APPENDICES TO BENEFIT/COST ANALYSIS FOR FINAL DEEP GAS RULE

Appendix 1: ESTIMATING DEEP DRILLING ACTIVITY AND DISCOVERIES

An estimate of the rate and magnitude at which drilling and production would occur with and without the incentive hinges on two factors – 1) the number of deep wells drilled and produced and 2) the size of the reservoirs discovered and produced. Note, we developed the estimates quoted in this section using the original price level assumption of $3.50/MCF. They illustrate the way we developed the original estimates of changes in drilling intensity due to the incentive. Subsequently, we uniformly escalated these estimates to reflect a higher more volatile gas price path, as discussed in Appendix 4. Thus, the relative, but not the absolute, size of the estimates in this Appendix are consistent with those reported in Appendix 4 and cited in the final rule.

1.1 Status Quo

Trends (TIMS) in drilling deep depths during the past 10 years in shallow water imply 12 new productive wells in a typical year in the 15,000-18,000 feet TVD SS interval (deep drilling depths) and 3 productive wells annually at deeper than 18,000 feet TVD SS (very deep drilling depths) without the incentive. Given the historic success rates and adjusting down for the fact than not all shallow water leases qualify for deep gas incentives, that number of productive wells indicates 37 total wells (productive and unproductive) would have been drilled annually in deep drilling depths and 11 wells to very deep drilling depths at least 18,000 feet TVD SS, for a total of 48 deep wells drilled each year. We assume all these new productive deep wells (i.e., original wells in the final rule) are on different leases so each earns an RSV. That yields an estimate of the maximum number of RSV's that would be used. Also, at some point in the future, the royalty incentive on new leases, begun in 2001 lease sales, alone should begin to increase the pace of this status quo deep drilling activity. We don't need to account for this effect on status quo production because this analysis focuses on deep drilling activity on existing leases whose prospects will not be subject to the new lease incentive.

Changes for the final rule result in adding an incentive for sidetracks to deep depths and for the first deeper well, i.e., the first sub-18,000 foot well (very deep well) on a lease that previously had production from a well only in the 15,000-18,000 foot interval (deep well). Sidetracks have recently made up 16% of deep wells, so extrapolating from our previous estimate for original wells, we expect 9.3 sidetracks {[(48 original wells/(1-

.16)]- 48} per year of the incentive. The deeper well change to the proposed rule adds about 6% (140) to the number of leases eligible for the deep gas incentive (those leases that already have a deep well, but only one(s) less than 18,000 feet subsurface). As such, it can be expected to increase the baseline number of very deep wells (those to sub-18,000 foot depths) without the incentive that would be drilled on leases that could qualify by about that much. That proportion works out to be 3.3 more very deep wells (6% of 11 very deep wells drilled per year) and 0.9 (rounded to 1) more successful very deep wells over the eligibility period. Together the sidetrack and deeper well additions increase the baseline to 44 wells and 15.2 completions in the 15,000-18,000 feet depth interval and 11.7 wells and 4 completions in the sub-18,000 foot drilling depth.

This incentive proposal should change recent trends and induce additional drilling and production from prospective but risky zones. For reasons enumerated in section III of the Benefit-Cost/Small Business and Regulatory Flexibility Analysis, we don't expect projected natural gas prices alone to stimulate all economically appropriate exploration and production on the OCS.

The qualification start date is the proposed rule publication date or March 26, 2003 for sidetracks and deeper wells as well as for original wells that qualify for the incentive. The qualification period remains open for 5 years after the effective date of the final rule. To account for the qualification time between the proposed rule and the final rule and since we have provided for an extension in certain situations at the end of the qualification period, we assume a 6 year qualification period.

To estimate the resource magnitudes associated with discoveries made from drilling under the status quo scenario, we assumed a continuation of previously discovered reservoir sizes in the GOM. Outside the Norphlet trend area, the TIMS data base shows 592 depleted, producing, producible, or undeveloped proved reservoirs in the 15,000-18,000 feet TVD SS interval with an average size of 21 billion cubic feet of gas equivalent (BCFE) and 17 such reservoirs in the sub-18,000 feet TVD SS category with an average size of 30.5 BCFE. We exclude the Norphlet discoveries from our inventory of past reservoir sizes as they are not typical of the remaining prospective sizes within deep and very deep drilling zones in the GOM on leases eligible for our proposal. The Norphlet trend off Mobile underlies less than 2% of the shallow water tracts in the GOM but contains 25% of all the reserves so far discovered deeper than 15,000 feet TVD SS and 3 times as many discovered reservoirs deeper than 18,000 feet TVD SS as the rest of the GOM combined. Due to its circumstance as the only intensively explored very deep play, Norphlet size data skews the image depicted by the limited historical data on the deep zones. Also, since Norphlet production is generally from deeper than 20,000 feet subsurface, the incentives in even the final rule will not apply to most Norphlet area leases.

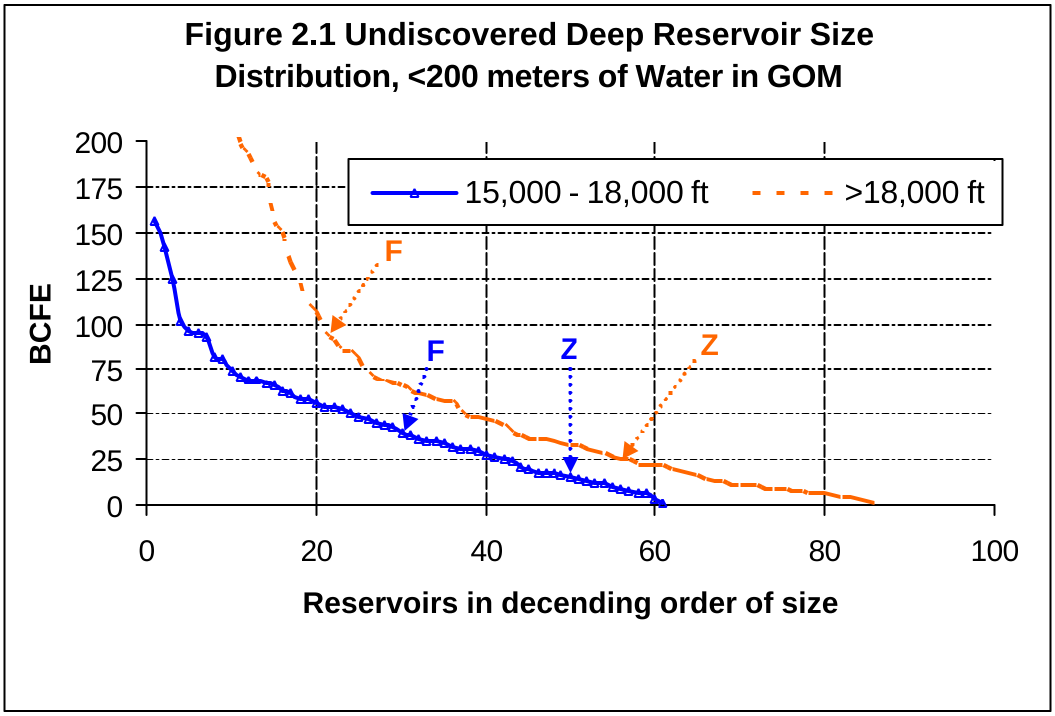
1.2 Additional Drilling

To determine the additional deep drilling of original wells induced by the incentive, we conducted an analysis of the minimum reservoir size that would be worth developing given a discovery, with and without the incentives, in conjunction with in-house geologic estimates of the size distribution of undiscovered deep depth reservoirs.

