EPA PUBLIC MEETING
NPDES Storm Water Permit Regulations for Small
Oil & Gas Construction Activities
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Dallas, Texas

REPORTED BY:

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P R O C E E D I N G S

MR. HANLON: Good morning, everybody. Welcome to Dallas. My name is Jim Hanlon. I'm the director of the Office of Wastewater Management of EPA in Washington. And it's our pleasure, on behalf of EPA, to host this discussion today on the Phase II oil and gas storm water permitting issue.

As you are probably aware, EPA, in December of 1999, published regulations affecting small construction. And small construction, in that definition, included all construction sites across the United States between one and five acres. That rule took effect in March of 2003. In March of 2003, based on information that we received after the December 1999 rule was published, we extended the deadline, the March 2003 deadline, as it affected construction at small oil and gas sites.

In March of this year, we again extended the deadline for 15 months. And what we're here today for is to have a discussion about issues surrounding construction at small oil and gas sites. And our plan, as was laid out in the Federal Register notice, is to publish a proposed regulation affecting those sites in September of this year and a final regulation following the following June, June of 2006.

Again, the purpose of today's meeting is information-gathering. We are thrilled by the turnout. Basically you are here expending your scarce travel resources and, more important than that, your personal time to help us gather information regarding this important subject.

What I'd like to do -- and I'll introduce our facilitator here in just a second, but there are a number of folks from our EPA Region 6 office in the audience. Bill Honker and Troy Hill are here. Bill's the deputy director of the water division, and Troy Hill is the head of the NPDES permitting program here in Region 6. And they've got a number of staff sprinkled around the room, so you may not know if you're sitting next to an EPA person or not, so be careful with your sidebar conversations.

With that, I will introduce Mr. Jim Elder. Jim is the -- our facilitator for today. He will explain the ground rules, the terms of engagement, and how we proceed -- propose to proceed through today's agenda. And he will introduce the head table here, so I won't do that.

But again, thank you very much for your participation. We look forward to your input. We will, before the end of the day, pass out an attendance list. Again, there were a good number of walk-ins, so we will add those folks who didn't pre-register and have copies of that list available by the end of the day. Thank you.

And as we get started here, Jim Elder will be our facilitator for today.

Jim.

MR. ELDER: Thank you, Jim.

If you're not sure of anybody's name, just call him Jim and that will probably work. Let me go over some of the logistics. The restrooms are directly outside the exits to your left. There's also another set to the right toward the stairwell that goes down to the lobby. So anytime you feel you have to get up and take care of that -- there's also phones over there as well.

And as Jim Hanlon said, we're going to hand out an attendance list at the end of the meeting. It will be available on the table in the back.

Let me explain. At the front table are designated representatives from state government, federal government, the oil industry and environmental groups. And those people are going to have priority, in terms of who gets to speak first, on certain occasions.

But this is a public meeting, so the people in the audience will have ample opportunity to participate as well. Just understand the order, in terms of how people are to be called upon.

I would ask the people at the front table, if they have a question or want to make a point, if they would turn their name plate on end or something so I know and so we don't have to have people raise their hands and act as though we're in grade school. We can do something a little more sophisticated than that.

Also, at lunchtime, we'll have -- I'll give an announcement about that. We'll have a list of restaurants that are recommended by the concierge that will be available in the back of the room as well. Lunch will be on your own so I hope you understand the logic of that.

And, first of all, I would like to then go around the front table and let everybody introduce themselves by name and what organization or company they're affiliated with.

So, ma'am, why don't we start with you.

MS. WROTENBERY: I'm Lori Wrotenbery. I'm the director of the oil and gas conservation division of the Oklahoma Corporation Commission, and I'm also a member of the board of STRONGER, Inc.

MR. TEMPLET: I'm David Templet, Devon Energy, Oklahoma City, and I'm representing independent producers -- an independent producer.

MR. MAYFIELD: My name is Tad Mayfield. I'm president of Goldston Oil Corporation. I represent a smaller oil and gas exploration and production company.

MR. HARE: My name is John Hare. I'm with the Bureau of Land Management in Washington, D.C.

MR. FLEMING: My name is Martin Fleming. I'm the executive vice president of Texas Independent Producers and Royalty Owners Association. We're a trade group in Texas representing individual producers.

MR. ADAMS: I'm Jeff Adams with -- regulatory affairs specialist with BP. I'm also the API chairman of the storm water task force.

MS. FISH: I'm Marilyn Fish, and I'm director of environmental health and safety for EOG Resources out of Houston.

MS. BUCCINO: I'm Sharon Buccino. I work as an attorney for the Natural Resources Defense Council and the Public Lands Program out of Washington, D.C.

MR. BAUMGARTEN: Good morning. My name is David Baumgarten. I'm the county attorney for Gunnison County in Western Colorado.

MR. ANDERSON: I'm Garland Anderson, and I'm here to represent Western Colorado Congress and Grand Valley Citizens Alliance and numerous other groups, environmental groups, in Colorado.

MR. ALLEMAN: David Alleman, U.S. Department of Energy. I'm with the oil and gas environmental research program out of Tulsa, Oklahoma.

MR. LEE: I'm Michael Lee. I'm an attorney with the United States Environmental Protection Agency and the general counsel's office in Washington.

MR. SMITH: I'm Jeff Smith. I'm with the EPA and the Office of Wastewater Management, and I'm the regulation manager for Phase II.

MR. HANLON: Jim Hanlon, Director of the Office of Wastewater Management in EPA.

MS. NAGLE: Deborah Nagle, Wastewater Management. I'm the branch chief for the industrial branch.

MR. FAULK: And can people hear if we don't use the microphone? Can anyone not hear?

(No response)

MR. FAULK: All right. I'm Jack Faulk, and I'm the storm water team leader in Washington.

MR. ELDER: What was your name again, Jack? We couldn't hear you.

MR. FAULK: Not Jim.

MR. ELDER: Right. He changed his name from Jim to Jack. Anyway, Jack is now going to give a presentation, an overview of the oil and gas storm water control activities. And don't be confused by the picture on the screen.

MR. FAULK: That's our new Washington baseball team.

Well, first, I want to say that it's been a bit of a circuitous route to get to this point, so I'm going to give an overview. Hopefully there aren't too many questions in between kind of the general overview. We could probably talk for the rest of the day just kind of how we got to this point, so I'm going to give a pretty basic overview.

If there are things that don't make sense, you know, if you have questions, we're going to have a little time after this talk, and then at the end of the day, I believe, there will be more time, just for more specific questions, kind of what we -- what you hear over the course of the day, so hopefully it makes sense and it doesn't confuse too many of you.

I'm going to talk a little bit about the history of how we got to this point; our rationale for actually having deferred the rule, deferred the rule twice; discuss some of the regulatory options that we're now considering; talk a little bit about where we stand, in terms of our analysis; and then, again, leave some time at the end for questions.

So chronology: In 1987, the Clean Water Act was amended to add the Water Quality Act that basically added provisions for EPA to control storm water, and the 1987 amendments talked about a two-phase program to do that.

The Phase I program, the act clearly identified the types of activities that Congress intended for EPA to require permits for, and those were medium and large municipalities, basically with populations over 100,000, and then industrial activities.

And through that industrial-activity definition, EPA included construction activity greater than five acres. So as part of the Phase I rule, we define large construction to be construction activity disturbing greater than five acres.

The 1987 amendment also included an exemption, and I'll show you an excerpt of that in a few slides. But basically, there was language in there that talked about certain oil-and-gas-related storm water discharges that the administrator, EPA, was not to permit.

So the rule for Phase I was promulgated in 1990, and it required the municipalities and industrial activities, including construction, to get permit coverage effective in 1992.

We then were required to do an analysis and prepare a report for Congress that identified additional sources that we felt required control, and that was the Phase II rule.

And in the Phase II rule, we identified small municipalities, certain small municipalities – I don't want to get too much into the definition of those, but it's about 5,000 or 6,000 municipalities nationwide that are required to get storm water permit coverage -- and then small construction, small construction being one to five acres in size.

Subsequent to the promulgation of that rule in 1999, we started to hear from a variety of folks that oil and gas had not necessarily been analyzed completely, and that there were some differences in the industry that didn't necessarily make their ability to get permit coverage that simple or clear. So based on a number of reasons, we ended up deferring the requirement for them to obtain permit coverage.

