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ESTIMATED ECONOMIC IMPACTS OF BLM LAND USE CHANGE ON THE OIL AND GAS INDUSTRY: THE LITTLE SNAKE RESOURCE AREA MANAGEMENT PLAN

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- *The four alternative plans under consideration will generate oil and gas industry sales of between $433 and $554 million per year from Moffat County."*
- *The chosen alternative will generate between 800 and 1,000 local jobs per year.*
- *The total tax effect of the local oil and gas industry on public lands will be $20-$27 million per year.*
- *The approximately 20% variation across alternatives is driven by the degree to which BLM lands are open to the industry.*
- *Total impact variation is reduced by expected increases in other affected industries.*

Introduction

The Bureau of Land Management (BLM) is part of the US Department of the Interior responsible for the management and conservation of resources on 258 million surface acres, as well as 700 million acres of subsurface mineral estate. These public lands make up about 13 percent of the total land surface of the United States and more than 40 percent of all land managed by the federal government. BLM Colorado and all BLM lands adhere to the principal of multiple-use management outlined by the Federal Land Policy and Management Act of 1976. This means that the BLM balances outdoor recreation and preservation of wildlife habitat, air and water, and other scenic and historical values with environmentally responsible commercial development of the land and its resources.[2]

The Little Snake Field Office (LSFO) includes aproximately 4.2 million acres of land in Moffat, Routt, and Rio Blanco Counties. The Little Snake Resource Management Plan Planning Area (RMPPA) within that area administers approximately 1.3 million acres of public land surface and mineral estate and 1.1 million acres of federal mineral estate where the surface is privately owned or state-owned. Of the 6 counties that have acreage within the RMPPA boundary, the economic effects will arguably impact Moffat County the most, as the overwhelming majority of BLM surface and subsurface land that will be affected by the new LSFO Resource Management Plan (RMP) lie within it. Some 95% of surface land owned by the BLM that lies within the RMPPA is within Moffat County (Table 1).

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[2] BLM. 2007. http://www.blm.gov/co/st/en/BLM_Information/about_blm.2.html

Therefore, the individual economic impact analysis of the natural resource based industries in the RMPPA under the different RMP alternatives will focus on the impacts found in Moffat County.

The goal of this research series is to inform the public regarding the economic tradeoffs and impacts the proposed LSFO RMP alternatives will have on the natural resource based economic activities on BLM properties under management of the LSFO.

Figure 1 - LSFO-Managed Surface Ownership Boundaries

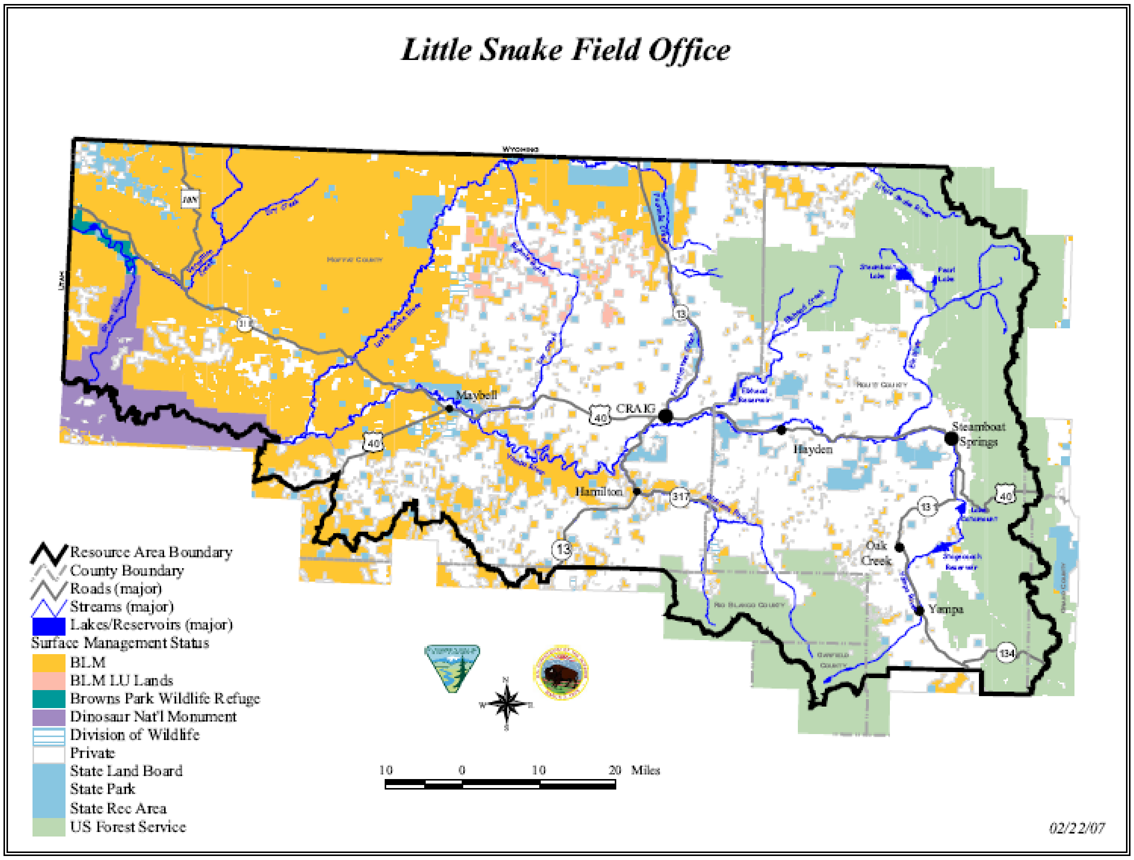

Table 1: LSFO-Managed Surface Ownership by County					
County	Acres of County within RMPPA Boundary	Acres of Surface Ownership			
		BLM LSFO	Other Federal Agencies	State of Colorado	Private
Moffat	2,620,700	1,285,200	136,000	183,500	1,016,000
Routt	1,399,300	59,900	566,700	68,100	704,600
Rio Blanco	133,800	4,300	107,900	0	21,600
Garfield	36,300	0	36,100	0	200
Grand	30,000	0	29,800	100	100
Jackson	1,600	0	1,600	0	0
Total	4,221,700	1,349,400	878,100	251,700	1,742,500