Within both drilling depth categories, we also computed the smallest expected reservoir size at which we anticipate that, under current lease terms, prompt exploration activity should be undertaken. Given the risks and costs expected, we found these promptly explorable (fully risked) reservoir sizes to be 50 BCFE in the 15,000-18,000 feet TVD SS interval and 90 BCFE in the sub-18,000 feet TVD SS category. These sizes are not representative of those found, but rather what lessees need to expect to find before they take on the high cost to drill a high risk prospect immediately in those deep zones. Indeed, reservoirs targeted at sizes as small as 35 BCFE and 55 BCFE in the two drilling depths respectively, could still be drilled with the expectation of some profit, but it would not be economically optimal to do so immediately. Moreover, after the exploration costs have been expended, it is profitable on a go-forward basis to develop even smaller reservoirs.

MMS has developed estimates of reservoir size distributions for undiscovered gas and oil resources in the two deep drilling depth categories to support the published estimates of 5 to 20 TCFE recoverable but undiscovered resources deeper than 15,000 feet TVD SS in the shallow waters of the GOM. These estimates were developed from a combination of proprietary data obtained from lessees and geologic estimates of originally in-place resources. We counted the number of reservoirs in this distribution at and above the promptly explorable sizes. The resulting sets of reservoirs represent those whose activity milestones would be little if any affected by new economic incentives. As such, they are taken to represent the base case view of the future potential; call them the baseline number of undiscovered reservoirs.

Next, we calculated in both drilling depth categories the smallest reservoir size at which development (rather than exploration) could be expected to occur following a confirmed discovery within the next 6 years with no royalty, but outside that time frame, if at all, otherwise. We estimated these minimum developable (a discovery having eliminated the exploration risk) reservoir sizes assuming no royalty to be about 15 BCFE in deep depths and 25 BCFE in very deep depths. The RSV alone reduced the minimum developable reservoir sizes by 15% to 20% from the full royalty size and by 20% to 30% when combined with the RSS in deep depths. Again we counted the number of fields in each drilling depth category whose size is expected to lie above these levels but below the minimum prompt exploration level sizes mentioned above. We assume reservoirs falling within this size range for each drilling depth category to have their activity milestones affected by the proposed royalty relief terms, resulting in additional drilling and production over the near term; call them the affected number of reservoirs. So, under the incentives more reservoirs will be explored and at earlier times, and more of those discovered will be developed rather than abandoned for economic reasons. Ample protections in the structure of the proposal guard against abandoning marginal discoveries (see pages 49-50). Figure 2.1 illustrates this process, where F represents the minimum reservoir size promptly explorable at full royalty and Z represents the minimum reservoir size developable at zero royalty.



Finally, for both drilling depth intervals, we computed the ratio of affected reservoirs to baseline reservoirs. The results are taken to represent the proportional annual increase in drilling over the next six years associated with the proposed royalty relief program. For example, in the 15,000-18,000 feet TVD SS interval, we found this ratio to be about 0.5; for the sub-18,000 feet TVD SS category, the ratio was about 2.0. So, in evaluating the royalty effects from the proposed program, we judged that drilling intensity would increase by 50% over the status quo in deep drilling depths, and by 200% in the very deep drilling depths. We use rough proportional increases rather than exact counts because undiscovered resource estimates change repeatedly as new information emerges.

As we derived the sidetrack incentive so it would have an effect parallel to the one for original wells (see Appendix 2), we assume drilling intensity on sidetracks will also increase by about 50% and 200% in the two deep drilling depth categories. This results in 7.9 added deep sidetracks (19% of the total added deep wells) and 2.7 added sidetrack successes (23% of the total) each year of the incentive.

As for the deeper wells, we note that past experience suggests that about 5% (8 out of 171) of leases have a very deep well success after a deep well success. The same 5% fraction of leases should also be credited with discovering additional very deep gas resources, what we might call a second order increment. In part we set the size of this added incentive at a level necessary to encourage the deeper drilling after a deep drilling success in the same area (i.e., the same lease). As such, it should result in about the same increment to drilling intensity for these leases as do the other incentive levels for leases to which they apply. These observations imply that 0.36 leases per year (5% of 6 leases with incremental successful original wells from 15,000-18,000 feet subsurface plus 5% of 1.3 leases with incremental successful sidetrack wells from 15,000-18,000 feet subsurface) will also have a successful very deep well. This represents about 1% of total added deep well successes. We report this small increment as all non-sidetrack wells, for clarity of presentation and to ease calculations, but apply it to a composite reservoir size to reflect that some of it should be attributed sidetracks. Accordingly, with our final rule we expect additional annual drilling of 18.6 wells with 7 discoveries in the 15,000-18,000 feet TVD SS interval, and 26.6 additional wells with 4.6 discoveries in the sub-18,000 feet TVD SS category. Table 1.1 summarizes these drilling activity parameters for the no incentive (baseline) case and for the incentive (affected number of wells) case. The numbers in parenthesis and in different, smaller font were used for the proposed rule analysis.

Table 1.1– Number of Deep Wells Drilled Annually
With and Without the Incentive (assuming $3.50/MCF average gas price)

Drilling depth interval	No Incentive		Proposed Incentive	
	Drilled	Produced	Drilled	Produced
15,000-18,000 feet TVD SS	44 (37)	15.2 (12)	62.6 (54)	22.2 (18)
Sub-18,000 feet TVD SS	13.8 (11)	4.0 (3)	40.4 (35)	8.6 (7)

To determine the resource magnitudes associated with these added discoveries, we again used estimates of the size distribution of undiscovered reservoirs. The average size of 61 undiscovered fields in the 15,000-18,000 feet TVD SS interval is 45.5 BCFE. This size exceeds (by a factor of 2) the average for previously discovered reservoirs in this interval. But the geologic estimates of undiscovered reserves are done, not in terms of individual reservoirs, but, in terms of fields which may contain several reservoirs. For purposes of estimating production flows from undiscovered fields, we assume an average of 2 development wells (reservoirs) per field. The first development (i.e., successful) well resolves the exploration risk associated with the field, so only one well per field incurs the failure rate we assume.

In the sub-18,000 feet TVD SS category, 86 undiscovered reservoirs are expected to average 97.3 BCFE. Again this size exceeds (by a factor of 3) the average for previously discovered reservoirs in this zone. While that seems counter-intuitive to the general expectation that the biggest and best reservoirs tend to be discovered first, remember these leases were acquired and are still held based largely on their less costly and less risky shallow drilling depth potential. As such, we infer that the deep potential in shallow water has not been systematically explored. Increasing the profitability of deep reservoirs relative to shallow reservoirs should redirect lessee attention to the deeper zones on their leases. The high average size in the sub-18,000 feet TVD SS category reflects an expectation that some large reservoirs remain to be found in this sparsely explored zone. The sub-18,000 TVD SS category is even less explored than the 15,000-18,000 feet TVD SS interval and is judged to contain most (80%) of the undiscovered deep gas resources. Further, the open-ended depth for the sub-18,000 feet TVD SS category hides the fact that it really encompasses multiple zones. In fact, excluding the Norphlet trend off Mobile, only 8% of the 208 wells drilled deeper than 18,000 feet TVD SS in the GOM are deeper than 21,000 feet TVD SS with no economic discoveries. So, the deepest part of this zone is essentially unexplored yet could contain large reservoirs like those found early in the development period of the shallower zones or the Norphlet trend.