And so in March of 2003, which was to be the day that construction, small construction, or the whole Phase II community was required to get permit coverage, we deferred, for two years, the requirement for oil-and-gas-related construction activity to get permit coverage.

In those subsequent two years, there was quite a bit of discussion, but we didn't reach resolution. And subsequently, in March of 2005, we deferred for another 15 months. And I'm sure most of you know that.

And we have a proposed time frame set for September of this year, with final action by June of 2006, which is basically when the existing deferral expires, so we hope to have final action before then.

The exemption in the Clean Water Act -- this is just very much an excerpt -- but 402(l)(2) says that the administrator shall not require a permit for discharges of storm water runoff from oil and gas exploration, production, processing or treatment operations or transmission facilities composed entirely of flows which are from conveyances or systems of conveyances used for collecting and conveying precipitation runoff and which are not contaminated.

We've defined construction activity – or in our regulation, we talk about construction activity being clearing, grading and excavating. Since 1992, we have interpreted that the construction activity at these oil and gas sites is different than the 402(l)(2) exemption, which we've -- we've interpreted to mean the actual industrial activity once the exploration, production, processing happens. But construction of facilities associated with that, we held, has been construction.

We have a couple of suits on going right now, and I don't necessarily know all the details, and probably can't even talk about the little that I do know, but again that -- there are couple of suits that are looking at that issue.

Just to give a general overview, the NPDES permitting program, which is basically the permits that we issue for wastewater, we -- EPA writes the rules, but then we allow states to be authorized to implement and issue permits and administer the program.

And, in fact, 45 of the 50 states have become authorized and issue the majority of the permits.

There are five states that EPA still issues permits for. And then there are a couple of states, Texas and Oklahoma, for example, that have certain pieces for which the state did not receive authorization.

So, in Texas, the state is not authorized to issue permits for oil-and-gas-related activities. In Oklahoma, it's actually oil and gas and certain agricultural activities. And then the blue states [on the map] are the few states where EPA is actually the permitting authority for federal facilities.

But generally, for oil and gas, it's five states, plus Texas and Oklahoma. And the fact that we issue permits in those states raises some different issues that states that haven't been administered – or that administer the program don't necessarily have similar issues, and we'll talk a little bit about those in a bit.

Some very general facts and figures. And probably everyone here is going to say, He doesn't know what he's talking about. But the numbers that we've been using is that approximately 28,000 well sites would have fallen under our construction program in 29 states, and those are the well sites.

And we know that there are additional pipelines and treatment facilities and so forth that add, I think, a few thousand to that figure, so a lot of you have probably seen a number of about 30,000 sites.

And generally that's the number that we've used. And we have an economic analysis that is in draft right now, or still under development. And the numbers used in there are again around 30,000.

The four states where EPA issues the permits that have significant oil and gas operations are Alaska, Texas, Oklahoma and New Mexico.

We heard from industry, and we have some industry experts at EPA, and their take has been that primarily activities in Alaska are greater than five acres and so really aren't too much at issue right now regarding the Phase II implications.

And then the one issue that has come up, that is specific to EPA-issued permits, is we have a requirement that when we take a federal action, that it has to be consistent with other statutes. And two of those statutes are the Endangered Species Act and the National Historic Preservation Act.

And it requires -- again, I'm probably going to get the wording a little bit incorrect, but generally it's requiring consultation with the services or with the historic preservation officers to ensure that the actions that we're authorizing are not going to negatively impact the activities that these statutes are trying to protect.

When we have authorized states to administer the program, that authorization process, where we're actually evaluating a state program and making a determination that they now -- the state now has the necessary regulations and procedures in place to administer the program, that has been our federal action and that has been where these statutes have been analyzed.

Once a state, Colorado, for example, gets the program, they don't have the similar actions that they have to take associated with each individual permit. They may opt to do that under state law but not under our NPDES program.

Now to deferral rationale. In the 1999 Phase II rule, there was an economic analysis that was prepared, and that economic analysis had one footnote on one page that made reference to the fact that EPA believed few, if any, oil and gas sites would fall within one to five acres. So it was in there that we basically said, you know, we don't expect there to be too many.

And I commented last meeting that – I don't know if it was clear enough -- that third or fourth hand we kind of heard that there was a determination that, well, generally a pad, if you look just at the pad and not the roads and other ancillary equipment, would be less than an acre, It'd be .7 acres, .8, and theoretically that was how this footnote ended up in the economic analysis.

We subsequently have learned or have heard from industry that when you look at each site and take into account roads and so forth, that actually few, if any, will be below one acre.

And so, you know, it was really that acknowledgment that maybe we didn't adequately look at that part of the universe, and that we should see what the economic impacts of our rule would be to that part of the universe, is what was -- was probably one of the key components for us deferring the rule.

I'm not going to talk too much about the economic impact analysis that we're conducting now. It's still in development, and I'll talk a little bit about it -- a little bit about it later on. I would probably say that, though, if there are questions, there's certainly people here better than me to answer them, so I will pass by that quickly.

We're also taking a look at the best management practices that are in place or being used in the industry, both for oil-and-gas-related construction activities, as well as other types of construction activities. So as we move forward, hopefully we can identify measures that work for the industry. And if there are measures that maybe necessarily haven't been used by oil and gas but that are appropriately used, that could potentially end up -- so we're not necessarily just, at this point, limiting it to what standard practices are in the industry.

And then we have a couple of options that we're contemplating right now and I'll show you those in a little bit, and that -- basically there's two options that we're considering.

There's a new waiver option. The Phase II rule for small construction actually allows certain activities to be waived from the requirement to get a permit. And the two waiver options that now exist are:

One, if you're in a location that there's not much rainfall and you have a short-duration project, it's called a low erosivity waiver form, and we have a calculation that can be used. And if you have a value – a certain value, you can actually be waived. And our take is that in certain parts of New Mexico and Texas and Oklahoma, that there may be some opportunities for that waiver.

There's a second waiver option for -- I'm getting warm up here -- second waiver option for TMDLs or water quality. If you can demonstrate that your discharge is not likely to impact water quality without having to get permit coverage, you can also be waived.

I think that's a much more difficult demonstration. And at this point, even outside of oil and gas, I'm not aware of that many construction sites that have opted to choose that waiver option.

We're now talking about a third waiver option that would look at short-duration projects. An I'll show you a little more of the details of that later. But basically, it would be a new option available for small construction, one to five acres in size, that would hopefully alleviate some of the concerns that we've heard that have been problematic.

We're then talking about a second option, and it's a non-permitting option. The Water Quality Act of 1987, with the two-phase program, Phase I it required EPA-issued permits. Phase II said that EPA would develop -- control a -- would develop practices or measures to control storm water but didn't necessarily require us to do it through our permitting program. We opted to do it through permits, so small construction sites now are regulated through permits.

But we're now looking at the possibility of trying to develop a program that wouldn't require permits and again may make it easier to meet the control requirements that the environmental protection that we're trying to obtain without necessarily going through all the administrative procedures that seem to be problematic.

And I'm going to walk through these real quickly, just for folks that are unaware of the existing construction program.

Right now construction activities that are located in the states where EPA issues permits, we have a construction general permit. The other 45 states generally use the same procedure. Some have a, sort of, permit-by-rule approach, although it's not necessarily permit by rule.

But, in general, the states require construction activities to get coverage under a general permit. And hopefully folks understand general permits. I'm not going to get into that. But the general permit is one permit that's issued statewide, or something similar to that, that's intended to cover a large number of sites with one action.

And the key component of that permit is for the site operator to develop a storm water pollution prevention plan, a SWPPP. And it's through that SWPPP where they’re -- the operator is assessing their site, identifying the environmental issues of the site, identifying what types of activities they're going to be doing, and kind of documenting their plan to protect the water body. And then it includes some routine maintenance and inspections.

And then, as I had talked about, for the EPA permits there are also some endangered species and historic property activities that need to be evaluated as part of that SWPPP preparation.

And this you probably can't see from there. I don't know if -- Jim, did you mention – I think the plan will be to post all the presentations online, so if you can't see it here -- and we don't have handouts -- it will be available at the EPA web site, that's epa.gov/npdes, and then through there it should be readily apparent where it's located.