Revising the LSFO RMP

Each surface and subsurface area under the management of the BLM has a field office which implements and enforces an RMP specifically designed for the property encompassed within the field office territory. An RMP can require modest revisions or even a complete reconstitution due to changes in public use and shifting demands for recreation, agriculture and livestock grazing, oil and gas productivity, and other factors.

The LSFO RMP was revised three times since its implementation in 1989. In 2001, the LSFO RMP began to consider the process of a complete review and revision due to the rise of management and travel concerns within the oil and gas industry, input from Moffat County and concerns of several environmental organizations. The Northwest Colorado Stewardship (NWCOS) and the BLM developed a collaborative strategy to revise the LSFO RMP in the spring of 2004. When the Little Snake RMP is completed, it will provide a comprehensive framework for managing the BLM-administered public lands and resources and allocating their uses in the RMPPA. One of the four alternatives detailed below will be chosen according to a defined political process, as outlined in Section 1.5 of the 2007 Draft Environmental Impact Statement (EIS) for the Little Snake RMP, and this economic analysis attempts to provide answers to the expected outcomes of that choice.[3]

LSFO RMP Alternatives

Four alternatives (A, B, C, and D) are described and examined in this analysis, each representing varying levels of management actions for each resource and resource use based on achieving the goals and objectives of the given alternative. The National Environmental Policy Act (NEPA) requires a no action alternative, and thus, Alternative A provides a status quo basis to compare the impacts of the differing alternatives.

Alternative B would allow the greatest extent of resource use within the RMPPA, while maintaining the basic protection required for managing resources. Under this alternative, protection of resources would be the least restrictive within the limits defined by law, meaning current designated protections such as areas of critical environmental concern (ACEC) and special recreation management areas (SRMA) would be removed, no new wild and scenic river (WSR) corridors would be recommended for designation, and opportunities for "unmanaged" motorized recreational experiences would increase. With this alternative, unlike Alternative A, areas designated as no surface occupancy (NSO) would also be designated as no ground disturbance (NGD) for other uses.

Alternative C is denoted as the 'preferred alternative' throughout the Draft EIS/RMP (2007), and emphasizes comprehensive multiple resource management in the planning area, protecting sensitive resources while applying the most current information to allow the BLM to set priorities based on flexible and proactive public land management techniques. Commodity production would be balanced against wildlife and vegetation protection, where exceptions could be granted according to established adaptive criteria (see Appendix E, Draft EIS/RMP 2007).[4] Area protections for sensitive resources would be limited to areas where such designations are necessary, while special management prescriptions would be applied to areas without such designations. Existing SRMAs would remain in place, while additional SRMAs and backcountry areas would be identified to provide diverse recreational experiences. More limitations and closures for off-highway vehicle (OHV) areas would occur, while some existing would stay in place. Areas considered no surface occupancy (NSO) would also be designated as no ground disturbance (NGD), as in Alternative B. This alternative would be implemented using the adaptive management approach, as outlined in Appendix M of the Draft EIS/RMP (2007).[5]

Alternative D would allow the greatest extent of resource protection among the four resource management alternatives, while still allowing resource use. Commodity production would be constrained to protect natural resource values or to accelerate their improvement, although exceptions would be granted within the guidelines of the adaptive criteria (see Appendix E, Draft EIS/RMP 2007).[4] Wildlife habitat protections would increase with management objectives focused on restoring vegetation communities to

[3] For information on revising the LSFO RMP see Chapter 1 of the Draft EIS/RMP 2007: http://www.co.blm.gov/lsra/rmp/documents/04_LSDEIS_Chapter_1_SFS.pdf

[4] Appendix E of the Draft EIS/RMP: http://www.co.blm.gov/lsra/rmp/documents/AppE_LSDEIS_Exceptions_Mods_Waivers.pdf

[5] Appendix M of the Draft EIS/RMP: http://www.co.blm.gov/lsra/rmp/documents/AppM_LSDEIS_Adaptive_Management.pdf

ecologically desirable levels. Designation of ACECs and WSRs would be maximized, with tighter restrictions in the designated areas to protect sensitive resources. Current SRMAs would stay in place while new SRMAs and backcountry areas would be designated to increase access to diverse recreational experiences. Areas open to OHV use would be decreased, and as in Alternatives B and C, areas considered NSO for oil and gas would also be considered NGD for other uses.[6]

Analysis of oil and natural gas activity in the Little Snake Field Office

One of the major economic activities on LSFO lands is drilling and extracting natural gas and oil. The LSFO field office, in its Reasonable Foreseeable Development (RFD) document, expects there to be significantly more activity in the future than in the past, as 2,221 wells currently exist but 3,031 wells could be drilled during the next twenty years. This is likely to create significant economic impacts. Moreover, there are numerous crossover effects and potential conflicts with other aspects of land management. For example, the existence of wells may impair the experience for hunters or hikers, which may affect visual resource management objectives within the plan. The construction of wells, access roads, and pipelines also disturbs the immediate ecology of an area, and in some analyses, has been shown to have wider impacts on migration patterns of elk or nesting behavior of wildlife. Finally, significant water is pumped out of oil and gas wells, which is usually of low quality and must be disposed of or recirculated back underground, which may also have potential environmental effects. In general, there was not enough data to incorporate these effects in the analysis, so they are discussed qualitatively at the end of the section.