Table 1.2 summarizes these reservoir size parameters. These sizes apply to all new deep wells since they come from the undiscovered field size distribution. The spreadsheet at the end of this Appendix titled "Detailed Specifications of DG Final Rule Alternatives" shows the breakdown of these assumed effects among the various kinds of wells.

Table 1.2 -- Average Reservoir Size (BCFE) for Discoveries With and Without the Incentive

Drilling depth interval	No Incentive (Status Quo) Like Previous Discoveries	Proposed Incentive Undiscovered Reservoirs
15,000-18,000 feet TVD SS	21	45.5
Sub-18,000 feet TVD SS	30.5	97.3

1.3 Royalty Losses and Gains

The cost of this royalty relief program is taken as the net forgone Federal royalty on deep gas production that would have been generated without this program. Note that any such net costs are in the form of transfer payments, so whatever the government loses is also an operator gain. In fact, there are no net real resource costs associated with the proposal. Operators will voluntarily select drilling projects, and our proposal simply expands the feasible set from which they can choose, with essentially no new or increased environmental risks from having to build new platforms and pipelines.

Direct royalty losses stem from deep wells that would be drilled and produced without this incentive and from credits against otherwise royalty-bearing production to which the RSS will be applied (status quo deep drilling). Offsetting these losses are royalty gains stemming from the added discoveries that are induced by the incentive (incremental and a portion of accelerated deep drilling) and which subsequently generate gas production above the royalty suspension volumes and liquids (condensate) production, all of which are royalty-bearing under the proposal. Because only a portion of the resources affected by the incentive program will be produced in any one year, we account for the time profile of these opposing effects, as well as for the time-adjusted dollar values.

Based on past trends in deep drilling, we estimate that for each year the drilling incentives will be in effect, about 283 BCF of reserves that would have been discovered that year in the absence of the incentive will in fact qualify for royalty suspension. This estimate starts with a calculation of maximum relief for such wells, 328 BCF [(15 BCF * 15.2 deep wells) + (25 BCF * 4 very deep wells)] and adjusts it for the reduced incentives that the sidetrack and deeper well shares receive. The adjustment involves two fractions, the sidetrack and deeper well share of deep wells and of the RSV for original wells. The RSV for the deeper wells is 40% the size of that for original wells, and we estimate (see page 10) that about 1% of all added wells will be deeper wells. Also, to treat the sidetracks in the same way, we use the median length of past sidetracks to deep depths (4,257 feet) to estimate that on average the RSV for sidetracks will be about 39% the size of that for original wells. We estimate that 17% of all added deep wells will be sidetracks and 22% of all added deep completions will be sidetracks. Calculating a weighted average indicates that the adjusted RSV for all successful deep wells will be 86% of the RSV for original wells (RSV_0) [77% of wells * 100% of RSV_0 + 1% of wells * 40% of RSV_0 + 22% of wells * 39% of RSV_0]. Thus, the adjusted estimated for this forgone RSV is 283 BCF (328 * 86%).

Further, we forecast that under the final rule provisions, there would be 40.4 wells drilled annually to depths deeper than 18,000 feet TVD SS, of which 31.8 would be unproductive. (See Table 1.1) The reduced success rate from historical experience (8.6 of 40.4 or about 20% instead of about 3 of 11 or 27%) reflects our expectation that a disproportionate share of the easiest to find prospects (i.e., largely those in the prolific Norphlet trend) have already been drilled, leaving a riskier set of prospects yet to be found. However, only a portion of those leases with an unsuccessful well would be able to actually use the royalty credit. Historically, TIMS data show that about two-thirds of the leases that drill very deep wells have other production against which they could apply the royalty suspension supplement. This implies that only about 21 of the 32 leases with unsuccessful wells would earn the royalty supplement of 5 BCF, thereby qualifying for a maximum RSS of 105 BCF of production that would occur anyway for royalty suspension. Making the same kind of adjustment we did for the RSV, a weighted average for the RSS for all very deep unsuccessful wells will be 85% of RSS_0 [80.5% of wells * 100% of RSS_0 + 4% of wells * 0% of RSS_0 + 16% of wells * 26.3% of RSS_0]. Thus, the adjusted estimated for this forgone RSS is 89 BCFE (105 * 85%). When added to the RSV losses on baseline production of 283 BCF, we obtain an overall estimate of accrued royalty losses of 372 BCFE annually from our proposal compared to the baseline.

Offsetting these royalty losses from productive and unproductive deep depth drilling would be gains from extra royalty-bearing resources discovered because of the incentive and produced after the RSV has been exhausted. Attributing the average reservoir sizes from Table 2.2 to the 7 added discoveries in 15,000 to 18,000 feet TVD SS drilling depths and 4.6 added discoveries deeper than 18,000 feet TVD SS, we forecast that projects totaling 768 BCFE [7 * 45.5 BCFE + 4.6 * 97.3 BCFE] in added reserves would be discovered in an average year of the incentive program. Of that amount, 190 BCFE {[(7 * 15 BCF) + (4.6 * 25 BCF)] * 86%} will receive the RSV; the remainder, 578 BCFE, will be the extra royalty bearing production.

It's important to point out that a portion of the added discoveries results from acceleration in activities that might reasonably be expected to occur anyway but later in time without the incentive. Discoveries and production simply moved forward in time creates relatively lower valued benefits compared to discoveries or developments which otherwise would not have occurred at all. For purposes of this analysis, we include in the added production estimates the difference between the full accelerated reservoir size and the present value of the same reservoir size produced in a future period.

A representative example of this would occur when producing a 60 BCFE reservoir is accelerated by 6 years as a result of royalty relief. In fact, this reservoir size is typical of what we would expect in the subset of accelerated reservoirs (i. e., better prospects than those that would not be discovered and produced at all absent the incentive). The present value on 60 BCFE is 40 BCFE [60/(1.07)^6], so 20 BCFE (60 – 40) of the accelerated production is treated as equivalent to incremental production and included in the added production attributed to royalty relief. With the parameters, 7% annual discount rate over 6 years, this acceleration premium conveniently works out to be 1/3 of the accelerated reservoir size.

To properly account for the incremental or non-accelerated part of the added reserves, i.e., incremental discoveries, we take into account both the chance of making discoveries without the incentive program and the likely difference in the size of an accelerated discovery versus a new discovery. In the sub-18,000 feet TVD SS zone, TIMS data show very few discoveries (only 18 out of 73) have occurred outside the Norphlet trend; and none produced below 21,000 feet TVD SS. Those that have been discovered tend to be much smaller (averaging 30 BCFE instead of 100 BCFE). These observations suggest that most, perhaps 3 of the 4 very deep added discoveries, will not happen at all absent the proposed drilling incentive. Thus, for the sub-18,000 feet TVD SS category, we estimate 336 BCFE (3.45 * 97.3) of extra reserves discovered annually are incremental, that is in reservoirs that would not be discovered without the incentive. Also, 37.3 BCFE (1/3 * 115 * 97.3) of accelerated production is counted as added production, meaning a total of 373.3 BCFE from very deep discoveries would be added on average each year the incentive is in effect. These discoveries are in reservoirs to which drilling is not simply accelerated, but would not have occurred otherwise. Further, 258 BCFE [373.3 – 4.6 * 25] of this increment occurs on royalty bearing production.

