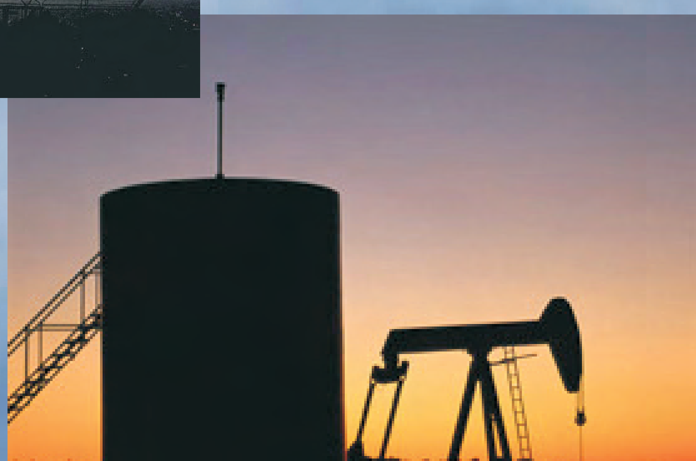
Economic Comparison of the Rules and Regulations of the Colorado Oil and Gas Conservation Commission (COGCC)

Final Report
January 2001



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State of Colorado
Department of Natural Resources

Economic Comparison of Oil and Gas Rules
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Executive Summary

Introduction

Hazen and Sawyer was retained by the Colorado Department of Natural Resources (DNR) to conduct an *Economic Comparison of the Rules and Regulations of the Colorado Oil and Gas Conservation Commission (COGCC*). The study was authorized by the Colorado State Legislature to investigate the impacts of significant rule changes following the passing of Senate Bill 94-177 (SB 94-177) in 1994. The intent of this legislation was stated as follows:[1]

> "It is declared to be in the public interest to foster, encourage, and promote the development, production and utilization of the natural resources of oil and gas in the state of Colorado IN A MANNER CONSISTENT WITH THE PROTECTION OF PUBLIC HEALTH, SAFETY AND WELFARE …"

Several goals were established for this study including the following:

- Perform a study of the costs of compliance with COGCC Rules and Regulations, both pre- and post- SB 94-177 over the life cycle of a well;
- Compare the compliance costs both pre- and post- SB 94-177, with the total costs to drill and complete a well in each of four location scenarios;
- Evaluate the cost of compliance with Rule 508 – Local Public Forums, Hearings on Applications for Increased Well Density and Public Issues Hearings;
- Compare Colorado's Oil and Gas Rules and Regulations with those in Wyoming, New Mexico and Utah; and
- Discuss impacts of the compliance costs on future oil and gas exploration and development work in Colorado.

Review of Colorado's Oil and Gas Rules and Regulations Pre- and Post- SB 94-177

Hazen and Sawyer first conducted a thorough review of Colorado's current Oil and Gas Rules and Regulations as well as those regulations in place prior to 1994. Table ES-1 provides an outline of the new rules and modifications made to Colorado's Oil and Gas Rules and Regulations since SB 94-177. As summarized in this table, rule additions or modifications impact every stage of the well life cycle.

[1] *Colorado Senate Bill 94-177, 1994.*

Table ES-1
Summary of Rule Changes and Modifications to Colorado Oil and Gas Rules and Regulations after Passage of Senate Bill 94-177

Well Life Cycle Stages	New Rules or Modifications Since SB 94-177 Was Passed in 1994: Rule Modification	New Rules or Modifications Since SB 94-177 Was Passed in 1994: New Rule or Requirement
1. Application for Permit to Drill	None	New Form 2A - Predisturbance Assessment (photographs, and soil and plant information)
2. Financial Assurance	Extended Scope of Financial Assurance for Soil Protection, Plugging and Abandonment	Required General Liability Insurance
		Required Seismic Financial Assurance
		Required Natural Gas Gathering Financial Assurance
		Excess Inactive Wells Financial Assurance
3. Notice and Consultation	None	Notice must be given to surface owner and local government designee 30 days prior to drilling a well
4. Building Surface Location and Access Roads	None	Required Soil Segregation and Protection
		Increased fencing when requested by surface owner
5. Application for a Pit to Accept Produced Water	Modification of pit permitting requirements	Required one-time inventory of pits
	Modifications of pit lining requirements	Required *Sensitive Area Determination*
		Permit or close existing pits
		Pits closed after 1997 must comply with new reclamation rules
6. Environmental Requirements	Increased requirements for exploration and production waste disposal	Required application for simultaneous injection wells
	Increased requirements for management and reporting of spills and releases (reporting to Director and surface owners, Site Investigation and Remediation Workplan)	

Table ES-1 (Cont.)
Summary of Rule Changes and Modifications to Colorado Oil and Gas Rules and Regulations after Passage of Senate Bill 94-177

Well Life Cycle Stages	New Rules or Modifications Since SB 94-177 Was Passed in 1994	
	Rule Modification	**New Rule or Requirement**
7. Drilling, Casing and Completing a Well	Increased requirements for Blowout Prevention Equipment (BOPE)	New Form 5A – Completed Interval Report
	Notice of casing repairs must be given to COGCC	Increased logging requirements
	Modification of production casing cementing and testing requirements	
8. Safety	None	New additional safety requirements for seismic operations
9. Flowline Regulations	None	New requirements for construction, maintenance, safety and abandonment of flowlines
10. High Density Areas	None	Standards for High Density Area designation
		Increased equipment setbacks, BOPE Requirements, control of fire hazards, trash removal, tank specifications, access roads, well site clearing, fencing requirements, berm construction and guy line anchors
		Operators must now identify plugged and abandoned wells
11. Fox Hill Protection Area	None	Increased surface casing requirements
12. Interim Well Site Reclamation	None	New requirements for subsidence reclamation, compaction alleviation, drill pit closure and revegetation
13. Reporting	Modified monthly production reporting requirements by well and formation	

Table ES-1 (Cont.)
Summary of Rule Changes and Modifications to Colorado Oil and Gas Rules and Regulations after Passage of Senate Bill 94-177

Well Life Cycle Stages	New Rules or Modifications Since SB 94-177 Was Passed in 1994	
	Rule Modification	**New Rule or Requirement**
14. Shutting-in Wells	None	New Form 5 – Completed Interval Report
		New Form 6 – Well Abandonment Report
		Mechanical Integrity Test for wells shut-in longer than six months.
15. Recompleting a Well	None	New remedial cementing requirements
16. Plugging and Abandoning a Well	None	New Form 6 - Well Abandonment Report
		Identification of a preferred plugging cement slurry method required
17. Final Well Site Reclamation	Modified Time Requirements for Reclamation	New Requirements to notify and consult with surface owners regarding reclamation of sites
		New Requirements for site investigation, remediation and closure
		New requirements for compaction alleviation, restoration and revegetation of well sites and access roads
		New reclamation requirements for pit closures

Life Cycle Analysis

After the regulation review was complete, Hazen and Sawyer developed a very detailed survey and conducted in-person interviews to collect compliance and operational cost data over the life cycle of a well both pre- and post- SB 94-177. The survey was then administered to small, medium and large operators who have oil and gas operations in one of four Colorado locations. The results were organized into an Excel spreadsheet for further analysis. In order to perform a consistent and relevant comparison, all cost data were converted into 1999 dollars using the U.S. GDP deflator.

Completed surveys and interviews from nine companies regarding the cost of oil and gas operations in Colorado were obtained. Of the nine companies surveyed, four are considered small, four medium, and one large in size. Although nine companies participated, not all participants completed each section of the survey. This was due to the following reasons:

- Not all companies participate in each stage of the life cycle (e.g., drilling companies do not operate wells);
- Companies have not experienced certain stages of the life cycle (e.g., wells are still operating and are not in need of final reclamation); or
- There was a lack of data on the cost of a particular life cycle stage.

Results of the Life Cycle Cost Analysis of Wells Both Pre- and Post- SB 94-177

The financial impacts of rule changes resulting from SB 94-177 are provided in Table ES-2. Column 1 of Table ES-2 shows the different stages of a well that were examined. Column 2 summarizes the change in average real cost in 1999 dollars at each stage of the well life cycle for small, medium, and large companies. For this analysis, large and medium companies were combined into one group because there is only one large company in the sample. For most stages, the cost is reported on a per well basis. However, there are some stages that are not reported on a per well basis such as the pit inventories, reporting requirements, and flowlines. Column 3 indicates the likelihood that the change in average cost per life cycle stage can be attributed to changes in Colorado's Oil and Gas Rules and Regulations.

Operational and regulatory costs of oil and gas operations have been changing in Colorado between 1994 and 2000. A survey based solely on costs could hide or magnify any impact that changes in regulations have had on the cost of oil and gas operations. Throughout the survey and interviews, Hazen and Sawyer has identified where possible the stages of the life cycle that have experienced significant changes in cost and whether the changes in oil and gas rules and regulations have played a part in these cost changes. The results are discussed below and summarized in Table ES-2.

For small companies the largest increase in real cost between 1994 and 2000 was for well recompletion and pit inventories. On average, the recompletion process has increased average cost per well by $24,614. Additionally, requirements for a one time pit inventory and subsequent closure, repair or replacement of pits (not reported by well) cost small companies on average $12,681. Small operators also reported increases in real cost per well between 1994 and 2000 for: Well Site Development ($3,434), Final Reclamation ($3,257), Interim Reclamation ($3,132 - $2,787), Shutting in a Well ($1,802), Plugging and Abandonment ($1,794) and Production Reporting ($1,086). Small operators experience additional cost increases for the Application for Permit to Drill (APD) process, Notice and Consult and Rig Moves and Set-ups that were under $1,000 per well.

Table ES-2
Summary of Financial Impacts of Rule Changes Resulting from SB 94-177

Well Life Cycle Stage	Average Change in Real Cost per Well of Each Life Cycle Stage between 1994 and 2000 by Size of Companies Surveyed (1999$)		Likelihood that Regulatory Changes have Impacted Real Cost of Each Life Cycle Stage	
(1)	(2)		(3)	
	Small	Medium and Large	Small	Medium and Large
1. APD Process	$244	$70	Significant	Significant
2. Posting Financial Assurance[1]	Small Increase	Small Increase	Low	Low
3. Notice and Consultation:				
Notice and Consult	$469	$1,130	Moderate	Moderate
Surface Owner Agreement	$147	$382	Low	Low
Surface Damage Payment	$585	$813	Low	Low
4. Building Well Site Locations and Access Roads:				
Rig Moves and Set Up	$97	$0	Indeterminate	Indeterminate
Well Site Development	$3,434	-$3,697	Moderate to Significant	Low
5. Preparing Application for a Pit to Accept Produced Water:				
Pit Inventory[2]	$12,681	$278,188	Significant	Significant
Pit Permitting	Insufficient data	Insufficient data	insufficient data	insufficient data
6. E&P Waste Management:				
Exploration Waste	See results for interim reclamation			
Production Waste	$911	-$581	Moderate	Low
7. Drilling, Casing and Completing a Well	see location scenarios			
8. Safety Requirements	Insufficient data	insufficient data	insufficient data	insufficient data
9. Flowlines[2]:				
Installation	8% increase	6% increase	Moderate	Low
Testing	$552	$368	Moderate	Low
Maintenance	-$194	$213	Low	Low
Reclamation	$34	$367	Moderate	Low
10. Interim Reclamation:				
Crop Lands	$3,137	-$246	Significant	Low
Non-Crop Lands	$2,787	-$28	Significant	Low
11. Production Reporting[2]	$1,086	$9,368	Significant	Significant
12. Shutting-in a Well	$1,802	$263	Moderate	Moderate
13. Recompletion	$24,614	$56,359	Low	Low
14. Plugging and Abandonment	$1,794	-$282	Low	Low
15. Final Well Site Reclamation:				
Crop Lands	$135	$1,259	Significant	Moderate
Non-Crop Lands	$3,257	$2,690	Significant	Moderate

[1] *The average change in cost was not reported due to significant differences in operations.*
[2] *Not reported on a per well basis. Pit inventory and production reporting costs are reported per company. Flowline installation cost is reported per flowline.*

Review of data and information collected from the survey appears to indicate that changes in some of the rules and regulations pertaining to oil and gas exploration and development have increased real costs to small operators. From Column 3 in Table ES-2, changes in rules and regulations have played a significant role in the cost increases to small operators associated with the Pit Inventories, Interim and Final Reclamation and Production Reporting. Additionally, the rule changes have likely played a moderate to significant role in the cost increases associated with Well Site Development. There is also a significant likelihood that rule changes have caused an increase in the APD process although the absolute cost change for the stage is quite low ($244 per well). An interesting insight that came up during the interviews is that the rules and regulations did not play a significant role in increasing costs associated with recompleting a well. Here, operators indicated the cost increase is mainly due to changes in technology and labor issues.

The changes in cost for the different stages of a well have been somewhat different for medium and large companies compared to small companies. For instance, large and medium sized companies have experienced a decrease in the average real cost for three well life cycle stages including: Production Waste Management, Plugging and Abandoning a Well, and Interim Well Site Reclamation. Much of the decrease in average cost for these three stages can be attributed to companies reducing the size of their well site locations. This reduces the cost to develop and reclaim disturbed areas. Companies have also experienced a cost savings in waste disposal costs through increased recycling methods that reduce the amount of waste fluids used and/or produced during drilling and production stages.

Large and medium sized companies also reported an increase in cost associated with Pit Inventories ($278,188), Well Recompletion ($56,359), Production Reporting ($9,368), the Notice and Consult Process ($1,130) and Final Well Site Reclamation ($2,690 - $1,259). Changes in rules and regulations have had a significant impact on cost increases for the Pit Inventory Process, and Production Reporting. Like small operators, it does not appear that changes in rules and regulations have played a part in the significant change in costs associated with Well Recompletion.

Surface Location Scenarios

This study also examined the cost to comply with COGCC Rules and Regulations, both pre- and post- SB 94-177, for each of the following location scenarios:

- **Scenario 1** - A well located in a relatively level pasture in Yuma County;
- **Scenario 2** - A well located in rural residential non-crop land in LaPlata County in Southwest Colorado;
- **Scenario 3** - A well located in high-valued agricultural crop lands in Weld County, Colorado, in the Fox Hills Aquifer Protection Area; and
- **Scenario 4** - A well located in a High Density Area as defined in the COGCC Rules and Regulations in or near a municipality in Weld County, Colorado.

The results of this analysis are discussed below.

Cost Change Under Scenario 1 – A Well Located in Yuma, County Colorado

Three companies that operate in Yuma County completed the survey. The analysis of data collected from these three companies is summarized in Table ES-3.

Table ES-3
Summary of Cost Changes and Regulatory Impacts for Surface Location Scenario 1
Well Located in Yuma County, Colorado

Well Life Cycle Stage	Average Change in Real Cost per Well at Each Life Cycle Stage between 1994 and 2000 for Operations in Yuma County (1999$)	Likelihood that Regulatory Changes have Impacted Real Cost of Each Life Cycle Stage
(1)	(2)	(3)
1. APD Process	$431	Significant
2. Posting Financial Assurance[a]	$1,419	Low
3. Notice and Consultation:		
Notice and Consult	$368	Moderate
Surface Owner Agreement	$365	Low
Surface Damage Payment	$399	Low
4. Building Well Site Locations and Access Roads:		
Rig Moves and Set Up[b]	$276	Low
Well Site Development	$538	Moderate to Significant
5. Preparing Application for a Pit to Accept Produced Water:		
Pit Inventory[a]	$13,353	Significant
Pit Permitting	Insufficient data[d]	Insufficient data[d]
6. E&P Waste Management:		
Exploration Waste	See results for interim reclamation	
Production Waste	$35	Low
7. Drilling, Casing and Completing a Well[c]	-$1,226	Moderate
8. Safety Requirements	Insufficient data[d]	Insufficient data[d]
9. Flowline Installation ($/ft)[a]	-$0.19	Low
12. Interim Reclamation:		
Crop Lands	$1,053	Significant
Non-Crop Lands	$619	Significant
13. Production Reporting[a]	$4,718	Significant
14. Shutting-in a Well	$698	Moderate
15. Recompletion[b]	-$12,798	Low
16. Plugging and Abandonment	-$111	Low
17. Final Well Site Reclamation:		
Crop Lands	$3,570	Significant
Non-Crop Lands	$5,914	Significant

[a] Not reported on a per well basis. Posting Financial Assurance, Pit Inventory and Production Reporting costs are reported per company. Flowline Installation cost is reported per flowline.
[b] Only one company reporting.
[c] Costs are highly dependent on well depth that ranges from 2,500 to 6,000 for the three respondents who operate in Yuma County.
[d] No companies operating in Yuma County responded to questions regarding pit permitting or safety requirements.

Six life cycle stages had cost changes greater than $1,000 per well between 1994 and 2000 for operations in Yuma County including Posting Financial Assurance, Pit Inventories, Interim and Final Well Site Reclamation, Production Reporting, and Recompletion. There is a significant likelihood that rule changes have caused cost increases in four of the six stages. These stages are Pit Inventories, Interim and Final Well Site Reclamation, and Production Reporting. The fifth stage to show a significant change in cost was Recompletion. However, unlike the other life cycle stages where cost increases occurred, the analysis indicated a significant cost decrease associated with recompleting wells in Yuma County which is not due to changes in the rules and regulations. However, only one company reported the cost of recompleting wells in Yuma County.

Cost Changes Under Scenario 2 – A Well Located in La Plata County, Colorado

One company that operates in LaPlata County responded to the survey regarding cost of their operations. The results are summarized in Table ES-4. Several interesting insights are apparent when examining Table ES-4. First, this company has experienced a reduction in average real cost for three well life cycle stages including Well Site Development and Interim and Final Well Site Reclamation. For all three stages, average real costs have decreased because the company reduced the size of their well site locations. This resulted in a reduction in development and reclamation costs.

Average real costs increased by more than $1,000 per well for a well in La Plata County for Surface Owner Agreements, Surface Damage Payments, Rig Moves and Set-ups, Pit Inventories, Production Waste Disposal, Drilling and Completing a Well and Recompletion. While this company experienced cost increases at several stages of the well life cycle, this company reported that changes in Colorado’s Oil and Gas Rules have had little impact. The changes in rules and regulations have likely had a significant impact on cost increases for the APD process and the mandatory pit inventory. However, the cost increase associated with the APD process has been quite minimal at $322 per well between 1994 and 2000. The cost of preparing a pit inventory was $13,353 for this company. The pit inventories represent a one-time cost for the company and are not reported on a per well basis.

Additionally, it is likely that changes in rules and regulations had a moderate impact on the cost associated with the surface owner notification process. Most operators, including the operator in LaPlata County, have indicated an increased tension between surface owners and operators. As a result, operators are spending more time in negotiations with surface owners regarding Surface Owner Agreements (SOAs) and damage payments. In La Plata County, SOA costs and surface damage payments have increased. Changes in rules and regulations have increased the rights of surface owners regarding oil and gas exploration and production operations. While these changes have not directly addressed the SOA costs or damage payments, they have increased the awareness of surface owners and may have indirectly impacted the negotiations between operators and surface owners. Therefore, it is concluded that the change in rules and regulations had a moderate impact on the notice and consultation stage of the well life cycle.

Table ES-4
Summary of Cost Changes and Regulatory Impacts for Surface Location Scenario 2
Well Located in LaPlata County, Colorado

Well Life Cycle Stage	Average Change in Real Cost per Well of Each Life Cycle Stage between 1994 and 2000 for Operations in LaPlata County (1999$)	Likelihood that Regulatory Changes have Impacted Changes Cost of Each Life Cycle Stage
(1)	(2)	(3)
1. APD Process	$322	Significant
2. Posting Financial Assurance[a]	No change	NA
3. Notice and Consultation		
Notice and Consult	$678	Moderate
Surface Owner Agreement	$2,712	Moderate
Surface Damage Payment	$1,896	Low
4. Building Well Site Locations and Access Roads:		
Rig Moves and Set Up	$1,356	Low
Well Site Development	-$20,890	Low
5. Preparing Application for a Pit to Accept Produced Water:		
Pit Inventory[a]	$4,033	Significant
Pit Permitting	Insufficient data	Insufficient data
6. E&P Waste Management:		
Exploration Waste	See results for interim reclamation	
Production Waste	$3,904	Low
7. Drilling, Casing and Completing a Well[b]:	$11,007	Moderate
8. Safety Requirements	insufficient data	insufficient data
9. Flowline Installation ($/ft)[a]	$0.35	Low
12. Interim Reclamation:		
Crop Lands	-$2,988	Low
Non-Crop Lands	-$2,988	Low
13. Production Reporting[a]	No change	NA
14. Shutting in a Well	$384	Moderate
15. Recompletion	$146,625	Low
16. Plugging and Abandonment:	$662	Low
17. Final Well Site Reclamation:		
Crop Lands	-$1,612	Low
Non-Crop Lands	-$1,612	Low

[a] *Not reported on a per well basis. Posting Financial Assurance, Pit Inventory and Production Reporting costs are reported per company. Flowline installation cost is reported per flowline.*
[b] *Based on preliminary drilling cost data.*

The LaPlata County operator also reported a significant average real cost increase associated with recompleting a well. The operator indicated the cost increase was primarily due to changes in technology and increasing labor costs and is not attributed to changes in Colorado's Oil and Gas Rules and Regulations.

Cost Changes Under Scenario 3 – Fox Hills Protection Area

A section of the survey specifically asked participants questions regarding their experience drilling in the Fox Hills Protection Area. Wells located in this area must comply with COGCC's Rule 317A which requires operators to increase the depth of surface casing of wells drilled in the Fox Hills Protection Area. The increased casing requirements have added significant costs to wells as summarized in Table ES-5.

Table ES-5
Change in Average Cost of Drilling Due to Increased Casing Requirements in the Fox Hills Protection Area Rules

Survey	Total Cost per Well to Drill in Fox Hills Protection Area (1999$)		Additional Cost per Well to Drill in the Fox Hills Protection Area (1999$)	Average Percentage Increase in Cost per Well to Drill in Fox Hills Protection Area
	Since 1994	Prior to 1994		
1	NA	NA	NA	NA
2	$16,907	$5,294	$11,613	219%
3	$13,697	$3,899	$9,798	251%
7	NA	NA	NA	NA
Average Cost Per Well for Small Companies	***$15,302***	***$4,597***	***$10,706***	***233%***
4	NA	NA	NA	NA
5	$9,784	$11,140	-$1,357	-12%
6	$14,676	$5,013	$9,663	193%
8	NA	NA	NA	NA
9	$8,806	$7,798	$1,007	13%
Average Cost Per Well for Medium and Large Companies	***$11,088***	***$7,984***	***$3,104***	***39%***
Average Cost Per Well for All Companies Surveyed	***$12,774***	***$6,629***	***$6,145***	***93%***

Two small operators reported average costs associated with drilling wells in the Fox Hills Protection Area both pre- and post- SB 94-177. Both small operators reported an increase of over 200 percent in the average cost associated with increased surface casing requirements. This added an estimated $10,700 per well to drilling operations for these operators. The cost increase was not as significant for medium and large companies who reported an average increase in cost of 39 percent due to the surface casing requirements. Large and medium operators indicated that well costs have increased on average by $3,100 per well due to the increased casing requirements.