The oil and gas industry consists of two primary sectors, drilling the wells to produce natural gas, oil, or both, and then an extraction activity, which occurs after the well has been drilled and the economic value has been determined. Oil wells are drilled in two phases: first the dry hole, or production phase, occurs, and afterwards a second completion stage is undertaken if the possibility for adequate volumes of hydrocarbons exists. We constructed two sectors to account for these phases, drilling and extraction/production. The drilling sector sells their output, a drilled well, to the second extraction sector, which pumps oil and natural gas from the ground under the well.

Key assumptions used in the analysis

As our IMPLAN model is just for one year, the sale of a drilled well is represented by its “amortized" value to the extraction sector, assuming that the well lasts thirty years and the discount rate is 6 percent.

If a well appears to be economic, the second completion stage is added to condition the well for production. In this case, the cost is about $1.233 million dollars for the production stage, while the total costs for adding the completion stage is $0.818 million. The estimated prevalence of “dry” holes, which do not undergo the completion stage, is expected to be 20% of wells drilled over the life of the Plan (Conrath, RFD, 2004).

The number of producing wells in LSFO during 2003 was 881, which includes some wells that reach back many years. In total, 2,112 wells existed, some of which were over sixty years old. The production of oil per well in 2003 was 419 barrels and 2116 million cubic feet (MCF) of natural gas. There were just 29 new wells drilled in 2002 and 59 in 2003. To get the average output value for each well, we used the prices from the RFD for 2002 at about $28 per barrel of oil and $3.80 per MCF of natural gas. These led to the average sales per well of $92,160 per well during 2002, which was comprised of $80,422 sales of natural gas and $11,738 sales of oil, making the typical a gas well, with far greater income from sales of natural gas.

In the next section, we present the approach used to determine the economic value of the increased oil and gas activity during the RMP time frame and also some issues in the analysis to this point.

Determination of the simulation values

A forecast of the increase in oil and gas activity throughout the life of the plan (20 years) is central to this analysis, as are the impacts of various restrictions on drilling. The forecasted number of wells to be drilled is taken from the RFD. The types of restrictions are summarized in the Energy Policy and Conservation Act (EPCA) Table, which shows the acreage under various designations, including those related to seasonal restrictions and others related to stipulations on surface occupancy (Table 2). The acreage and

[6] For detailed descriptions of the four LSFO RMP alternatives see Chapter 2 of the Draft EIS/RMP: http://www.co.blm.gov/lsra/rmp/documents/05_LSDEIS_Chapter_2_SFS.pdf

Table 2: Area (Acres) open for drilling & liquid output per Energy Policy & Conservation Act (EPCA) designation, by alternative

Designation	Units	Alternative A	Alternative B	Alternative C	Alternative D
Open subject to standard lease terms & conditions	Area (Acres)	640,600	1,601,190	520,230	413,210
	Total Liquids (MMBbl)	88,340	270,601	85,657	54,191
	Total Natural Gas (Bcf)	3,137,054	9,251,066	3,072,976	1,776,737
Open subject to controlled surface use	Area (Acres)	129,730	154,150	157,980	110,300
	Total Liquids (MMBbl)	15,471	15,327	20,700	5,035
	Total Natural Gas (Bcf)	541,104	617,783	731,075	103,513
Cumulative timing stipulations <3 mo	Area (Acres)	12,730	0	13,390	12,960
	Total Liquids (MMBbl)	923	0	923	923
	Total Natural Gas (Bcf)	22,334	0	22,334	22,334
Cumulative timing stipulations 3-6 mo	Area (Acres)	272,830	146,240	319,110	319,950
	Total Liquids (MMBbl)	76,825	4,070	72,861	73,960
	Total Natural Gas (Bcf)	3,003,491	45,279	2,830,024	2,876,020
Cumulative timing stipulations 6-9 mo	Area (Acres)	843,490	4,100	862,850	849,960
	Total Liquids (MMBbl)	107,556	1,327	110,768	107,438
	Total Natural Gas (Bcf)	3,214,654	50,395	3,351,191	3,209,966
Cumulative timing stipulations >9 mo	Area (Acres)	28,970	0	2,210	29,300
	Total Liquids (MMBbl)	9,391	0	455	9,509
	Total Natural Gas (Bcf)	389,736	0	14,696	394,424
Open subject to no surface occupancy	Area (Acres)	217,020	22,440	267,840	500,510
	Total Liquids (MMBbl)	17,744	1,525	23,985	97,201
	Total Natural Gas (Bcf)	420,792	27,889	591,023	3,583,136
Recoverable NSO* (within ¼ mile internal buffer of NSO areas)	Area (Acres)	146,370	20,330	171,180	238,230
	Total Liquids (MMBbl)	11,922	1,105	15,580	34,497
	Total Natural Gas (Bcf)	281,561	16,402	389,870	1,133,516
(beyond ¼ mile internal buffer of NSO areas)	Total Liquids (MMBbl)	5,823	420	8,406	62,705
	Total Natural Gas (Bcf)	139,231	11,487	201,153	2,449,620
Closed to leasing	Area (Acres)	78,230	78,230	189,220	272,850
	Total Liquids (MMBbl)	68	68	2,495	17,214
	Total Natural Gas (Bcf)	273	273	80,792	613,075

estimated natural gas and oil resources are reported for each designation and management alternative. This provides a starting point that, along with certain assumptions, can be used to determine the number of wells to be drilled and their associated costs.