In the more active 15,000-18,000 feet TVD SS interval, there is no compelling reason to expect either the new or accelerated share of added reserves to exceed the other, so we assume that 3.5 of the 7 discoveries are incremental or would not happen absent the incentive and 3.5 are accelerated discoveries. However, on average, the accelerated discoveries here are probably larger (i.e., more profitable) than the new discoveries that would not happen absent the incentive.

So, we used 60 BCFE as a representative size for accelerated discoveries on these deep depth reservoirs. Thus, for the 15,000-18,000 feet TVD SS interval, this leaves 178 BCFE [(7 * 45.5 BCFE) – (1 – 1/3) * (3.5 * 60 BCFE)] of the added reserves. Further, 73 BCFE [178 – (7 * 15)] of this increment occurs on royalty bearing production. Thus, the sum of new incremental royalty-bearing production for both drilling depth categories is 331 BCFE. Table 1.3 summarizes the amount of gas that will be affected in a typical year by the proposed deep gas drilling incentives.

Rows one and three of Table 1.3 compute the direct royalty losses from deep drilling that would occur anyway, either immediately or eventually. The first 3 rows show the forgone royalty associated with well that would be drilled anyway. The fourth row shows our estimate of reserves affected by the incentive; the fifth row shows the accelerated portion of affected reserves; the sixth row shows the portion of accelerated reserves we treat as added production. The seventh row shows the incremental reserves; the eight row shows the total added production; and the ninth and tenth rows shows the royalty-free production from added reserves. All of the RSV on the accelerated

Table 1.3 -- Average Annual Incremental Effect on Royalty-Bearing Production for Proposed Incentive (assuming $3.50/MCF average gas price)

Row		Proposed Incentive	
		Drilled	Produced
1	Unneeded RSV accrued by unaffected wells (BCF)		[15.2 * 15 + 4 * 25] * 0.862 = 283 (12*15 + 3*25 = 255)
2	Leases with a failed very deep well and shallow production	[40.4 – 8.6] * 2/3 = 21 {(35 – 7) * 2/3 = 19}	
3	Unneeded RSS accrued (BCFE)	0.85 * 5 * 21 = 89 (5*19 = 95)	
4	Reserves affected annually (BCFE)		[(22.2 – 15.2) * 45.5] + [(8.6 – 4) * 97.3] = 768 {[(18 – 12) * 45.5] + [(7 – 3) * 97.3] = 662}
5	Accelerated production (BCFE)		3.5 * 60 + 1.15 * 97.3 = 322 (3 * 60 + 1 *97.3 = 277)
6	Acceleration premium considered part of added production (BCFE)		1/3 * 322 = 107.3 (1/3 * 277 = 92.4)
7	Incremental production (BCFE)		[7 * 45.5 – 3.5 * 60] + 3.45 * 97.3 = 445 {(6 * 45.5 – 3 * 60) + 3 * 97.3 = 385}
8	Added production (BCFE)		442 + 107.3 = 552 (385 + 92.4 = 477.4)
9	RSV accrued by incremental production (BCF)		{[(22.2 – 15.2) * (1/2) * 15] + [*8.6 – 4) * (3/4) * 25]} * 0.862 = 119.6 {[(18 – 12) * (1/2) * 15] + [(7 – 3) * (3/4) * 25] = 120}
10	RSV accrued by accelerated production (BCF)		{[(22.2 – 15.2) * (1/2) * 15] + [*8.6 – 4) * (1/4) * 25]} * 0.862 = 70 {[(18 – 12) * (1/2) * 15] + [(7 – 3) * (1/4) * 25] = 70}

production is included because that production is unavailable later when it would have paid full royalty. A portion of the lost royalty is offset by the gain from the earlier production of the accelerated reserves portrayed by the premium shown in row 6. In the table, the numbers in parenthesis and in different, smaller font were used for the proposed rule analysis.

This extra production will generate net social benefits in the form of net income for operators that would not have occurred without the incentive. For the added discoveries, the RSV's and, indirectly, the RSS's are the economic factors that make drilling some uneconomic reservoirs profitable. Though all the RSV (119.6 BCF + 70 BCF) and RSS (89 BCFE) results in new net income to the operator, only the RSV associated with incremental production contributes to net social benefits. The RSV associated with accelerated production and the RSS are simply transfers from the Government. Since the incremental production would not have occurred at full royalty, the government does not forgo this royalty. With a landed gas price of $3.50 per MCF (less transportation costs of $0.25 for MCF), a one-sixth royalty generates $0.54 per MCF. We take the midpoint, $0.27 per MCF, as being representative of the profitability of each new MCF produced, i.e., $32.3 million (119.6 BCF * $0.27 per MCF) from incremental production and $18.9 million (70 BCF * $0.27 per MCF) from accelerated production. The incremental production over the 6 years we expect the incentive program to be active results in $193.8 million (32.3 * 6) in accrued new profits. This entire $193.8 million new profit estimate cannot be interpreted as a net increase in producer surplus because some will be offset by reduced production and profits for gas producers displaced by some of the incremental deep gas production. These displaced producers will be those who cannot afford to produce at the slightly reduced market price resulting from the added deep gas production. The calculation reported on page 28-29 of the main analysis implies that producer surplus represents about 40 percent or about $117 million of the net social benefit from this incentive.

The RSS of 89 BCFE can be taken against otherwise profitable production, so the added income to the operator is equal to the full value of the relief, $0.54 per MCF, or $49.7 million. Thus, we estimate the total annual new income accrued to operators under the proposal to be about $101 million ($32.3 million + $18.9 million + $49.7 million).

1.4 <u>Monetizing the Net Royalty Effect</u>

Previous discussion dealt with volumes of royalty-bearing and royalty-free production resulting from drilling activity induced by the incentive on average each year it is in effect. To compare the royalty losses with the E.O. 12866 and SBRFA criteria, volumes of royalty-bearing production should be converted into monetary terms. Doing so means taking account of the difference in the time profile of when the royalty costs and benefits will be realized. Production affected by this temporary policy will emerge over a number of years after the policy expires. Three assumptions are critical to the monetary estimate –the rate at which the royalty suspension volume and additional reserves are produced, the ratio of the gas to the liquids in the deep gas well production, and the prices used for gas and condensate.

TIMS data indicate that average gas production rates for wells in 3 drilling depth categories are as follows:

- 0-15,000 feet TVD SS – 1 BCF per year
- 15,000-18,000 feet TVD SS – 2.5 BCF per year
- greater than 18,000 feet TVD SS – 4.6 BCF per year

Applying those flow rates to the RSV and RSS amounts in alternative #1 indicates that it would typically take 5 to 6 years (15/2.5 or 25/4.6) for a single deep well to use the proposed RSV's in each drilling depth. Multiple wells on a lease could shorten that period, but would add cost for the lessee. In practice, decline rates could affect the duration of both RSV and the post-RSV (royalty-bearing) production. As with price variation through time, we omit these complications as beyond the needs of this analysis. Determination of the RSS duration is also complex as it can be used by gas and oil in shallow wells and by the liquids portion of deep wells on leases that subsequently drill a productive deep well. We assume that it takes a fixed period of 2 years to use up the RSS to reflect a likely combination of several shallow wells and perhaps some deep condensate production. Deep gas production eligible for relief would first use its RSV before applying the RSS.