Overall, all companies except one reported a significant increase in the cost to drill in the Fox Hills Protection Area. All of the cost increase can be attributed to the rule change that requires operators to run surface casing to a minimum of 5 percent of total well depth. Respondents indicated they have been required to increase the depth of surface casing from 200 to 500 feet prior to SB 94-177 to 500 to 1000 feet under the new rule. Surface casing normally costs $18 to $20 per foot. Thus, this requirement can and does increase well drilling costs in this area.

Cost Changes Under Scenario 4 – High Density Areas in Weld County, Colorado

Scenario 4 is defined as a well located in a high-density area in or near a municipality in Weld County. The cost analysis of wells located in high density areas considered the compliance and operating costs associated with 17 specific rules promulgated under COGCC's Rule 603.

At this time, none of the participants surveyed and interviewed were able to report cost information on the specific requirements for operations in high-density areas. This is due to two reasons. First, several of the companies surveyed do not operate in high-density areas. Second, of the companies that do operate in high-density areas, they were unable to separate the cost of specific high-density rules.

While no data were collected to indicate how the change in high-density rules has affected the average real cost of drilling oil and gas wells in these areas, some information was obtained during the interviews. Companies operating in high-density areas indicated that operating in these areas, especially along the Front Range, is becoming increasingly difficult. This is not necessarily due to regulatory requirements placed on operators by COGCC, but due to the increasing requirements of local governments. In many areas, operators need to obtain special use permits from counties or municipalities to drill wells which adds another layer of regulation to these operations.

Many of the small operators interviewed indicated that they are no longer looking to operate in areas that may be designated as high density. This is due to the increased requirements of oil and gas operations in these areas. There is also a concern among small operators that drilling in high-density areas increases their risk and liability. Smaller companies appear unwilling to take on these risks at this time.

Analysis of Cost of Compliance for Rule 508

Hazen and Sawyer evaluated the cost of compliance with *Rule 508 – Local Public Forums, Hearings on Applications for Increased Well Density and Public Issues Hearings*. Rule 508 addresses Local Public Forums, COGCC Hearings and Public Issues Hearings as they apply to applications for increased well density.[2] Rule 508 is initiated when an application is made to the COGCC to create a new drilling unit or request additional wells within an existing drilling unit that were not previously approved by COGCC. According to this rule, COGCC requires a Public Forum to consider input from local governments and the public on the potential impacts to the

[2] *Colorado Oil and Gas Conservation Commission, Rules and Regulations, Rule 508 – LOCAL PUBLIC FORUMS, HEARINGS ON APPLICATIONS FOR INCREASED WELL DENSITY AND PUBLIC ISSUES HEARINGS, July 30, 1998.*

environment, public health, safety and welfare from increased well density in a particular area. A COGCC Hearing will take place following a Public Forum to address the technical merits of an application. Upon conclusion of the COGCC Hearing, COGCC can order a Public Issues Hearing at the request of the applicant or a local government representative or at the discretion of COGCC. A Public Issues Hearing will be granted if the local government representative raises issues regarding the impacts of an application to the environment, public health, safety or welfare. Upon conclusion of the Public Issues Hearing, COGCC can approve the application with certain conditions that address concerns raised in the hearing, approve the application and stay its effective date to further address public concerns regarding the application, and/or deny the application.

A separate survey instrument was developed for Rule 508 so all operators who have participated in this process could be surveyed and interviewed. As of August 2000, COGCC has initiated and completed nine 508 Processes regarding well density applications in Colorado. Seven different companies have participated in this regulatory process. The 508 survey was sent in June 2000 to all seven companies that have participated in the process. Three of the seven companies have returned the written survey while two companies responded verbally regarding their experience. The results are summarized in Table ES-6.

The first two survey respondents participated in the 508 Process in 1999 and completed the Local Public Forum and the COGCC Hearing on their application for increased density. In both cases, a Public Issues Hearing was not required and thus these companies did not report any costs associated with this stage of the 508 Process. Both companies reported similar costs for the Local Public Forum of $4,500 and $4,238, respectively. However, Respondent 2 reported a higher cost for the COGCC Hearing. These companies reported that the process did not present a hardship to their operations, and one company indicated they thought the process and COGCC were quite helpful in educating the public to understand the issues related to their application.

Table ES-6
Estimated Cost of the 508 Process – Local Public Forums, Hearings on Applications for Increased Well Density and Public Issues Hearings

Survey Number	Estimated Cost of Local Public Forum	Estimated Cost of COGCC Hearing on Application	Estimated Cost of Public Issues Hearing	Total Estimated Cost of the 508 Process
1	$4,500	$2,750	NA	$7,250
2	$4,238	$4,128	NA	$8,366
3	$28,000	$56,100	$66,000	$150,100
4	NA	NA	NA	$772,425

Respondent 3 completed the 508 Process in 2000. The application was for a change in well spacing in LaPlata County. The company reported that the total cost of this process was $150,100. This includes $28,000 for the Local Public Forum, $56,100 for the COGCC Hearing and $66,000 for the Public Issues Hearing.

Respondent 4 provided the project team with a cost itemization for a 508 Process that was completed during 2000 for an application in Garfield County. The total cost of this particular process was estimated at $772,000, which included all outside consultants and legal services as well as in-house costs. In this particular case, the respondent was asked to complete a Local Public Forum, a COGCC Hearing and a Public Issues Hearing. The cost data provided by this company was not itemized by each stage of the 508 Process as was provided by the other respondents.

A fifth company responded to the 508 survey questions during an interview regarding the more detailed survey on well life cycle cost. This company went through the process in 1999 for an application to increase well spacing in eastern Colorado. The company representative indicated that actual costs of the process were difficult to estimate. However, he felt the cost to complete the process was minimal and, at most, took two or three days of staff time to complete. He also indicated that the 508 Process was generally not a significant issue in eastern Colorado and, therefore, had not caused a significant cost to his company in terms of time or money to complete the 508 Process.

The cost of the recently completed 508 Processes is significantly higher than those reported for forums and hearings completed in earlier years. There are two possible reasons for this phenomenon. First, the cost to complete this process is highly correlated with the location in Colorado where the application for changes in well spacing is to occur. Certain areas in Colorado have become significantly contentious regarding certain types of development, including oil and gas development. In these cases, companies are allocating more resources to address public concerns regarding impacts of their operations. Second, it appears that, as time goes on, public awareness of the 508 Process may be increasing. It is likely that companies can expect more public involvement in the 508 Process, which can lead to increasing costs for well spacing application approvals.

Insights from Comparison of Oil and Gas Rules and Regulations in the Four States

Colorado's oil and gas regulations were compared to those in the states of New Mexico, Wyoming and Utah. Upon review and comparison of rules and regulations in the four states, several insights were apparent. These insights are as follows.

1. Wyoming, Utah and New Mexico rely on a more flexible set of rules and regulations that are interpreted at the discretion of Directors and staff.

Upon review and comparison of rules and regulations in the four states, it became apparent that Colorado has chosen to use a system which establishes specific statewide standards that must be met by all operators throughout Colorado. While there are situations where standards are varied for different parts of the state (e.g., Fox Hills Protection Area) there are many other examples where standards are applied equally across all locations and operators. For example, operators are required to meet safety standards, pit requirements, reclamation standards in all parts of the state. This is in contrast to the other states, which rely more on Director and staff discretion when establishing requirements at various locations around their states or at individual drill site locations.

2. Colorado has established rules and regulations regarding many issues that are not addressed in the rules and regulations of the other states.

Since passage of SB 94-177, Colorado has enacted several new rules and regulations that are not addressed by the other states. These include Surface Owner Protection, Financial Assurance, High Density Rules, Flowline Regulations and Interim Well Site Reclamation Requirements. It is likely that some of these rules, especially high-density requirements, are due to public pressures and concerns associated with Colorado's increasing population. The other states have not experienced population pressures as great in the 1990s as has been common throughout Colorado. Therefore, it is expected that complaints by the public against oil and gas operations would be more prevalent in Colorado versus the other states evaluated. COGCC is thus more likely to respond to these concerns with increased requirements to protect public health, safety and welfare.

3. Colorado has established more surface owner rights and public involvement than other states.

Colorado has deviated from the other states by establishing a series of surface owner rights and public involvement requirements covering many areas of a well's life cycle. For instance, operators are required to consult with surface owners prior to drilling a well (Notice and Consult and Financial Assurance Requirements), for spill notification and prior to final well site reclamation. Additionally, Colorado established the 508 Process that requires public input on issues related to public health, safety and welfare associated with changes in well spacing requirements. While other states do have provisions that require public hearings on certain issues related to oil and gas operations, their requirements are not as extensive as those in place in Colorado.

4. Colorado appears to mandate public involvement while the other states encourage more voluntary cooperation between surface owners and operators

Another issue related to this subject is that some of the other states encourage cooperation between oil and gas operators and surface owners regarding impacts and damages of oil and gas operations and mitigation strategies to avoid damages or compensate owners. For instance, Utah encourages the use of Surface Owner Agreements between operators and surface owners, which address owner concerns. If there is not an agreement between surface owners and operators, the Division will complete an inspection of the site prior to approving final reclamation and the surface owner is invited to attend. In this case the regulators encourage cooperation between the parties and only get involved when an agreement is not reached.

5. Other states have some ability to coordinate local government involvement while Colorado's more autonomous local governments tend to add their own requirements for drilling approval.

Another difference between the other states and Colorado is that, in some cases, the other states try to assist local governments in expressing their concerns regarding oil and gas operations. States such as Utah have organized a Natural Resource Development Committee that consists of local government representatives. This committee has the right to comment on drilling applications and represents local government interests. In Colorado, many local governments are becoming more involved in the regulation of oil and gas operations and appear to be more autonomous than local governments in other states. Oil and gas companies have indicated that this is adding time and costs to their operations, along with another layer of regulation. While it may be possible to coordinate different levels of government involvement in the other states, it is not apparent that this would be possible in Colorado given the difference between the state and local government regulatory authorities over various siting and production issues.

Impacts of Oil and Gas Regulations on Future Oil and Gas Exploration and Development in Colorado

There are some important insights that can be gained from the survey and interviews which provide some indication of how the industry is and will be impacted by regulations in the future. The inferences drawn from this study are as follows.

- **Oil and Gas Rules and Regulations implemented after passage of SB 94-177 have had differing cost impacts among companies depending on their size. Small companies have tended to see larger cost increases than medium and large sized companies.**

Throughout the survey and the interviews, there appeared to be a difference of opinion between small and medium to large companies on the cost impact of changes in Colorado's Oil and Gas Regulations due to SB 94-177. In general, small companies reported greater increases in the average cost of drilling and production associated with changes in rules and regulations. The opposite was true for medium and large companies, which in general, indicated that the changes in rules and regulations have not had a significant impact on costs. Many of the large and medium sized companies indicated that they had voluntarily implemented many of the requirements prior to the 1994 rule change. Therefore, it is likely that these companies would not realize a cost impact due to changes in the rules after SB 94-177.

Additionally, companies of different sizes may be impacted differently by changes in regulations based on their ability to absorb and/or reduce regulatory costs. For instance, it is likely that medium and large companies are more likely to be able to absorb higher regulatory costs than smaller companies. Additionally, medium and large companies may be able to implement operational changes that reduce the impacts of increased regulatory requirements. For example, companies may be able to avoid increased reclamation costs (required by new regulations) by reducing the size of the drill pad locations.

- **Small companies have indicated they are avoiding areas that increase their cost and liability. This includes high-density areas, the Fox Hills Protection Area and areas that involve secondary water production.**

Many of the small operators that were surveyed and interviewed indicated they are now deliberately avoiding drilling in areas that are perceived to increase cost or liability for their operations. This includes high-density areas, the Fox Hills Protection Area, and areas that have secondary water production. Regulatory requirements and liabilities have increased since 1994. For instance, some small companies indicated that the disposal of drilling and production fluids might lead to future liabilities as has happened at a disposal site in Weld County. This site and all companies that have used the facility for disposal are subject to an investigation on disposal practices. Some of the smaller operators indicated they would rather avoid areas with secondary water production to reduce potential liability. Therefore, small companies may prefer to avoid drilling and producing in these areas given the higher cost of compliance since SB 94-177 and the perceived assessment of increased liability that these areas possess.

The increase in cost associated with the new rules and regulations may thus be playing a part in the consolidation or reduction in the number of small companies that are drilling or operating in basins within Colorado. Such is the case in the Denver-Julesburg Basin, which has realized a reduction in the number of small companies that are operating in this area. The reduction in drilling operations and service companies has contributed to increasing costs of services used by the remaining small companies, which has compounded the cost increases in these areas. While it is not inferred that the rules and regulations are completely responsible for cost increases to small operators, they may be playing a part in the decision of small companies to cease operations. It is likely that this trend will continue in the future.

While the number of companies drilling and operating in the state may be decreasing, this does not imply that the number of wells and the amount of oil and gas produced in the state are decreasing. However, it appears that the large and medium sized companies in Colorado will carry out future oil and gas production in the state instead of small companies.

Recommendations

The analysis presented here evaluates the financial impacts of changes in Colorado's Oil and Gas Regulations after passage of SB 94-177. Additionally the study compares Colorado's Oil and Gas Rules and Regulations with those in place in New Mexico, Wyoming, and Utah. From the results of this study, Hazen and Sawyer proposes recommendations to be considered by the Colorado Department of Natural Resources and the Colorado Oil and Gas Conservation Commission. These recommendations are as follows.

1. Evaluate the flexibility of Oil and Gas Rules and Regulations used in Colorado.

As discussed in Section 7.0 of this report, Colorado's Oil and Gas Rules and Regulations have developed around a traditional standards-based format. In other words, COGCC has continued to draft standards that must be met by operators regardless of the size of operations or differences in site locations. This type of system tends to offer certainty and administrative ease through the use of regulatory penalties that all operators are meeting a set target in terms of environmental protection. However, numerous studies have shown that this type of system is inflexible and can be economically inefficient.

Inflexible regulations have a number of potentially negative impacts. The regulations fail to take into consideration differences in location characteristics (e.g., statewide reclamation standards).

The regulations offer no incentives for companies to employ methods or technologies that go beyond standards set by the regulations. When COGCC specifies certain technologies for implementing regulations, such as the specific cement slurry for plugging or indicating four ways for disposal of produced water, it does not allow for potentially lower cost options that may also improve environmental quality. Finally, standards can be quite inflexible, contradictory and costly for operators. For example, reclamation regulations require both eliminating noxious species and revegetating the well-site area. This is often difficult since the extermination spray used on noxious weeds also hinders the growth of indigenous species. Colorado DNR and COGCC should continue to evaluate all parts of the regulatory system to determine if there are other methods that can be employed that would insure protection of public heath, welfare and safety in a more cost efficient matter.

2. Evaluate the apparent differential impact of Oil and Gas Regulations on small operators and determine if policies can be implemented to reduce harmful impacts to small operators.

Colorado DNR and COGCC should continue to evaluate the apparent differential impact of Oil and Gas Rules and Regulations on small-sized companies. Throughout the surveys and interviews, small operators reported greater increases in cost associated with new rules and regulations passed since SB 94-177 than medium and large size companies. Policies can be implemented that help small companies come into compliance with new regulatory requirements. For example, this could include extending regulatory time periods and providing training programs and/or expert advice on specific regulatory issues for smaller companies**.**

3. Encourage cooperation between surface owners and oil and gas operators

Colorado DNR and COGCC should continue to promote sensible cooperation between surface owners and operators. There are indications that changes in certain rules and regulations have contributed to surface owners becoming more involved in the regulatory process. The interaction of surface owners and operators should be encouraged to establish requirements and expectations for operators prior to commencing drilling and production operations and to explain the process to the affected surface owners. Efforts should be made to establish working rules that encourage surface owners and oil and gas operators to use Surface Owner Agreements where possible in a timely, cost effective manner. Regulatory agencies should avoid becoming directly involved in this process if possible or hindering the ability of these parties to reach reasonable agreements.

4. Continue to improve the cost-effectiveness of methods and processes that encourage public comment and involvement in the regulation of oil and gas operations.

Efforts should be taken to improve the process by which public comment is encouraged regarding oil and gas operations in Colorado. This is especially true for the 508 Process, which may become increasingly more costly for operators and COGCC to complete and administer. Regulators should continue to balance the cost of this process with the benefits. It appears that the 508 Process could cost some companies in excess of $100,000 to complete; and this amount may be increasing. However, a couple of the operators have asserted that the 508 Process provided a beneficial avenue through which the operators could educate the public about their technology and explain the needs for changes in well spacing requirements. Additionally, these operators also benefited from understanding the public's concerns and issues and could address them early in the process prior to potential litigation. However, it should be noted that the costs of complying with the 508 Process in specific locations have been significant.

Colorado DNR and COGCC should evaluate this system to ascertain whether the regulatory goals and benefits of this process are worth the administrative costs to the agency as well as the potential loss of revenue from oil and gas operators no longer operating in those locations. Colorado DNR and COGCC should examine if a more cost effective method can be developed and implemented which meets the public input needs for changes in well spacing.

5. Evaluate methods to coordinate local government comment and local regulations.

Efforts should be undertaken to improve the relationship between COGCC and local governments to avoid overlapping regulations that impact oil and gas operations in the state. More and more local governments are beginning to regulate oil and gas operations within their jurisdiction even though they may not have the staff or expertise to properly analyze the impacts of such mining operations on their constituents. These additional conditions of approval imposed by local governments are oftentimes unanticipated by the oil and gas operators and increase the regulatory uncertainty of drilling in the area. COGCC can play a role in either educating local agencies on technical issues related to oil and gas operations or assuring these agencies that state requirements protect local jurisdictions from harmful impacts. COGCC might want to consider some sort of systematic process where local governments can have limited input throughout the process, which would be monitored by the state. These actions would certainly help to eliminate overlapping regulatory requirements that may not be improving public health, safety and welfare of local lands; they may also increase the regulatory certainty for operators and reduce unanticipated conditions for approval.

6. Continue to evaluate the benefits and costs of Oil and Gas Rules and Regulations and the impacts on small, medium and large companies as the first step to achieve a cost-effective and fair regulatory program.

Finally, Colorado DNR and COGCC should continue to evaluate the benefits and costs of their regulations relevant to oil and gas operations. This exercise is necessary to determine the effectiveness of each regulation in meeting its stated regulatory goal as well as evaluating the impact of the requirement on operations. There may be lags involved with regulatory implementation that affect when parties realize the benefits and costs of regulations. These lags can be evaluated over time with regulatory reviews and analysis. Regulatory regimes are dynamic institutions that must evolve with changes in environmental conditions, economic conditions and public opinion. Colorado DNR and COGCC have a unique opportunity to help the regulatory process develop in a manner that is cost efficient while meeting the goal of protecting public health, welfare and safety.

1.0 Introduction

Hazen and Sawyer was retained by the Colorado Department of Natural Resources (DNR) to conduct an *Economic Comparison of the Rules and Regulations of the Colorado Oil and Gas Conservation Commission (COGCC).* The study was authorized by the Colorado State Legislature to investigate the impacts of significant rule changes following the passing of Senate Bill 94-177 in 1994. The intent of this legislation was stated as follows:[1]

> "It is declared to be in the public interest to foster, encourage, and promote the development, production and utilization of the natural resources of oil and gas in the state of Colorado IN A MANNER CONSISTENT WITH THE PROTECTION OF PUBLIC HEALTH, SAFETY AND WELFARE …"

Several goals for this project were established in the Request for Proposal and are as follows:

- Perform a study of the costs of compliance with COGCC Rules and Regulations, both pre- and post- SB 94-177 over the life cycle of a well;
- Compare the compliance costs both pre- and post- SB 94-177, with the total costs to drill and complete a well in each of the four location scenarios;
- Evaluate the cost of compliance with Rule 508 – Local Public Forums, Hearings on Applications for Increased Well Density and Public Issues Hearings;
- Compare Colorado's Oil and Gas Rules and Regulations with those in Wyoming, New Mexico and Utah; and
- Discuss impacts of the compliance costs on future oil and gas exploration and development work in Colorado.

Hazen and Sawyer first conducted a thorough review of Colorado's current oil and gas regulations as well as those regulations in place prior to 1994. The result of this review was an understanding of the rule changes that were implemented after the passage of Senate Bill 94-177. The results of this regulatory review are discussed in Section 2.0.

After the regulation review was complete, Hazen and Sawyer developed a very detailed survey to collect compliance and operational cost data over the life cycle of a well both pre- and post-SB 94-177. The survey was then administered to small, medium and large operators who have oil and gas operations in one of four Colorado locations. The results of the survey provided cost information that was used to evaluate the compliance and operational costs across the life cycle of a well for wells drilled in Colorado. The data and information collected from the survey was also used to evaluate the financial impact of changing regulatory requirements on small, medium and large operators as well as impacts to future exploration and development in Colorado. The

[1] *Colorado Senate Bill 94-177, 1994.*

steps taken to develop and administer the survey are discussed in Section 3.0. Analyses of the results are provided in Section 4.0.

Hazen and Sawyer developed a second survey to evaluate the cost of compliance with *Rule 508 – Local Public Forums, Hearings on Applications for Increased Well Density and Public Issues Hearings*. The survey was administered to all entities that have participated in this regulatory process. The survey design and results are discussed in Section 5.0.

Section 6.0 presents the results of the comparison of Colorado's Oil and Gas Rules and Regulations in Colorado, Wyoming, Utah and New Mexico. Section 7.0 discusses the potential impacts of compliance cost on future oil and gas exploration and development in Colorado. Section 8.0 summarizes the results of this study and the recommendations for improving the cost effectiveness of Colorado's oil and gas rules and regulations.

2.0 Review of Colorado's Oil and Gas Rules and Regulations Pre- and Post- SB94-177

An in depth review of the relevant oil and gas rules and regulations in Colorado prior to and subsequent to Senate Bill 94-177 was conducted. The rules and regulations were summarized in terms of their potential cost impact on the following segments of a well life cycle:

1. Preparing an Application for Permit to Drill for a well;
2. Posting appropriate financial assurance;
3. Performing notice and consultation with surface owners prior to drilling a well;
4. Preparing an application for a pit to accept produced water;
5. Building surface well site locations and access roads;
6. Drilling, casing and completing a well;
7. Performing interim well site reclamation;
8. Reporting production and payment of COGCC levy during the life of a well;
9. Shutting-in or temporarily abandoning a well for several years;
10. Recompleting a well and commingling production;
11. Plugging and abandoning a well at the end of its useful life; and
12. Performing final well site reclamation.