The general approach follows: We assume that there will be a “desired” average of 151 wells drilled per year to meet the RFD target of 3,031 wells put in place during the twenty-year period of the plan. The immediate questions are about how to determine under which designations these wells will be drilled, how much they will cost, and, indeed, whether all 151 wells will be drilled each year. We assume first that companies will target areas where they can get the greatest amount of natural gas (as gas is about three times more prevalent as oil in Moffat County), so wells would likely be placed in the designated areas following the proportions of total availability of gas (Table 2). Thus, in Alternative A, there are 11.2 million BCF in total identified gas resources under the various designations and, of that, 3.2 million BCF, or 28.8% of the gas, is found under acreage with 6-9 month seasonal restrictions. Gas companies will thus try to drill 28.8% of the wells within that area, with higher costs than if that resource had been under the open lease stipulation.

Several of the designations require special attention or can be merged with others. First, the acreage facing cumulative timing stipulations of less than three months is merged with the open lease designation, as there is little acreage in that category and also only a small amount of gas to be found (see Row 3, Table 2). (In fact, the desired number of wells in this designation averages to zero across all alternatives.) Likewise, designations with stipulations greater than nine months are quite restrictive, so much so that it appears best to make that small amount of acreage and possible gas recovery added to the “closed to leasing” section.

Cost variations across designations
Each other designation will lead to varying drilling costs and will affect the decision of companies about whether to drill. The first is the open lease with standard terms, which is modeled as the “base”, with its costs reported below. Drilling in areas with this stipulation offer the lowest costs to operators. The open leases with surface control, the second category in the table, will be modeled by increasing construction costs by 20%, as these stipulations often require adjustment in location, land preparation or reclamation.

There are two categories of seasonal restrictions, 3-6 months and 6-9 months. It is clear that if firms are restricted to drilling during a short period, in the aggregate there needs to be more drilling rigs and crews available to meet that demand. In general, it takes about 20 days to drill a well with a team of 7-10 workers, including professional and overhead staff. One crew can then drill 16-17 wells per year. This means that it takes ten crews to do the 151 wells assumed in this analysis. For the first seasonal designation, we assume that the restrictions are about 4.5 months, the mid point of the 3-6 month range. This implies that the increases in labor and rigs needed would be about 35%. The availability of these rigs would be a factor of how much of a region faces these limits, the general tightness in supply due to national drilling levels, and other factors that are quite difficult to forecast. In alternatives A and C, areas with seasonal restrictions contain over half of the gas resources.

To implement these restrictions, we assume that the prices of rig-related capital and labor increase by one quarter of the increase in the required stock of rigs and workers. This leads to an increase in selected costs of 8.25% for the 3-6 month timing restriction. A similar process would suggest that 7.5 month restrictions on average for the 6-9 month designation would lead to a 17.5% change in those costs. In addition, there might be wells that are “caught” in the middle of construction as the restriction goes into effect, so that capital is tied up for several months in partially finished wells. It was estimated by Julander Energy sources that this might be 10% of wells during the 3-6 month seasonal restrictions and 25% of wells drilled in the 6-9 month designation. These added financial costs are also incorporated in the simulations. (In both cases, it is assumed that production costs listed in a later table need to be financed for 4.5 months and 7.5 months respectively, at an 8% interest rate).

The last three lines show various designations that are continuous throughout the year. Clearly, no wells will be drilled in those areas with “No Leasing” restrictions. Also, BLM has determined that wells in the unrecoverable No Surface Occupancy (NSO) must be drilled too far away from gas resources to make economic sense. The wells that companies would like to drill in these areas simply will not be attempted. However, the recoverable NSO areas listed in the EPCA table (Table 2) could be potentially accessed but at higher costs. BLM has argued that the horizontal and directional drilling required in these NSO areas would increase costs by 36%.

This analysis will incorporate these varying costs of drilling in two ways. First, we reduce the number of wells drilled in response to increased costs of drilling using a core of concept from economics called the supply elasticity. Moreover, we adjust the budgets presented in the following section to reflect the higher costs assumed above for the various scenarios. Supply elasticities describe the response to an increase in prices or costs. In our case the increases are in input costs, which lower the profitability of drilling a well, and therefore the likelihood that it will be undertaken. Results from the literature show that price (not cost) elasticities run from 0.4 to 1.6 depending on the time frame incorporated, and the product being produced. The interpretation is based on percentage responses, so an elasticity of 0.75 says that, given a ten percent increase in prices, there will be an increase in wells drilled of 7.5 percent, or that the response is three quarters as great as the increase in costs.

We found no articles giving input cost elasticities, so the output elasticity values found in the literature are used as starting points but are given an opposite direction. Thus, as the costs of producing a well increase, the number of wells drilled will *decrease*. From discussions, it appears that the increases in costs would still leave profitable opportunities in many cases, at least given high prices for gas and oil that might exist in the future, so that many operators would continue to drill. However, some high-cost operators, or those with better possibilities in other fields, might not choose to drill in face of the cost increases assumed for the various designations. However, with higher prices, and developed infrastructure to transport the gas, many wells will be added despite higher costs. Thus we use a relatively low elasticity of 0.5 to capture the response of wells to the higher costs in this analysis.