But this basically just outlines the procedure for how a permitee -- or how a site operator, who's intending to construct a site, will go through and identify potential endangered-species issues and work with the services, if need be, to make sure that they have adequate management practices in place; and then to develop their plan and submit their notice of intent; then implement their plan and stabilize the site; and then when they're completed, submit that notice of termination that takes them out of the permit responsibilities.

The construction SWPPP, the basic components of that are the site description, identifying the controls that will be used to control the -- primarily the sediment, maintenance procedures, and then inspection requirements.

Site description: This is primarily our permit; although, again, most states have similar requirements. It's just basically requiring the operator to clearly identify the site and what's around the site and where the controls are going to be located, where the discharge is going to be located, the receiving stream, potentially any of the concerns of that receiving stream, so that they can take adequate steps to protect that stream.

And then our permit again requires that you properly select and install the sediment controls, remove sediment, go through these stabilization practices.

In our construction permit, we talk about stabilization. And we added some language in the most recent permit that talks about some, in the arid areas, ways that you can meet the final stabilization criteria, not necessarily having to wait until the vegetation has fully developed, and then the various structural controls that are discussed in certain situations certainly apply or certainly would be appropriate.

Our permit does -- and, again, a lot of times we find proper installation of BMPs, but the problems turn out to be poor maintenance and lack of inspection. So we do have regular requirements or requirements for regular maintenance and regular inspection and documentation of that. And again, this is one of the areas that industry has identified as difficult in certain instances.

So our two options that we're now talking about, the first one I mentioned is a waiver option. And what we're looking at right now would be just for small construction sites, less than five acres, and it could get waived from the NPDES permit requirement provided that they met certain criteria.

And, you know, the types of criteria that we're looking at are: That it's a short-term construction project, and right now we have a less than 30-day time frame being looked at; the proximity to the water body may also be a consideration; slope, region, other site-specific considerations.

But the key component would be that you could be waived provided that you also implemented certain best management practices. So it basically says, if you did these types of storm water controls, you could be waived under certain scenarios.

And again, the BMPs that we're talking about look very similar to the BMPs that the construction site operator outside of the oil and gas industry has to meet already. So from an environmental standpoint, we're hoping that we would have similar protections through this approach and it would be waived.

And we've talked about potential for documentation or some type of submission of a tracking, just to -- so that you could notify EPA that, I'm being waived and here's where I'm located and I'm certifying that I've implemented my BMPs consistent with the waiver requirements.

The second waiver offer -- or second option that we're considering is the non-permitting option. And in that case, it would not be a waiver. It would -- it'd probably best be described as a direct rule, wherein the regulations it would say, If you operate oil-and-gas-construction-related activity disturbing one to five acres, you must do X, Y and Z.

And similar to the waiver and similar to our existing program, it would lay out some type of BMP approach that you would not need the permit, you would not need the waiver. It would just basically require each of those sites to implement the certain procedures that were identified in the rule.

Somewhat of a question is, Well, why do you have these three different options? And a great deal of it is really more the administrative aspects associated with EPA as the permitting authority.

We have additional endangered species consultation and historic preservation activities and some of the SWPPP site-specific requirements, and a lot of those are adding time delays and a lot of those are difficult to do far enough in advance.

And I think Tad and Dave will probably talk to folks here a little bit about some of the delays or concerns associated with delays in the industry. But we're trying to come up with a program that will give us comparable environmental protection to the existing Phase II requirement and hopefully make something that works for the industry as well.

I mentioned we were doing an economic analysis. We've been doing that actually for quite a while. We're looking at the baseline, the existing Phase II rule, and what would the economic impact and environmental benefit be by the industry having to comply with those existing requirements.

We're then also looking at, these two options, what are the economic benefits, or what's the difference that could be gained in using either of those two options.

And I'm not quite sure if there's too much more I want to say about economic analysis. Again, there are other folks here that can answer about that.

But the direct cost and the indirect cost, when we did the Phase II rule, it was based primarily or exclusively on direct cost, and it was the cost of developing plans, the cost of implementing BMPs, the notice of intent, the potential ESA and NHPA-related considerations.

Industry has told us about some of the indirect costs associated by delays associated with complying with our permit. And again, some of these terms are confusing to me. But in general, it's -- as a project is delayed or the inability to get on a site happens, it can significantly impact the cost to the industry, and so we actually are now looking at those indirect costs. And some of you may be familiar that the Department of Energy had a study done that also looked at the economics of the industry and it showed some pretty significant indirect costs.

With that, the next steps: Gather additional information, what we're doing here; complete our economic analysis, that we hope to have or will have available as part of the proposed rule making in September; and then comment period with our plan for final rule making in June, I think June 12th of next year.

And with that, I will sit down, take any simple questions, or defer to someone else.

MR. ELDER: All right. If there are questions about Jack's presentation, I'd like to give the people at the front table the opportunity to ask them first, and at that point let people from the audience ask questions as well.

Are there any questions from people at the front table?

David?

MR. BAUMGARTEN: Please.

I just wanted to make sure that there is not an option of a further delay.

MR. FAULK: I don't have a microphone.

MR. HANLON: I'll answer that.

My boss has been -- made it clear to me that he does not expect the deadline to be deferred again, so we are sort of committed to those dates that Jack just summarized.

MR. BAUMGARTEN: Thank you.

MR. ELDER: Any others at the front table?

(No response.)

MR. ELDER: Any questions from the audience?

Yes, sir. Would you either speak up or come to the microphone between the aisles.

MR. BUTLER: My name is Don Butler, National Energy Group here in Dallas. And I was wondering if -- you talked about the 30-day construction activity may be complete within 30 days. But by the time we get a rig there, start to drill the well and complete the well, if it's successful, and then we build the facility itself, after that move everything off, we just have a well head and tank battery off, that may well take 60 to 90 days.

The option you mentioned, Jack, does that include just 30 days from your initial build location, or are you talking about from when we first get out there to with just the tank battery installed?

MR. SMITH: Talking about just construction activity -- this is Jeff Smith from EPA -- just construction activities for the site itself. We're not talking about moving in, you know, tank batteries and that sort of thing.

When you've constructed the road, constructed the pad, when you have a stable site that you can move your rig onto, then the construction phase is over and you enter another phase, which is the drilling phase.

MR. ELDER: Any other questions from the audience?

AUDIENCE MEMBER: Can I follow up on that?

MR. SMITH: Sure.

AUDIENCE MEMBER: You're still going to have to come in, reclaim the location, you're still bringing equipment in, you're closing up your reserve pits, moving dirt. But, like you said, once you initially construct your site, then that stops.

If you can get it constructed in 30 days, irregardless of what you do after that point, you can gain an option or waiver?

MR. SMITH: That's what I was led to understand.

MR. ELDER: Jeff?

MR. ADAMS: Jeff Adams with BP.

That's been one of the concerns that -- that we've stated. As in with all rules, the devil's in the details.

You talked about erosivity waiver earlier, and it's become not very useful because of the details of the erosivity waiver. It pretty much says, until a very tightly defined temporary stabilization, final stabilization, and that keeps us from using that waiver.

And the exact type of details that this gentleman was talking about are the same type of things that could keep this waiver from being useful.

Thirty days is a very reasonable time frame to have active construction or dirt activity disturbed, and getting that active disturbance done and stabilized to a certain point, it's a very reasonable time frame, but the details could make it to where you have to plan for a much longer piece of time. So that's what we're talking about, active construction time.

And we understand that that's what EPA means for that 30-day period to be, is active construction, we're actively disturbing dirt and getting it to where you can use it for whatever purpose its intended to be used for, such as a drilling pad or a well.

MR. ELDER: Sharon?

MS. BUCCINO: Yes. I just was wondering if EPA could elaborate a little bit more on -- there was some mention if -- this is in, I guess, the various options, how the -- referred to as the maintenance and inspection component will be built into that, because you had a line there that said, commitment to do the BMPs. But what's the intent and the mechanism for building in that maintenance and inspection component?

MR. FAULK: Well, that -- again, the devil's in the details. But the fact is the plan is that we would have -- as that waiver eligibility, you would be required to design and install BMPs and maintain those BMPs and then – and potentially -- I mean, the inspection requirements and failure to do so would make you not eligible for the waiver or not eligible if we went with a non-permitting approach, so that it would lay out the requirements, and failure to meet those requirements would then subject you to discharge without a permit or the need to get permit coverage.