The results of this task were organized into a *Regulatory Review Document* that was instrumental in preparing the survey instrument used to collect data on compliance and operational costs over the life cycle of a well. The Regulatory Review Document is provided in Appendix A of this Final Report.

Table 2.1-1 provides an outline of the new rules and modifications made to Colorado's Oil and Gas Rules and Regulations resulting from SB 94-177. As summarized in this table, rule additions or modifications impact every stage of the well life cycle.

Table 2.1-1
Summary of Rule Changes and Modifications to Colorado Oil and Gas Rules and Regulations after Passage of Senate Bill 94-177

Well Life Cycle Stages	New Rules or Modifications Since SB 94-177 Was Passed in 1994	
	Rule Modification	New Rule or Requirement
1. Application for Permit to Drill	None	New Form 2A - Predisturbance Assessment (photographs, and soil and plant information)
2. Financial Assurance	Extended Scope of Financial Assurance for Soil Protection, Plugging and Abandonment	Required General Liability Insurance
		Required Seismic Financial Assurance
		Required Natural Gas Gathering Financial Assurance
		Excess Inactive Wells Financial Assurance
3. Notice and Consultation	None	Notice must be given to surface owner and local government designee 30 days prior to drilling a well
4. Building Surface Location and Access Roads	None	Required soil segregation and protection
		Increased fencing when requested by surface owner
5. Application for a Pit to Accept Produced Water	Modification of pit permitting requirements	Required one-time inventory of pits
	Modifications of pit lining requirements	Required *Sensitive Area Determination*
		Permit or close existing pits
		Pits closed after 1997 must comply with new reclamation rules
6. Environmental Requirements	Increased requirements for exploration and production waste disposal	Required application for simultaneous injection wells
	Increased requirements for management and reporting of spills and releases (reporting to Director and surface owners, Site Investigation and Remediation Workplan)	
7. Drilling, Casing and Completing a Well	Increased requirements for Blowout Prevention Equipment (BOPE)	New Form 5A – Completed Interval Report
	Notice of casing repairs must be given to COGCC	Increased logging requirements
	Modification of production casing cementing and testing requirements	
8. Safety	None	New additional safety requirements for seismic operations
9. Flowline Regulations	None	New requirements for construction, maintenance, safety and abandonment of flowlines

Table 2.1-1
Summary of Rule Changes and Modifications to Colorado Oil and Gas Rules and Regulations after Passage of Senate Bill 94-177

Well Life Cycle Stages	New Rules or Modifications Since SB 94-177 Was Passed in 1994	
	Rule Modification	New Rule or Requirement
10. High Density Areas	None	Standards for High Density Area designation
		Increased equipment setbacks, BOPE Requirements, control of fire hazards, trash removal, tank specifications, access roads, well site clearing, fencing requirements, berm construction and guy line anchors.
		Operators must now identify plugged and abandoned wells
11. Fox Hill Protection Area	None	Increased surface casing requirements
12. Interim Well Site Reclamation	None	New requirements for subsidence reclamation, compaction alleviation, drill pit closure and revegetation
13. Reporting	Modified monthly production reporting requirements by well and formation	None
14. Shutting-in Wells	None	New Form 5 – Completed Interval Report
		New Form 6 – Well Abandonment Report
		Mechanical Integrity Test for wells shut-in longer than six months.
15. Recompleting a Well	None	New remedial cementing requirements
16. Plugging and Abandoning a Well	None	New Form 6 - Well Abandonment Report
		Identification of a preferred plugging cement slurry method required
17. Final Well site reclamation	Modified time requirements for reclamation	New requirements to notify and consult with surface owners regarding reclamation of sites
		New requirements for site investigation, remediation and closure
		New requirements for compaction alleviation, restoration and revegetation of well sites and access roads
		New reclamation requirements for pit closures

2.1 Changes in Oil and Gas Rules and Regulations in Colorado According to a Well Life Cycle

A goal of this project was to evaluate the operational and compliance cost of oil and gas operations according to the different stages of a well's life cycle. This section discusses, in detail, the changes in rules and regulations that may have impacted operators costs. The results are organized by the well life cycle stages.

2.1.1 Preparing an Application for Permit to Drill for a Well (APD)

Since SB 94-177, COGCC now requires Form 2A as part of the APD process. Form 2A requires a Pre-Disturbance Assessment that includes a scaled drawing of the proposed well location, current land use, two photographs of location, and soil and plant information. Additionally, the COGCC Director now submits copies of Form 2/2A to a local government who reviews and provides comments to COGCC on the application. Comments from the local designees are submitted to the Director and the applicant within seven days from the submission of Form 2/2A. The new regulations add a stipulation that the Director can extend application review up to ten additional days upon written request from the local government designee. Additionally, if operations do not commence within one year after date of the approval, the permit is null and void. Prior to SB 94-177, applicants were required to submit Form 2, which has approximately the same information as is required now. However, a Pre-Disturbance Assessment (Form 2A), is new since SB 94-177.

2.1.2 Posting Appropriate Financial Assurance

With SB 94-177, financial assurance requirements have increased significantly. There are new financial assurance provisions for general liability insurance, natural gas gathering systems, and seismic operations. Additionally, operators are now required to post additional financial assurance for excess inactive wells. Finally, the provisions for financial assurance for soil protection, plugging and abandonment of wells have increased in scope with the new rule changes.

2.1.3 Notice and Consultation

Often a Surface Owner Agreement is obtained with the surface owners, but is not required under either the old or the new regulations. Prior to SB 94-177, notice was required to be given to the tenant or surface owner not more than 6 weeks and not less than 7 days before commencing earthwork for drilling operations. Under current regulations, operators must try to give notice to surface owners and post a notice at well sites at least 30 days prior to operation. Additionally, notice must be posted on the property, notice must be given to the local government designee, and notice must be given for subsequent well operations. The operator is required under the new regulations to use its best efforts to consult in good faith with the affected surface owner. If requested by the local governmental designee, the operator shall give the governmental designee the opportunity to consult.

2.1.4 Pit Inventory and Permitting

Pit Inventory

The new regulations promulgated since SB 94-177 required operators to submit to the COGCC Director by December 1995; an inventory identifying production pits, buried or partially buried produced water vessels, blowdown pits, and basic sediment/tank bottom pits existing as of June 30,1995. This inventory included water quality data, if it was available. Pits closed prior to December 1997, were to be reclaimed in accordance with the 1000 series rules and were required only to submit a Sundry Notice. Pits closed after December 1997, shall be closed in accordance with the 900 Series Rules and reclaimed in accordance with the 1000 Series Rules.

Pit Permitting

Prior to SB 94-177, COGCC rules required operators to permit all production pits except those that received produced water at an average daily rate of less than five barrels per day calculated on a monthly basis for each month of operation. The rules did not have a provision for drilling pits. The rules required that special production pits, which received more than five barrels of fluids per day should have a permit pursuant to the requirements of the production pits. Additionally, COGCC required special purpose pits used in flaring or venting operations to be properly banked, including provisions for combustible materials.

The most significant change in permitting pits is the *Sensitive Area Determination* requirement. For unlined production pits and special use pits constructed prior to July 1, 1995 and not closed by December 30, 1997, operators were required to conduct a Sensitive Area Determination. COGCC required the use of the Sensitive Area Determination Decision Tree to evaluate the potential impact of existing pits on ground water and submit data and analyses on Sundry Notice Form 4. Additionally, all production pits producing less than five barrels a day were exempted from permitting requirements under prior rules, whereas now the five barrel exemption applies only to unlined production pits outside sensitive areas.

2.1.5 Building a Surface Well Site Location and Access Roads

Prior to 1994, operators were to remove and store soil that would be used in reclamation, though COGCC did not require soil to be segregated. Since SB 94-177, the significant change regarding building the well site location and access roads is that soils must now be segregated and protected on both crop and non-crop lands during operations. Operators must minimize land disturbances. Additionally, access roads must be built to minimize erosion on land affected by oil and gas operations. The modified rules now require operators to fence drill sites, access roads, and/or reserve pits when requested by a surface owner. Prior to SB 94-177, all pumps, pits, wellheads and production facilities were required to be adequately fenced to restrict access by unauthorized persons. Additional provisions that have been added or modified since SB 94-177 include spacing requirements for wells deeper than 2,500 feet and requirements that restrict drill pad locations to non-steep slopes.

2.1.6 Drilling, Casing, and Completing a Well

Since SB 94-177, there have been several changes to requirements for drilling, casing and completing a well. Operators must now file Form 5A, the Completed Interval Report, and all wells must now be logged. There are new standards for production casing cementing and pressure testing. Additionally, the requirements for blowout protection have been modified.

2.1.7 Environmental Requirements

Since SB 94-177, there have been two rule changes including: 1) new provisions for simultaneous injection wells; and 2) new requirements for spills, including surface owner consultation and a Site Investigation and Remediation Workplan. Additionally, modifications were made to rules regarding the handling of exploration and production (E&P) waste.

Spills and Releases

Since SB 94-177, the COGCC has changed their rules regarding the management and reporting of spills and releases. When operators find spills exceeding 5 barrels, they must report the spill or release to the Director on the Spill/Release Report (Form 19) within ten days. The report includes information on initial mitigation, site investigation and remediation. In addition, spills greater than 20 barrels must be reported verbally to the COGCC Director within 24 hours. The new regulations also specify that spills/releases of any size which impact or threaten to impact any waters of the state, residence, or occupied structure, livestock or public byway, should be verbally reported to the Director as soon as practicable after discovery. Prior to SB 94-177, operators reported spills and releases of over five barrels to the Director but no other information was required.

Remediation of Spills and Spill Prevention

Prior to SB 94-177, all spills of E&P waste, crude oil, or water-based bentonitic drilling fluids were required to be remediated immediately but no Site Investigation and Remediation Workplan was required. Since SB 94-177, the COGCC Director may require operators to prepare a Site Investigation and Remediation Workplan (Form 27) if it is determined that the spill or release has caused or threatens to cause significant environmental impact to air, water, soil or other biological resources. A workplan may also be required to ensure that remediation of a spill or release will meet the water quality standards set by the Colorado Water Quality Control Commission. The workplan includes a Sensitive Area Determination, sampling and analysis of soil and groundwater, management of E&P waste, pit evacuation, compliance with water quality standards, and proper reclamation as required by the 1000 Series Rules. Rule 910 establishes allowable soil and groundwater concentrations that must be met by remediation actions. Additionally, a new rule requires operators to make a good faith effort to consult with surface owners before remediation of a spill or release. The Site Investigation and Remediation Workplan is new under the current regulations.

Management of Exploration and Production (E & P) Waste

Rule changes after SB 94-177 require all operators to properly handle, store, treat and dispose of E&P waste so that it does not cause significant impacts to air, water, soil and biological resources. In accordance with the current regulations, produced water must be treated before it is placed in a production pit and disposed of in four specific ways (injection well, evaporation in permitted pit, disposed of at permitted commercial facility or disposal by road spreading) or reused and recycled. Requirements also specify the proper disposal of drilling fluids, water based bentonitic drilling fluids and other oily waste. Prior to SB 94-177, wells producing five barrels or less per day, on average, over a month period, were exempted from the above regulations.

2.1.8 Safety Requirements

Most of the safety requirements have remained the same since SB 94-177. The only significant change affects seismic operations. Although much of the information required to be submitted to the COGCC prior to commencing seismic operations is the same, it must now be submitted on Form 20, the Notice of Intent to Conduct Seismic Operations. The new regulations have additional provisions, including how to store explosives, blasting distances, requirements to avoid unstable soils when saturated, and plugging shot holes to prevent public access.

2.1.9 Flowline Regulations

Prior to SB 94-177 there were no rules or regulations for flowlines. New rules and regulations regarding the construction, maintenance, safety and reclamation of flowlines have been established since SB 94-177 under the 1100 Series Rules. Provisions were included for the design of flowlines, materials and cover used. When excavating, backfilling and/or reclaiming flowline sites, operators must segregate topsoil and protect it against subsidence and erosion. Operators are now required to pressure test flowlines to their maximum anticipated operating pressures before operations can commence. Flowlines should be maintained and repaired to avoid failures, leakage and corrosion. Additionally, operators must repair flowlines to ensure that injuries to persons or damage to property are avoided. Flowlines are required to be properly marked in designated high-density areas or where the flowline crosses a public right-of-way or utility easement. Operators with flowlines are required to participate in the Colorado's One Call notification system. The rules also specify requirements for abandoning and reclaiming flowlines.

2.1.10 High Density Area Rules and Regulations

Prior to SB 94-177, the regulations allowed persons to apply to the COGCC to have any tract of land designated as a high-density area. Additionally there were regulations for high-density areas that included setbacks from occupied buildings (still required after SB 94-177) and requirements for the development of multiple reservoirs (not mentioned in the new regulations).

The new rules and regulations passed after SB 94-177 specify that high-density areas shall be determined by calculating the number of occupied building units within the 72 acre area defined by a 1000-foot radius from the wellhead or production facility. The new regulations have increased the setbacks for production equipment and wellheads as well as increased fencing requirements in high density areas. There are new provisions for encroaching development, BOPE requirements, control of fire hazards, loadlines, removal of surface trash, guy line anchors, berm construction, tank specifications, access roads, and well site clearing (all not included prior to SB 94-177).

2.1.11 Fox Hill Aquifer Protection Area Rules and Regulations

New rules and regulations were developed after SB 94-177 regarding the Fox Hills Aquifer Protection Area located in Weld County. When operating in this area, operators are required to take extra steps to protect the aquifer including the installation of surface casing to a minimum depth of 5 percent of the projected total depth of the well. Additionally, for non-exploratory wells, operators are required to run surface casing to a depth of 50 feet below the Fox Hills transition zones.

2.1.12 Performing Interim Well Site Reclamation

Most of the interim well site reclamation regulations are new since SB 94-177. The additional requirements include subsidence reclamation, compaction alleviation, drill pit closure, and revegetation. The rules and regulations specify that all disturbed areas not needed for production operations should be reclaimed as nearly as practicable to their original condition, including removal of debris and backfilling of bore holes. On crop lands, all guy lines/anchors should be removed and, if left, they should be buried and marked. Additionally, interim reclamation on crop lands should occur no later than 3 months upon completion of drilling and if subsidence occurs, additional topsoil should be added and lands releveled. On non-crop lands, interim reclamation should occur no later than 12 months after drilling is complete.

All areas compacted by the drilling operations which are no longer needed following completion of drilling are required to be cross-ripped to alleviate compaction of soils. On crop land, compaction alleviation should be undertaken when the soil moisture at the time of ripping is 35 percent of field capacity.

As part of the interim reclamation, drill pits on croplands are required to be closed such that disposal of fluids and cuttings do not result in the formation of an impermeable barrier. Water-based drilling fluids should be removed from drilling pits and disposed of in accordance with 900 Series Rules. Drill pits on non-crop lands should be backfilled so that the soil is returned to its original relative position. A minimum of 3 feet of backfill cover is required over drilling pit contents. If subsidence occurs on both types of lands (crop and non-crop) within 2 years, additional topsoil should be added and the ground releveled.

On crop lands, operators are required to replace segregated soil horizons to their original positions and till adequately. The area should be treated to prevent invasion of undesirable species and to prevent erosion. Any perennial forage crops present before disturbance should be reestablished. On non-crop lands, operators should also replace segregated soils to their original positions and till adequately. Additionally, reseeding on non-crop lands should take place during the first favorable season. Operators are required to consult with the local soil conservation office to determine what seed to use in various areas.

Prior to SB 94-177, interim site maintenance and soil stabilization of drilling locations was required to take place as conditions permitted. Drilling locations were required to be restored to their original conditions insofar as is practicable as soon as site conditions reasonably permit following the completion of drilling and completion operations but in no event later than 6 months after completion.

2.1.13 Reporting Production and Payment Of COGCS Levy During the Life of a Well

Since SB 94-177, the regulations now require that the Operator's Monthly Production Report be provided by well and by formation, where as previously it was reported by lease. Additionally, since the passage of the SB 94-177, the Mill Levy has increased by a small amount. However, currently the Environmental Response Fund Levy has been reduced to $0 because the fund total has reached its statutory limit.

2.1.14 Shutting-in or Temporarily Abandoning a Well for Several Years

Since SB 94-177, operators are required to complete the new Form 5 (Drilling Completion Report) to begin the process of shutting-in or temporarily abandoning a well. This form notifies the Director of the suspension of activities at the site. Additionally, a copy of all logs, drill stem tests, and core analyses must be submitted. The Completed Interval Report (Form 5A) and Well Abandonment Report (Form 6) are also required (which were not required prior to SB 94-177).

The rules regarding the process for shutting-in a well have not changed significantly since SB 94-177 with one exception. There is a new bonding requirement of $5,000 per well for each "excess" inactive well. In addition, the Director is requiring a Mechanical Integrity Test (MIT) within six months of well shut-in as opposed to two years as had been allowed in the past. This is consistent with the rules prior to and after 1994.

2.1.15 Recompleting a Well and Commingling Production

Both before and after SB 94-177, recompleting a well must begin with Form 2 and the associated fees as well as a Sundry Notice (Form 4), which details the work and a wellbore diagram. Since 94-177, the Director may now require remedial cementing during recompletion operations. Commingling is encouraged to minimize surface disturbance and is conducted at the discretion of the operator unless otherwise stated by the COGCC. Prior to SB 94-177, multiple zone completions required an application to the Director, including location of all wells and a diagrammatic sketch of the mechanical installation. This requirement is no longer in the rules.

2.1.16 Plugging and Abandoning a Well at the End of Its Useful Life

SB 94-177 resulted in modified rules regarding well plugging and abandonment. Operators are now required to submit Form 6 (Well Abandonment Report). Additionally, plugging requires that the original substance be kept in its own reservoir and the rules and regulations now specify the preferred plugging cement slurry. Prior to SB 94-177, this method was not specified.

2.1.17 Performing Final Well Site Reclamation

The significant change in the final reclamation requirements since SB 94-177 is the site investigation, remediation and closure requirements. Additionally, the operators are now required to consult with the surface owner concerning final reclamation.

Reclamation Specifics.

After SB 94-177, changes in the rules and regulations require that reclamation be completed within 3 months on crop lands and within twelve months on non-crop lands after plugging the well. Prior to SB 94-177, reclamation work was required to be completed within six months of plugging a well for both crop and non-crop lands. Under both sets of rules all pits should be backfilled, all surface equipment removed, and the location graded and recontoured. Additional well locations, access roads and associated facilities must be reclaimed. However, the modified regulations after SB 94-177 require compaction alleviation, and restoration and revegetation of well sites and access roads.

Rules promulgated after SB 94-177 require production and special purpose pits to be closed in compliance with 900 Series Rules for E&P waste. Additionally all pits should be backfilled and returned to original relative positions. If subsidence occurs, additional topsoil should be added and lands re-leveled as close as practicable to the original contour.

The new rules promulgated after SB 94-177 consider final reclamation to be complete for release of financial assurance when:

1. Observation of Director over two growing seasons has indicated no significant unrestored subsidence on crop land;
2. The total cover of live perennial vegetation provides soil erosion control as determined by the Director through a visual appraisal on non-crop lands;
3. Disturbance from flowline installations is reclaimed when the area is capable of supporting the pre-disturbance land use;
4. A Sundry Notice (Form 4) has been submitted; and
5. Final reclamation inspection has been completed by Director.

Site Investigation, Remediation, and Closure.
The entire site investigation, remediation and closure process is new since SB 94-177. The new rules require site investigation, remediation and closure (Rule 909) for final reclamation of pits other than drilling pits and plugged and abandoned well sites. The site investigation, remediation and closure requires a Sensitive Area Determination, sampling and analyses, management of E&P waste, pit evacuation, and remediation and reclamation. It also requires that operators prepare and submit Form 27, a Site Investigation and Remediation Workplan. Allowable concentrations for soil and groundwater standards are also given in the new rules and regulations.

Notify and Consult Surface Owners.
Operators must now notify the surface owners of reclamation and closure more than 30 days prior to the date of estimated closure operations. Prior to SB 94-177, the operator was required to notify the surface owner and surface tenant not less than 7 days before any final site reclamation and restoration was to take place. Additionally, under current regulations, the operator is required to use its best efforts to consult in good faith with the affected surface owner (not required prior to SB 94-177). If requested by the local governmental designee, the operators should also consult with the local governmental designee (not required prior to SB 94-177).

3.0 Oil and Gas Operator Survey

One goal of this project was to collect and evaluate site specific cost information and data on the operational and compliance costs for small, medium and large operators of oil and gas wells at various locations throughout Colorado. To accomplish this task, a detailed survey was designed to address operational and compliance cost issues related to the life cycle of a well for operations located in Colorado. The survey design phase encompassed three steps: regulation review, background interviews, and survey development and pre-testing. The regulatory review process was discussed in Section 2.0. The remaining steps are discussed below.

3.1 Survey Development

Upon review of the relevant regulations, the cost changes to operators that likely occurred due to SB 94-177 were identified. Cost changes were identified as either changes in cost of compliance with the relevant COGCC rules and regulations or cost changes associated with operating the well during its life cycle. Consideration was also given to the influence of these rules and regulations and operating costs on small, medium, and large oil and gas operators in Colorado.

The background information obtained during the regulatory review process was then used in a series of interviews and meetings with COGCC staff, industry representatives and oil and gas operators that addressed issues related to oil and gas operations in Colorado. The interviews were conducted to accomplish the following goals:

- Identify the objectives of the Colorado Department of Natural Resources (DNR) in utilizing the survey information and results;
- Define terminology (for example, what is meant by a small operator, etc.);
- Gather information regarding the rules, regulations, compliance issues, SB 94-177 issues, and other relevant information needed to develop a useful survey;
- Estimate specific compliance and operating costs for small, medium, and large operators before and after SB 94-177; and
- Collect other relevant information needed for survey implementation such as operator contacts.

After completing the interviews, a draft survey instrument was developed. The survey instrument was then thoroughly reviewed during a focus group meeting with a panel of industry representatives to ensure proper wording, to identify confusing terminology, to identify redundant questions and to discuss other relevant issues. Eight individuals participated in this focus group and represented small, medium and large oil and gas companies. The information collected during this focus group meeting was integrated into a final survey instrument that was used for this project. A copy of the survey instrument is provided in Appendix B.