In Table 3 we show how wells might be distributed under each alternative and designation reported in the EPCA table, taking into account variations in the economic costs in the different areas. The first panel shows the distribution of the “desired” wells across the various designations. Because each alternative differs with regard to the acreage placed in various designations, the natural gas resource in the mineral estate below the acreage varies as well. We assume that companies will initially want to drill where there is the greatest likelihood of obtaining natural gas, irrespective of where the reserves fall. Thus, in Alternative A, about 29% of the total natural gas is found in areas which are open to leasing under standard terms, so that firms would want to put 44 of 151 wells in those areas during a typical year, *prior* to the economics being taken into account. In Alternative B, where far more land is open without restriction for almost all of the acreage and natural gas underneath, nearly all wells (140) would be drilled in these areas, with few in areas with any other designation. There is in fact little area contained at all in these other designations. In Alternative D, there are far more restrictions, so oil companies are faced with drilling in higher cost designations more often.

As noted in the earlier section, firms will be less attracted to areas where there are high costs imposed, and at the margin, fewer firms will drill in the higher cost areas. The response is summarized, again as covered earlier, in the supply elasticity with respect to an increase in costs (which is assumed to be -0.5). The percentage increases in costs is given in the middle panel of Table 3, along with the number of wells that are *not* drilled, either because resources are unrecoverable or because higher costs induce a negative reaction within the industry. The added costs amount to only 1.35% for surface control, but they climb by 25.3% when there are restrictions of 6-9 months. In addition, there are areas with unrecoverable resources or which are closed entirely to leasing. As a result, fewer than the 151 expected wells are put into place in all Alternatives except B.

The table shows that there is no penalty from higher costs in Alternative B, but this grows to 52 wells in Alternative D, over one third of the initial expected wells, where there are extensive restrictions on drilling. The alternatives A and C are nearly the same, as they have designations that lead to a reduction in 15 and 18 wells respectively. The bottom panel gives the net number of wells to be drilled by designation, and taking the economic reactions to higher costs into account.

Estimated budgets for drilling and extraction

The budgets in Table 4 are taken from an Authority for Expenditures (AFE) provided from industry sources and converted into the IMPLAN sectoring scheme to derive the costs of drilling each well. The extraction budget was taken from IMPLAN, as it appeared to be

Table 3: Hypothesized distribution of wells drilled by BLM Mgt. alternative and designation

Initial distribution of wells without impact and restrictions

	BLM Management Alternatives			
	A	B	C	D
Open Lease	44	140	43	21
Open subject Surface control	8	9	10	1
3-6 month seasonal limits	42	1	40	35
6-9 month seasonal limits	45	1	47	39
Recoverable NSO	4	0	6	14
Nonrecoverable NSO	2	0	3	29
No Leasing	5	0	1	12
Total	151	151	150	151

Reduction in wells due to being unrecoverable or costly

	BLM Management Alternatives				
	A	B	C	D	% Increase in Costs
Open Lease	0	0	0	0	--
Open subject Surface control	0	0	0	0	1.35
3-6 month seasonal limits	5	0	4	4	21.6
6-9 month seasonal limits	6	0	6	5	25.3
Recoverable NSO	0	0	1	2	24.4
Nonrecoverable NSO	2	0	3	29	--
No Leasing	5	0	1	12	--
Total	18	0	15	52	

Based on an input cost elasticity of 0.5

Net Wells Drilled (No.)

	BLM Management Alternatives			
	A	B	C	D
Open Lease	44	140	43	21
Open subject Surface control	8	9	10	1
3-6 month seasonal limits	38	1	36	31
6-9 month seasonal limits	40	1	41	34
recoverable NSO	3	0	5	12
Nonrecoverable NSO	0	0	0	0
No Leasing	0	0	0	0
Total	132	151	135	99

Table 4: Moffat County estimated gas drilling, completion and extraction budgets

Sales/Production Per well	1,191,741	892,996	92,146
	Individual Well Cost ($)		
Costs by Sector	Dry Hole	Completion	Extraction
Crop			23
Pasture			
Cattle			
Other Animal			
Other Agriculture			
Coal			
Power			34
Water	51,490		931
Heavy Construction	112,735	27,500	34
Oil Gas Drilling	388,000	317,900	68
Oil Gas Extraction	36,000		32,770
Manufacturing	302,936	352,146	9,194
Wholesale trade		-	3,224
Transport	3,500	65,620	2,497
Retailing		-	4,461
Food/Bev. Retailing		-	57
Communication		-	11
Finance Insurance Real Estate	74,000	49,075	454
Professional Services	44,000		1,146
Health		-	8,070
Recreation		-	-
Outfitters		-	45
Hotels		-	-
Food Services		-	68
Other Services	5,000	-	114
Government		-	488
Total			63,746
Employee Compensation	43,500	31,250	9,858
Proprietor income	110,580	28,505	8,919
Proprietor Income	20,000	21,000	6,034
Business Taxes		-	3,589
Total Costs	1,191,741	892,996	92,146

reasonable. Only the extraction levels were increased to match known values from the RFD and conversations with Fred Conrath of the BLM.

The key assumptions used in creating the drilling budget are presented below. First, we used a representative AFE (Authority for Expenditure) for 8,500 feet, which came from the Peance Basin, not identical but similar to the Cretaceous Seas that formed deposits in Moffat County. This was adjusted through conversations with Dick Pate of Julander Energy. The costs were converted from this AFE into our 29 sector grouping for IMPLAN for two categories, the dry hole phase, which is required for all wells, and the completion phase, which is only undertaken when there is enough evidence that there will be sufficient resources found. After the completion drilling is finished, there is the ongoing servicing and extraction of hydrocarbons from the wells. The structure of the budgets is such that the extraction phase “purchases” a completed well from the drilling phase, but it is just an amortized portion that is charged to a given year. We further assume that these costs reflect the “base” costs of drilling without any restrictions.

