing program and for the production effects of the EPact05 program to flatten out. Changes in the estimates after that point essentially reflect changes in the path of the projected gas price level more than 15 years in the future.

Net social benefits are the sum of the net gains to producers and consumers associated with the additional production attributable to the EPact05 incentive. These benefits are measured as changes in consumer and producer surplus compared to a status quo or baseline amount that would occur in the absence of the incentive. These benefits exclude the transfer payments that consist primarily of changes resulting from the royalty relief in the amount of Federal royalty payments and domestic expenditures to purchase status quo quantities of gas. Consumer surplus is the difference between the value consumers place on the additional production and its market value. Producer surplus is the difference between the market price and the cost of additional production (including the cost of drilling unsuccessful wells).

Table F reports annual estimates and their present value through 2022 of the increase in consumer and producer surplus from this incentive with a PT of \$6.88. Tables G, H and I report comparable estimates with a PT of \$5.65, \$4.47 and \$3.70, respectively.

Comparison of the results reported in Tables E through I indicates the EPact05 deep gas incentives would provide (in present value terms) a negligible net gain to society, e.g., about \$40 thousand for a fiscal cost of \$447 million with a \$6.88 PT, \$16 thousand for a fiscal cost of \$260 million with a \$5.65 PT, \$4 thousand for a fiscal cost of \$100 million with a \$4.47 PT, or \$1.6 thousand for a fiscal cost of \$38 million with a \$3.70 PT. (Note as well that the fiscal cost element is itself primarily a transfer payment.) This classic measure of real economic benefits is very small compared to the defined (fiscal) cost for each of the alternatives. Accordingly, the relative size of the benefit-cost ratios presented here does not provide meaningful support to any one PT over the others. Rather, the more compelling comparison is the relative fiscal cost of the alternative PT’s, i.e., those in Table E, with some appeal to the added production associated with these PT’s along with the implied Congressional intent of the statute.

Table F – Annual Producer and Consumer Surpluses and the Present Value
2007 through 2022 with a Price Threshold of $6.88/MMBtu
(Thousands of 2006 dollars)

YEAR	CONSUMER SURPLUS	PRODUCER SURPLUS
2007	$0.02	$0.01
2008	$0.06	$0.04
2009	$0.1	$0.09
2010	$0.4	$0.3
2011	$0.8	$0.6
2012	$1.3	$0.9
2013	$1.9	$1.3
2014	$2.6	$1.8
2015	$3.2	$2.2
2016	$4.0	$2.8
2017	$5.0	$3.4
2018	$5.6	$3.8
2019	$6.2	$4.2
2020	$7.0	$4.9
2021	$7.3	$5.0
2022	$7.7	$5.3
NPV @ 7%	$24.0	$16.5

Table G – Annual Producer and Consumer Surpluses and the Present Value
2007 through 2022 with a Price Threshold of $5.65/MMBtu
(Thousands of 2006 dollars)

YEAR	CONSUMER SURPLUS	PRODUCER SURPLUS
2007	$0.02	$0.01
2008	$0.05	$0.04
2009	$0.1	$0.07
2010	$0.2	$0.2
2011	$0.4	$0.3
2012	$0.6	$0.4
2013	$0.8	$0.6
2014	$1.1	$0.7
2015	$1.3	$0.9
2016	$1.6	$1.1
2017	$2.0	$1.4
2018	$2.2	$1.5
2019	$2.4	$1.7
2020	$2.7	$1.9
2021	$2.7	$1.9
2022	$2.8	$1.9
NPV @ 7%	$9.6	$6.6

Table H – Annual Producer and Consumer Surpluses and the Present Value
2007 through 2022 with a Price Threshold of $4.47/MMBtu
(Thousands of 2006 dollars)

YEAR	CONSUMER SURPLUS	PRODUCER SURPLUS
2007	$0.02	$0.01
2008	$0.04	$0.03
2009	$0.08	$0.05
2010	$0.1	$0.08
2011	$0.2	$0.1
2012	$0.2	$0.1
2013	$0.3	$0.2
2014	$0.3	$0.2
2015	$0.3	$0.2
2016	$0.4	$0.3
2017	$0.5	$0.3
2018	$0.5	$0.4
2019	$0.6	$0.4
2020	$0.6	$0.4
2021	$0.5	$0.4
2022	$0.5	$0.4
NPV @ 7%	$2.5	$1.7

Table I – Annual Producer and Consumer Surpluses and the Present Value
2007 through 2022 with a Price Threshold of $3.70/MMBtu
(Thousands of 2006 dollars)

YEAR	CONSUMER SURPLUS	PRODUCER SURPLUS
2007	$0.02	$0.01
2008	$0.04	$0.03
2009	$0.07	$0.05
2010	$0.08	$0.06
2011	$0.1	$0.07
2012	$0.1	$0.08
2013	$0.1	$0.08
2014	$0.1	$0.08
2015	$0.1	$0.09
2016	$0.1	$0.1
2017	$0.2	$0.1
2018	$0.2	$0.1
2019	$0.2	$0.1
2020	$0.2	$0.1
2021	$0.1	$0.09
2022	$0.1	$0.08
NPV @ 7%	$0.98	$0.67

Summary

Using assumptions about prices, discount rates, and well flow rates, MMS estimated the fiscal costs and net social benefits to society from added deep gas production. Fiscal costs emerge from net forgone royalty, that is, royalty obligations that would have been collected in the absence of royalty relief less new royalty collected from added production due to the incentive. Added production consists of production from reservoirs unlikely to be drilled under normal conditions and from a portion of reservoirs only likely to be drilled in the future after information, technology, and costs improve, i.e., accelerated production. The net social benefit measure used in this analysis, consisting of consumer and producer surplus, does not include the sizeable transfers brought about by the deep gas incentives under each PT option. One of these important transfers, already counted as a fiscal cost, is of course from the government to producers in the form of royalty relief. The other significant transfer-type effect is from producers to consumers, and derives from reduced market clearing prices for all of the domestic gas production, occasioned by the added deep gas supply brought about by the deep gas incentives under each PT option. Although traditional economic analysis does not count these effects as real net social benefits, it's quite likely that conceptually they were important considerations to those in Congress supporting the statute.