3.2 Survey Administration

A highly detailed survey undertaken by an in-person interview process was used to collect site specific operational and compliance cost data over the life of a well. The first step in administering the survey was to identify the target population and to select the sample of operators. The Colorado Oil and Gas Association (COGA) was instrumental in identifying participants for the survey. Hazen and Sawyer completed this subtask in consultation with the COGA who identified seventeen operators that met the following criteria:

- Their operations are located in one of the four location scenarios; and
- They have oil and gas experience in Colorado both pre- and post- SB 94-177 (1994).

Both criteria were essential in collecting the relevant information and cost data for this project. In addition to the operators and drillers recommended by COGA, Hazen and Sawyer identified three other operators who met the above listed criteria and were interested in participating in the survey.

Hazen and Sawyer and COGA first contacted the potential operators by telephone to locate the person or persons who have the ability to answer the survey questions. The primary company contact was then mailed a survey so that he/she would have adequate time to gather the needed information. For many companies, successful completion of the survey required input from many persons within that company. Therefore, it was desirable to have one contact who was responsible for ensuring the survey was completed.

The survey was initially mailed on June 8, 2000, to seventeen operators. The operators were given a deadline of June 23, 2000, to complete the written survey and return it to Hazen and Sawyer. Hazen and Sawyer received 10 surveys. Of these, nine are considered complete. The project team contacted participants on a weekly basis and most indicated they were working towards completing the survey. However, some operators indicated they would be unable to complete the survey given their extraordinarily busy drilling schedule.

Hazen and Sawyer worked extensively with the operators to complete the survey and improve the response rate. For instance, the project team identified three additional operators in August 2000, who met the survey criteria and were interested in participating in the survey.

Once Hazen and Sawyer received a completed survey, the participants were contacted for a follow-up interview. During these interviews, Hazen and Sawyer discussed specific answers to survey questions, asked additional questions that were not included in the survey, and discussed other issues related to oil and gas operations in Colorado.

4.0 Cost Analysis

As discussed above, completed surveys and interviews are available from nine companies regarding the cost of oil and gas operations in Colorado. Of the nine companies surveyed, four are considered small, four medium, and one large in size. The distinction between the size of companies was primarily based on the number of wells that have been drilled since 1994. Small companies were those that have drilled 500 or less wells since 1994. Companies were classified as large or medium if they drilled more than 500 wells in Colorado since 1994. There were exceptions to this general rule. For example, a company may have been classified as large if it drilled less than 500 wells but it has a very large number of wells that it operated in Colorado. Additionally, another company was classified as small even though they drilled over 700 wells since 1994. This was due to the fact that they specialized in drilling operations and do not operate any wells.

The results of the survey provide data that was used to evaluate the average compliance and operational costs across the life cycle of a well for wells located in Colorado. The data and information from the survey and interviews were organized into an Excel spreadsheet for further analysis. In order to perform a consistent and relevant comparison, all cost data were converted to 1999 dollars using the U.S. GDP deflator.

The data and information collected were analyzed according to the goals and objectives of this project and the results are summarized in this section. Where possible the compliance and operating costs to small, medium and large oil and gas operators under the following situations were evaluated:

- Pre- and Post- SB 94-177; and
- Surface Location Scenarios.

These situations are discussed below.

4.1 Life Cycle Analysis for Small, Medium and Large Companies

Data and information collected from the surveys and interviews were organized according to fifteen categories that represent the life cycle stages of a well. The categories are as follows.

1. Preparing an Application for Permit to Drill for a well;
2. Posting appropriate financial assurance;
3. Performing notice and consultation with surface owners prior to drilling a well;
4. Building surface well site locations and access roads;
5. Preparing an application for a pit to accept produced water;
6. Exploration and production (E&P) waste management;
7. Drilling, casing and completing a well;

8. Safety requirements;
9. Flowline requirements;
10. Performing interim well site reclamation;
11. Reporting production and payment of COGCC levy during the life of a well;
12. Shutting-in or temporarily abandoning a well for several years;
13. Recompleting a well and commingling production;
14. Plugging and abandoning a well at the end of its useful life; and
15. Performing final well site reclamation.

The cost data was used to analyze the impact of significant rule changes made to Colorado's Oil and Gas Rules and Regulations after passage of Senate Bill 94-177. Additionally, the difference in impacts to small, medium and large companies were evaluated where possible. A summary of the results is provided in the next two subsections.

Although nine companies completed the survey, not all participants completed each section. This was due to the following reasons:

- Not all companies participate in each stage of the well's life cycle (e.g., drilling companies do not operate wells);
- Companies have not experienced certain stages of the life cycle (e.g., wells are still operating and are not in need of final reclamation); or
- There was a lack of data on the cost of a particular life cycle stage.

The number of observations per each life cycle stage by operator size is provided in Table 4.1-1.

4.2 Results of the Life Cycle Cost Analysis of Wells Both Pre- and Post- SB 94-177

The financial impacts of rule changes resulting from SB 94-177 are provided in Table 4.2.1. The data and information collected during the survey were used to examine the changes in costs associated with different stages of a well from 1994 and 2000. SB 94-177 was passed in 1994 and led to numerous changes to Colorado's Oil and Gas Rules and Regulations as discussed in Section 2.0. The survey instrument allows one to measure the impact of the numerous rule changes on the costs associated with different stages of a well. Additionally, the data and information was used to examine what impact the rules and regulations have had on the costs to small, medium and large companies.

Column 1 of Table 4.2-1 shows the different stages of a well that were examined. Column 2 summarizes the change in average real cost in 1999 dollars at each stage of the well life cycle for small, medium, and large companies. For this analysis, large and medium companies were combined into one group given the small number of respondents representing large companies. For most stages, the cost is reported on a per well basis. However, there are some stages that are not reported on a per well basis such as the pit inventory, reporting requirements, and flowlines. Pit inventory and reporting requirement costs are reported per company. Flowline installation cost is reported per flowline. Column 3 indicates the likelihood that the change in average cost per life cycle stage can be attributed to changes in Colorado's Oil and Gas Rules and Regulations.

For small companies the largest increase in real cost between 1994 and 2000 has been for recompletion and pit inventories. On average, the recompletion process has increased the average cost by $24,614 per well. Additionally, requirements for a one time pit inventory and subsequent closure, repair or replacement of pits (not reported by well) cost small companies on average $12,681 per company. Small operators also reported increases in real cost per well between 1994 and 2000 for: Well site Development ($3,434), Final Reclamation ($3,257), Interim Reclamation ($3,132 - $2,787), Shutting-in a Well ($1,802), Plugging and Abandonment ($1,794) and Production Reporting ($1,086). Small operators experienced additional cost increases for the ADP process, Notice and Consult and Rig Moves and Set-ups that were under $1,000 per well.

Review of data and information collected from the survey appears to indicate that changes in some of the rules and regulations pertaining to oil and gas exploration and development have increased real costs to small operators. From Column 3 in Table 4.2-1, changes in rules and regulations have played a significant role in the cost increases to small operators associated with the Pit Inventories, Interim and Final Reclamation and Production Reporting. Additionally, the rule changes have likely played a moderate to significant role in the cost increases associate with Well Site Development. There is also a significant likelihood that rule changes have caused an increase in the APD process, although the absolute cost change for this stage is quite low ($244 per well). An interesting insight that came up during the interviews is that it appears that the rules and regulations did not play a significant role in increasing costs associated with recompleting a well. Here, operators indicated the cost increase is mainly due to changes in technology and labor issues.

The changes in cost for the different stages of a well have been somewhat different for medium and large companies compared to small companies. For instance, large and medium sized companies have experienced a decrease in the average real cost for three well life cycle stages including Production Waste Management, Plugging and Abandoning a Well and Interim Well Site Reclamation. Much of the decrease in average cost for these stages can be attributed to companies reducing the size of their well site locations. This reduces the cost to develop and reclaim disturbed areas. Companies have also experienced a cost savings in waste disposal costs through increased recycling methods that reduce the amount of waste fluids used and/or produced during drilling and production stages.

Table 4.1-1
Number of Respondents by Life Cycle Stage and Size of Company

Well Life Cycle Stage (1)	Number of Respondents by Size of Company (2)	
	Small	Medium and Large
1. APD Process	4	5
2. Posting Financial Assurance	4	3
3. Notice and Consult	4	4
Surface Owner Agreement	4	4
Surface Damage Payment	3	4
4. Building Well Site Locations and Access Roads		
Rig Moves and Set Up	2	4
Well site Development	4	5
5. Preparing Application for a Pit to Accept Produced Water		
Pit Inventory	3	4
Pit Permitting	1	0
6. E&P Waste Management		
Exploration Waste	3	4
Production Waste	1	4
7. Drilling, Casing and Completing a Well	4	5
8. Safety Requirements	0	0
9. Flowlines	3	4
10. Interim Reclamation		
Crop Lands	4	4
Non-Crop Lands	3	4
11. Production Reporting	3	3
12. Shutting-in a Well	3	3
13. Recompletion	1	3
14. Plugging and Abandonment	3	3
15. Final Well Site Reclamation		
Crop Lands	1	4
Non-Crop Lands	2	4

Large and medium sized companies also reported increases in costs associated with Pit Inventories ($278,188), Well Recompletion ($56,359), Production Reporting ($9,368), Notice and Consult Process ($1,130) and Final Well Site Reclamation ($2,690 to $1,259). Changes in rules and regulations have had a significant impact on cost increases for the Pit Inventory Process, and Production Reporting. Like small operators, it does not appear that changes in rules and regulations have played a part in the significant change in costs associated with Well Recompletion.

The following section describes, in detail, the analysis of costs associated with each stage of the well life cycle.

Table 4.2-1
Summary of Financial Impacts of Rule Changes Resulting from SB 94-177

Well Life Cycle Stage (1)	Average Change in Real Cost per Well of Each Life Cycle Stage between 1994 and 2000 by Size of Companies Surveyed (2)		Likelihood that Regulatory Changes have Impacted Changes in Real Cost of Each Life Cycle Stage (3)	
	Small	**Medium and Large**	**Small**	**Medium and Large**
1. APD Process	$244	$70	Significant	Significant
2. Posting Financial Assurance[1]	Small Increase	Small Increase	Low	Low
3. Notice and Consultation				
Notice and Consult	$469	$1,130	Moderate	Moderate
Surface Owner Agreement	$147	$382	Low	Low
Surface Damage Payment	$585	$813	Low	Low
4. Building Well Site Locations and Access Roads				
Rig Moves and Set Up	$97	$0	Indeterminate	Indeterminate
Well site Development	$3,434	-$3,697	Moderate to Significant	Low
5. Preparing Application for a Pit to Accept Produced Water				
Pit Inventory[2]	$12,681	$278,188	Significant	Significant
Pit Permitting	Insufficient data	Insufficient data	insufficient data	insufficient data
6. E&P Waste Management				
Exploration Waste	See results for interim reclamation			
Production Waste	$911	-$581	Moderate	Low
7. Drilling, Casing and Completing a Well	See location scenarios			

Table 4.2-1
Summary of Financial Impacts of Rule Changes Resulting from SB 94-177

Well Life Cycle Stage (1)	Average Change in Real Cost per Well of Each Life Cycle Stage between 1994 and 2000 by Size of Companies Surveyed (2)		Likelihood that Regulatory Changes have Impacted Changes in Real Cost of Each Life Cycle Stage (3)	
	Small	**Medium and Large**	**Small**	**Medium and Large**
8. Safety Requirements	Insufficient data	Insufficient data	insufficient data	insufficient data
9. Flowlines[2]				
Installation	8% increase	6% increase	Moderate	Low
Testing	$552	$368	Moderate	Low
Maintenance	-$194	$213	Low	Low
Reclamation	$34	$367	Moderate	Low
10. Interim Reclamation				
Crop Lands	$3,137	-$246	Significant	Low
Non-Crop Lands	$2,787	-$28	Significant	Low
11. Production Reporting[2]	$1,086	$9,368	Significant	Significant
12. Shutting-in a Well	$1,802	$263	Moderate	Moderate
13. Recompletion	$24,614	$56,359	Low	Low
14. Plugging and Abandonment	$1,794	-$282	Low	Low
15. Final Well Site Reclamation				
Crop Lands	$135	$1,259	Significant	Moderate
Non-Crop Lands	$3,257	$2,690	Significant	Moderate

1 The average change in cost was not reported due to significant differences in operations.
2 Not reported on a per well basis. Pit inventory and production reporting costs are reported per company. Flowline installation cost is reported per flowline.

4.3 Detailed Cost Analysis of the Life Cycle of a Well Pre- and Post- SB 94-177

This section reports the cost of a well for each life cycle stage both pre- and post- SB94-177 using survey responses.

4.3.1 General Company Information

In Section 1 of the survey, participants were asked questions regarding general operations such as how long the company has been operating in Colorado, the number of wells drilled prior to and after 1994, whether wells were drilled on crop or non-crop lands, and where the company typically operates. The results are summarized in Table 4.3-1.

Table 4.3-1
General Information on Number of Wells Drilled by Companies Surveyed both Pre- and Post- SB 94-177

	Average Number of Wells per Company Drilled by Companies Surveyed
Before 1994	
Total Wells	593
Crop Lands	238
Non-Crop Lands	313
After 1994	
Total Wells	365
Crop Lands	193
Non-Crop Lands	154

Companies were also asked where they typically operate in Colorado. The responses to this question are summarized in Table 4.3-2

Table 4.3-2
Location Where Companies Surveyed Normally Operate

Location	Number of Companies Who Indicated They Normally Operate in Each Area
NE Colorado (e.g., Yuma and Washington counties)	3
D-J Basin (e.g., Weld and Adams counties)	5
San Juan Basin	1

Participants were also asked whether or not they had hired additional staff specifically to address regulatory issues. Five of the eight companies did indicate they had hired additional staff to address regulatory issues related to operations in Colorado.

Companies were then asked to rate whether or not the “regulations promulgated in association with SB 94-177 have had an impact on your activities and operations in Colorado.” The results are summarized in Tables 4.3-3 and 4.3-4.

Table 4.3-3
Responses to Question, “Do you feel the regulations promulgated in association with SB 94-177 have had an impact on your activities and operations in Colorado?”

Response	Number of Responses
No Impact at All	0
Very Little Impact	0
Some Impact	3
Significant Impact	4
Very Significant Impact	0

Table 4.3-4
Responses to Question “Overall, do you feel that the regulations promulgated in associated with SB 94-177 have had a positive or negative impact on your activities and operations in Colorado?“

Response	Number of Responses
Very Positive Impact	0
Some Positive Impact	0
Negligible Impact	2
Some Negative Impact	6
Very Negative Impact	1

4.3.2 Preparing an Application for Permit to Drill a Well

In the second section of the survey, participants were asked six questions regarding their experience preparing an Application for a Permit to Drill a Well (APD Process). The results are summarized in Table 4.3-5. All eight respondents indicated an increase in average real costs to complete the APD process relative to rules and regulations prior to SB 94-177 (prior to 1994). For all companies, the average real cost (1999 $) to complete the APD process was $484 per well prior to 1994. This real cost increased to $742 per well in 2000 representing a 53 percent increase in average real cost. It appears that the cost of this process is slightly higher for small companies than for medium and large companies. Prior to 1994, the average cost of the APD process for small companies was $425 per well and increased to $669 per well in 2000 for a 57 percent overall increase. Large and medium companies experienced a 51 percent increase in average real cost to complete the APD process from $531 per well prior to 1994 to $601 per well in 2000.

The increase in cost of the APD process is likely being driven by the increased requirements placed on operators since SB 94-177. Operators must now submit Form 2A that requires location photographs and soil and plant information. These stipulations were not required prior to 1994.

Table 4.3–5
Cost of APD Process

Survey Number	Total Costs for APD Process per Well Since 1994 (1999$)	Total Costs for APD Process per Well Prior to 1994 (1999$)	Percentage Increase in Real Cost to Complete APD
1	$646	$167	286%
2	$856	$585	46%
3	$587	$390	51%
7	$587	$557	5%
Average for Cost for Small Companies	***$669***	***$425***	***58%***
4	$1,419	$875	62%
6	$895	$668	34%
5	$587	$390	51%
8	$489	$167	193%
9	$616	$557	11%
Average Cost for Medium and Large Companies	***$801***	***$531***	***51%***
Average Cost for All Companies	***$742***	***$484***	***53%***

4.3.3 Posting Appropriate Financial Assurance

In Section 3 of the survey, participants were asked a series of questions regarding financial assurance (FA) requirements for operations in Colorado. This includes FA requirements for 1) soil protection, plugging and abandonment; 2) surface owner protection; 3) excess inactive wells; 4) general liability insurance; and 5) natural gas gathering systems. Six companies responded to at least some of the questions regarding the form of FA they use. The other respondents did not answer these questions because of lack of information regarding their companies' FA procedures or the question was not relevant to their operations. Of the six companies that responded, four indicated they normally obtain bonds for FA while one company uses a corporate insurance carrier.

Companies were asked about their specific experience using surface owner protection FA. Four companies responded fully regarding their normal practices using surface owner protection as well as the estimated cost of such FA. One company provided information on their use of surface owner protection FA after 1994 but did not have information prior to this date. The results are summarized in Table 4.3-6.

Table 4.3-6
Surface Owner Protection Financial Assurance

Survey No.	Estimated Total Cost of FA for Surface Owner Protection after 1994	Individual Well or Statewide Blanket Bond	Estimated Total Cost of FA for Surface Owner Protection prior to 1994	Individual Well or Statewide Blanket Bond
1	NA	NA	NA	NA
2	Annual Cost of $600	Blanket	Annual Cost of $600	Blanket
3	NA	NA	NA	NA
4	NA	NA	NA	NA
5	Annual Cost of $1,100	Blanket	Annual Cost of $100	Blanket
6	One-time cost of $5,000	NA	NA	NA
7	Annual Cost of $500	Blanket	NA	NA
8	Annual Cost of $125	Blanket	Annual Cost of $100	Blanket
9	$25,000 Bond	Blanket	$25,000 Bond	Blanket

Note: NA means not available or not applicable.

Three companies indicated they pay between $125 and $1,100 annually for surface owner protection FA currently. One company indicated they incurred a one-time cost of $5,000 to cover the 20 percent of their wells that do not have a Surface Owner Agreement. Another company indicated that they hold a $25,000 bond for FA associated with surface owner protection.

Companies were also asked about their experience regarding soil protection, plugging and abandonment FA. The results are summarized in Table 4.3-7. Two companies indicated that they incurred a total annual cost of $250 and $600, respectively, for a statewide blanket bond. These companies have less than 100 operating wells in the state. These two companies indicated the annual cost of FA for soil protection, plugging and abandonment had not changed since 1994. One company indicated they paid a total of $2,000 per year for FA for soil protection, plugging and abandonment on all their wells in Colorado. This company has more than 100 operating wells in the state. This company did not have information on the cost of this FA prior to 1994. One other company indicated they currently put up an $80,000 Certificate of Deposit to cover FA for soil protection, plugging and abandonment on their wells statewide. This company operates less than 100 wells in Colorado. The cost of FA for this company has increased from $28,000 prior to 1994.

Two of the nine companies indicated they had "excess" inactive wells. Companies have the option to obtain additional FA for these inactive wells, or they can submit a plan to plug and abandon or return the wells to production. One company indicated they did incur $2,500 to prepare a plan for excess inactive wells and returned 116 wells to production and plugged an additional 54. While the company did indicate that it cost approximately $10,000 to plug the 54 wells, they were certain that costs would have been incurred at some point in the future.

Table 4.3-7
Soil Protection, Plugging and Abandonment Financial Assurance Cost

Survey No.	Estimated Total Cost of FA for Soil Protection, Plugging and Abandonment after 1994	Individual Well or Statewide Blanket Bond	Estimated Total Cost of FA for Soil Protection, Plugging and Abandonment prior to 1994	Individual Well or Statewide Blanket Bond
1	Annual Cost of $250	Blanket	Annual Cost of $250	NA
2	Annual Cost of $600	Blanket	Annual Cost of $600	Blanket
3	NA	NA	NA	NA
4	NA	NA	NA	NA
5	$80,000 Certificate of Deposit	Blanket	$28,000 Certificate of Deposit	Blanket
6	NA	NA	NA	NA
7	Annual Cost of $2,000	Blanket	NA	NA
8	NA	Blanket	NA	Blanket
9	$25,000 Bond	Blanket	$25,000 Bond	Blanket

Note: NA means not available or not applicable.

Five of the nine respondents provided full information on their annual cost of general liability insurance, which ranged from $3,500 to $100,000 per year, currently. The results are provided in Table 4.3-8. All companies that responded to questions regarding general liability insurance indicated that their annual costs had increased. The increase in cost is likely due to the increased size of operations for the companies surveyed as well as a general increase in the cost of insurance.

Two companies indicated they carried FA for natural gas gathering systems. The total cost to these companies ranged from $500 to $1,300 per company per year. There is no data available on the cost of natural gas gathering system FA prior to 1994.

Table 4.3-8
Cost of General Liability Insurance

Survey No.	Total Annual Cost of General Liability Insurance Since 1994 (1999$)	Total Annual Cost of General Liability Insurance Prior to 1994 (1999$)	Percentage Change in Total Annual Cost of General Liability Insurance
1	$3,914	$2,674	46%
2	$3,424	$2,117	62%
3	$34,244	$11,140	207%
4	NA	NA	NA
5	NA	NA	NA
6	$53,812	NA	NA
7	$97,839	$33,421	193%
8	$14,732	$13,294	11%
9	NA	NA	NA

Note: NA means not available or not applicable.

Most companies surveyed indicated they have not realized a significant increase the amount of FA or insurance coverage as a result of the new regulations. It may be that bonding or insurance companies have not concluded that the change in regulations has added significant liability to operations that would require additional coverage. Additionally, these companies indicated any increase in cost of FA is more associated with changes in market conditions rather than changes in the rules and regulations. However, there were instances where companies, especially one small company, did realize a significant increase in the cost of FA. Part of this cost may be attributable to increasing FA requirements placed on companies by COGCC. Of the companies interviewed, it appears that the change in rules and regulations regarding FA have had minimal impact on companies up to this point.

4.3.4 Notice and Consultation

Participants were asked eleven questions regarding the notice and consultation process with surface owners and local governments prior to drilling a well in Colorado both pre- and post- SB 94-177. The results of these questions are summarized in Table 4.3-9. The questions focused on three important areas: 1) the average cost per well of the notice and consult process; 2) the average cost per well to obtain a surface owner agreement (SOA); and 3) the average cost per well of surface damage payments made to surface owners. The first five rows show the average cost for each of the small operators surveyed. Below this is the average cost for each medium and large company. This is followed by the average cost for all companies surveyed.