Results of oil and gas simulations

The results in this section assess the impacts of the oil and gas simulations from two separate perspectives. The analysis first looks at the drilling phase, and shows the *annual* impacts for a typical year during the Plan period. The numbers of wells drilled varies by management alternative, as described in Table 3. The second part of the presentation is the ongoing extraction phase. This analysis is placed ten years into the plan as well, when up to 1,510 wells have been drilled (in Alternative B); however, with 20 percent dry holes, the number of new producing wells for that alternative is 1,208.

There is also significant variation across alternatives: in alternative D, the pro-environmental alternative, there are only 99 wells drilled per year, so that after ten years, taking into account twenty percent dry holes, there are just 792 wells in production. The other alternatives are intermediate versions: the annual drilling of 132 wells in Alternative A leads to 1,056 wells, while, in Alternative C, the 135 wells drilled on average leads to 1,080 wells that extract natural gas and oil ten years after the Plan has been initiated. Again, the analysis will present the *annual* results for a typical year ten years in the future. The stipulations described in the EPCA table (Table 2) affect costs of drilling, but much less so for extraction. Once the wells are drilled, most impacts from BLM stipulations are finished, while the large extraction stream endures for many years. While separated, these two phases are, in general, discussed together.

It is clear that the sales values of drilling up to 151 wells each year are high, as the direct impacts range from $223 to $294 million in value. (These values make sense, as each well costs about $2 million if completed and there are up to 151 wells drilled in a typical year). The reasons that these vary are related to the number of wells that are not drilled, as shown in Table 3, which shows the reduction in drilling based on costs or accessibility to resources. It is also due to having more wells in designations with higher costs, which can only be justified if there are higher sales values. ("Sales" in this case are really the value of the wells transferred into the extraction phase). An interesting dimension of this analysis is that higher indirect and induced sales values can be obtained in scenarios with higher costs, or more restrictive designations. Thus, the overall values in Table 5 in Alternative A and C exceed those in Alternative B. The higher costs imposed by the designations lead to higher costs and therefore higher sales values. The multipliers are from 1.3 (Alternative B) to 1.4, which are reasonable given the type of industry and small geographical area considered.

The extraction phase is based on the number of producing wells, which vary considerably across alternative. The pattern of sales in this activity follows the number of installed wells more closely than in the drilling phase, as costs are the same across all alternatives. Thus, the largest number of wells, and consequently sales, is drilled in Alternative B. The multiplier effects are however very small, at about 1.06 in all

Table 5: Impact analysis results on total annual sales (US$ Millions)

	BLM Management Alternatives			
Categories	A	B	C	D
Oil and Gas Drilling				
Direct Impact	287.871	288.126	294.488	296.779
Indirect Impact	89.134	62.469	91.210	74.445
Induced Impact	25.772	26.454	26.400	19.816
Total Impact	402.778	377.049	412.098	317.286
Oil and Gas Extraction				
Direct Impact	146.000	167.000	149.300	109.500
Indirect Impact	5.074	5.803	5.188	3.805
Induced Impact	3.690	4.221	3.773	2.767
Total Impact	154.764	177.024	158.262	116.073

cases. Local sales are therefore not stimulated very much during this phase.

The employment values reported in Table 6 are quite high, and they come mainly from indirect and induced effects. These come from purchases of inputs by drilling and extraction industries and the added expenditures of laborers and households. For instance, the direct employment effects account for only 91 employees in Alternative A, while the indirect and induced effects add an incredible 778 persons, implying a very high multiplier of 9.55. Following the same logic, that higher costs create higher demand for inputs, the total employment across the alternatives in the drilling phase is not driven simply by the number of wells drilled, so that the total in Alternative C of 891 persons exceeds that in Alternative B despite the greater number of wells drilled in B. For extraction, the direct employment effects add only 15 employees in Alternative D, while the indirect and induced effects add another 60 persons, implying a still high multiplier of 5.0. Again, the employment in the extraction phase, while having high multipliers, still seems to follow the general pattern related to the number of installed wells in the various alternatives.

While these multipliers are very high, we believe that they are viable. First, they are associated with other multipliers, such as value added and sales, which are very plausible. Secondly, these two sectors have the highest output-labor ratios of any industries in the county. So, for example, the output: labor ratio is $2.77 million: 1 laborer in oil drilling and $1.33 million: 1 laborer in oil extraction. By comparison, in coal it is $231 thousand: 1 laborer and $96 thousand: 1 laborer in construction. The implication is that few laborers are used in the oil industries compared to other sectors in the county. However, these industries are expected to grow considerably and attain high sales and input purchases levels. Thus even with very low local purchases, the values are high and the created indirect and induced employment will be high, especially relative to the small direct value. Thus, large multipliers make sense.

Table 7 contains the value added figures, which present patterns similar to the sales and employment tables. The pattern of value added in the drilling phase does not strictly follow the number of wells, but is affected by the costs of production as well, while in production (or extraction) of oil and gas, value added is correlated clearly with the numbers of wells drilled. Alternative B provides total value added of $26.9 million, while Alternative D provides only $17.6 million. The most notable part of the value added is its small size, which suggests that the ongoing contribution to the local economy is small relative to its nominal size.

Tables 8 and 9 show the contributions to taxes by level of government for the two phases of oil and gas activity. In Alternatives A, B and C, total tax receipts are over $25 million for drilling, but are closer to $20 million for Alternative D. As in other cases, the greater part of tax revenue is related to income and profit taxes and are Federal receipts. The local entities and State receive nearly the same amounts from drilling operations. About 82.5% of all tax receipts attributed to this sector go to the Federal government, with the State of Colorado receiving 9.3% of the taxes generated, while the local county and city take is about 8.1%.