MR. ELDER: Anyone else?

Yes, Martin?

MR. FLEMING: Martin Fleming.

I'd like to just respond to the gentleman's question out in the audience, because I think it hits the crux for us of one of the fundamental issues of this rule, which is that industry considers clearing, grading and excavating activities of oil and gas E&P facilities, exploration and production facilities, to be, in fact, exploration and production activities.

And so, I mean, I just want to make sure -- I know y'all have heard us tell you that over and over, but it's an important thing to bring out early in the discussion because I think it's one of the fundamental conflicts that we've had as this rule's developed.

MR. ELDER: And one more time. Anybody else like to ask any questions about Jack's presentation?

(No response.)

MR. ELDER: Okay. Hearing none, we're now going to move to the participant statements.

There were originally 12 people that signed up to speak. I just came up with a very sophisticated system to decide the order of speakers, that was alphabetically by first name.

But David Baumgarten is already on the agenda at 1:30, so he would've been first, but he's going to speak then so, therefore, the opening statement goes to David Polter.

David.

MR. POLTER: Good morning. Thank you. My name is Dave Polter. I'm an environmental consultant. I'd like to offer technical comments reflecting concerns common with various oil and gas operators with whom we work here in Region 6.

The first point we'd like to make is that small oil and gas construction activity should remain permanently exempt from storm water permitting. Small oil and gas construction activities are substantially different from other small construction activities, and due to these differences should not be subjected to the same permitting requirements.

The duration of construction activities associated with the installation of oil and gas wells and associated gathering lines is very short. Typically these activities are completed within two months of initiation.

The well pad, upon installation, is typically not revegetated and serves as a platform for subsequent drilling activities, followed by equipment installation and well operation.

The typical small well installation project disturbs less than five acres, after the pad is installed (normally completed within a few weeks of project initiation), a high percentage (greater than 50 percent) of the area originally disturbed is permanently stabilized.

Given the typically brief nature of the soil disturbance activities and the small size of these sites, permit coverage and the associated SWPPP preparation and implementation requirements are inappropriate and unnecessary.

We advocate retaining permitting requirements for those sites disturbing greater than five acres but endorse and strongly encourage the agency to permanently extend the exemption from permitting for small oil and gas construction sites disturbing less than five acres.

The next point I'd like to make relates to subpart 9.C.1.a.i of the construction general permit that requires operators in New Mexico to prepare and implement a sediment control plan or SCP as part of the SWPPP. We find this is impractical and the EPA has not appropriately handled the economic impact that this provision will have on small construction activities.

According to this provision, operators in New Mexico must prepare and implement an SCP as part of the SWPPP and use soil loss prediction models, such as SEDCAD 4.0, RUSLE, SEDIMOT II, MULTISED, et cetera, to demonstrate that implementation of site-specific practices will result in sediment yields that will not be greater than sediment yield levels from preconstruction and undisturbed activities.

Our experience with these various soil loss prediction models referenced in the CGP indicates that ensuring that there is no increase in sediment yield and flow velocity from preconstruction, undisturbed conditions, will essentially require construction of retention basins to capture and control all runoff at every well construction site.

While other erosion and sedimentation control devices and strategies may be effective at reducing sediment yield, they are not capable of preventing any increase in sediment yield.

While the use of detention basins may be appropriate for long-term and large-scale construction projects, they are impractical for use in small well site construction projects.

Many well locations, particularly in New Mexico and Colorado, are in upland areas or on hillsides, where construction of sediment basins is physically limited by topography and may result in substantially more soil disturbance than the well itself.

Within the oil and gas construction industry, there's virtually no precedent, that we're aware of, for use of sediment basins for small oil and gas well construction sites.

The economic impact of the SCP requirement, the use of soil loss prediction models, and the attendant structural controls that would be required are not accounted for in EPA's economic impact analysis.

The standard SWPPP and BMP requirements provide sufficient erosion and sediment controls for construction activities in New Mexico and the additional and burdensome SCP requirements should be eliminated.

Additionally, there's this issue that the SCP has to be certified in New Mexico by a professional engineer. We understand there's 30,000-some-odd new well sites a year, and it's not clear to us that there's really adequate engineering certification capacity to handle all the site-specific certifications that would be required.

Additionally, for the larger sites, where this SCP would be required, we'd like the EPA to clarify that the certification required by the PE need not require a site-specific inspection by the PE. Either they, or their agents, could conduct site-specific requirements or inspections that would be required.

And then lastly, an issue that is of concern relates to the notion of what constitutes a common plan of development. And our concern here is that a common plan of development to use, in terms of whether you've exceeded your five-acre threshold or even a one-acre threshold, should not encompass construction activities conducted by complete -- completely separate operators, where neither operator has any controls over activities of the other.

This situation occurs where -- in a fairly common scenario where you have, say, Operator A, who may choose to install a well for which well construction activities will not result in soil disturbance greater than the applicable permitting threshold, Operator B may then, in turn, choose to run a gathering line through Operator A's well, and Operator B's activities are also less than the permitting threshold, but when taken together they may exceed that threshold.

Currently we understand EPA's interpretation of that is it constitutes common plan of development, but, in fact, neither operator can control the other operator's activities and make separate economic and construction decisions, and, in fact, once the permit will be issued, the only control that the operator would have would be over their own activities. So we would seek to have EPA clarify that, in that circumstance, it does not constitute a common plan of development.

Thank you very much.

MR. ELDER: Thank you.

If there are questions from the speakers, I'd like you to hold them until after all the speakers have given their presentations. We'll deal with them then.

Our next speaker is Garland Anderson. Garland, you can either stay at the table and use the microphone, or come up here, either one.

MR. ANDERSON: I have a PowerPoint.

MR. ELDER: All right. We're going to deviate from this sophisticated list while that is being set up and go to the next speaker, Janet McQuaid.

Janet.

MS. McQUAID: I have chosen not to speak.

MR. ELDER: Okay. Lori Wrotenbery.

MS. WROTENBERY: Yes. And I'm on the program this afternoon, if you wanted to --

MR. ELDER: We're going to get through this in no time.

Mark Carl? Please, Mark, I hope you have something to say.

MR. CARL: Does that mean I get 15 minutes?

MR. ELDER: No. Still five.

MR. CARL: My name is Mark Carl and I'm the federal projects director for the Oil & Gas Compact Commission.

In May of 2003, the Interstate Oil & Gas Compact Commission, with funds provided by the Department of Energy National Environmental Technology Laboratory, tasked a storm water work group to determine how best to meet EPA's needs regarding NPDES storm water management practices and to develop appropriate guidance based on this program.

In today's presentation, I'm only discussing the findings and recommendations of the members of this work group, as the report has not been brought up for approval.

The work group included sections in the report to address the issue of current state water protection storm water programs and the appropriateness of the developing guidance documented based on those programs.

In the first section, they outline existing state storm water programs. The work group believes that developing specific storm water management practices would be impractical because of diversity of site-specific factors that need to be considered.

The work group concluded that remaining exempt states are appropriately managing storm water discharging. The work group evaluated the scope and effectiveness of the existing state water protection programs by: One, web-based search for state best management practices storm water sediment control; two, they surveyed management practices for storm water sediment control; and, three, they surveyed the extent of storm water related incidents in Kansas, New

Mexico, Oklahoma and Texas, which comprise 45 percent of all onshore drilling activity in the U.S. during the last three years.

The second section discusses existing state guidelines for storm water. This work group found there are numerous manuals and guidelines that describe the management practices of storm water control among the states.

The work group also found significant differences exist between management practices for large, long-lived commercial, residential and industrial construction sites and those preparation activities.

The third section discusses survey of state program elements. The work group developed and submitted a questionnaire to all 30 non-member states to solicit information regarding state programs relevant to storm water and water management practices.

The survey reveals that current storm water regulations and practices are adequate across the producing states. Four states reported significant problems with storm water discharges from the exploration and preparation activities prior to the implementation of the additional regulation.

Those states, Louisiana, West Virginia, Pennsylvania, Kentucky, could be characterized as states having relatively high rainfall. Twenty-six states confirms that their oil and gas regulations or regulations of other agencies within their state are currently addressing storm water discharge concerns.