Regardless, while the incremental supply added to domestic stocks as a result of the incentive does generate some real net gain to society, it is tiny across the entire range of PT options. Because the quantified measure of benefits is so small, the much larger fiscal cost calculations dominate the comparison and choice of a PT. However, the choice of the PT option with the least fiscal cost must be weighed against the potential for litigation if a lessee were to challenge this decision as an unreasonable exercise of agency discretion under EPact05.

The next lowest PT option is $4.47 and is the preferred option. Besides the relatively low fiscal cost ($100 million over 15 years) and expected production almost twice that of the lowest PT considered, its advantages include consistency with a long established gas PT (i.e., the original gas price threshold from the Deep Water Royalty Relief Act of 1995, expressed in 2006 dollars). Also, a PT of $4.47 is considerably less than the level of the gas price threshold used both for recently issued deepwater leases and for shallow water leases drilled to deep depths. So, it also serves to compensate for the absence of a sunset provision in conjunction with the main incentive to which it applies, i.e., added RSV's for ultra-deep gas production.

Appendix A: Influences Included and Excluded from the Analysis of the Effects of Price Threshold on Incremental Production and Forgone Royalty Associated with the Ultra-deep and Extended Deep Gas Incentives

<table>
<tr><th>Included</th><th>Excluded</th></tr>
<tr><td>Observed deep drilling intensity during the period when the existing incentive was in effect</td><td></td></tr>
<tr><td>Separation of incremental drilling due to incentive from extra drilling due to higher price during observation period</td><td>Adjustment for tempering effect a $9.88 PT may have had on observed baseline drilling (i.e., assumes operators ignored PT between 4/03 and 6/05)</td></tr>
<tr><td>Baseline ultra-deep drilling intensity by dividing all baseline wells at least 18,000 ft subsea using relative size of resources less than and more than 20,000 ft subsea</td><td rowspan="2">Any difference in risk between wells drilled 18,000-20,000 ft subsea and wells drilled more than 20,000 ft subsea</td></tr>
<tr><td>Average reservoir sizes in 3 drilling depth categories based on latest MMS assessment of undiscovered resources</td></tr>
<tr><td>Decline curve in rate of production from deep gas wells</td><td></td></tr>
<tr><td>Smaller RSV for sidetracks and deeper deep wells while deep well incentive lasts (same as in original analysis)</td><td>Sharing of one RSV by multiple deep wells on the same lease (i.e., assumes all new productive deep wells are on different leases none of which ever before produced from a deep well)</td></tr>
<tr><td>Reduced value from delay in use of 10 BCF added for ultra-deep wells while deep wells also get an incentive</td><td>Effects of ultra-deep drilling incentive on production and royalty after 2025</td></tr>
<tr><td>Future gas price path taken from EIA Annual Energy Outlook 2006</td><td></td></tr>
<tr><td>Tempering effect of various PT’s on incremental drilling resulting from incentive</td><td></td></tr>
<tr><td>Feedback effects of extra royalties generated by the incentive and PT to get net estimate of forgone royalty</td><td></td></tr>
<tr><td>Effect of indeterminate PT within a range during the year assumed to elapse between proposed rule and final rule</td><td></td></tr>
</table>

Appendix B: Attached spreadsheets contain the calculations discussed in the body of this paper. The files "DGEAII ultra deep wells.xls", "DGEAII slope deep wells.xls" and "DGEAII shelf deep wells.xls" each contain 3 worksheets.

- The first worksheet in each, labeled "Incentive effects" calculates average annual drilling based on the assumptions derived from MMS data for the 2003 to 2005 period, enhances this drilling in ultra-deep drilling depths for the added RSV, and distributes resulting production and RSV's over the period 2010 to 2045 using factors derived from MMS regional office estimates on deep and ultra-deep resources, reservoir sizes and production rates in 0 to 400 meters of water in the GOM.
- The second worksheet labeled "Price threshold effects" tempers incremental drilling for the effect of price thresholds on the expected value of the incentive and distributes resulting production and RSV's over the period 2010 to 2045. Inputs for the frequency of prices above the threshold are taken from a Monte Carlo simulation using @Risk (which is not enclosed). That model simulates gas price and frequency above the PT annually 2006-2025 over 1,000 iterations. Prices and frequencies in later years were extrapolated using a 3 year rolling average.
- The third worksheet labeled "Net forgone royalty" calculates and combines the 4 elements of net forgone royalty. Inputs for incremental and status quo production are taken from the first spreadsheet and frequency of price above the threshold and the conditional average prices (when above and when below the threshold) are taken for the Monte Carlo simulation.

The file "CS and PS effect of ultra-deep gas RSV" calculates the consumer and producer surplus. Inputs for incremental production are taken from the other spreadsheets. Inputs for U.S. market price, consumption, and production of natural gas come from the AEO 2007.