Table 6: Impact analysis results on employment

	BLM Management Alternatives			
Categories	A	B	C	D
Oil and Gas Drilling				
Direct Impact	91	104	93	68
Indirect Impact	446	434	457	349
Induced Impact	332	341	340	256
Total Impact	869	879	891	672
Oil and Gas Extraction				
Direct Impact	20	23	20	15
Indirect Impact	32	37	33	24
Induced Impact	48	54	49	36
Total Impact	100	114	102	75

Table 7: Impact analysis results on total value added (US$ Millions)

	BLM Management Alternatives			
Categories	A	B	C	D
Oil and Gas Drilling				
Direct Impact	29.307	33.401	29.822	22.249
Indirect Impact	28.140	25.251	28.742	22.659
Induced Impact	15.167	15.592	15.453	11.845
Total Impact	72.614	74.244	74.018	56.754
Oil and Gas Extraction				
Direct Impact	15.124	17.301	15.468	11.343
Indirect Impact	4.060	4.646	4.154	3.045
Induced Impact	4.341	4.964	4.438	3.255
Total Impact	23.525	26.911	24.060	17.644

In regard to the extraction, or production phases of the industry, the total receipts are far smaller, but the proportions across government entities are similar to the drilling phase. One notable aspect of these tables is that the amount going to local entities is fairly consistent with values reported in the baseline report, which showed approximately $1.0 million received by Moffat County from oil and gas-related taxes. These come from a combination of the extraction activity and drilling operations. Thus, moving into the future, localities could expect an added $1.0 million in tax revenues as the industry doubles by adding 1,000 producing wells. Of course, this revenue stream will require continued drilling to be achieved, and there will certainly by significant added government costs associated with the larger industry, so this will not be a windfall.

Table 8: Oil and gas drilling's expenditures effects on taxes (US$ Millions)

	BLM Alternatives			
	A	B	C	D
Federal taxes				
Employee taxes	3.218	3.251	3.298	2.484
Corporate taxes	1.954	3.046	2.002	1.500
Household/sales taxes	15.778	15.134	16.162	12.138
Indirect Business taxes	0.769	0.751	0.790	0.591
Sub-total federal taxes	21.719	22.182	22.252	16.714
State taxes				
Employee taxes	0.130	0.131	0.133	0.100
Corporate taxes	0.403	0.410	0.414	0.311
Household/sales taxes	1.196	1.225	1.225	0.920
Indirect Business taxes	0.727	0.710	0.747	0.559
Sub-total state taxes	2.456	2.476	2.519	1.890
Local (City and County) taxes				
Indirect Business taxes	2.006	1.959	2.062	1.544
Household/sales taxes	0.135	0.138	0.138	0.104
Sub-total local taxes	2.140	2.097	2.200	1.647
Sub-total state and local taxes	4.597	4.573	4.719	3.538
Federal, state and local taxes	26.316	26.755	26.972	20.251

Table 9: Oil and gas extraction effects on taxes (US$ Millions)

	BLM Alternatives			
	A	B	C	D
Federal taxes				
Employee taxes	0.331	0.379	0.339	0.249
Corporate taxes	0.190	0.217	0.194	0.142
Household/sales taxes	1.496	1.712	1.530	1.123
Indirect Business taxes	0.215	0.246	0.220	0.161
Sub-total federal taxes	2.232	2.554	2.283	1.675
State taxes				
Employee taxes	0.013	0.015	0.014	0.010
Corporate taxes	0.047	0.053	0.048	0.035
Household/sales taxes	0.113	0.130	0.116	0.085
Indirect Business taxes	0.203	0.233	0.208	0.153
Sub-total state taxes	0.377	0.431	0.385	0.283
Local (City and County) taxes				
Indirect Business taxes	0.561	0.642	0.574	0.421
Household/sales taxes	0.013	0.015	0.013	0.010
Sub-total local taxes	0.574	0.657	0.587	0.431
Sub-total state and local total	0.951	1.088	0.972	0.713
Federal, state and local total	3.183	3.641	3.255	2.388

The final two tables, Tables 10 and 11, show in detail how various sectors in the economy are affected by the economic presence of the oil and gas industry. They first show the direct effects, which, in this case, are simply the value added created by the oil and gas drilling and production activities. These purchases lead to a series of indirect effects, which are given in the third columns of the tables. The sectors benefiting the most, indirectly, through purchases by the oil and gas drilling industry are government (somewhat mysteriously), the oil drilling industry itself, construction, power, coal, manufacturing, and finance, insurance and real estate (FIRE). These industries receive more than $2.0 million in value added as a result of the activity of the drilling industry. There are a large number of other sectors that benefit from purchases by drilling operations as well.

An examination of the induced effects, which arise from purchases by laborers hired as a result of direct and indirect impacts, shows a quite different pattern, but one that is consistent with the economic contribution of consumers purchasing goods and services with their received labor income. The largest industries affected are housing services, health and retailing, the very sectors that account for large purchases by workers. The other induced effects reflect the wide variety of sectors related to the range of purchases that families and consumers make.

The extraction industry portrays a significantly different pattern of indirect effects, which leads to benefits to services, wholesale trade, power, transport, and oil drilling, which each receive more than $100,000 in value added from purchases related to oil production activities. The induced effects, which are related to the purchases by the households who received labor and capital income, are the same in both cases, and indeed, across the entire analysis.

Important economic factors not reflected in the simulations

Aspects of seasonal restrictions

Seasonal restrictions create a number of complexities for the analysis that are not, in general, included in the modeling but are nonetheless important. First, there are different perspectives on the actual costs of seasonal restrictions, and secondly there are socio-cultural aspects of seasonal restrictions. Each of these restrictions is discussed on the following page.