The fourth section discusses survey storm water incidents. In order for the work group to better determine that there's significant pollution problems with storm water discharges, they contacted district staff to determine the number.

From 2000 to 2003, the number of incidents in all four states average approximately two per state per year. Clearly the number of incidents associated with storm water discharge is small compared to the amount of exploration and production activity in the state.

The work group did not find justification for requiring a storm water discharge for small exploration site activities. They also found that the federal permitting requirements level risk to the environment, and it is not feasible for single-standard requirements for appropriate storm water discharge throughout the United States.

They look at managing discharges from larger sites, and there is no indication of significant threat to the environment than storm water discharging activities.

Additionally, in regard to threatening endangered species and historic site issues, the work group found the evaluation associated with determining whether or not to drill a site would impact threatened and endangered species, expensive and time-consuming.

The small footprint of exploration and production activities does not support the need for extensive surveys.

The work group's conclusion is the existing state programs already sufficiently address these areas and the federal guidelines are inappropriate and unnecessary and the increased regulatory requirement negatively impacts needed energy production.

Thank you.

MR. ELDER: Thank you.

Our next speaker will be Garland Anderson.

MR. ANDERSON: Erosion and sedimentation and pollution from oil and gas construction is harming streams across the United States. My name is Garland Anderson. I'm a citizen representative of Colorado and the numerous groups, which I'll speak about here shortly.

I'm representing the Grand Valley Citizens Alliance, High Country, San Juan, Western Colorado Congress, several others. We're talking about quite a few people here that are involved in the impact of oil and gas construction activities in our Nation's waterways.

This chart shows over 18,500 people in eight states. Actually it's 20,000 plus the -- in eight states, so there's quite a -- quite a few people involved and paying attention to the aftermath and what's going on.

Storm water discharge problems: The problems associated with storm water discharge from oil and gas construction sites are not isolated. These problems occur from New Mexico to North Dakota.

The runoff and the erosion from these sites causes pollution and sedimentation in our streams and our rivers. The cost to remediate these problems is generally shifted from the producers to the local rural communities.

I also want to mention that the whole reason that a lot of us are here today is because of the siltation and sedimentation. We're concerned about what's happening to our Nation's waters.

Here we're looking at San Juan County in New Mexico right now, for example. These are the roads that are used to access the well pads. They represent one source.

Now, while I'm on this road here, let me just mention, in our county alone, Garfield County, Colorado, one of many, many counties, or hundreds of counties in these eight states, and probably in others, just in our county alone there's over 10,000 wells that are proposed.

Now, an average well gets 10 fracs. Fracing operation goes to keep the well living. Sometimes there are five, sometimes two or three, but in our county it's a great deal more because of the types of areas that are hitting the rocks and so forth.

So if you do ten fracs times ten thousand, you're going to have 100,000 truck trips for just one truck. Typically ten trucks are not unusual. Fracing operations will have a whole mess of trucks, six or so, or eight. And then there's a lot of other trucks coming and going. You're looking at over a million trips. In Garfield County -- we're talking one county -- over a million trips of trucks going up and down these roads, dirt roads. And then there's miles and miles and miles of roads not counting the pads. I just wanted to get on that one point there.

This is a San Miguel picture. Machinery and trucks on this pad are turning their soil into just a real mess. And this is not uncommon at all. This is a daily occurrence for many, many operators.

Here's a spot in our county, just one of many. Sediment has washed off of a well pad and all of that ultimately winds up in the streams and in the rivers, killing plant life, affecting fish and all kinds of microorganisms farther down the line, of which, by the way -- the EPA determined in 1998 -- they even reported that siltation is the largest cause of impaired water quality in rivers, and it still is.

Sublett County, Wyoming. At this site in Wyoming there's no perimeter fencing, for example, to prevent runoff. The deeply eroded gullies sent soil down to the drainage about a quarter of a mile. The gullies were even big enough to swallow trucks in this particular instance. Here's some erosion gullies that are leaving a well pad, just for an example.

Here's another in San Juan County. These spills occur real frequently and, without appropriate best management practices, these chemicals are washed off site, contaminating streams and damaging soil.

This salt water spill occurred seven years ago and has sterilized the soil. And there's a lot of production water, by the way, that gets involved in this operation. And the farther you go down in the ground, the saltier the water, to a point to where it's non-potable.

And especially when you get involved in CBM, coal bed methane, there's a tremendous amount of salt coming up now, that's going to have to be dealt with as well, that's also affecting things. And, of course, you've seen the hazards of that in some of the other states, Montana, Wyoming, and so forth.

And the last picture here is Garfield County, just one site of a waste tank valve that had been left open. Now, this is an accident, but this is one well pad that may have as many as six or eight or ten wells on it with lots of activity.

And this is one that we happened to see. A lot of them are way out in the boonies, out-of-sight-out-of-mind kind of situations, so that water is all running off into some stream below somewhere.

So in conclusion, I just want to throw in that the construction of the roads and the drilling pads can be harmful to water quality. The oil and gas construction activities must not be exempted from the clean water protection.

When you look at a well pad, we're talking size, some of them as little as a couple of acres or whatever, but that hasn't been the case in our county.

In our county we're looking at four, five, six acres, they've got eight acres now, and ten-acres pads, so some of those are already qualifying for the issue here, but they're not even talking about the roads. And we've got miles and miles of dirt roads that have an enormous amount of runoff.

That's pretty well it. I just wanted to share that with you. Thank you very much. Any questions?

MR. ELDER: Not right now.

MR. ANDERSON: All right.

MR. ELDER: Thank you.

The next scheduled speaker is Mike Decker.

MR. DECKER: My name is Michael Decker. I'm with the Oklahoma Corporation Commission.

We filed a brief in the 5th and 7th Circuits in support of industry efforts to define better or to challenge EPA interpretations of the general permit and the exemption for oil and gas. I would simply like to point your attention to the actions of our state and the states of Louisiana and Texas to file similar briefs.

We have taken the position that the exemption of the Clean Water Act should be construed to make certain that the NPDES permitting requirements are not applicable to oil and gas. And we would hope that the result from the appeals that have been taken will clarify the problem and hopefully resolve some of the issues we're discussing today.

Thank you.

MR. ELDER: Tim Baker, you're going to pass, okay.

Tom Fisk.

MR. FISK: Good morning. My name is Tom Fisk, and I'm here today representing the Gas Processors Association.

I'd like to thank the EPA for inviting the Gas Processors Association for the opportunity to comment on the proposed NPDES storm water permit coverage that will be disturbing from one to five acres of land in the oil and gas industry.

The EPA has a direct interest in this proposed rule making and the protection of the waters of the U.S. as it pertains to the oil and gas industry.

There are four points that I'd like to discuss this morning, including the Clean Water Act exemption impact, proposed rule making to our industry, funding and staffing issues due to the large number of potential permitted projects, and streamlining of the permitting process.

We were very pleased the see that the EPA has re-evaluated the scope of the oil and gas exemptions to the Clean Water Act. The EPA should also evaluate these exemptions as they apply to sites that are five acres or more in size.

The GPA feel that all of these construction activities are an integral part of oil and gas production and should be exempt from storm water permitting. However, if the EPA proceeds and requires small one to five-acre oil and gas construction projects obtain coverage under some type of storm water permit, the impact to our industry would be great.

In 2004, GPA collected and submitted some data to the Department of Energy. I would like to break down that data so you can see what it will have on the industry.

In that data we provided, it was estimated that, within the GPA membership, there are over 8200 ground-disturbing pipeline construction projects annually. And I'm speaking pretty specific here to linear construction projects.

These numbers included well head and gathering pipeline connections and gathering line construction projects. Construction projects, pressure sites, processing plants were not included in this total. Of those 8300 construction projects, approximately 5700 were less than one acre. Over 300 of those sites were five acres or more that required coverage under the current permits. That leaves over 2,300 sites of ground disturbing activities that are between one and five acres in size that would be subject to permitting.

This reflects a nearly eightfold increase in construction projects requiring permits under EPA's current rule. This number is conservative since access roads and other potential construction activities will move that additional sites be covered under the one to five acre rule.

With this in mind, the EPA must ensure that there is sufficient staffing or funding within the permitting agencies that will oversee the storm water program to be able to handle the large volume of small oil and gas construction permitting process and the inevitable questions to agencies relating to the permitting activities.