The total average real costs per well pre- and post- SB 94-177 to complete the notice and consult process are summarized in Columns 2 through 4 in Table 4.3-9. For small companies the average cost to complete this process has increased by over 600 percent from $76 per well in 1994 to $545 in 2000. One small operator indicated that the notice and consult process has had a minimal cost impact to his operations, and that this has not changed over the relevant timeframe. For large and medium companies, the average real cost of notice and consult has increased by 647 percent from $175 per well in 1994 to $1,305 per well in 2000. The average real cost to all companies for completing the notice and consult process has increased by over 500 percent from $136 per well in 1994 to $868 per well in 2000.

Columns 5 through 7 summarize the average real cost per well to obtain a Surface Owner Agreement (SOA) both pre- and post- SB 94-177. For small operators, the average real cost per well to obtain an SOA has increased on average by 32 percent from $455 per well in 1994 to $602 in 2000. However, one company did indicate that the cost to obtain a SOA remained constant. When converted to real 1999 dollars, the real costs of obtaining a SOA for this operator had actually decreased. For large and medium sized companies, the average real cost per well to obtain an SOA increased on average by 40 percent from $952 per well in 1994 to $1,334 per well in 2000. For all companies, the average real cost to obtain an SOA increased from $703 to $968 per well or a 38 percent increase.

Operators were asked an additional question during the interviews regarding surface damage payments that was not included in the survey instrument. The results are shown in Columns 8 through 10. Three small operators answered the question regarding surface damage payments. One small operator indicated that surface damage payments were on average $1,671 prior to 1994. However, he no longer pays surface owners for damages because of the increased reclamation requirements for wells drilled in Colorado. Overall, surface damages paid by small operators have increased from $1,225 prior to 1994 to $1,810 IN 2000 representing a 48 percent increase.

For medium and large companies, the average real cost of surface damage payments increased from $2,367 in 1994 to $3,180 in 2000 for a 34 percent increase. Overall, the average real cost for surface damage payments for all companies increased by 45 percent from $1,878 per well prior to 1994 to $2,723 per well in 2000.

Table 4.3-9
Real Cost for Notice and Consultation Process

Survey No.	Total Average Cost per Well for Notice and Consult (1999$)			Total per Well Cost of Obtaining a Surface Use Agreement (1999$)			Total Cost per Well of Surface Damage Payment (1999$)		
	Since 1994	Prior to 1994	% Change	Since 1994	Prior to 1994	% Change	Since 1994	Prior to 1994	% Change
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Minimal	Minimal	NA	$318	$2	14,171%	NA[a]	$1,671	NA
2	$411	$33	1130%	$300	$2	13,376%	$2,152	$891	141%
3	$342	$84	310%	$616	$702	-12%	NA	NA	NA
7	$881	$111	690%	$1,174	$1,114	5%	$1,468	$1,114	32%
Average Cost for Small Companies	***$545***	***$76***	***615%***	***$602***	***$455***	***32%***	***$1,810***	***$1,225***	***48%***
4	$528	$201	163%	$881	$401	120%	$1,468	$1,671	-12%
5	$245	$245	0%	$2,301	$955	141%	$3,914	$2,785	40%
6	NA	NA	NA	$685	$780	-12%	NA	NA	NA
8	$2,935	$223	1217%	NA	NA	NA	$4,892	$2,228	119%
9	$734	$56	1217%	$1,468	$1671	-12%	$2,446	2,785	-12%
Average Cost for Medium and Large Companies	***$1,305***	***$175***	***647%***	***$1,334***	***$952***	***40%***	***$3,180***	***$2,367***	***34%***
Average Cost for All Companies Surveyed	***$868***	***$136***	***537%***	***$968***	***$703***	***38%***	***$2,723***	***$1,878***	***45%***

a The operator indicated that with increased requirements for interim and final well site reclamation, there was no need to pay surface owner damages.
Note: NA means not available or not applicable.

Overall there appears to be an increase in the cost of completing the notice and consult process for all companies. There are likely two reasons for the cost increase. First, there has been an increase in the requirements for the notice and consult process. Operators are required to give notice to surface owners at least 30 days before a well is drilled. Notice must also be posted at the well site and given to a local government designee. These requirements have likely played a part in the increased costs of notice and consultation. The more likely reason for the rising costs of notice and consult is the need to increase consultation and negotiations with surface owners regarding issues associated with drilling wells in Colorado. With the change in rules regarding notice and consult, surface owners now have more access to operators and the COGCC regarding surface impacts associated with oil and gas development. In response to this, operators now have to spend more time with surface owners and the local government designee prior to drilling a well.

4.3.5 Building surface well site locations and access roads

In Section 5 of the survey, participants were asked questions regarding the itemized costs of building drill site locations and access roads. A summary of the results of this section are provided in Table 4.3-10. The cost data were aggregated to show two aspects of site preparation to drill a well including: 1) rig moves and set-ups; and 2) building the well site and access road.

The average real cost for rig moves and set-ups both pre- and post- SB 94-177 are shown in Columns 2 and 3 in Table 4.3-10. Overall the average real cost of rig moves and set-ups per well have increased slightly between 1994 and 2000. Prior to 1994, the average cost of rig moves and set-ups was approximately $7,005 per well. The real cost of rig moves increased modestly by 2000 to $7,089 per well.

Some participants have indicated that the cost of rig moves may be affected by the change in regulations that require that notice be given to surface owners at least 30 days before drilling can commence. Operators indicated during the interviews that this can impact their ability to schedule rig moves in the most cost-efficient manner. For instance, an operator may not be able to drill a well on an adjacent location without first moving off-site due to the notice requirement. This can lead to increased travel time and risks associated with having rigs on the road more frequently. While it is possible that these regulatory changes have had a slight impact on the costs of rig moves, it is not conclusive from the survey results that this is having a significant impact on operators.

The change in average real costs per well of well site development are summarized in Columns 5 through 7. Small companies reported over a 130 percent increase the average real cost to develop a well site and access roads from $2,587 in 1994 to $6,021 in 2000. Alternatively, large and medium companies indicated that the cost of well site development had decreased over the study period by 28 percent. For these companies, the average real cost decreased from $13,010 in 1994 to $9,313 in 2000. For all companies the average real cost for well site development decreased by 8 percent.

Table 4.3-10
Total Real Cost of Well Site Development

Survey No.	Total Cost per Well of Rig Moves and Set Up (1999$)			Total Costs per Well to Develop Well Site Location and Access Roads (1999$)		
	Since 1994	Prior to 1994	% Change	Since 1994	Prior to 1994	% Change
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	NA	NA	NA	$3,180	$2,451	30%
2	NA	NA	NA	$3,779	$3,578	6%
3	$8,316	$7,241	15%	$2,446	$2,089	17%
7	$6,360	NA	NA	$14,679	$2,229	558%
Average Cost for Small Companies	***$7,338***	***$7,241***	***1%***	***$6,021***	***$2,587***	***133%***
4	$2,671	$2,395	12%	$5,019	$4,334	16%
5	NA	NA	NA	$4,060	$4,233	-4%
6	$8,316	$7,241	15%	$3,424	$2,367	45%
8	$9,784	$11,140	-12%	$31,470	$52,360	-40%
9	NA	NA	NA	$2,593	$1,755	48%
Average Cost for Medium and Large Companies	***$6,924***	***$6,926***	***0%***	***$9,313***	***$13,010***	***-28%***
Average Cost for All Companies Surveyed	***$7,089***	***$7,005***	**1%**	***$7,850***	***$8,377***	***-8%***

Note: NA means not available or not applicable.

The change in regulations may be having an impact on the increasing cost of developing well site locations, especially for small operators. Regulatory changes that appear to be impacting small operators are requirements to segregate and protect top soil when developing the site and the increased frequency of requests by surface owners to fence the drill pad and equipment. Some of the participants indicated that development costs increased by $400 to $500 per site to perform soil segregation and protection. Medium and large operators did not indicate that this change in regulations had affected their operations because this was a practice they normally employed when developing drill sites.

Small operators also reported that they have experienced an increased cost associated with fencing the drill pad and equipment at the request of surface owners. The COGCC regulations now give surface owners the right to request fencing around the drill site. Small operators reported a $300 to $800 increase in cost of fencing per site due to the additional requests by surface owners. Large and medium companies did not indicate that this requirement had affected their cost of well site development. One large company reported an overall decrease in the cost of developing wells sites due to the fact they have been able to reduce the average size of their locations. Reducing the footprint of the well site has decreased their development and reclamation costs associated with drilling locations. The reduction in well development cost of this one operator (40 percent) is driving the results that show a decrease in well site development for all operators surveyed.

4.3.6 Preparing an Application for a Pit to Accept Produced Water

The survey focused on two aspects of the regulations related to drilling and production pits. First, questions were developed to elicit information on the average one-time cost for companies to complete an inventory and close existing pits from 1995 to 1997. Second, questions were included on the survey to gain an understanding of the average cost to permit pits under current regulations and whether operators have changed certain aspects of their operations as a result of these rules.

A summary of the results on pits is provided in Table 4.3-11. Seven of the nine companies surveyed indicated they completed a pit inventory and repaired, replaced or closed existing pits as required by COGCC. On average companies spent $164,131 to inventory and, where necessary, close, repair or replace their pits. The average cost to inventory their pits was estimated at $4,500 per company. Additionally, four companies indicated they closed, repaired or replaced between 3 and 17 pits while one company indicated they closed over 400 pits. Three of the four companies indicated the cost to close, repair or replace these pits ranged from $1,300 to $17,000 for the entire process. The company that closed over 400 pits indicated a one-time cost of over $500,000 to complete this process.

Table 4.3-11
Cost of Pit Inventories and Repair, Replacement and Closure of Pits, Pit Permitting and Change in Operations

Survey No.	One Time Cost of the Pit Inventory and Repair, Replacement or Closure of Pits 1995-1997	Pit Permitting Costs per Pit Since 1994 (1999$)	Pit Permitting Costs per Pit Prior to 1994 (1999$)	One Time Cost to Switch from Pits to Tanks or to Land Farm (1999$)
(1)	(2)	(3)	(4)	(5)
1	$1,534	NA	NA	$28,444
2	$17,184	NA	$557	NA
3	NA	NA	NA	NA
7	$14,878	NA	NA	$65,000
Average Cost for Small Companies	***$12,055***	NA	***$557***	***$46,020***
4	$24,681	NA	NA	NA
5	$539,867	NA	NA	NA
6	na	NA	NA	NA
8	$4,033	NA	NA	NA
9	$544,169			
Average Cost for Medium and Large Companies	***$278,188***	*NA*	*NA*	*NA*
Average Cost for All Companies Surveyed	***$164,131***	*NA*	***$557***	***$46,020***

Note: NA means not available or not applicable.

As part of the survey, participants were also asked if they completed a "Sensitive Area Determination." Four companies indicated they had completed Sensitive Area Determinations for between 1 to 14 pits. The average cost of this process ranged from $50 to $3,000.

Participants were also asked a series of questions regarding the cost to permit pits pre- and post-SB 94-177. Only one participant answered this question and indicated the average cost to permit a pit prior to 1994 was $557. The other survey participants indicated they did not have to permit any pits and thus did not have any cost information on this process.

Finally, participants were asked whether they had changed any part of their operations regarding the disposal of produced water. Only two companies indicated they had made changes to their operations. The first company indicated they had switched to using tanks from earthen pits. This company now places produced water in a tank that is hauled to an offsite disposal area. A second company indicated they had purchased a farm to use for land farming their oil production waste. The cost to switch to tanks was estimated to be $28,444 while the price of the land farm was estimated at $65,000.

An interesting insight that came out of the interviews is that operators, especially small operators, are beginning to avoid wells or areas that have a tendency to have secondary water production. Several small operators indicated they no longer drill in areas known to have secondary water production and one participant indicated he now plugs producing wells if water is being produced simultaneously. These operators are concerned with the increasing levels of liability and the potential permitting cost associated with the disposing of produced water and would rather avoid the situation.

4.3.7 Exploration and Production Waste Management

An issue related to pits was included in Section 7 of the survey that asked participants a series of questions regarding their handling of exploration and production (E&P) waste. Issues related to exploration waste are discussed under "Interim Well Site Reclamation" in Section 4.3.9. For production waste, participants were asked about the average annual cost per well to dispose of production waste and the results are summarized in Table 4.3-12.

Five participants responded regarding their production waste process. The other companies did not respond to this section for two reasons. First, some of the companies interviewed were drilling companies and do not operate on the production side. Additionally, some of the companies interviewed indicated they do not have significant waste production with their wells and thus do not incur costs associated with this process.

The results are mixed for the five companies that responded. One small company indicated that their production waste disposal cost had increased from nearly zero to $1,712 per well per year. This company was using evaporation pits to dispose of production waste and has switched to using tanks and hauling waste offsite for disposal. Thus, they have experienced a significant increase in real costs associated with disposal of production waste.

Table 4.3-12
Real Cost of Production Waste Disposal and Spill Management

Survey No.	Average Annual Cost per Well of Production Waste Disposal (1999$)			Total Average Cost per Spill of Spill Management (1999$)		
	Since 1994	Prior to 1994	% Change	Since 1994	Prior to 1994	% Change
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	NA	NA	NA	NA	NA	NA
2	NA	NA	NA	$1,159	$211	449%
3	NA	NA	NA	$28,633	$2,825	914%
7	$1,712	$0	NA	NA	$634	NA
Average Cost for Small Companies	***1,712***	***$0***	***--***	***$14,896***	***$1,223***	
4	$274	$312	-12%	$18,900	$11,088	70%
5	$352	$401	-12%	NA	NA	NA
6	NA	NA	NA	NA	NA	NA
8	$10,735	$14,639	-27%	$3,851	$1,968	96%
9	$734	$836	-12%	NA	NA	NA
Average Cost for Medium and Large Companies	***$3,024***	***$4,047***	***-25%***	***$11,376***	***$6,528***	***74%***
Average of All Companies Surveyed	***$2,761***	***$3,237***	***10%***	***$13,136***	***$3,345***	***10%***

Note: NA means not available or not applicable.

For all large and medium companies, there has been a decrease in the average real cost of production waste disposal. Three of the four companies indicated their costs had remained constant over the study period. When converted to 1999 dollars, the real costs of disposal decreased by 12 percent. The fourth company indicated its annual disposal costs had decreased from $14,639 in 1994 to $10,735 today. The cost decreases for this company are due to changes in their operations.

Four companies provided full information on the cost of spill management both pre- and post-SB 94-177 that are summarized in Table 4.3-12. The other companies did not respond to questions on spills because they have not had to deal with a spill at any of their locations.

It appears that the average cost of spill management has increased from $3,345 prior to 1994 to $13,136 currently. It is likely that some of the cost increase is due to more stringent requirements placed on operators regarding spills by the COGCC. Participants who did submit information on spills indicated costs have increased due to the fact that spills over 20 barrels must comply with increased requirements. This includes the 900 Series Rules that address Exploration and Production Waste. The rules have new provisions for surface owner notification, Site Investigation and Remediation Workplan, soil and water sampling, Sensitive Area Determination, and pit evacuation. Operators must also comply with the 1000 Series Rules that address proper reclamation. It is worth noting that while the new stipulations have likely impacted the real cost of spill cleanups, the difference in real cost could also be due to other site-specific characteristics such as size of the spill, location, etc.

4.3.8 Drilling, Casing and Completing a Well

In Section 8.0 of the survey, participants were asked a series of questions regarding actions related to drilling, running surface casing, and completing a well. The section began with a question on where participants normally operate and the average depth of the wells they have drilled since 1994. Participants were then asked to summarize their average cost to drill a well, run surface casing, and perform pressure testing for the average well in the area in which they typically operate. The results are summarized in Table 4.3-13.

Great care must be taken when comparing drilling costs across companies and areas. This is due to a number of characteristics that can affect the cost of drilling a well in a particular area. With that caveat in mind, the responses were organized in Table 4.3-13 by area of operation and the average depth per well. According this table, all but two companies experienced an increase in the average real cost to drill, run surface casing and pressure test a well over the study period, while one company had virtually no change in real cost (-0.2%). In the DJ Basin, the average change in real costs for each respondent ranged from a decrease of 12 percent to an increase of 25 percent. For companies that operate in NE Colorado, the change in real cost ranged from a decrease of 0.2 percent to an increase of 33 percent. One respondent, who operates in the San Juan Basin, indicated their real cost of drilling, running surface casing and pressure testing wells had increased by 7 percent.

Table 4.3-13
Average Cost of Drilling, Casing and Pressure Testing by Area and Depth of Well

Survey No.	Total Cost of Drilling, Running Surface Casing, and Pressure Testing per Well (1999$) Since 1994	Prior to 1994	% Change in Cost	Average Well Depth	Location
(1)	(2)	(3)	(4)	(5)	(6)
3	$87,077	$69,628	25%	8000	DJ Basin
5	$89,425	$101,824	-12%	7500	DJ Basin
6	$91,969	$80,768	14%	8000	DJ Basin
7	$90,746	$75,964	19%	7000	DJ Basin
9	$102,731	$106,798	-4%	7500	DJ Basin
Average Cost	***$92,390***	***$86,996***	***6%***		
1	$28,000	$24,574	14%	4300	NE Colorado (Yuma, Washington counties)
2	$69,466	$52,249	33%	6000	NE Colorado (Yuma, Washington counties)
4	$56,747	$56,861	-0.2%	2500	NE Colorado (Yuma, Washington counties)
Average Cost	***$51,404***	***$44,561***	***15%***		
8	$166,180	$155,173	7.1%	2350	San Juan Basin (SW Colorado)

The increase in the real cost of drilling, running surface casing and pressure testing for most respondents is likely due to three influences: 1) increased casing requirements placed on operators by COGCC; 2) increased labor costs in Colorado; and 3) consolidation of drilling companies in Colorado.

Several respondents indicated that increased casing requirements had been placed on their operations for wells drilled after 1994. The increased casing requirements add additional cost to drilling wells within the state. Estimates of the cost of the increased casing requirements by respondent are summarized in Table 4.3-14. Columns 2 and 3 show the average depth and real cost to run surface casing per well in 2000 required by COGCC. This is then compared to the average depth and real cost to run surface casing prior to 1994 in Columns 4 and 5. Participants reported that on average their wells required 100 to 400 feet of additional surface casing to satisfy COGCC permitting requirements today versus requirements prior to 1994. This requirement has added an additional $1,600 to $8,600 per well (see Column 6).

Table 4.3-14
Change in Average Cost to Run Surface Casing in Wells in Colorado

Survey No.	Average Depth of Surface Casing Since 1994	Average Real Cost per Well for Surface Casing Since 1994 (1999$)	Average Depth of Surface Casing Prior to 1994	Average Real Cost per Well for Surface Casing Prior to 1994 (1999$)	Average Increase in Real Cost per Well Due to Increased Casing Requirements
(1)	(2)	(3)	(4)	(5)	(6)
2	500'	$14,187	350'	$10,918	$3,269
3	700'	$13,697	300'	$8,355	$5,342
4	400'	$7,631	300'	$5,985	$1,646
6	700'	$13,697	300'	$8,355	$5,342
7	400'	$13,697	250'	$5,013	$8,684

During the interviews, respondents indicated two other influences that are affecting the cost of drilling, surface casing and pressure testing. First, Colorado has experienced a very tight labor market over the last two years. Given that oil and gas drilling operations are somewhat labor intensive, operators are experiencing increased costs associated with higher wages. This has impacted the general cost of drilling wells in Colorado.

Additionally, the oil and gas industry in Colorado has been experiencing a consolidation of companies. Fewer companies drilling within the state, especially within certain regions, has led to a decrease in competition. As a result, there has been a general increase in the cost of drilling operations. Some of the cost increase associated with drilling, running surface casing, and pressure testing wells can be attributed to this phenomenon.

Participants were also asked two questions regarding well logging costs both pre- and post- SB 94-177. When developing the survey, concerns were raised by industry representatives that increased logging requirements placed on operators by COGCC had increased logging costs and the potential for lost equipment in holes. The questions included in the survey were designed to capture impacts of increasing logging requirements.

The average real costs of well logging both pre- and post- SB 94-177 are shown in Table 4.3-15. In general, all participants but two reported an increase in the real cost of well logging operations. The change in average real cost of logging ranged from a decrease of 12 percent to an increase of 134 percent. Although the new rule requires all wells to be logged, respondents indicated that the cost increase was not due to any changes in logging requirements imposed by COGCC. All the respondents indicated that they logged over 90 percent of their wells prior to the rule change. Therefore, most wells would have been logged anyway, thus the change in the rule would not have an impact on most companies. During the interviews operators stated that the increased cost associated with logging has been impacted by an increase in the cost of labor and a consolidation of companies that offer this service.

Table 4.3-15
Well Logging Costs

Survey No.	Total Cost of Logging a Well Since 1994 (1999$)	Total Cost of Logging a Well Prior to 1994 (1999$)	Percentage Change in Real Cost of Well Logging
(1)	(2)	(3)	(4)
1	$4,011	$3,342	20%
2	$3,424	$2,897	18%
3	$3,718	$3,119	19%
4	$3,180	$3,342	-5%
5	$2,935	$3,342	-12%
6	$3,718	$3,119	19%
7	$4,158	$3,119	33%
8	$6,849	$6,127	12%
9	$7,827	$3,342	134%
Average Cost per Well	$4,425	$3,528	25%

A final set of questions in this section focused on the average cost to complete a well pre- and post- SB 94-177. The results are summarized in Table 4.3-16. The table is organized by average well depth and location of wells. In general, the average real cost of completing a well has decreased in the D-J Basin and NE Colorado. However, the one participant who operates in the San Juan Basin indicated an increase of 5 percent in the average real cost to complete a well.

Table 4.3-16
Well Completion Costs

Survey No.	Total Cost of Completing a Well Since 1994 (1999$)	Total Cost of Completing a Well Prior to 1994 (1999$)	Percentage Increase in Real Cost of Well Completion	Average Depth	Location
(1)	(2)	(3)	(4)	(5)	(6)
3	NA	NA	NA	8000	DJ Basin
5	$208,446	$237,347	-12%	7500	DJ Basin
6	NA	NA	NA	8000	DJ Basin
7	$146,759	$135,147	9%	7000	DJ Basin
9	$206,881	$215,000	-4%	7500	DJ Basin
Average Cost	***$187,362***	***$195,855***	-4%		
1	$144,411	$155,409	-7%	4300	NE Colorado
2	$40,095	$44,539	-10%	6000	NE Colorado
4	$60,660	$60,782	0%	2500	NE Colorado
Average Cost	***$110,957***	***$117,320***	-5%		
8	$234,814	$224,452	5%	2350	San Juan Basin (SW Colorado)

Note: NA means not available or not applicable.