Wells having a discovery virtually always produce both liquids (oil or condensate associated with gas) and gas (natural gas or gas associated with oil). In alternative #1 (and all options) the RSV only applies to the gas part of a new deep well's production. The liquids part of the production pays royalty (see proposed section 203.42(f)). According to the TIMS data base, the ratio of gas to oil can vary greatly, from 2 to 53,000 MCF gas per barrel of oil (bbl). The weighted average and the median for the 171 deep and very deep producing deep wells listed in the TIMS data base is 26 MCF gas/bbl oil. In combination with the gas to oil ratio, this means that while a well is producing 26 MCF of gas worth $91 at a price of $3.50/MCF it is also producing 1 barrel of oil (condensate) worth $28. Or, of every $119 of value produced from the deep well during the royalty suspension period, $28 or 23.5% will pay royalties.

For purposes of the calculation, we assumed a constant landed gas price of $3.50/MCF (and a wellhead price of $3.25). That is below the levels experienced in 2000 and 2001 but above the annual averages before and since, and above the levels EIA projects in its most recent AEO 2003 (which falls from $3.60 in 2000 to $2.66 in 2005 and then gradually rises to $3.26 by 2020). We use the high flat price so as to be conservative and not understate potential royalty losses. Notice that this price assumption does not approach the price threshold value, so we do not deal with the effects of a price spike discontinuing the RSV and RSS. For condensate value, we used a crude oil price of 8 times our gas price assumption (like the Deep Water Royalty Relief Act), or $28/bbl relative to our gas market price assumption of $3.50/MCF. Recent gas market experience suggests that future gas prices will be higher than those expected when the last AEO was released. For the final rule analysis, we include a calculation of the major effects at both the price used for the proposed rule analysis and at a higher price level designed to be more representative of recent gas price expectations.

One other issue, the tax applied to the extra profit lessees collect, affects the quantification of the net royalty effect. Since lower royalty payments mean more company taxable income, our annual estimates of royalty receipts forgone is in part offset by higher tax payments. We have not included this factor in the estimates reported here, so we are being conservative in the estimate of actual forgone receipts associated with this proposal.

Appendix 2: <u>DETERMINATION OF THE EQUIVLATENT SIDETRACK INCENTIVE</u>

One purpose of royalty relief for deep sidetracks is to avoid occasionally distorting the deep drilling decision in favor of an inefficient well which might occur when offering royalty relief only for original (non-sidetrack) deep wells. The proper royalty suspension volume is generally less for sidetracks than for non-sidetrack deep wells because sidetracks tend to be shorter and thus less costly, and perhaps less risky than non-sidetrack deep wells. We derived the royalty suspension volume and supplement for a sidetrack from the levels chosen for an original well. Accounting for the wider variability in drilling length and thus cost for a deep sidetrack as opposed to an original deep well was the main feature in this derivation. The derivation used a three step process.

A. We adjusted inputs to the drilling and development cost model used to help determine the original deep well royalty relief amounts to reflect a sidetrack. From the TIMS data base we obtained the measured depths and drilling days (or rates of penetration) for deep sidetrack and non-sidetrack wells. We developed comparative costs for sidetrack and non-sidetrack wells by combining median values for these factors with input factor-cost values (the day rates for drilling rigs, cost per foot for steel casing and tubing, and installed costs for platform and equipment modifications) used to help set the original well RSV and RSS amounts. Finally, we used chance of success estimates to determine the full cycle cost of drilling and, when successful, completing a deep well of each type.

B. We next calculated the proportion of full cycle costs for a non-sidetrack deep well represented by the value of its royalty suspension volume. With an iterative process, we then determined the royalty suspension volume for a sidetrack of a given length that represented the same proportion of its full cycle cost. TIMS data suggests that deep sidetracks tend to be drilled in less risky situations more often than non-sidetrack deep wells. We explored the effect that a greater chance of success for sidetracks than for non-sidetrack wells had on this relation. We found the risk effect to be relatively small, i.e., 50% increase in chance of success leads to about a 15% reduction in sidetrack royalty suspension volume. Rather than pin down a risk difference, we assumed the same risks and included this minor effect in the determination of the equivalent royalty suspension volume for sidetracks by rounding coefficients down in the regression process described next.

C. We calculated royalty suspension volumes for a range of sidetrack lengths that corresponded to the proportional effect that a uniform royalty suspension volume has on reducing non-sidetrack well costs. Using simple regression analysis of the sidetrack royalty suspension volume associated with different measured depths, we estimated the functional form for a sidetrack royalty suspension volume that is "equivalent" to the fixed royalty suspensions volume for a non-sidetrack well. The resulting form contains a variable component associated with drilling length (measured depth) and a fixed component which we attribute to the well completion and platform/equipment upgrades necessary to realize the royalty suspension volume when the well is successful.

D. This approach does not retrace all the steps used in the base analysis for the original (non-sidetrack) well royalty suspension volume. In particular, it does not attempt to sort resource estimates and a distribution of undiscovered field sizes relevant to sidetracks from that for non-sidetrack deep wells. Nonetheless, it offers a method for setting sidetrack royalty suspension volumes that is consistent with those for non-sidetrack wells. Thus, we presume the resulting sidetrack royalty relief amounts achieve an equivalent boost to sidetrack drilling intensity as for non-sidetrack wells. In the analysis of incentive benefits and costs we include the effect of sidetracks by setting the number of sidetrack deep wells and of deep completions at their historic share relative to original deep wells.

Appendix 3: CALCULATION OF EFFECTS FOR RSV/RSS ALTERNATIVES

We measured the likely effect of the deep gas incentive with a 6 step process. The following description of this process identifies the labeled columns on the spreadsheet calculations shown in Appendix 5 used for each alternative. The title at the top of each spreadsheet indicates the alternative it covers.

A. We estimated the size of production anticipated from deep wells in the absence of any royalty suspension incentive. This baseline simply multiplies the average number of successful wells drilled by the average reservoir sizes found in the recent past. The column labeled C on each spreadsheet displays the expected deep reserves discovered annually without royalty relief. We applied average well flow rates from the recent past to distribute reserves over a production period in column D. Columns E and F separate the flow into gas and condensate with a gas to oil ratio typical of deep reservoirs. For reference, column B reports deep gas production likely from leases that already have deep wells.

B. We estimated the change in drilling intensity (number of new deep wells) likely to result from the proposed royalty suspension. Using an in-house geologic estimate of the size distribution of undiscovered deep depth fields, we counted the number of undiscovered fields at or above breakeven sizes determined with and without royalty suspension. Breakeven field sizes were determined with cash flow analysis and assumptions about chances of drilling success, drilling costs, gas prices, and lessee discount rates. Because resource estimates change frequently, we used relative rather than absolute numbers of fields to establish the change in drilling intensity. The box in the upper right hand corner of the spreadsheet labeled Drilling Intensity Effects displays the resulting well counts and related production characteristic assumptions. Appendix 1 explains this analysis in more detail.