In addition, there are secondary permitting agencies that will be affected by the large increase in permits, such as wildlife service, state and federal historic preservation offices.

I would like to stress that there is a large difference between commercial or housing development construction activities and the linear oil and gas pipeline construction activities.

Linear construction in the oil and gas business is short-lived and may only span a few days. At the end of construction, all the disturbed areas are returned to original contours and re-seeded. The risk of pollution for this type of activity is less than commercial housing development that may have construction active for many months.

Due to this reduced risk of pollution and reducing the impact to our industry funding and staffing issues, the GPA suggests that the EPA streamline the permitting process and storm water pollution prevention plan requirements to reduce the burden of industry and regulatory agencies. Our suggestions include:

Allow permit by rule. An alternative to this would be allow permitting by geographical area. This would be done by grouping sections, regions, counties, states that would eliminate the seven-day waiting period for each individual construction project except for the initial seven-day waiting period of geographical area.

Second, inspection requirements should be reduced. The GPA suggests that inspections be required once every two weeks during construction, and then once final stabilization and seed has been placed, waiting for final stabilizations, inspections could be conducted once every two months until the final stabilization is complete.

Three, the storm water prevention plan requirements to include requirements that are specific to linear oil and gas construction projects. For example, the areas that would be disturbed versus areas that are not disturbed is disturbed during construction. Also, observing the water conditions once construction is complete is difficult since most of these areas are unmanned.

Finally, allow a clear exemption for projects that are not in immediate vicinity or do not cross waters in the U.S. since there would be no discharge to these waters. This could be easily done by geographical area or region. And then also in those are slopes, distances to water.

This concludes our comments for this morning. Again, I want to thank you for allowing us the time to speak.

MR. ELDER: Thank you.

Next speaker is Sharon Buccino. Sharon, would you like to come up here?

MS. BUCCINO: Thank you.

My name is Sharon Buccino, and I'm an attorney for the National Resources Defense Council in Washington, D.C. And NRDC is a nonprofit membership organization. We work on a range of environmental issues for public health to public lands. We have over 500,000 members across the country. We have offices in Washington, D.C., where I work, New York City, San Francisco, and Los Angeles.

We also work very closely with the Clean Water Network, which is a network of local citizens across the country working to maintain and restore water quality, and these citizens depend on clean water for their jobs, their health, and their quality of life.

I'd like to make three points today: One is that oil and gas construction does harm water quality; second, that the permits ensure that oil and gas companies use best management practices to control storm water pollution; and, third, that the permits also are the way to ensure that the development, where it's occurring, is done right and it's diffusing the controversy that can surround it.

I guess I'll just ask this question rhetorically now, we'll have some more discussion later, but I welcome the chance to be here and hear the different perspectives.

As I was looking at those photographs, the question that came to my mind and that I'm interested in hearing some response to is what the rationale is that the oil and gas operators offer in terms of why they should be exempt from storm water pollution.

So separate from the legal arguments, in terms of what actually may be covered by the existing language in the Clean Water Act and what isn't, I'm very interested in the rationale that's behind that and why controls for storm water should not be in place and why there shouldn't be a permit mechanism to provide some accountability and assurance.

What I wanted to focus on regarding the harmed water quality actually is the growth in oil and gas activity. And this is particularly occurring in the west. A lot of it is happening in the Rocky Mountain region.

And since 2001, the Department of Interior has taken numerous actions to accelerate energy development. We had the executive order issued by President Bush in May of 2001 specifying various agency actions to expedite energy projects, including the formation of the White House energy project streamlining task force. And I think what you're seeing is that the citizen concerns are the loudest where growth is the greatest. And let me just give you a few numbers.

The amount of land leased by the Bureau of Land Management for oil and gas development is up by 16 percent. It set a new record for number of drilling permits approved. They set that in fiscal year 2004. It's still going up.

In 2004, BLM approved over 6,000 drilling permits, which was up from 3,800 permits in the previous fiscal year. So new drilling pads are being built every day and miles of roads and pipelines are being constructed.

EPA has estimated that approximately 30,000 new oil and gas construction sites are occurring each year. Yes, this definitely affects the cost-to-permit actions, but it also -- the failure to regulate also has significant costs.

When you have that many new construction starts happening each year, significant damage is occurring now with each year of delay, and that's why there's so much controversy and concern about the various deferral rules that have happened.

The construction activity has real and immediate impact on the Nation's waters. We already heard the quote from EPA's report that siltation is the largest cause of impaired water quality in rivers. EPA has also said that erosion rates from construction sites are much greater than from almost any other land use. The air conditions in the West make the matters worse.

And just to give you some numbers. From Colorado alone, if you look at the waters that are listed as impaired, that are violating the state's water quality standards, 82 or 74 percent of the 111 waters listed as impaired in Colorado are impaired for sediment and 67 of those are impaired by sediment alone.

Going to the issue of the permits. You know, certainly there are good actors out there doing the right thing, but we need the rules to ensure that the bad actors are also delivering the protection that's necessary to water quality. And there are countless examples of the protections not being put in place, and it's the permits that provide the mechanism to ensure that those best management practices are put in place and deliver results.

And the last point I'd like to make is that NRDC, along with the citizens of the Rocky Mountain region and elsewhere, do not oppose use of public lands for energy development, but it's critical that where that development occurs it's done right, and the permits are the mechanism to ensure that. They also are the mechanism that allows for the controversy to be diffused, for the citizens' concerns to be heard and addressed, and that's what is going to allow energy development to accelerate and go forward more quickly.

Thank you.

MR. ELDER: Thank you.

First, are there any other people in the audience that would like to give a statement that did not register to that effect? If not, are there any questions for the people that didn't give presentations?

And hopefully our microphone is now working.

Any questions from the front table?

Sharon.

MS. BUCCINO: I just had a question. I wanted to better understand the comment that was made, I think it was by Mr. Polter, about the control, the different operators, and it went to the issue to the common plan of development.

And I guess I'm a little bit confused and just wanted to be enlightened why Operator A, who is drilling the drilling pad, does not have control over it. I think it was a gathering line that was described attaching to that drilling pad. And I admit I don't know the details of the operation, so if you would just elaborate on that a little bit.

MR. POLTER: Sure. Thanks.

The scenario I was describing is I think fairly common, where operators have various outlets for taking away product from a well. They can pipe it, they can haul it, they can run it through a gathering system. And that may be separate economic drivers for different operators to embark on a project.

And where a well goes in and it has options to go to multiple pipelines or to take it away via truck, they'll approach the gathering operator and say, Do you want this project for your pipeline? If they make a decision and say, Yes, they'll run that as their cost to run to that well. One is the operator and the other one is running the gathering system.

And in some cases -- we've run across it recently -- it was very close to five acres. We evaluated it with the operators, in terms of who was subject to permitting, if anybody. It turns out it was less than five acres, but there are many situations where we do have more than five acres.

That is a common plan of development in the fact you would go out and get a permit that's Operator A for some portion less than the five acres and you would have no control over the other portion that was operated by Operator B. They would have to get some other permit. And it just seems that you would have your permitting obligations determined by the actions of a separate party.

MS. BUCCINO: I guess just kind of from the public perspective, it's hard to -- there has to be some way to get the gas out from the well site.

And so when you're looking at that situation and you describe it that way, I understand the issues of control, but the fact is there's a lot -- there's a large area of land that's being disturbed.

So, should that just be, defined -- should the problem just be defined in a way so everybody is responsible? I think that's the concern.

AUDIENCE MEMBER: Well, I understand that point as well. But I think most, at least the operator's I'm familiar with, engage in best management practices anyway under their POM, so I think the operators who are represented here probably are engaging in BMPs anyway.

MR. ELDER: Okay. David.

MR. TEMPLET: You said earlier that permits provide a mechanism to protect water quality. Why would a permit provide any more protection than the requirement for the industry to implement a reasonable-and-prudent-practices approach for all construction? Why does a permit have to provide that additional -- how does it provide that additional degree of protection?

MS. BUCCINO: Well, I think what's critical is not necessarily the form of the administrative process, but it's why I asked this question about the maintenance and inspection earlier.

So I think if -- I mean, in this case, unlike some other pollution control situations, I think there is probably agreement that the best management practices are relatively, you know, simple, straightforward, relatively inexpensive.