4.3.9 Safety Requirements

Section 9.0 of the survey focused on safety requirements for drilling operations pre- and post- SB 94-177. Of the surveys completed, only one respondent answered questions regarding safety issues. This company indicated that the average cost of safety measures had increased from approximately $3,000 per well in 1994 to $3,400 per well in 2000. Most companies surveyed indicated that, while they do comply with certain safety requirements, it was difficult to break out the cost of these requirements from other drilling costs. This is especially true for operators who use turnkey contracts for drilling purposes. It is likely that the increase in safety requirements has not had a significant impact on the average drilling costs in Colorado.

4.3.10 Requirements and Costs of Flowlines

COGCC established new rules for flowline construction, maintenance, safety and abandonment under the 1100 Series Rules after SB 94-177. Section 10 of the survey was designed to solicit information from companies on their experience installing, maintaining and reclaiming flowlines. This section summarizes the results.

Table 4.3-17 summarizes the average real cost per foot of flowline installation both pre- and post- SB 94-177. Three of the four small companies interviewed reported cost data ($/foot) on flowline installation. One company indicated that the real cost of flowline installation had decreased since 1994. However, two other companies reported an increase in the real cost of flowline installation by as much as 32 percent between 1994 and 2000.

Table 4.3-17
Average Cost of Flowline Installation

Survey No.	Total Cost ($/ft) of Flowline Installation (1999s)		
	Since 1994	Prior to 1994	% Change in Cost
(1)	(2)	(3)	(4)
1	$3.91	$4.46	-12%
2	$3.77	$3.51	7%
3	NA	NA	NA
7	$5.14	$3.90	32%
Average Cost for Small Companies	***$4.27***	***$3.95***	***8%***
4	$1.96	$2.23	-12%
5	$4.30	$3.34	29%
6	NA	NA	NA
8	$24.46	$23.66	3%
9	$4.89	$4.47	9%
Average Cost for Large and Medium Companies	***$8.90***	***$8.43***	***6%***
Average Cost for All Companies Surveyed	***$6.92***	***$6.51***	***6%***

Note: NA means not available or not applicable.

The overall average real cost of flowline installation has increased by 8 percent for small companies and 6 percent for large and medium sized companies. For all companies surveyed, the average real cost of flowline installation increased by 6 percent over the study period.

It is likely that much of the increase in the average real cost for flowline installation is due to new flowline regulations. This includes provisions for design, materials and proper cover used during flowline installation.

In the next section of the survey, participants were also queried regarding their experience with pressure testing flowlines. The results of the pressure testing questions are shown in Table 4.3-18. Under the 1100 Series Rules, operators are now required to pressure test flowlines to their maximum anticipated operating pressures. The questions in Section 10 asked participants to estimate the cost to pressure test flowlines both pre- and post- SB 94-177. According to Table 4.3-18, small companies have experienced a 372 percent increase in costs due to flowline pressure testing from $149 per line prior in 1994 and $700 per line in 2000. The significant increase in the cost of pressure testing for small companies was driven by the fact that two companies reported that they did not normally pressure test flowlines prior the rule change. One company indicated they normally pressure-tested flowlines prior to 1994 but also experienced a 120 percent increase in the cost to test lines.

Table 4.3-18
Cost of Flowline Pressure Testing

Survey No.	Total One-Time Cost of Flowline Pressure Testing Since 1994 (per Flowline) (1999$)		
	Since 1994	**Prior to 1994**	**% Change in Cost**
(1)	**(2)**	**(3)**	**(4)**
1	$489	$0	489%
2	$636	$0	636%
3	NA	NA	NA
7	$978	$446	120%
Average Cost for Small Companies	***$701***	***$149***	***372%***
4	$1,272	$1,170	9%
5	$685	NA	NA
6	NA	NA	NA
8	$1,468	$1,420	3%
9	NA	NA	NA
Average Cost for Large and Medium Companies	***$1,370***	***$1,295***	***6%***
Average Cost for All Companies Surveyed	***$969***	***$607***	***60%***

Note: NA means not available or not applicable.

The two large and medium sized companies responded to the question regarding the cost to pressure test flowlines. The first company indicated that they now incur, on average, a real cost of $685 per line to pressure test their flowlines. While this company did indicate they regularly pressure-tested flowlines prior to 1994, they did not have access to specific cost data on this action. The other two companies indicated they have experienced a 3 percent and 9 percent increase in the average real cost of flowline pressure testing since 1994.

Overall, it appears that the average cost of flowline pressure testing has increased for operators, although the impact of the regulation on these costs varies from company to company. For instance the rule change appears to have affected small companies differently than large and medium sized companies. Two of the small companies interviewed indicated they normally did not pressure test their flowlines prior to the rule change. Therefore, the new regulation has added that additional cost to their operations. However, for companies that did normally pressure test flowlines prior to the rule change, the new requirement has had a mixed impact on their development costs. One small company did report a significant increase in flowline pressure testing cost, while two larger companies reported a small increase in average real cost of testing. It is likely that the new regulations have had a bigger impact on the cost to small operators and less of an impact on medium and large sized companies.

Participants were also asked questions regarding their experience with the "One Call" Database system. COGCC now requires operators to participate in the system that maintains a database on all pipelines in the state. Operators were initially asked to provide flowline locational information for the database that can be used for emergency purposes. The participants of the survey were asked to estimate the cost of locating all flowlines for the One Call database. It appears that the cost of this requirement was minimal to operators at approximately $100 to $250 per company.

Another area evaluated under Section 10 of the survey was the annual cost to repair and maintain flowlines under the rules both pre- and post- SB 94-177. The results are summarized in Table 4.3-19. According to this table, small operators reported a decrease in the average annual real cost of flowline maintenance of 9 percent. Large and medium sized companies reported an increase in the annual real cost of flowline maintenance of 12 percent from $1,758 prior to 1994 to $1,971 in 2000. For all companies that responded to this question, the annual flowline maintenance cost appears to have increased by a modest 3 percent.

Table 4.3-19
Annual Cost of Flowline Maintenance

Survey No.	Average Cost per Company of Flowline Maintenance (1999$)		Change in Annual Cost of Flowline Maintenance
	Since 1994	Prior to 1994	% Change in Cost
(1)	(2)	(3)	(4)
1	NA	NA	NA
2	$3,424	$3,899	-12%
3	NA	NA	NA
7	$587	$501	17%
Average Cost for Small Companies	***$2,006***	***$2,200***	***-9%***
4	$440	$0	440%
5	$196	$111	76%
6	NA	NA	NA
8	$5,278	$5,164	2%
9	NA	NA	NA
Average Cost for Large and Medium Companies	***$1,971***	***$1,758***	***12%***
Average Cost for All Companies Surveyed	***$1,985***	***$1,935***	***3%***

Note: NA means not available or not applicable.

Finally, companies were asked to estimate the average cost of flowline reclamation both pre- and post- SB 94-177. Table 4.3-20 summarizes the results. Small operators reported a 3 percent increase in the cost of flowline reclamation between 1994 and 2000. On average, flowline restoration cost has increased for small companies from approximately $1,128 per line prior to 1994 to $1,162 per line in 2000. The two large and medium sized companies responded to this question and indicated that reclamation costs have increased 35 percent from approximately $1,052 per line in 1994 to $1,419 in 2000. For all companies, flowline reclamation cost was shown to have increased by 67 percent.

The increase in flowline reclamation cost can be partially attributed to the change in rules. COGCC now specifies requirements for flowline abandonment and reclamation in the 1100 Series Rules. The new rule states requirements for subsidence and compaction alleviation, restoration, and revegetation of flowlines according the requirements established under rule 1003 and 1004 for reclamation of well site locations. It appears that these new requirements for flowline reclamation are having an impact on operators.

Table 4.3-20
Annual Cost of Flowline Reclamation

Survey No.	Average Cost per Flowline for Flowline Reclamation (1999$)		
	Since 1994	Prior to 1994	% Change in Cost
(1)	(2)	(3)	(4)
1	na	na	na
2	$1,184	$323	266%
3	na	$0	na
7	$783	$446	76%
Average Cost for Small Companies	***$1,162***	***$1,128***	***3%***
4	na	na	na
5	$2,348	$2,005	17%
6	na	na	na
8	na	na	na
9	$489	$98	400%
Average Cost for Large and Medium Companies	***$1,419***	***$1,052***	***35%***
Average Cost for All Companies Surveyed	***$1,201***	***$718***	***67%***

Note: NA means not available or not applicable.

4.3.11 Performing Interim Well Site Reclamation

Most of the interim well site reclamation rules are new since SB 94-177. Requirements focus on subsidence and compaction alleviation, drill pit closure and revegetation. Section 13 of the survey presented a series of questions to participants on their experience with interim well site reclamation on both crop and non-crop lands. This section summarizes the results.

Interim Reclamation on Crop Lands

The average real cost of interim well site reclamation on crop lands both pre- and post- SB 94-177 is summarized in Table 4.3-21. Participants were first asked to estimate the cost to dispose of fluids and cuttings from the drilling operation pre- and post- SB 94-177. Columns 2 through 4 show the responses. For small companies, the average real cost to dispose of fluids and cuttings has increased by over 326 percent. This is due to the fact that three out of the four small operators interviewed indicated that prior to 1994, they used a land farming technique to dispose of fluids and cuttings. This basically involved spreading the fluids and cuttings on the ground near the drill site where they dried. The operators reported a minimal cost for this method of disposal. New rules have increased the requirements for disposal of drilling fluids and cuttings and it appears the new requirements have increased the costs to small operators.

Four large or medium sized companies responded regarding the cost of fluid and cutting disposal. Two companies indicated a relatively small increase in the average real cost of disposal from 2 percent to 5 percent. A third company reported a 67 percent decrease in the cost of fluid and cutting disposal. The company representative indicated their cost of disposal had decreased due to a new process that recycles drilling mud. This allows the company to use less make-up mud on site during drilling and decreases disposal cost.

Another cost item summarized in Table 4.3-21 is the total cost of interim well site reclamation. All four small companies reported their average real cost of interim reclamation; and their responses are reported in Columns 5 through 7. Small operators reported a significant increase in the cost of interim reclamation between 1994 and 2000. On average, the real cost of interim reclamation per well increased from $706 per well in 1994 to $2,620 per well in 2000 or a 271 percent increase. It is likely that most of the cost increase is due to the increased requirements placed on operators for interim reclamation after SB 91-177.

Large and medium sized companies also reported an increase in the cost of interim well site reclamation, however, the increase was not as significant as was reported for small operators. On average, the average real cost of interim reclamation increased from $4,714 per well prior to 1994 to $5,173 per well in 2000 or an increase of 10 percent. Overall, the average increase in interim reclamation for all companies surveyed was 44 percent between 1994 and 2000.

Interim Well Site Reclamation on Non-Crop Lands

The average real cost estimates for interim well site reclamation on non-crop lands as reported by companies surveyed are summarized in Table 4.3-22. In Columns 2 through 4 the average real cost of fluid and cutting disposal as reported by small, medium and large companies is provided. Only one small company responded to questions regarding disposal of fluids and cuttings during interim well site reclamation on non-crop lands. The other small companies indicated they did not have experience with fluid or cutting disposal on non-crop lands. The one small company reported an increase of $734 per well for exploration waste disposal on non-crop lands. Four large and medium sized companies reported changes in disposal costs for fluids and cuttings on non-crop lands. These companies reported a decrease in the average real cost of disposal between 1994 and today by an average of 22 percent. Overall, the average cost of fluid and cuttings disposal for wells on non-crop lands decreased by 16 percent from 1994 to 2000.

Small companies again reported a significant increase in the average real cost of interim well site reclamation on non-crop lands as was reported for these activities on crop lands. Columns 5 through 7 summarize the responses from three out of the four small companies. On average, small companies reported a 190 percent increase in the cost of interim well site reclamation for wells on non-crop lands. Large and medium sized companies also reported an increase in the average real cost of interim well site reclamation. For these companies interim well site reclamation increased 17 percent from $3,217 per well prior in 1994 to $4,452 per well in 2000. Overall, the average real cost of interim well site reclamation on non-crop lands for all companies surveyed increased by 47 percent.

Table 4.3-21
Cost Estimates of Interim Reclamation on Crop Lands

Survey No.	Cost per Well of Fluids and Cuttings Disposal for wells on Crop Lands (1999$)			Cost per Well of Interim Reclamation on Crop Lands (1999$)		
	Since 1994	Prior to 1994	% Change in Cost	Since 1994	Prior to 1994	% Change in Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	NA	NA	NA	$1,468	$0	1468%
2	$734	$0	734%	$2,260	$1,710	32%
3	$1,468	$0	1,468%	$2,935	$0	2935%
7	$1,468	$0	1,468%	$3,816	$1,114	243%
Average Cost for Small Companies	***$1,223***	***$0***	***1,223%***	***$2,620***	***$706***	***271%***
4	$1,076	$1,114	-3%	$2,006	$1,560	29%
5	$3,620	$3,565	2%	$4,892	$4,122	19%
6	NA	NA	NA	NA	NA	NA
8	$1,468	$4,456	-67%	$6,360	$5,487	16%
9	$2,935	$2,785	5%	$7,436	$7,687	-3%
Average Cost for Medium and Large Companies	***$2,275***	***$2,980***	***-24%***	***$5,173***	***$4,714***	***10%***
Average Cost for All Companies Surveyed	***$1,824***	***$1,703***	***8%***	***$3,896***	***$2,710***	***44%***

Note: NA means not available or not applicable.

Table 4.3-22
Cost Estimates of Interim Reclamation on Non-Crop Lands

Survey No.	Cost of Fluids and Cuttings Disposal for Wells on Non-Crop Lands (1999$)			Cost per Well of Interim Reclamation on Non-Crop Lands (1999$)		
	Since 1994	Prior to 1994	% Change in Cost	Since 1994	Prior to 1994	% Change in Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	NA	NA	NA	NA	NA	NA
2	NA	NA	NA	$2,651	$2,128	25%
3	NA	NA	NA	$2,935	$0	2935%
5	$734	$0	734%	$3,816	$1,114	243%
Average for Small Companies	***$734***	***$0***	***734%***	***$3,134***	***$1,081***	***190%***
4	$1,076	$947	13.65%	$2,886	$2,172	33%
5	$3,620	$3,565	1.55%	$4,892	$4,122	19%
6	NA	NA	NA	NA	NA	NA
8	$1,468	$4,456	-67%	$6,360	$5,520	15%
9	$2,935	$2,785	5%	$3,669	$3,454	6%
Average for Medium and Large Companies	***$2,275***	***$2,93***	***-22%***	***$4,452***	***$3,817***	***17%***
Average for All Companies Surveyed	***$1,967***	***$2,351***	***-16%***	***$3,887***	***$2,644***	***47%***

Note: NA means not available or not applicable.

The increased requirements placed on operators regarding interim well site reclamation have had an impact on the cost as reported by the companies surveyed. The requirements appear to have had a larger cost impact on small companies than on large or medium sized companies. This may be due to the fact that large and medium sized companies employed many of the same requirements now listed in the regulations prior to the rule change. As a result, the regulations have not had a significant impact on medium and large operators' costs. In some cases, such as with fluids and cuttings disposal, the average real cost has actually decreased for some companies. This is not the case for the small companies, who in general are reporting significant increases for fluid and cuttings disposal and total interim reclamation costs. For all companies, the cost of interim well site reclamation appears to be higher for wells located on crop lands than for wells located on non-crop lands.

4.3.12 Reporting Production and Payment of COGCC Levy During the Life of a Well

Since SB 94-177, COGCC has made some changes in the way operators report production. The regulations now require that operators report monthly production by well and formation. Prior to this rule change, operators could report monthly production by lease. Section 14 presented three questions regarding the cost of converting to this new reporting system. Conversion costs across all companies varied dramatically from $0 to $24,550. For some companies, the change in reporting requirements required a significant change in computer operations. Additionally, some companies indicated their annual cost had increased to comply with the new reporting requirements. This was the case for operators who have more than one well on a common meter. One operator indicated that the new reporting requirements meant increased testing, accounting and other actions for their commonly metered wells. These actions cost the company an additional $1,200 per month for the 100 wells that are on a common meter. For other companies, the change in reporting did not significantly affect their operations because they organized production data by well and formation prior to the rule change.

Participants were also asked whether they have realized a cost savings since the new reporting system was put in place. Of the companies interviewed, none indicated they had realized a cost savings from the new system. Finally, participants were asked if they realized any benefits associated with the new system. All but one company indicated the new system did not offer any additional informational benefits. However, one company indicated they have realized a benefit associated with their exploration activities. This company typically likes to explore in areas with heterogeneous reservoir characteristics. Production data organized by well and formation is very useful for exploration in these areas.

4.3.13 Shutting-in or Temporarily Abandoning a Well

Section 15 of the survey asked the respondents a series of questions regarding their experience with shutting-in and temporarily abandoning wells. A summary of the responses is provided in Table 4.3-23. Three small companies responded to questions regarding shutting-in wells. Two of these companies indicated that their average cost to shut-in a well had increased from essentially zero prior to 1994 to between $1,468 and $4,011 per well in 2000. A third small company indicated their average real cost to shut-in a well had decreased by 11 percent from $680 prior to 1994 to $607 in 2000.

Three large or medium sized companies also responded to questions regarding shutting-in a well. For these companies, the average real cost to shut-in a well had increased by 64 percent from $413 to $670 per well.

Overall, the average cost to shut-in a well for all companies surveyed has increased by over 323 percent. For some companies, the cost to shut-in a well has increased from $0 prior to 1994 to as much as $4,011 per well in 2000. Most companies indicated a slight increase in average cost to file Form 5 and Form 6 to shut-in a well. However, the greatest impact on the cost of shutting-in a well has been the increased frequency of completing a Mechanical Integrity Test (MIT) required by COGCC in order to shut-in a well. While the rules regarding the process for shutting-in a well have not changed, it appears that COGCC's interpretation of how these rules should be applied has evolved since 1994. COGCC is now requiring MITs on an increasing number of wells. Some respondents indicated that these increasing MIT requirements have added an additional $600 to $4,000 per shut-in well.

Table 4.3-23
Average Cost of Shutting-in or Temporarily Abandoning a Well

Survey No.	Average Cost per Well to Shut-in or Temporarily Abandon a Well (1999$)		
	Since 1994	Prior to 1994	% Change in Cost
(1)	(2)	(3)	(4)
1	$1,468	$0	1468%
2	$607	$680	-11%
3	NA	NA	NA
7	$4,011	$0	4011%
Average Cost for Small Companies	***$2,029***	***$227***	***796%***
4	NA	NA	NA
5	$391	$0	391%
6	NA	NA	NA
8	$1,148	$764	50%
9	$489	$474	3%
Average Cost for Medium and Large Companies	***$676***	***$413***	***64%***
Average Cost for All Companies Surveyed	***$1,352***	***$320***	***323%***

Note: NA means not available or not applicable.

4.3.14 Recompleting a Well and Commingling Production

In Section 16 of the survey, respondents were asked questions regarding the average cost to recomplete a well, both pre- and post- SB 94-177. Table 4.3-24 summarizes the results of this section. Only one small company responded to questions regarding recompletion of wells. The other small companies indicated they had not been through this process. This company indicated their average real cost had increased from $55,702 per well prior to 1994 to $80,316 per well in 2000. Three large or medium sized companies responded to this section. For one company, the average cost to recomplete a well had decreased by 12 percent. For the other two respondents, the average real cost had increased by over 50 percent. Overall, the average real cost of recompleting a well increased by 39 percent from $124,739 per well prior to 1994 to $173,161 per well in 2000.

The companies that responded to this section indicated that the increase in cost was driven by changes in technology and increasing labor costs. Most companies did not feel that changes in regulations had a significant impact on the average real cost to recomplete a well. However, one company did indicate that new rules had caused delays in plans to recomplete wells in some areas.

Table 4.3-24
Cost to Recomplete a Well

Survey No.	Total Cost per Well to Recomplete a Well (1999$)			Total Cost per Well of Remedial Cementing During Recompletion (1999$)
	Since 1994	Prior to 1994	% Change in Cost	
(1)	(2)	(3)	(4)	(5)
1	NA	NA	NA	NA
2	NA	NA	NA	NA
3	NA	NA	NA	NA
7	$80,316	$55,702	44%	$7,044
Average Cost for Small Companies	***$80,316***	***$55,702***	***44%***	***$7,044***
4	NA	NA	NA	NA
5	$98,328	$111,126	-12%	$19,568
6	NA	NA	NA	NA
8	$415,914	$269,289	54%	$61,325
9	$98,084	$62,834	56%	$15,331
Average Cost for Medium and Large Companies	***$204,109***	***$147,750***	***38%***	***$32,075***
Average Cost for All Companies Surveyed	***$173,161***	***$124,738***	***39%***	***$25,817***

Note: NA means not available or not applicable.

4.3.15 Plugging and Abandoning a Well at the End of its Useful Life

In Section 17 of the survey, respondents were asked three questions regarding plugging and abandoning wells. A summary of the results is shown in Table 4.3-25. Three small companies completed this section, indicating the change in average real cost to plug and abandon a well ranged from a decrease of 12 percent to an increase of 62 percent.

Table 4.3-25
Cost to Plug and Abandon a Well

Survey No.	Average Cost per Well to Plug and Abandon a Well (1999$)		
	Since 1994	**Prior to 1994**	**%Change in Cost**
(1)	**(2)**	**(3)**	**(4)**
1	$1,223	$1,393	-12%
2	$8,825	$8,467	4%
3	NA	NA	NA
7	$13,551	$8,355	62%
Average Cost for Small Companies	***$7,866***	***$6,072***	***30%***
4	NA	NA	NA
5	$10,175	$10,695	-5%
6	NA	NA	NA
8	$10,410	$9,748	7%
9	$7,925	$8,912	-11%
Average Cost for Medium and Large Companies	***$9,503***	***$9,785***	***-3%***
Average Cost for All Companies Surveyed	***$8,685***	***$7,928***	***10%***

Note: NA means not available or not applicable.

For large and medium sized companies, the change in the average real cost to plug and abandon a well ranged from a decrease of 11 percent to a 7 percent increase. Overall, it appears that the average cost to plug and abandon wells has increased by 10 percent from $7,928 per well prior to 1994 to $8,685 in 2000.

Respondents indicated during the interviews that any increase in the cost associated with plugging and abandoning wells was not due to changes in rules or requirements.

4.3.16 Performing Final Well Site Reclamation

The last section of the survey focused on the average real cost of final well site reclamation. Like interim well site reclamation, COGCC has made significant changes to the requirements for final well site reclamation. Significant changes that were made after SB 94-177 include site investigation, remediation and closure requirements. Additionally, operators are now required to consult with the surface owner concerning final reclamation plans. Questions in Section 18 were designed to determine if the rule changes have added additional costs for final well site reclamation. The results for crop and non-crop lands are discussed below.