C. We then estimated additional resources resulting from the increased drilling intensity associated with the proposed incentive. We derived this estimate by multiplying the average size of all estimated undiscovered deep reservoirs by the increased number of successful wells associated with the incentive. We used historical success rates to set the expected number of successful wells. The additional resources included only a portion of those reservoirs that would have been discovered later (accelerated). We used qualitative judgments, also explained in Appendix 1, to divide reservoirs that would not have been discovered in the foreseeable future (incremental) from the accelerated discoveries. The portion of accelerated discoveries included in the additional resource estimate is the difference between the full reservoir size and the present value of the same reservoir size discovered x years from now. Column J reports this added reserve estimate for each of the 6 years we assume the incentive will be in effect. Columns G, H, and I assign RSV and RSS to the drilling and discoveries associated with baseline reservoirs and distributes this forgone royalty over time with typical well flow rates. The box at the top middle of the spreadsheet labeled Incentive Size and Duration displays the RSV and RSS amounts and associated production periods.

D. We next estimated the annual increase in deep production from these additional resources. Columns L and O distribute the added reserves shown in column J over time with typical well flow rates. Column K assigns the RSV to the added reserves. Since reservoir sizes are reported in barrels of oil equivalent or cubic feet of gas equivalent, we split reservoirs in to gas and condensate portions. This is important because the royalty suspension volumes only apply to the gas portions. Columns M and N separate the added production flow into gas and condensate with a gas to oil ratio typical of deep reservoirs.

E. We applied assumptions about wellhead gas prices and ratios of gas to oil (condensate) in deep reservoirs to the increase in deep production each year to estimate the annual changes in royalty that flow from the proposed incentive. Column P computes the net change in royalty from flows shown in columns I, M, and N using assumptions shown in the box in the upper left hand corner of the spreadsheet labeled Market and Product Characteristics. The Column labeled Transfers from Gov't to Producers shows the value of the royalty-free production shown in column I. Column K reports RSV on production that would not have occurred without the incentive and so is not a transfer. Since this gas would otherwise not be produced at all under foreseeable conditions and without royalty relief, and certainly not if the existing infrastructure were not available, these effects will not be offset by less production and higher prices to consumers later.

F. We applied assumptions about gas supply and demand elasticity and future domestic demand for gas to the increase in deep production each year to estimate the annual net social benefits and changes in transfers to consumers that flow from the proposed incentive. The shift in the gas supply curve resulting from the incentive is shown in Column S (column R minus Q or columns L plus M). Column T adjusts the amount in column S to the increase in market equilibrium quantity (39.5%) associated with the elasticity assumptions shown in the Market and Product Characteristics box. Column U computes the change in equilibrium price associated with that change in equilibrium quantity. Column V reports EIA's forecast of domestic demand over the period relevant to the deep gas incentive. Column W computes the transfer from producers to consumers from the price reduction in column U applied to the quantity in column V. Finally, column X computes the net social benefit or surplus (triangle ghj in Figure 1) as the change in equilibrium quantity occasioned by the incentive times ½ the royalty cost savings associated with the incentive.

Appendix 4: <u>PRICE THRESHOLD</u>

In the economic analysis of the production and fiscal effects of the deep gas rule we assumed the price threshold had no influence on drilling intensity and discoveries, in effect the price threshold would never be breached. The rationale for this assumption is that discontinuation of royalty suspension coincides with a period of a significant premium relative to the price for which OCS operators plan. By definition, that premium is large enough to cover full royalty and leave as much profit, i.e., incentive to drill, as royalty relief would have at the planned for price. A price threshold serves to rescind the royalty relief during a period of such high prices.

4.1 <u>Full Royalty Equivalent Price</u>

In a stable price world, a price threshold could be set by calculating a full royalty equivalent price with a 3 step process. A full royalty equivalent price exceeds the expected price by the value of the RSV and the RSS. Using parameters from other parts of this analysis, the full royalty equivalent price can be found as follows.

1. In the 15,000-18,000 range: Using the assumptions that the probability of finding gas = 1/3, the average reservoir size = (45.5 BCF+60 BCF)/2 =52.3 BCF, and the royalty rate = 1/6;

$$\begin{pmatrix}\text{Probability of}\\ \text{finding gas}\end{pmatrix}\left[15BCF*(\frac{\$4.11}{MCF})*(\frac{10^6\,MCF}{BCF})+\begin{pmatrix}\text{Average size}\\ \text{of reservoir} - 15BCF\end{pmatrix}*\left(\frac{\$4.11}{MCF}\right)*(\frac{10^6\,MCF}{BCF})(1-\text{Royalty Rate})\right]-$$

$$\text{cost of drilling well} = X*\begin{pmatrix}\text{Average size}\\ \text{of reservoir}\end{pmatrix}*(\frac{10^6\,MCF}{BCF})*(1-\text{Royalty Rate})*\begin{pmatrix}\text{Probability of}\\ \text{finding gas}\end{pmatrix}-\text{cost of drilling well}$$

Simplifying by eliminating common terms;

$$\left[15bcf*(\frac{\$4.11}{MCF})+\begin{pmatrix}\text{Average size}\\ \text{of reservoir} - 15BCF\end{pmatrix}*\left(\frac{\$4.11}{MCF}\right)*(1-\text{Royalty Rate})\right]=X*\begin{pmatrix}\text{Average size}\\ \text{of reservoir}\end{pmatrix}*(1-\text{Royalty Rate})$$

Solving for X, one gets \$4.34.

2. In the 18,000 foot or deeper range: Using the assumptions that the probability of finding gas = 1/5, the average reservoir size = 97.3 BCF, and the royalty rate = 1/6;

$$\left[\begin{pmatrix}\Pr obability\,of\\ finding\,gas\end{pmatrix}\left[25BCF+\begin{pmatrix}Average\,size\\ of\ reservoir-25BCF\end{pmatrix}*(1-Royalty\,Rate)\right]+\begin{pmatrix}1-\Pr obability\,of\\ finding\,gas\end{pmatrix}*5BCF\right]*\left(\frac{\$4.11}{MCF}\right)=$$

$$=X*\begin{pmatrix}Average\,size\\ of\ reservoir\end{pmatrix}*(1-Royalty\,Rate)*\begin{pmatrix}\Pr obability\,of\\ finding\,gas\end{pmatrix}$$

Solving for X, one gets $5.33.

3. Combining the two values weighted by the incremental production contribution expected at each depth (42% in the 15,000 -18,000 foot depth and 58% in the sub-18,000 foot category) yields a uniform full royalty equivalent price of $4.91.

Refinements for the inclusion of sidetracks and for the conversion of price per MCF to price per Btu could be added. However, those would not include a much more important adjustment necessary to set a workable price threshold. Because annual gas prices fluctuate around the long term average, lower RSV and RSS values in some years would be offset by higher values in other years, except when a price threshold crops the relief in one or more of those high relief-value years. To avoid dampening the incentive to drill, the price threshold needs to be above the full royalty equivalent price enough to nullify an expectation that relief will be lost in a high-value year. In developing the proposed rule assuming a $3.50 expected average price, we opted for a $5.00 price threshold (about 15% cushion above the equivalent price) to minimize expectation that royalty relief would be cropped. Numerous comments on the proposed rule and the likelihood that future gas prices will be higher and significantly more volatile than in the past convinced us of the need for a less restrictive price threshold.