At least from our perspective, the critical piece is making sure that you have enforcement mechanism to ensure that those BMPs do go in place and that there is some monitoring to ensure that if the fence rips or something there's a system in place to fix it and you actually are producing the results.

So I think you have that mechanism in the permits now. If there's an alternative that delivers the same accountability and the same results at less administrative cost, I think that's a win/win situation, but it's ensuring that enforcement or mechanism for accountability, that's the critical issue.

MR. TEMPLET: Yeah. I think we agree.

We're on the same page there.

MR. FLEMING: I think this point that we're on here, it goes back to some of the slides that were shown. And I think that even discussing the exemption, if you have a site in which there's an active unit, active flow off of that site, then that's a site that would be required to have a permit, and failure to have the permit would be subject to penalties and enforcement mechanisms that EPA has at its disposal for those violations.

MS. BUCCINO: Well, I just want to push back a little bit and get you to elaborate a little bit more on the issue of the exemption. Because I think I -- if -- I guess I'm frustrated and I don't really understand the effort that some companies are making to ensure -- to ensure that the current language of the Clean Water Act is read in a way that completely exempts these activities. Because what I see when I look at that is an unwillingness to address the problem of the water pollution that's occurring rather than trying to find the most efficient way of addressing it. Because the result is there is therefore no legal requirement and therefore no leverage to -- and no accountability to bring the companies to the table that are not taking the right steps and to make -- and to make sure that those mechanisms are put in place. And there are plenty of examples where it's not happening.

MR. ADAMS: I think the point is basically the same one. The permit exemption only applies if the storm water is not contaminated. If storm water is flowing off the site that has sediment in it, it does not qualify for the exemption.

And maybe that's a misunderstanding in some companies that they say that just because we have an exemption we don't have to do anything. That's not true, because you don't qualify for the exemption if you are polluting. You need a permit. And that permit is to help -- is to make sure that that contamination is controlled and minimized. So there is enforcement mechanism, or there -- that's the intent of the exemption, is that if you've got contaminated storm water, you have to have a permit. You don't qualify for the exemption.

The permit brings with it a lot of administrative verbiage and time requirements, and those are what the industry is saying are hard to live with. The cost of the controls are reasonable, and they're controls that we put in place anyway. I'm not saying it's done in absolutely every instance, and that's what enforcement is there for. And again, the mechanism is that they should have a permit because the exemption doesn't give you the right to do whatever you want.

MS. BUCCINO: Well, that's an -- I have not actually heard that description of the characterization of the exemption before, and I don't know -- there may be some lawyers who are involved directly in the litigation.

My brief reading of some of the papers that have been involved do not characterize the exemption that way. They're characterized in the language in the Clean Water Act as removing EPA's authority to regulate this type of activity.

So what I heard you saying was that if a company -- if one of these well sites has not put in the controls that would actually prevent any sediment from going into the waterways, you could -- of course, you have a monitoring problem, but if you documented sediment occurring, then I guess what I heard you saying was that there is a clear legal requirement to have it in that situation.

That is not my understanding of some of the arguments that have been made in the litigation challenging EPA's authority.

MR. ELDER: Anyone else like to address that issue?

Martin.

MR. FLEMING: I don't want to argue the briefs, because this is not the form to do that. But my understanding of the briefs is -- in fact, that position was articulated in industry briefs. I want to just make that point for the record, but I want to be careful not to argue the briefs.

MS. McQUAID: My name is Janet McQuaid.

As the position of industry with respect to contamination in the briefs that were filed in the 5th Circuit, there is no position with respect to contamination because that has not been developed in the rules at this point. So at this point, our position has simply been to state the language of the statute. And that does say that if an oil and gas discharge to waters of the U.S. is contaminated, then a permit is required.

EPA has defined that in the rules and we have not challenged that definition and are satisfied with that definition and, moreover, have not taken the position. And because the issue has not been raised, then EPA has no further authority to apply any other definition to contamination in the litigation.

MS. BUCINO: I guess what I mean, what I see as relevant to this discussion is I think there is a potential middle ground to find the win/win solution, but it requires an assumption of EPA's authority to address this pollution problem, which I haven't heard anybody really debate that there's not water quality pollution occurring from this type of activity.

MR. BUTLER: I have a comment on that. I'll make it brief. Hopefully I'm speaking loudly enough. I'd like to remind all our colleagues here we're talking about construction activities.

MR. ELDER: Please identify yourself again.

MR. BUTLER: My name is Don Butler. I work in Dallas for National Energy Group, the publicly traded oil and gas company.

We are talking about construction activities, and I'd implore that examples being used in these situations, that we keep them relevant and pertinent to those types of activities.

And even though you acknowledge yourself that many of these operations were -- you know, many demonstrations that you showed there were from spills. If you're going to use these things, keep the examples specific to construction activities.

And again, when it's stated that there is pollution from oil and gas activities, specifically construction activities, which you referred to, Sharon, is that you site some examples in some reports and studies for our benefit, too, that demonstrate to those of us that are present here today, specific instances where construction activities have caused damages in these areas.

Thank you.

MS. BUCCINO: I'd like to respond to that because I think the burden is clearly on the industry, and it's precisely because EPA has already made the case, and it was in the context of the Phase II rule making that storm water from construction activities causes significant water pollution problems. And because that demonstration has already been made, in my view it's industry's burden to show that their construction is somehow different than the construction that EPA has already documented causes problems.

And I also wanted to address the issue of construction related to what happens later on and the difficult task of drawing a line regarding where construction ends.

What I saw in those photographs was -- what it called to my mind was if steps like the re-seeding and re-vegetation had occurred after construction, you wouldn't have the same kind of pollution happening during the operations.

And again, I don't think the public concern is with the situations as was mentioned, in terms of the pipelines that are properly re-seeded. It's the situations where those actions aren't happening that you end up with activities that look like that, which are fairly typical across the Rocky Mountain regions, where I'm familiar, and so the result is water pollution, and that's what the concern is with.

MR. ELDER: Jim Hanlon.

MR. HANLON: As Jack Faulk summarized in his presentation, the agency's interpretations going back to the early 1990s is that construction at oil and gas sites, certainly the Phase I sites, had been included in the permitting program, and those sites have been permitted for the last ten or more years.

The focus of discussion today is on the Phase II sites. Again, our interpretation to date has been construction is included in the scope of the regulatory programs, that they are not exempt; although, in the Federal Register notice announcing the deferral of the March 2005 limitation date, we said, in addition to options for regulating of construction and small oil and gas sites, we would also be looking at the terms of the exemption. So we are doing that.

But as we sit here today, as I mentioned in opening remarks, and as Jack followed up on, the focus of our discussion is sort of what are the options that lie before us to deal with managing construction and runoff of construction at the small sites.

And again, there are actions ongoing in the courts, there's action ongoing on the Hill that may deal with this. But I would suggest that, to the extent possible, we focus our energies in terms of how to best manage the runoff from these sites. I think that's where we have the potential of making the most progress today.

AUDIENCE MEMBER: Clarification on the statement.

MR. ELDER: Hold on, please.

AUDIENCE MEMBER: In the beginning --

MR. ELDER: Identify yourself.

MR. CARTER: Mickey Carter.

In the beginning, I guess it was Jack that said that small construction sites was not considered in the Phase II rule making, that you didn't consider them part of the rule making. Therefore you hadn't looked at them and that was the purpose of the deferral, was to go back and take a look at them, so they haven't been proven yet to be a significant cause of any runoff, or is that incorrect?

MR. HANLON: Let me clarify that.

Basically what the record for the December 1999 Phase II storm water rule assumed -- well, first of all, it said that all construction between one and five acres in scope, so basically there's no question. If you disturb between one and five acres, you're in scope, you're covered by that regulation and permits that follow.

What we understood at the time was that very few oil and gas sites were in that window of one to five acres. The information we had available at the time was that you're either over five acres or you're under one, and that there's a very small segment of the industry that are one to five acres, so we were projecting relatively little impact of the rule on small oil and gas construction, not that they were exempt, but we thought the impact was minimal.

All right. As the March 2003 date approached during the summer of 2002, we were approached by representatives of the industry that said we probably had it wrong, that that was not solid information. And it was on that basis that we issued the first deferral and began the assessment of what the industry looks like and what really happens on the ground in terms of how many sites would be in that one to five acre window.