Final Reclamation on Crop Lands

Table 4.3-26 summarizes the responses to questions regarding final well site reclamation on crop lands. The average total costs to remove surface equipment and reclaim the well site are summarized in Columns 2 through 4. Five companies responded to this section of the survey. The other respondents indicated that they had not been through the process and were unable to report any cost information. One small company that did respond indicated that it had experienced a slight increase of one percent in the real cost to remove surface equipment and perform final well site reclamation between 1994 and 2000. The average cost for the four large and medium-sized companies that responded increased by 20 percent. However, one company reported a 24 percent decrease in the average cost of final well site reclamation. The reason for the significant decrease in cost for this company was due to the reduction in the size of well site location. This reduces the cost of reclaiming a well site. Overall, the average cost for all five companies to remove surface equipment and reclaim sites increased by 15 percent.

The average real costs to dispose of fluids and other waste during well site reclamation are summarized in Columns 5 through 7. Four companies who responded to this part of the survey indicated an average increase in the real cost of fluid and waste disposal of 24 percent from $979 per well prior to 1994 to $1,211 per well in 2000.

Final Well Site Reclamation on Non-Crop Lands

Table 4.3-27 summarizes the responses to questions regarding final well site reclamation on non-crop lands. Columns 2 through 4 show the average estimated real costs per well of surface equipment removal and site reclamation for six respondents. According to the information provided, small companies experienced an 18 percent increase in the average real cost to remove surface equipment and restore well site locations on non-crop lands. Large and medium companies experienced a 29 percent increase in the average cost of final well site reclamation on non-crop lands.

In columns 5 through 7, the average costs per well of fluid and waste disposal are summarized. Here, one small company provided information on the average cost of fluid and waste disposal. This company indicated their cost had increased from $251 per well prior to 1994 to $342 per well in 2000. The three large and medium sized companies responded to the questions regarding the average cost of fluid and waste disposal. These companies experienced a 1,370 percent increase for waste disposal from $109 per well prior to 1994 to $1,595 per well in 2000. Overall, the average cost to dispose fluid and waste increased by 668 percent from 1994 to 2000.

Respondents were also asked to estimate the average time and cost needed to comply with surface owner notification and Form 27 requirements. Three participants responded to this question and on average, the cost to complete Form 27 and surface owner notification has added an additional $670 per well after 1994 or a 479 percent increase.

Examining the average real cost changes for final reclamation on both crop and non-crop lands indicates that all but two companies have experienced an increase in cost after 1994. It is likely

Table 4.3-26
Cost of Final Well Site Reclamation - Crop Lands

Survey No.	Average Cost per Well of Site Reclamation and Removal of Surface Equipment for Wells on Crop Lands (1999$)			Average Cost per Well of Disposing of Production Fluids and Waste for Wells Located on Crop Lands (1999$)		
	Since 1994	Prior to 1994	% Change in Cost	Since 1994	Prior to 1994	% Change in Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	NA	NA	NA	NA	NA	NA
2	$7,118	$7,074	1%	NA	NA	NA
3	NA	NA	NA	NA	NA	NA
7	NA	NA	NA	$342	$251	37%
Average Cost Per Well for Small Companies	***$7,118***	***$7,074***	***1%***	***$342***	***$251***	***37%***
4	$9,686	$3,955	145%	$3,914	$3,342	17%
5	$2,935	$2,785	5%	$489	$223	120%
6	NA	NA	NA	NA	NA	NA
8	$5,000	$6,612	-24%	NA	NA	NA
9	$6,066	$6,305	-4%	$98	$102	-4%
Average Cost Per Well for Medium and Large Companies	***$5,922***	***$4,914***	***20%***	***$1,500***	***$1,222***	***23%***
Average Cost Per Well for All Companies Surveyed	***$6,161***	***$5,346***	***15%***	***$1,211***	***$979***	***24%***

Note: NA means not available or not applicable.

Table 4.3-27
Final Reclamation on Non-Crop Lands

Survey	Average Cost of Site Reclamation and Removal of Surface Equipment for Wells on Non-Crop Lands (1999$)			Average Cost of Disposing of Production Fluids and Waste for wells located on Non-Crop Lands (1999$)		
	Since 1994	Prior to 1994	% Change in Cost	Since 1994	Prior to 1994	% Change in Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	NA	NA	NA	NA	NA	NA
2	$7,597	$7,420	2%	NA	NA	NA
3	NA	NA	NA	NA	NA	NA
7	$8,414	$6,127	37%	$342	$251	37%
Average Cost Per Well for Small Companies	***$8,006***	***$6,773***	***18%***	***$342***	***$251***	***37%***
4	$10,762	$4,390	145%	$4,207	$1	--
5	$2,935	$2,785	5%	$489	$223	120%
6	NA	NA	NA	NA	NA	NA
8	$5,000	$6,612	-24%	NA	NA	NA
9	$2,446	$2,542	-4%	$89	$102	-12%
Average Cost Per Well for Medium and Large Companies	***$5,286***	***$4,082***	***29%***	***$1,595***	***$109***	***1370%***
Average Cost Per Well for All Companies Surveyed	***$5,280***	***$4,928***	***7%***	***$629***	***$171***	***668%***

Note: NA means not available or not applicable.

that a certain proportion of these costs are due to new requirements implemented by COGCC after SB 94-177. This includes actual reclamation requirements as well as notification and reporting standards.

4.4 Surface Location Scenarios

This study also examined the cost to comply with COGCC Rules and Regulations, both pre- and post- SB 94-177 in four locations as described as follows.

- **Scenario 1** - A well located in a relatively level pasture in Yuma County;
- **Scenario 2** - A well located in rural residential non-crop land in LaPlata County;
- **Scenario 3** - A well located in high-valued agricultural crop lands in Weld County, in the Fox Hills Aquifer Protection Area; and
- **Scenario 4** - A well located in a High Density Area as defined in the COGCC Rules and Regulations in or near a municipality in Weld County.

The results of this analysis are discussed below.

4.4.1 Cost Change Under Scenario 1 – A Well Located in Yuma, County Colorado

Three companies that operate in Yuma County completed the survey. The analysis of data collected from these three companies is summarized in Table 4.4-1. Column 1 lists the stages of the well life cycle. Column 2 summarizes the change in average cost for the companies that operate in Yuma County for each stage of the well life cycle between 1994 and 2000. Column 3 indicates the likelihood that changes in oil and gas regulations have impacted the change in cost of operations.

Six life cycle stages had cost changes greater than $1,000 per well between 1994 and 2000 for operations in Yuma County including Posting Financial Assurance, Pit Inventories, Interim and Final Well Site Reclamation, Production Reporting, and Recompletion. There is a significant likelihood that rule changes have caused cost increases in four of the six stages. These stages are Pit Inventories, Interim and Final Well Site Reclamation, and Production Reporting. Unlike the other life cycle stages where cost increases occurred, the analysis indicated a significant cost decrease associated with recompleting wells in Yuma County which is not due to changes in the rules and regulations. However, only one company reported the cost of recompleting wells in Yuma county.

Table 4.4-1
Summary of Cost Changes and Regulatory Impacts for Surface Location Scenario 1 - A Well Located in Yuma County, Colorado

Well Life Cycle Stage	Average Change in Real Cost per Well at Each Life Cycle Stage between 1994 and 2000 for Operations in Yuma County (1999$)	Likelihood that Regulatory Changes Have Impacted Real Cost of Each Life Cycle Stage
(1)	(2)	(3)
1. APD Process	$431	Significant
2. Posting Financial Assurance[a]	$1,419	Low
3. Notice and Consultation:		
Notice and Consult	$368	Moderate
Surface Owner Agreement	$365	Low
Surface Damage Payment	$399	Low
4. Building Well Site Locations and Access Roads:		
Rig Moves and Set Up[b]	$276	Low
Well Site Development	$538	Moderate to Significant
5. Preparing Application for a Pit to Accept Produced Water:		
Pit Inventory[a]	$13,353	Significant
Pit Permitting	Insufficient data[d]	Insufficient data[d]
6. E&P Waste Management:		
Exploration Waste	See results for interim reclamation	
Production Waste	$35	Low
7. Drilling, Casing and Completing a Well:[c]	-$1,226	Low
8. Safety Requirements	Insufficient data[d]	Insufficient data[d]
9. Flowline Installation ($/ft)[a]	-$0.19	Low
12. Interim Reclamation:		
Crop Lands	$1,053	Significant
Non-Crop Lands	$619	Significant
13. Production Reporting[a]	$4,718	Significant
14. Shutting-in a Well	$698	Moderate
15. Recompletion[b]	-$12,798	Low
16. Plugging and Abandonment	-$111	Low
17. Final Well Site Reclamation:		
Crop Lands	$3,570	Significant
Non-Crop Lands	$5,914	Significant

a Not reported on a per well basis. Posting financial assurances, pit inventory and production reporting costs are reported per company. Flowline installation is reported per foot.
b Only one company reporting.
c Costs are highly dependent on well depth that ranges from 2,500 to 6,000 for the three respondents who operate in Yuma County.
d No companies operating in Yuma County responded to questions regarding pit permitting or safety requirements.

4.4.2 Cost Changes Under Scenario 2 – A Well Located in La Plata County, Colorado

One company that operates in LaPlata County responded to the survey regarding the cost of their operations. The results are summarized in Table 4.4-2. Several interesting insights are apparent when examining Table 4.4-2. First, this company experienced a reduction in average real cost for three well life cycle stages including Well Site Development and Interim and Final Well Site Reclamation. For all three stages, average real costs have decreased because the company reduced the size of their well site locations. This resulted in a reduction in development and reclamation costs.

Average real costs increased by more than $1,000 per well for Surface Owner Agreements, Surface Damage Payments, Rig Moves and Set-ups, Pit Inventories, Production Waste Disposal, Drilling and Completing a Well and Recompletion. While this company experienced cost increases at several stages of the well life cycle, this company reported that changes to Colorado's Oil and Gas Rules have had little impact. The changes in rules and regulations have likely had a significant impact on cost increases for the APD process and the mandatory pit inventory. However, the cost increase associated with the APD process has been quite minimal at $322 per well between 1994 and 2000. The cost of the pit inventory was $4,033 and represents a one-time cost for the company. This cost is not reported on a per well basis.

Additionally, it is likely that changes in rules and regulations had a moderate impact on the cost associated with the surface owner notification process. Most operators, including the operator in LaPlata County, have indicated an increased tension between surface owners and operators. As a result, operators are spending more time in negotiations with surface owners regarding Surface Owner Agreements and damage payments. In La Plata County, SOA costs and surface damage payments have increased. Changes in rules and regulations have increased the rights of surface owners regarding oil and gas exploration and production operations. While these changes have not directly addressed the SOA or damage payments, they have increased the awareness of surface owners and may have indirectly impacted the negotiations between operators and surface owners. Therefore, it is concluded that the change in rules and regulations had a moderate impact on the notice and consultation stage of the well life cycle.

Rule changes have also likely had a moderate impact on the cost associated with shutting-in a well in LaPlata County. Here, rule changes have increased the reporting requirements. Additionally, COGCC, under the new rules, has increased the frequency of requiring MITs on shut-in wells. These changes have increased cost. However, they do not completely account for the cost increase under this well life cycle stage in LaPlata County. Therefore, it was concluded that the rule changes have had a moderate impact on the average cost of shutting-in a well. However, the increase in average cost of shutting-in a well in LaPlata County is not significant at $384 per well pre- and post- SB 94-177.

The LaPlata County operator also reported a significant average real cost increase associated with recompleting a well. The operator indicated the cost increase was primarily due to changes in technology and increasing labor costs and is not attributed to changes in Colorado's Oil and Gas Rules and Regulations.

Table 4.4-2
Summary of Cost Changes and Regulatory Impacts for Surface Location Scenario 2 - A Well Located in LaPlata County, Colorado

Well Life Cycle Stage	Average Change in Real Cost per Well of Each Life Cycle Stage between 1994 and 2000 for Operations in LaPlata County (1999$)	Likelihood that Regulatory Changes have Impacted Real Cost of Each Life Cycle Stage
(1)	(2)	(3)
1. APD Process	$322	Significant
2. Posting Financial Assurance[a]	No change	Low
3. Notice and Consultation		
Notice and Consult		
Surface Owner Agreement	$2,712	Moderate
Surface Damage Payment	$1,896	Low
4. Building Well Site Locations and Access Roads		
Rig Moves and Set Up	$1,356	Low
Well site Development	-$20,890	Low
5. Preparing Application for a Pit to Accept Produced Water		
Pit Inventory[a]	$4,033	Significant
Pit Permitting	insufficient data	insufficient data
6. E&P Waste Management		
Exploration Waste	See results for interim reclamation	
Production Waste	$3,904	Low
7. Drilling, Casing and Completing a Well[b]	$11,007	Moderate
8. Safety Requirements	insufficient data	insufficient data
9. Flowline Installation ($/ft)[a]	$0.35	Low
12. Interim Reclamation		
Crop Lands	-$2,988	Low
Non-Crop Lands	-$2,988	Low
13. Production Reporting[a]	No change	Low
14. Shutting-in a Well	$384	Moderate
15. Recompletion	$146,625	Low
16. Plugging and Abandonment	$662	Low
17. Final Well Site Reclamation		
Crop Lands	-$1,612	Low
Non-Crop Lands	-$1,612	Low

a Not reported on a per well basis.
b Based on preliminary drilling cost data.

4.4.3 Cost Changes Under Scenario 3 – Fox Hills Protection Area

A section of the survey specifically asked participants questions regarding their experience drilling in the Fox Hills Protection Area. COGCC has passed special rules that relate to oil and gas operations in the Fox Hills Protection Area since the passage of SB 94-177. Wells located in the Fox Hills Protection Area must comply with COGCC's Rule 317A. The rule addresses special drilling issues related to additional surface casing requirements for well control and aquifer protection.

The survey and interviews were successful in collecting data on the average real cost associated with rules regarding the Fox Hills Protection Area. Under guidelines passed after SB 94-177, operators now are required to increase the depth of surface casing that is run in wells drilled in the Fox Hills Protection Area. The increased casing requirements have added significant costs to wells as summarized in Table 4.4-3.

Table 4.4-3
Change in Average Cost of Drilling Due to Fox Hills Protection Area Rules

Survey	Total Cost per Well to Run Surface Casing in Fox Hills Protection Area (1999$)		Additional Cost per Well to Drill in the Fox Hills Protection Area (1999$)	Average Percentage Increase in Cost per Well to Drill in Fox Hills Protection Area
	Since 1994	Prior to 1994		
1	NA	NA	NA	NA
2	$16,907	$5,294	$11,613	219%
3	$13,697	$3,899	$9,798	251%
4	NA	NA	NA	NA
5	NA	NA	NA	NA
Average for Cost Per Well for Small Companies	***$15,302***	***$4,597***	***$10,706***	***233%***
6	$9,784	$11,140	-$1,357	-12%
7	$14,676	$5,013	$9,663	193%
8	NA	NA	NA	NA
9	$8,806	$7,798	$1,007	13%
Average for Cost Per Well for Medium and Large Companies	***$11,088***	***$7,984***	***$3,104***	***39%***
Average for Cost Per Well for All Companies Surveyed	***$12,774***	***$6,629***	***$6,145***	***93%***

Note: NA means not available or not applicable.

Two small operators reported average costs associated with drilling wells in the Fox Hills Protection Area both pre- and post- SB 94-177. Both small operators reported an increase of over 200 percent in the average cost associated with increased surface casing requirements in the Fox Hills Protection Area. This added an estimated $10,700 per well to drilling operations for these operators. The cost increase was not as significant for medium and large companies who reported an average increase in cost of 39 percent due to the surface casing requirements. Large and medium operators indicated that well costs have increased on average by $3,100 per well due to the increased casing requirements.

Overall, all companies except two reported a significant increase in the cost to drill in the Fox Hills Protection Area. All of the cost increases can be attributed to the rule change that requires operators to run surface casing to a minimum of 5 percent of total well depth. Participants indicated they have been required to increase the depth of surface casing from 200 to 500 feet prior to SB 94-177 to 500 to 1000 feet under the new rule. Surface casing normally costs $18 to $20 per foot, thus this requirement can and does add significant cost to well drilling in this area.

4.4.4 Cost Changes Under Scenario 4 – High Density Areas in Weld County, Colorado

Scenario 4 is defined as a well located in an area with high population density in or near a municipality in Weld, County. The cost analysis of wells located in high density areas considered the compliance and operating costs associated with 17 specific rules promulgated under COGCC's Rule 603. These rules include the following provisions that are in addition to the other drilling rules:

- Additional setback requirements for wellheads and production equipment;
- Additional blowout preventor equipment (BOPE) requirements for drilling and well services operations;
- Additional BOPE and drill stem testing requirements;
- Additional pit level indicators;
- Additional fencing, loadline, berm, guy line anchors, and access road requirements;
- Additional control of fire hazards and removal of surface trash;
- Additional tank specifications;
- Additional well site clearing requirements;
- Identification of plugged and abandoned wells; and
- Requirements to develop from existing well pads.

Section 12 of the survey asked participants questions regarding their experience operating in "High Density" areas. At this time, none of the participants surveyed and interviewed were able to report specific cost information on the specific requirements for operations in high density areas. This is due to two reasons. First, several of the companies surveyed do not operate in high density areas. Additionally, of the companies that do operate in high density areas, they were unable to separate out the cost of specific high density rules.

While no data was collected to indicate how the change in high density rules has affected the average real cost of drilling oil and gas wells in these areas, some information was uncovered during the interviews. Companies operating in high density areas indicated that operating in these areas, especially along the Front Range, is becoming increasingly difficult. This is not necessarily due to regulatory requirements placed on operators by COGCC but due to the increasing requirements of local governments. In many areas, operators need to obtain special use permits from counties or municipalities to drill wells which adds another layer of regulation to these operations.

Many of the small operators interviewed indicated that they are no longer looking to operate in areas that may be designated as high density. This is due to the increased requirements of oil and gas operations in these areas. There is also a concern among small operators that drilling in high density areas increases their risk and liability. Smaller companies appear unwilling to take on these risks at this time.

5.0 Analysis of Rule 508 Cost of Compliance

A second survey instrument was designed to address issues related to *Rule 508 - Local Public Forums, Hearings on Applications for Increased Well Density and Public Issues Hearings*. A separate survey instrument was developed for Rule 508 so all operators who have participated in this process could be surveyed and interviewed. Therefore, some operators were interviewed solely for their experience associated with Rule 508. Other operators participated in both surveys. A copy of the Rule 508 survey instrument is provided in Appendix C.

By June of 2000, COGCC had initiated and/or completed nine 508 Processes regarding well density applications in Colorado. Seven different companies participated in this regulatory process. The 508 survey was sent in June 2000 to all seven companies that have participated in the process. Three of the seven companies returned the survey regarding their experience while two responded verbally; two other companies indicated they were unable to complete the survey due to their very busy drilling schedule.

Rule 508 addresses Local Public Forums, COGCC Hearings and Public Issues Hearings as they apply to applications for increased well density.[1] Rule 508 is initiated when an application is made to the COGCC to create a new drilling unit or request additional wells within an existing drilling unit that were not previously approved by COGCC. According to this rule, COGCC requires a Public Forum to consider input from local governments and the public on the potential impacts to the environment, public health, safety and welfare from increased well density in a particular area. A COGCC Hearing will take place following a Public Forum to address the technical merits of an application. Upon conclusion of the COGCC Hearing, COGCC can order a Public Issues Hearing at the request of the applicant or a local government representative or at the discretion of COGCC. A Public Issues Hearing will be granted if the local government representative raises issues regarding the impacts of an application to the environment, public health, safety or welfare. Upon conclusion of the Public Issues Hearing, COGCC can approve the application with certain conditions that address concerns raised in the hearing, approve the application and stay its effective date to further address public concerns regarding the application, and/or deny the application.

The 508 survey was designed to ask participants questions regarding their experience with the 508 Process, including an estimate of cost to complete the process such as labor hours, expert witness testimony, research requirements, and other administrative costs. The cost of this process appears to vary depending on the site location. Additionally, it appears that, as time goes on, the public is becoming more educated and involved which can increase the complexity and length of the process.

Three participants completed the 508 Survey and the results are summarized in Table 5.1-1. The first two survey respondents participated in the 508 Process in 1999 and completed the Local

[1] *Colorado Oil and Gas Conservation Commission, Rules and Regulations, Rule 508 – LOCAL PUBLIC FORUMS, HEARINGS ON APPLICATIONS FOR INCREASED WELL DENSITY AND PUBLIC ISSUES HEARINGS, July 30, 1998.*

Public Forum and the COGCC Hearing on their application for increased density. In both cases, a Public Issues Hearing was not required, and thus these companies did not report any costs associated with this stage of the 508 Process. Both companies reported similar costs for the Local Public Forum of $4,500 and $4,238, respectively. However, Respondent 2 reported a higher cost for the COGCC Hearing. These companies reported that the process did not present a hardship to their operations, and one company indicated they thought the process and COGCC were quite helpful in educating the public regarding the issues related to their application.

Table 5.1-1
Estimated Cost of the 508 Process - Local Public Forums, Hearings on Applications for Increased Well Density and Public Issues Hearings

Survey	Estimated Cost of Local Public Forum	Estimated Cost of COGCC Hearing on Application	Estimated Cost of Public Issues Hearing	Total Estimated Cost of the 508 Process
001	$4,500	$2,750	NA	$7,250
002	$4,238	$4,128	NA	$8,366
003	$28,000	$56,100	$66,000	$150,100
004	NA	NA	NA	$772,425

Note: NA means not available or not applicable.

Respondent 3 summarized the costs associated with a 508 Process that was completed in 2000. The application was for a change in well spacing in LaPlata County. The company reported that the process cost $150,100. This includes $28,000 for the Local Public Forum, $56,100 for the COGCC Hearing and $66,000 for the Public Issues Hearing.

Respondent 4 provided the project team with a cost itemization for a 508 Process that was completed during 2000 for an application in Garfield County. The total cost of this particular process was estimated at $772,425. This includes all outside consulting and legal services as well as in-house costs. In this particular case, the respondent was asked to complete a Local Public Forum, a COGCC Hearing on the Application and a Public Issues Hearing. The cost data provided by this company was not broken out by each stage of the 508 Process as was provided by the other respondents. However, a great deal of detail was provided on the type of services used to complete the process.

A fifth company responded to the 508 survey questions during an interview regarding the more detailed survey on well life cycle cost. This company went through the process in 1999 for an application to increase well density in eastern Colorado. The company representative indicated that actual costs of the process were difficult to estimate. However, he felt the cost to complete the process was minimal and, at most, took two or three days of staff time to complete. He also indicated that the 508 Process is generally not a significant issue in eastern Colorado and therefore, has not caused a significant cost to his company in terms of time or money to complete the 508 Process.