To rigorously deal with the dampening effect of a price threshold, we explicitly included price volatility in our model of production and incentive effects of royalty relief. For options involving a continuous price threshold (that is one in effect over the whole period when RSV and RSS will be produced), we use the overall likelihood that price fluctuations, centered on the current EIA/MMS price forecast, breach the price threshold as a measure of the size of the dampening effect on drilling. The dampening effect under this approach is spread over the whole incentive period, reflecting the fact that at least part of relief earned by any qualified wells is rescindable. In contrast, a price threshold waiver exempts all of the RSV and RSS earned by some qualified wells (those drilled early enough in the incentive period so all the RSV and RSS will be produced royalty-free regardless of price). For waiver options, we dampened only drilling exposed to price threshold violations, and then only by the likelihood of violations occurring in relevant years.

4.2 Likelihood of Breaching the Price Threshold

To estimate those likelihoods, we used a price process model that simulates typical price fluctuations around a (mixture of the most recent short and long term) price series forecast by EIA. If gas price is high, overall demand for natural gas will tend to diminish according to short-term elasticity of demand. The effect would be to keep price spikes short-lived. To simulate these forces, we adopt a price process that is "mean-reverting". The start price is an assumption. Subsequent prices are derived from the combination of a reversion factor and a random selection from a standard normal distribution determined by a volatility factor. Econometric studies using EIA monthly data from 1986-2002 recommend a reversion factor of 0.75 and 20% for a volatility factor. More recent gas price fluctuations (1995-2002) appear more consistent with a greater volatility factor of 30%. A sample price is generated as follows. Suppose the model yields a price of $6 in year T and the mean to which it is reverting is $4. In year T + 1, the model yields a random price drawn from a standard normal distribution with a standard deviation of 30% and around a mean of $4.50 [6 – 0.75 times (6 – 4)].

With this model, we find that the average annual gas price exceeds a range of possible price thresholds with the frequency shown in the 2nd column in Table 4.1. For example, in the price process simulation with a starting price of $4.85 and a $9.34 price threshold, 3% of the years from 2004 through 2012 over 1,000 trials had a sample price above $9.34. Under the price threshold waiver options, the frequency shown in the second column is a combination of 2 elements, the likelihood of price above the threshold in years after the waiver ends, weighted by the proportion of RSV exposed in those years and averaged over the period 2004 through 2012 (the years we estimate all the RSV will be produced). For example, a $5.40 price threshold waived until 2012 has a 31% chance of being exceeded in 2012 assuming a 30% price volatility factor. However, only ¼ of the RSV earned in the last of the 6 qualifying years is exposed to this risk, assuming the RSV takes an average of 4 years to produce. To convert to a risk comparable to that for the continuous price threshold, we divide the effect in that one year by the 9 years we assume it takes to produce all the RSV. Thus, a 31% chance of price threshold violation in 2012 becomes a 0.9% risk of losing incentive [31% * ¼ * 1/9]. Equivalent, but more involved calculations convert frequencies of price above $7.58 in the years 2009 to 2012 (9.3%, 7.9%, 7.2%, and 6.8%, respectively) to a risk of losing incentive of 2%.

Table 4.1 – Dampening Effects of Alternative Price Thresholds

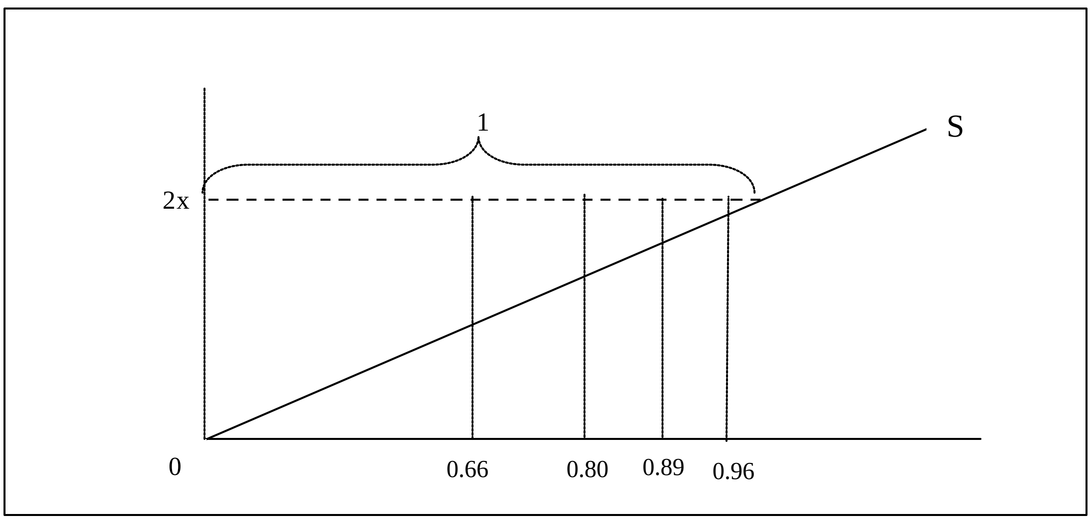
Price Threshold (2004 year $/MMBtu)	Risk or Frequency Fluctuations About the MMS/ EIA Price Series Exceeds Threshold (30% Volatility)	Average Extra Discoveries per Year at $4.11 gas (BCFE)	Incremental Reserves Relative to No Price Threshold	Producer Surplus (million$ of present value)
None	0%	764	100%	$116
$5.41	*27%*	501	66%	$102.6
$6.49	*16%*	614	80%	$111.4
$7.58	*9%*	683	89%	$114.6
$8.66	*5%*	722	95%	$115.7
$9.34	*3%*	734	96%	$115.8
Waived until 2009, then $7.58 in 2009 dollars	*2%**	740	97%	$115.9
Waived until 2012, then $5.40 in 2012 dollars	*0.9%**	754	99%	$116

* Weighted average over the whole incentive period of chance price exceeds threshold in non waiver years adjusted for the portion of RSV exposed in those years.

We compute the dampening effect of a price threshold in the 3rd and 4th columns using a ratio of the expected value of the incentive with and without a price threshold. The following illustrates the computations in the 15,000 – 18,000 foot category in the case of a $9.34 price threshold invoked in 2004 and escalated for inflation in subsequent years. A 3% chance that the price threshold will be breached is analogous to the geologic risk that a well will be unsuccessful. With no threshold, the expected value of the incentive is 5 BCF (15 BCF times 1/3 chance of drilling success) times the expected price (P). With a threshold having a 3% chance of being exceeded the expected value of the incentive is 4.85 BCF [15 BCF times 1/3 times (1 – 0.03)] times the expected price when the threshold is not violated (P’). We find that the average price in the 97% of the cases when a $9.34 price threshold is not violated (P’) is 99% of P. Thus, the expected value under this price threshold is 96% [4.85 times 0.99)/5] that of the no threshold expected value. Similar computations yield the same change in expected value in the sub-18,000 foot category with this price threshold. The difference of 30 BCF (in the 3rd column) equates to about 2 fewer deep wells a year.

Producer surplus is the difference between the market price and the cost of additional production (including the cost of drilling unsuccessful wells). With no price threshold, maximum producer surplus is achieved. The Figure 6.1 depicts this maximum producer surplus and the portions associated with several price thresholds. The area (2x * 1)/2 = x represents the producer surplus associated with no price threshold, that is the maximum, which we have estimated in the RIA to be 40% of $290 million or $116 million. The $9.34 price threshold provides 96% of the extra reserves and (with a supply elasticity of 1 meaning the change in value is proportional to the change in quantity) 99.84% {[(2x * 1)/2] – [2(4% * 4%)/2]} of the producer surplus, or $115.8 million, as does no price threshold. These results reflect the general presumption that the most risky and costly prospects are the ones not drilled if the incentive is dampened by the price threshold.