Table 10: Sector level direct, indirect and induced impacts on value added for the oil and gas drilling industry (BLM Alternative C , by Expenditure Category in US$ Millions)

		Impacts		
Categories	Direct	Indirect	Induced	Total
Housing Services		0.000	3.112	3.112
Government		5.449	0.615	6.064
Oil Gas Drilling	32.253	4.161	0.001	36.416
Heavy Construction		4.007	0.033	4.040
FIRE		3.463	1.110	4.573
Manufacturing		2.541	0.172	2.713
Coal		2.458	0.179	2.637
Power		1.887	0.625	2.512
Services		1.607	0.858	2.465
Transport		1.479	0.198	1.678
Oil Gas Production		1.100	0.071	1.172
Wholesale Trade		0.902	0.862	1.764
Water		0.571	0.016	0.587
Retailing		0.504	2.738	3.242
Other Services		0.397	1.031	1.428
Communication		0.215	0.378	0.593
Food/Bev. Retailing		0.082	0.523	0.605
Hotels		0.060	0.212	0.272
Recreation		0.053	0.006	0.059
Food Services		0.045	0.621	0.666
Cattle		0.038	0.006	0.044
Other Animal		0.027	0.013	0.040
Pasture		0.024	0.005	0.029
Other Agriculture		0.010	0.007	0.017
Health		0.001	3.321	3.322
Crop		0.001	0.001	0.002
Total	32.253	31.085	16.713	80.051

The first perspective has to do with the foregone revenues from a seasonal restriction. The main cost of course is that a well will not be completed. The issue then is what costs are increased and what revenues are foregone. As noted earlier, suppose that the production phase of a well has been incurred but the completion phase cannot be finished due to the seasonal restriction. Clearly, the well will miss the revenue stream from that year, and, if it is winter, when natural gas prices are the highest, an opportunity will be lost for selling at the seasonal high point. The question is what the actual costs are, which can be seen from the sales and cost sides.

First, in regard to sales of gas, the key issue would be that the resource is still in the ground, so that it could be sold the next year. (Contrast this with the situation in fresh fruit, where, if a season is missed, the value of production is lost forever). Thus, the income stream is deferred by one year. Depending on prices of natural gas in the future, this missed year of output could lead to either higher or lower revenues, but the determination of this effect is beyond the scope of this research. The main cost associated with this deferral is that access to monetary resources from sales is reduced by one year and thus firms must borrow. The actual cost is thus the interest on the borrowed funds equivalent to one year of output of the well.

Table 11: Sector level direct, indirect and induced impacts on value added for oil extraction (BLM Alternative C, by Expenditure Category in US$ Millions)

		Impacts		
Categories	Direct	Indirect	Induced	Total
Services		0.363	0.082	0.445
Wholesale Trade		0.224	0.082	0.307
Power		0.170	0.059	0.229
Transport		0.151	0.019	0.169
Oil Gas Drilling		0.127	0.000	0.128
Oil Gas Production	5.544	0.095	0.007	5.646
Government		0.084	0.059	0.142
FIRE		0.076	0.106	0.182
Other Services		0.042	0.098	0.140
Communication		0.039	0.036	0.075
Coal		0.030	0.018	0.048
Manufacturing		0.024	0.017	0.041
Heavy Construction		0.018	0.003	0.021
Retailing		0.017	0.260	0.277
Hotels		0.011	0.020	0.031
Food Services		0.010	0.059	0.070
Food/Bev. Retailing		0.003	0.050	0.052
Health		0.000	0.315	0.316
Housing Services		0.000	0.296	0.296
Others		0.005	0.005	0.010
Total	5.544	1.489	1.591	8.624

On the cost side, there are also financial resources that are tied up, so that costs have been incurred but cannot be covered by revenues. There is, moreover, a problem in that increased resources are required in aggregate because more workers and drilling rigs, etc. must exist to meet the restricted window of drilling. This is hard to assess, however, because it requires an understanding of the wider regional and national markets. Indeed, we have made assumptions on increased costs and the consequent reduction in production, which we incorporated in the model. Thus, we conclude that the main added costs of seasonal restrictions not in our model are the deferred revenues.

Socio-cultural effects of oil and gas seasonal restrictions

One critical issue noted by NWCOS participants, but which is not included in this analysis, is the need to use more temporary workers when there are seasonal restrictions. These laborers cannot obtain permanent employment throughout the year, so they would not live in Moffat County, but would be migrants who might be housed in temporary quarters. They would not make the expenditures that permanent residents do, and, without that vested interest, little service to the community would be seen and the likelihood of increased negative social behavior often associated with these migrants might be seen, including drugs and other anti-social behavior. This would add costs to the seasonal restrictions to the community that would not be faced by the operating firms.

Impacts on the effects in migration patterns and deterioration of the other resources

One aspect of oil and natural gas production and drilling is effects on the migration patterns of large game. Studies recently have noted changes in migration patterns and deleterious effects on availability of large game within the areas being drilled. This could reasonably be expected to have negative effects on the harvest of hunters, but it was not possible to get sufficient detail to make predictions. The migration patterns of elk, location of wells, and the coefficients relating the two were simply not known, so we simply note that this could be a negative effect of oil and gas drilling. The other effect that is not included in the model is the impact on hunters' experience from hunting in areas where the vista is dotted with gas and oil wells.

Other resources such as water quality and surrounding streams and ponds might be affected, as will the ecology of areas around drilling pads, and those that are found near access roads that might provide greater opportunities for off-highway vehicle (OHV) activity. These aspects will be extended in the next versions of this document.