The cost of the two 508 Processes completed in 2000 were significantly higher than those completed in 1999. There are likely two possible reasons for this phenomenon. First, the cost to complete this process is highly correlated with the location in Colorado where the application for changes in well spacing is to occur. Certain areas in Colorado have become significantly contentious regarding several types of development, including oil and gas development. In these cases, companies are allocating more resources to address public concerns regarding impacts of their operations. Second, it appears that, as time goes on, the public may become more aware of the 508 process. It is likely that companies can expect more public involvement in the 508 process, which can lead to increasing costs of well spacing application approvals.

6.0 Regulatory Comparison with Other Western States' Oil and Gas Regulations

Colorado's Oil and Gas Rules and Regulations were compared to those in the states of New Mexico, Wyoming and Utah. The comparison focused on the life cycle of the well as presented earlier in this document. The regulatory comparison was organized into a spreadsheet that documents the regulatory differences among the four states. A table that outlines the regulatory framework for oil and gas regulations relevant in each state is provided in Appendix D. A summary of the regulatory comparison is provided below.

Many of the oil and gas regulations among the states are very similar. However, this section focuses on the areas where the regulations vary across states. Generally, Colorado, since the passage of Senate Bill 94-177, has instituted several regulations that are unique to the state. Colorado has regulations that address the following topics: Interim Reclamation, Flowlines, High Density Areas, Safety Rules, and Financial Assurance for Surface Owner Protection. Colorado, throughout its new regulations, has a specific focus on surface owner rights, manifested in the notice and consult regulations, financial assurance, spill notification, and final wellsite reclamation. Additionally, Colorado has established the 508 process that allows for local government and public input regarding the impact of changes in well spacing requirements on public health, safety and welfare.

The regulations for Utah and Wyoming have less emphasis on specific requirements and focus more on agency discretion and flexibility. Utah requires an on site pre-drill evaluation as part of its Application for a Permit to Drill process. This evaluation is used to characterize the land for the purposes of notifying and consulting the surface owners. It also serves as a discretionary tool to address soil removal and segregation, spacing exemptions, restoration requirements, and the site's environmental sensitivity ranking which affects pit permitting requirements. Wyoming's regulations also possess requirements that are discretionary in nature. The state may require a pre-drill assessment for the pit review process if needed. Wyoming has also established a final reclamation process that is in accordance with landowner's wishes (or resembles the original vegetation and contour of the lands). This allows the operators to work directly with the landowners on these types of issues.

6.1 Application for Permit to Drill

Colorado has a unique pre-disturbance assessment APD process. Unlike the other states, the APD process requires a photograph of the location and soil and plant descriptions. Utah utilizes an on-site pre-drill evaluation (approximately 75 percent of the time) to characterize the existing condition of the land. Wyoming will sometimes require an on-site evaluation while reviewing the pit application. New Mexico can require an onsite pre-drill evaluation if an operator seeks a non-standard location approval. At this time, Colorado does not require a pre-drill evaluation by COGCC's Director or staff.

6.2 Financial Assurance

Colorado is the only state that requires surface owner protection financial assurance. All states have a so-called "plugging" bond, though each state has its own policy for establishing the cost of the financial assurance. New Mexico appears to have the lowest cost requirements for this plugging bond. Colorado and Wyoming require financial assurance for seismic operations, while Utah and Wyoming do not. Colorado is the only state to require financial assurance for general liability. Colorado and Wyoming have specific regulations for increasing the financial assurance for inactive or dormant wells, while Utah and New Mexico do not. Additionally, Colorado has the only specific time requirement of two growing seasons before releasing the bond; the other states require that sufficient restoration and plugging take place prior to bond release. However, both Utah and Wyoming require inspections prior to bond release. Financial assurance for facilities that dispose of exploration and production (E&P) waste facilities varies from state to state. Utah has fewer financial requirements than does Colorado for E&P waste facilities and New Mexico and Wyoming do not have financial requirements for these facilities.

6.3 Notice and Consult

Surface owners are required to be notified prior to commencing drilling operations in all states except New Mexico, where there are no such requirements. Colorado requires not only notice to surface owners and the local governmental designee, but must also make a good faith effort to consult with these groups. New Mexico requires notice to the local government only if the well is within limits of a city, town or village. Utah requires that a governmental body, the Natural Resource Development Committee, be contacted for comment if a new oil and gas development is established or if a well is approved more than a mile from an existing oil and gas development.

6.4 Development of Well Site Location

The only significant difference between the four states regarding development of well site locations deals with soil segregation and protection. Colorado requires that the soil be segregated into A, B, and C horizons for crop lands and A horizon for non-crop lands. Wyoming specifies that soil be segregated but does not require protection; both Colorado and Utah require that stockpiled soils be protected. Utah can require that soil be segregated; this would be determined at the pre-drill site evaluation. New Mexico has no provisions for soil removal, segregation and protection.

6.5 Spacing Requirements

Colorado's new regulations include Rule 508, which requires a Local Public Forum, a hearing in front the Commission, and a Public Issues Hearing to address issues related to public health, safety and welfare associated with an application to change well density. The other states require an application for exemption from spacing requirements and may require a hearing on the application. However, the other states do not require the level of public scrutiny that is possible under Colorado's Rule 508 for well spacing application approval.

6.6 Pits

Most pits in all four states must be permitted prior to commencement of work. Colorado has two exemptions: lined pits outside sensitive areas and unlined production pits outside of sensitive areas receiving less than 5 barrels of produced water per day. Wyoming requires that pits in non-critical areas receive a one-time approval to construct and use a workover pit or a completion pit.

Colorado has the most stringent closure requirements for pits. A Site Investigation and Remediation Workplan must be developed to insure that soil and groundwater meet state standards. The pits must be backfilled and returned to original positions. Both Wyoming and New Mexico require that the Commission be allowed to witness closure operations and determine if reclamation meets requirements. Wyoming has more flexible requirements that specify that the closure standards and groundwater testing be determined by the Supervisor based upon site specific conditions. Utah requires that pit contents meet the Division's cleanup levels or background levels prior to burial. New Mexico requires a site assessment when closing unlined pits to determine the extent to which soils and/or groundwater may have been contaminated.

6.7 Exploration and Production Waste Disposal

The significant difference in E&P waste management regulations is the spill requirements for Colorado. Colorado requires surface owner notice and consult when a spill occurs while the other states do not have this requirement. Additionally, Colorado and New Mexico have state water and soil quality standards that must be met during remediation. Utah and Wyoming do not specify water or soil standards that must be met during site remediation in their regulations.

6.8 Drilling, Casing and Completing a Well

Most requirements for drilling, casing and completing a well are similar across states. However, Colorado has a new regulation requiring that all wells be logged. The other states require that log reports be submitted, although there is no minimum requirement for the number of wells that need to be logged.

6.9 Safety Requirements

Colorado has specific regulations for safety requirements that the other states appear not to address. Colorado's regulations comprise the following requirements that are not required in other states: rig floor safety valves, static charge, well servicing pressure checks, air and gas drilling, noise abatement, lighting, and visual impact mitigation. While other states appear not to address the safety issues in their oil and gas regulations, during the interviews, regulators in some of the other states indicated that safety regulations for oil and gas operations are covered under other statutes or regulated by other agencies.

6.10 Flowline Requirements

Colorado is the only state that has specific requirements for flowlines. The new regulations passed since SB 94-177 address installation, repairs, safety requirements and reclamation. The other states do not address flowlines in their regulations at this time.

6.11 High Density Area Rules

Colorado is also unique in their High Density Area Rules. These new rules which address oil and gas drilling in areas designated as "high density" require operators to meet a series of safety and spacing requirements. The other states do not address these issues in their regulations.

6.12 Interim Well Site Reclamation

Since SB 94-177, Colorado passed requirements for interim reclamation. These requirements are unique to Colorado, as they are not addressed in the other states' oil and gas rules and regulations.

6.13 Reporting Production of Payment and Levies

Similar production reports are required by the agencies of the four states. However, the mill levies required by the states are quite different: Colorado requires $0.0012 per dollar value of production; Wyoming requires $0.0006 per dollar value of production; Utah requires $0.002 per dollar value of production; and New Mexico does not have a mill levy. Additionally, Colorado' regulations include an Environmental Fund Levy, which is currently set at $0 since the fund is at its statutory cap. New Mexico has an environmental levy on oil and gas operations.

6.14 Shutting-In or Temporarily Abandoning a Well

The allowable shut-in time appears to vary from state to state. Colorado requires that wells be plugged and abandoned or returned to production within 6 months of being shut-in. Utah and Wyoming require that wells be returned to production within 12 months and 24 months, respectively. New Mexico appears to have the most flexible schedule by allowing wells to be shut-in for 5 years. All states can extend the period of time if an extension is filed with the agency. Additionally, Colorado and Wyoming have bonding requirements for inactive wells. New Mexico sometimes requires bonding for inactive wells and Utah does not have any regulations pertaining to inactive wells.

6.15 Recompleting a Well and Commingling Production

There are a few differences between states regarding well recompletion and commingling of production. Remedial cementing is required during recompletion in New Mexico while Colorado requires remedial cementing only upon recommendation by the Director. Remedial cementing is not required in Wyoming and New Mexico. Prior approval is necessary in Wyoming, Utah and New Mexico before commingling of production. However, in Colorado, commingling is encouraged at the discretion of the operator.

6.16 Plugging and Abandoning a Well

There are no significant differences between the states regarding requirements for plugging and abandoning a well.

6.17 Final Wellsite Reclamation

Requirements for final well site reclamation appear to differ among the states. Colorado now requires operators to notify and consult with surface owners regarding final reclamation of a site. In Utah, the regulations encourage the use of a Surface Owner Agreement, which would address surface owner concerns for final reclamation. However, if there is no Surface Owner Agreement, the Division completes an inspection of the site for reclamation purposes, and the surface owner is invited to attend. In Wyoming and New Mexico, there are no requirements for surface owner notice and consult regarding final well site reclamation.

Additionally, Colorado requires that segregated soil horizons be replaced and revegetated while Wyoming requires that the land resemble the original vegetation and contour of the land. At the present time, there are no revegetation provisions in Utah and New Mexico. Colorado is the only state to require compaction alleviation. Also, Colorado has established a timetable of when reclamation must be completed. For crop lands, reclamation must be completed in 3 months. For non-crop lands, Colorado requires the operator to complete reclamation within 12 months. Utah requires that well site restoration be completed within 1 year following plugging. The are no specific time provisions for final reclamation for Wyoming and New Mexico.

6.18 Insights from Comparison of Oil and Gas Rules and Regulations in the Four States

Upon review and comparison of rules and regulations in the four states, several insights were apparent. These insights are as follows.

1. Wyoming, Utah and New Mexico rely on a more flexible set of rules and regulations that are interpreted at the discretion of Directors and staff than does Colorado.

Upon review and comparison of rules and regulations in the four states, it became apparent that Colorado has chosen to use a system, which establishes specific statewide standards that must be met by all operators throughout Colorado. While there are situations where standards are varied for different parts of the state (e.g., Fox Hills Protection Area), most standards are applied equally across all locations and operators. For example, operators are required to meet safety standards, pit requirements, and reclamation standards in all parts of the state. This is in contrast to the other states, which rely more on Director and staff discretion when establishing requirements at various locations around their states or at individual drill site locations.

2. Colorado has established rules and regulations regarding issues that are not addressed in the rules and regulations of the other states.

Colorado has enacted several new rules and regulations since passage of SB 94-177 that are not addressed in the other states. This includes Surface Owner Protection Financial Assurance, High Density Rules, Flowline Regulations and Interim Well Site Reclamation Requirements. It is likely that some of these rules, especially, high density requirements, are due to public pressures and concerns associated with Colorado’s increasing population. The other states have not experienced population pressures as great in the 1990s as have occurred throughout Colorado. Therefore, it is expected that complaints by the public against oil and gas operations would be more prevalent in Colorado versus the other states evaluated. Therefore, COGCC would be more likely to respond to these concerns with increased requirements to protect public health, safety and welfare.

3. Colorado has established more surface owner rights and public involvement than other states.

Colorado has deviated from the other states by establishing a series of surface owner rights and public involvement in many areas of oil and gas rules and regulations. For instance, operators are required to consult with surface owners prior to drilling a well (Notice and Consult and Financial Assurance Requirements), for spill notification, and prior to final well site reclamation. Additionally, Colorado established the 508 Process that requires public input on issues related to public health, safety and welfare associated with changes in spacing requirements for wells. While other states do have provisions that require public hearings on certain issues related to oil and gas operations, these opportunities are not encouraged to the same extent as those in place in Colorado.

4. Colorado appears to mandate public involvement while the other states encourage more voluntary cooperation between surface owners and operators

Another issue related to this subject is that some of the other states encourage cooperation between oil and gas operators and surface owners regarding impacts and damages of oil and gas operations and mitigation strategies to avoid or compensate owners. For instance, Utah encourages the use of Surface Owner Agreements between operators and surface owners, which address owner concerns. If there is not an agreement between surface owners and operators, the Division will complete an inspection of the site prior to approving final reclamation and the surface owner is invited to attend. In this case the regulators encourage cooperation between the parties and only get involved with the process when an agreement is not reached.

5. Other states have some ability to coordinate local government involvement and their comments on drilling operations, while Colorado's more autonomous local governments tend to add their own conditions for approval to drill.

Another difference between the other states and Colorado is, in some cases, the other states try to assist local governments in expressing their concerns regarding oil and gas operations. States such as Utah have organized a Natural Resource Development Committee that consists of local government representatives. This committee has the right to comment on drilling applications and represents local government interests. In Colorado, many local governments are becoming more involved in the regulation of oil and gas operations and appear to be more autonomous than local governments in other states. This has added another layer of regulation to oil and gas operations in Colorado, which companies have indicated is adding time, and cost to their operations. While it may be possible to coordinate different levels of government involvement in the other states, it is not apparent that this would be possible in Colorado given the different state and local government regulatory jurisdiction over various aspects of oil and gas development. Additionally, the counties themselves have differing opinions on the extent of local government oversight of such operations.

7.0 Impacts of Oil and Gas Regulations on Future Oil and Gas Exploration and Development in Colorado

There are some important insights that can be gained from the survey and interviews, which provide some indications of how the industry is and will be impacted by regulations in the future. The inferences drawn from this study are as follows.

- **Colorado's Oil and Gas Rules and Regulations implemented after passage of SB 94-177 have had differing cost impacts among companies depending on their size. Small companies have tended to see larger cost increases than medium and large sized companies.**

Throughout the survey and the interviews, there appeared to be a difference of opinion between small and medium to large companies on the cost impact of changes in Colorado's Oil and Gas Regulations due to SB 94-177. In general, small companies reported greater increases in average cost of drilling and production associated with changes in rules and regulations. The opposite was true for medium and large companies, which in general, indicated the changes in rules and regulations have not had a significant impact on costs. Many of the large and medium sized companies indicated that they had voluntarily implemented many of the new requirements into their operations prior to 1994. Therefore, it is likely that these companies would not realize a cost impact due to changes in the rules after SB 94-177.

- Small companies have indicated they are avoiding areas that increase their cost and liability. This includes High Density Areas, the Fox Hills Protection Area and areas that involve secondary water production.

Many of the small operators who were surveyed and interviewed indicated they are now purposely avoiding drilling in areas that are perceived to increase cost or liability for their operations. This includes High Density Areas, the Fox Hills Protection Area, and areas that have secondary water production. All these areas have increased regulatory requirements for operators since 1994 and increased liabilities associated with operations. For instance, some small companies indicated that the disposal of drilling and production fluids may lead to future liabilities as has happened at a disposal site in Weld County. This site and all companies that have used the facility for disposal are subject to an investigation on disposal practices. Some of the smaller operators indicated they would rather avoid areas with secondary water production to reduce potential liability from such a situation. Therefore, small companies may prefer to avoid drilling and producing in these areas given the higher cost of compliance since SB 94-177 and the perceptions of increased liability in these areas.

- **The increase in cost associated with the new rules and regulations may thus be playing a part in the consolidation or reduction in the number of small companies that are drilling or operating in basins within Colorado.**

Such is the case in the D-J Basin, which has realized a reduction in the number of small companies that are operating in this area. The reduction in drilling operations and service companies has contributed to increasing costs of services used by small companies, which has compounded the cost increases in these areas. While it is not inferred that the rules and regulations are completely responsible for cost increases to small operators, they may be playing a part in small companies ceasing operations. It is likely that this trend will continue in the future.

While the number of companies drilling and operating in the state may be decreasing, this does not imply that the amount of wells or even the amount of oil and gas produced in the state are decreasing. However, it appears that more large and medium sized companies versus small companies in Colorado will carry out future oil and gas production in the state.

8.0 Recommendations

The analysis presented here evaluated the financial impacts of changes in Colorado's Oil and Gas Regulations after passage of SB 94-177. Additionally, the study compared Colorado's Oil and Gas Rules and Regulations with those in place in New Mexico, Wyoming, and Utah. From the results of this study, Hazen and Sawyer proposes several recommendations to be considered by Colorado Department of Natural Resources and the Colorado Oil and Gas Conservation Commission that will improve the cost efficiency of oil and gas regulations that protect public health, safety, and welfare. These recommendations are as follows.

1. Evaluate the flexibility of Oil and Gas Rules and Regulations used in Colorado.

As discussed in Section 7.0 of this report, Colorado's Oil and Gas Rules and Regulations have developed around a traditional standards-based format. In other words, the COGCC has continued to draft standards that must be met by operators regardless of the size of operations or differences in site locations. This type of system tends to offer certainty through the use of regulatory penalties that all operators are meeting a set target in terms of environmental protection. However, numerous studies have shown that this type of system is inflexible and can be economically inefficient.[1]

Inflexible regulations have a number of potentially negative impacts. The regulations fail to take into consideration differences in location characteristics (e.g., state-wide reclamation standards). The regulations offer no incentives for companies to employ methods or technologies that go beyond standards set by the regulations. When the COGCC specifies certain technologies for implementing regulations, such as the specific cement slurry for plugging or indicating four ways for disposal of produced water, it does not allow for potentially lower cost options that may also improve environmental quality. Finally, standards can be quite inflexible, contradictory and costly for operators. For example, reclamation regulations require both eliminating noxious species and revegetating the well-site area. This is often difficult since the extermination spray used on noxious weeds also hinders the growth of indigenous species. Colorado DNR and the COGCC should continue to evaluate all parts of the regulatory system to determine if there are other methods that can be employed that would insure protection of public heath, welfare and safety in a more cost efficient matter.

2. Evaluate the apparent differential impact of Colorado's Oil and Gas Rules and Regulations on small operators and determine if policies can be implemented to reduce harmful impacts to small operators.

Colorado DNR and the COGCC should continue to evaluate the apparent differential impact of Oil and Gas Rules and Regulations on small-sized companies. Throughout the surveys and interviews, small operators reported greater increases in cost associated with new rules and regulations passed since SB 94-177 than medium and large size companies. Policies can be implemented that help small companies come into compliance with new regulatory requirements.

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[1] *Pierce, David W. and R. Kerry Turner, "Economics of Natural Resources and the Environment", The Johns Hopkins University Press, Baltimore, Maryland, pp. 102-107, 1989.*

For example, this could include extending regulatory time periods and providing training programs and/or expert advice on specific regulatory issues for smaller companies.

3. Encourage cooperation between surface owners and oil and gas operators.

Colorado DNR and the COGCC should continue to promote sensible cooperation between surface owners and operators. There are indications that changes in certain rules and regulations have contributed to surface owners becoming more involved in the regulatory process. The interaction of surface owners and operators should be encouraged to establish requirements and expectations for operators prior to commencing drilling and production operations and to explain the process to the affected surface owners. Efforts should be made to establish working rules that encourage surface owners and oil and gas operators to use Surface Owner Agreements where possible in a timely, cost effective manner. Regulatory agencies at the state or local level should avoid becoming directly involved in this process, if possible, or hindering the ability of these parties to reach reasonable agreements.

4. Continue to improve the cost-effectiveness of methods and processes that encourage public comment and involvement in the regulation of oil and gas operations.

Efforts should be taken to improve the process in which public comment is encouraged regarding oil and gas operations in Colorado. This is especially true for the 508 Process, which may become increasingly more costly for operators and the COGCC to complete and administer. Regulators should continue to balance the cost of this process with the benefits. It appears that the 508 Process could cost some companies in excess of $100,000 to complete, and this amount may be increasing. However, a couple of the operators have asserted that the 508 Process provided a beneficial avenue through which the operators could educate the public about their technology and explain the needs for increased well density. Additionally, these operators also benefited from understanding the public's concerns and issues and could address them early in the process prior to potential litigation. However, it should be noted that the costs of complying with the 508 Process in specific locations have been significant.

Colorado DNR and the COGCC should evaluate this system to ascertain whether the regulatory goals and benefits of this process are worth the administrative costs to the agency as well as the potential loss of revenue from oil and gas operators no longer operating in those locations. Colorado DNR and the COGCC should examine if a more cost effective method can be developed and implemented which meets the public input needs for increased well spacing.

5. Evaluate methods to coordinate local government comment and local regulations.

Efforts should be undertaken to improve the relationship between the COGCC and local governments to avoid overlapping regulations that impact oil and gas operations in the state. More and more local governments are beginning to regulate oil and gas operations within their jurisdiction even though they may not have the staff or expertise to properly analyze the impacts of such mining operations on their constituents. These additional conditions of approval imposed by local governments are oftentimes unanticipated by the oil and gas operators, increasing the regulatory uncertainty of drilling in the area. The COGCC can play a role in either educating local agencies on technical issues related to oil and gas operations or insuring these agencies that state requirements protect local jurisdictions from harmful impacts. COGCC might want to consider some sort of systematic process where local governments can have limited input throughout the process, which would be monitored by the state. These actions would certainly help to eliminate overlapping regulatory requirements that may not be improving public health, safety and welfare of local lands, while increasing the regulatory certainty for operators and reducing unanticipated conditions for approval.

6. Continue to evaluate the benefits and costs of Colorado's Oil and Gas Rules and Regulations and the impacts on small, medium and large companies as a first step to achieve a cost-efficient and fair regulatory program.

Finally, Colorado DNR and the COGCC should continue to evaluate the benefits and costs of their regulations relevant to oil and gas operations. This exercise is necessary to determine the effectiveness of each regulation in meeting its stated regulatory goal as well as evaluating the impact of the requirement on operations. There may be lags involved with regulatory implementation that affect when parties realize the benefits and costs of regulations. These lags can be evaluated over time with regulatory reviews and analysis. Regulatory regimes are dynamic institutions that must evolve with changes in environmental conditions, economic conditions and public opinion. Colorado DNR and the COGCC have a unique opportunity to help the institution develop in a manner that is cost efficient while meeting the goal of protecting public health, welfare and safety.