Figure 4.1 – Producer Surplus at Different Price Thresholds



4.3 Production and Fiscal Effects of a Binding Price Threshold

The effect of a binding price threshold on two measures – the incremental production expected from the royalty relief and the fiscal cost of that royalty relief – were central to the final policy decision about the price threshold parameters. To quantify that effect, we estimated the likelihood that potential fluctuations around the most recent EIA gas price forecast would exceed various price thresholds.

Two assumptions facilitate this exercise. One, in comparison to royalty relief without a price threshold, the presence of a price threshold dampens the royalty-relief induced increase in drilling intensity by the proportion that the price threshold reduces the expected value of the relief. Two, drilling intensity is adjusted for the likelihood of violation over the period when RSV and RSS amounts will be produced.

Table 4.2 illustrates results for a price threshold of $9.34 starting in the year 2004.

Table 4.2 -- Price Threshold Effects on Incremental Production and Fiscal Revenue.

		$9.34 Price Threshold starting in 2004							
	MMS-EIA Price Forecast Current$	2% Price Threshold Current$	Incremental Production Bcfe	Likelihood of Price Threshold Violation	Royalty Lost from RSV & RSS on Status Quo Production	Royalty Gain on Incremental Liquids	Royalty Gain on Incremental Gas Above RSV	Royalty on Incremental Gas when Price Threshold Exceeded	Net Forgone Royalty million 2003$
2003	$4.85								
2004	$4.76	$9.34	70	7.3%	$116	$14	$0	$98	-$87
2005	$4.68	$9.53	141	5.7%	$224	$27	$0	$197	-$173
2006	$4.61	$9.72	211	4.4%	$275	$39	$0	$295	-$212
2007	$4.54	$9.91	281	3.3%	$323	$50	$0	$394	-$250
2008	$4.46	$10.11	346	2.5%	$312	$59	$36	$394	-$200
2009	$4.38	$10.31	410	1.8%	$300	$67	$69	$394	-$151
2010	$4.31	$10.52	405	1.4%	$196	$64	$100	$295	-$25
2011	$4.44	$10.73	399	1.2%	$104	$64	$134	$197	$98
2012	$4.58	$10.94	394	1.3%	$52	$64	$170	$98	$183
2013	$4.73	$11.16	388	nr	$0	$63	$206		$270
2014	$4.87	$11.39	388	nr		$64	$208		$273
2015	$5.02	$11.61	323	nr		$54	$175		$229
2016	$5.17	$11.85	259	nr		$44	$142		$185
2017	$5.33	$12.08	194	nr		$33	$107		$140
2018	$5.50	$12.32	129	nr		$22	$72		$95
2019	$5.67	$12.57	65	nr		$11	$37		$48
2020	$5.85	$12.82		nr		$0	$0		$0
Overall			4,402	3.23%	$1,903	$738	$1,457	$2,362	$424
PV at	7%		2,570		$1,409	$433	$725	$1,700	-$147
Through 2013 only									
Overall			3,044	3.23%	$1,903	$510	$715	$2,362	-$547
PV at	7%		1,990		$1,409	$336	$409	$1,700	-$561

The calculations embedded in each column of this table are as follows.

1) MMS-EIA Price Forecast = price series obtained by adjusting the EIA forecast of prices in 2 ways. First we merged EIA's most recent *Short-term Energy Outlook* (STEO) and *Annual Energy Outlook 2003* (AEO) by means of the growth rate connecting the 2004 price from the STEO with the 2010 price from the AEO and continuing the AEO series after 2010. Second, we added $0.32/MCF to shift the EIA

"wellhead" price forecast to a "landed" basis. This is the value upon which we based the royalty collection estimates. For comparison to the price threshold option, the table displays these forecast values in current dollars by inflating the constant dollar series at 2% annually.

2) Incremental Production = both the royalty-free and royalty-bearing production (including condensate and production after the RSV has been exhausted) from resources discovered by incremental drilling arising from royalty relief. As with the base analysis, we deem all the extra drilling (to targets that would not be drilled under status quo conditions) and 1/3 of accelerated drilling (targets that would be drilled only later under the status quo) incremental drilling.
3) Likelihood of Price Threshold Violation = frequency in each year the price threshold for that year is exceeded by a price simulated with a mean-reverting price process model, using a mean of the MMS/EIA price for that year and reversion and volatility parameters estimated from past EIA price data.
4) Royalty Lost from RSV & RSS on Status Quo Production = royalty lost on production (RSV on gas and RSS on gas and oil) that would have occurred with no incentive. This forgone royalty is determined by the 1/6 royalty rate and a value based on a truncated average of prices for the portion of time the price threshold is not violated. This value will be somewhat below the overall average gas price. For instance, when the likelihood of price threshold violation is 3%, we estimate that the truncated average price for the 97% of the time the price threshold is not violated is about 99% of the overall average, or $3.96 when the overall average is $4.
5) Royalty Gain on Incremental Liquids = the extra royalty collected on incremental production of condensate. Since this production pays royalty regardless of whether the price threshold is violated, we value it at the overall average price for condensate.
6) Royalty Gain on Incremental Gas Above RSV = the extra royalty collected on incremental production of gas once the RSV has been exhausted. Again this production pays royalty regardless of whether the price threshold is violated, so we value it at the overall average price for gas.
7) Royalty on Incremental Gas when Price Threshold Exceeded = royalty that would be due on the gas portion of production that is added by the incentive if the actual prices

exceed the specified threshold price. This royalty offset to forgone royalty is determined by the 1/6 royalty rate and a value based on a high average of prices for the portion of time the price threshold is violated. This value will be somewhat above the price threshold level. For instance, when the likelihood of price threshold violation is 3%, we estimate that the high average price for those 3% of cases is about 12% above the price threshold, or $10.46 when the price threshold is $9.34.

8) Net Forgone Royalty = expected forgone royalty when price threshold violations are taken into consideration {[#4 times (1 - #3)] + #5 + #6 + (#7 times #3)}.

Appendix 5: SPREADSHEETS

Royalty Effects of Deep Gas Rule (15, 25/5) Plus Sidetracks and Deeper Well Slide and No Price Threshold

Royalty Effects of Deep Gas Rule (15, 25/5) with EIA/MMS Price Forecast and No Price Threshold

Royalty Effects of Deep Gas Rule (10, 20/5) Plus Sidetracks and Deeper Well Slide and No Price Threshold

Royalty Effects of Deep Gas Rule (10, 20/5) with EIA/MMS Price Forecast and No Price Threshold

Sensitivity of Forgone Royalty and Net Social Benefit to Drilling and Success Increases (No Price Threshold)

Detailed Specification of DG Final Rule Alternatives [Proposed Rule Calculation shaded]

Assumption for Final DG Rule Analysis, RSV and RSS Adjustment Calculations

Forecast Absolute Royalties With and Without Incentive ($3.55/MCF Gas)

Oil and Gas Price Effects

Price Sensitivity Inputs

Summary of Price Threshold Effects on Production and Fiscal Revenue (20% Price Volatility)

Summary of Price Threshold Effects on Production and Fiscal Revenue (30% Price Volatility)