So again, we didn't think there were many in scope, but those that were were clearly intended to be covered by the December 1999 rule.

MR. CARL: My name is Mark Carl with the Oil & Gas Compact Commission. And my concern with what I've been hearing is that the requirement of a permit is going to solve the problem.

The states have these regulations and rules enacted within their states to control these problems. They have the manpower; they have people out, the eyes out in the field; they know who's out there. EPA is not going to have any people out there inspecting these sites. It's going to be really no different from what it is. And I feel like really you should be working more with the states to get them to work with them to get this problem solved.

I'm not sure that EPA is the answer here. And I still say the states have the people and the manpower and the regulations to control this, and they do a pretty good job. They work with these oil companies. They know them personally. And they have the phone numbers and they can call them directly and get problems solved immediately, not six months down the road.

MS. BUCCINO: I don't have any illusions that the permit, in and of itself, will solve the problem, but at least right now some permit is better than no permit.

And I'm not sure you have an agreement from all the state agencies that they have the manpower and the resources to address the problem.

And, of course, there's the distinction between the oil and gas commissions in the state versus the water quality commissions, and often you have a difference of interest and a difference of resources there.

MR. ELDER: Martin.

MR. FLEMING: I think this also begs the discussion of the fact that, do you look at the fundamentally different areas in which oil and gas operations take place, differences in topography and conditions and rainfall, et cetera? Because a lot of the discussions have centered around the Rockies and Colorado, and that's a very different topography than we see in Texas, which, in fact, is a state that doesn't have delegation, and so our interaction with EPA is very critical and is a very different thing.

In Colorado, for example, my understanding is it has a pretty stringent storm water rule; although, you might disagree, from an industry perspective it's a pretty stringent rule in place. And state agencies have the authority to do that, and we're seeing that take place across the country.

So as we go forward and talk about best practices approaches, the flexibility to apply varieties of circumstances is really critical because the differences of someone operating, say, in Pecos County in Texas versus Gunnison County in Colorado are great. There's a tremendous difference in topography and frankly the amount of rainfall and potential impact.

MR. ELDER: David.

MR. BAUMGARTEN: If I might, a suggestion has been made that regulation qualifies as quality and may not be necessary based on the industry regulating itself. And what authority does the industry have for situations like that other than regulation qualified by law?

MR. HANLON: I think presentations that are lined up during the rest of the day will speak to some of the practices that are being developed and sort of how they may be used at different regulatory agencies, so we're certainly going to get to that as part of the planned discussion, and it may be useful to sort of let the agenda proceed, and if those questions aren't answered, move back to it.

MR. ADAMS: I agree with that point, but I also want to make the point that we're not saying that storm water management should not be regulated.

What we're saying is that there's regulations already in place, and that sometimes lack of manpower in the states, sometimes lack of education from some of the industry, may be resulting in not sufficient controls being put in place on the ground.

The solution to that is not additional permitting, administrative burden placed on the operators that are trying to do practices already. I believe the answer is more to enforcing what's already in place.

We already have a permitting program in place that says if you have contaminated storm water leaving the site, you have to have a permit. You don't qualify for the exemption. Putting another permitting program in place is not going to do any more good than what we already have. If you don't have the enforcement behind it, you don't have the resources to help identify and find the operators that are not doing this, then you're not getting to where the problem is.

The operators -- and I think the majority of the operators already know that they need to have practices in place, and do. We don't need additional administrative burden on top of those operators. We need to educate and enforce against the ones who are doing that.

And you're right, industry doesn't have the mechanism or authority to enforce on other operators. That's the EPA, the state agency's authority and right to do that. I suggest that it's more making sure they have the resources and the aids that they need to do that job, not additional permitting restrictions.

MR. ELDER: Okay. I think we're going to get into that.

David, did you have something?

MR. TEMPLET: That's okay. You can move forward.

MR. ELDER: Anybody else from the audience that would like to ask a question of any of the speakers?

(No response.)

MR. ELDER: All right. If not, the next presentation is an oil and gas overview. Dave Perkins is going to lead that off, followed by Tad Mayfield.

MR. PERKINS: My name is Dave Perkins out of Houston, Texas, operator that operates in most of the oil and gas states in the United States and across various countries and overseas.

What I would like to present this morning is a brief overview for the audience to help set the foundation of understanding as we walk our way through just our practices in oil and gas to get to the permit process we've been talking about this morning.

To give you an idea, we put together this pictorial cartoon that gives you a look at the road to energy. And we'll start here in the lower left corner with this road across the energy trail for domestic oil and gas extraction.

Our first step begins over here in the left, and we're going to talk about the geophysical process. Because oil and gas, which is different than many of the other construction activities, oil and gas is all about the subsurface and the access to the subsurface. And so our first step is really a look at that subsurface through geophysical equipment with usually either vibration or explosive technique, which give us a signal down into the formation here at the bottom of the slide, which is reflected back and recorded at the surface and gives our petrophysicists and geologists some data in which to try to define some subsurface structure for the potential for oil and gas.

Once a target has been identified, then all of a sudden we start into the land leasing objectives of oil and gas. And we're going to give you some additional details of this leasing challenge because there are some very specific requirements in leasing which I don't think the general public is aware of.

But leases have penalties and deadlines. They also oftentimes have multiple surface owners in many of the states outside the Western United States, where in the West we get into federal lands, but we have multiple surface and mineral lease holders, very competitive situations, and oftentimes the lease conditions raise the clock for oil and gas construction.

Moving on from leasing, we then look at the regulatory permitting process, whether that's a state or a federal process, and then depending upon the leasing that we have, what type of permit applications we have.

We have state, federal and private lands to deal with. We have the construction; the drilling; the pipelines; the road right-of-ways; we get into air; waterwaste; historical preservation issues; cultural issues; vegetation; wetlands; wildlife issues that we have to take into account for our regulatory process.

If all that comes together, we will finally start our construction of a well pad.

We've seen some photographs this morning on construction. And as Jim has mentioned, with EPA, our purpose here this morning is to identify some inputs on the one to five acre sites.

And I think some of the photographs this morning said the permit process -- it seemed to me that construction of roads and some of the well pads that we saw probably are in excess of five acres and are in the permitting and the construction permit requirements and that would get into the compliance of those permits and not so much the permits themselves.

But we would then have construction of a drill pad, which would have a drilling rig of multiple sizes, depending on the depth and type of wells that we want to try to address, in the lower part of the screen here, to target our oil and gas location.

If the well is successful, then the rig will be moved off and the well location will be finalized. We'll put equipment on there for production purposes. We would then extract the hydrocarbons, which typically also have a water component. Some of this was shown this morning on some previous photographs.

Oil and gas is then, in the green and red lines, taken from the production at the well head. And separation of the water typically again goes to a water disposal and back underground.

If a well is unsuccessful, surface equipment is not utilized. We then go into an abandoned operation. We'll plug the well out per the state oil and gas regulations and we will restore the surface back to original condition.

I'd like to stop for a moment and step back now from the oil and gas trail and make a comparison between oil and gas and real estate construction practices.

On the left-hand side of the screen we have an illustration of a real estate tract, and on the right-hand side of the screen we have the same tract utilized for oil and gas.

Some of the differences here are – the real estate industry is about the surface and the development of that surface and then developing the blueprint for their construction, whereas oil and gas is about the subsurface and trying to find a target below ground that we have an access point from aboveground.

The oil and gas challenges we have is that when we're looking below ground, whether or not we'll go from one well to two wells or multiple wells, beyond that is depending upon the success and the data collected from each of these wells; whereas, in comparison to the real estate construction practices, they've got a blueprint that then goes and fully exploits that surface acreage and utilizes pretty much all the surface for their real estate plans.

To just summarize our real estate versus oil and gas: Real estate is a surface-driven construction practice versus a subsurface target-driven application for oil and gas. The land and real estate is typically acquired and owned; whereas, in oil and gas, we typically lease the land from a surface owner, which then requires a series of deadlines and other issues that we are going to address here in just a moment in more detail.

Real estate has a number of timelines, however, that are typically much more flexible than what the oil and gas timelines are, which oftentimes create a deadline on the lease terms which could expire and lose the lease altogether and lose the project.

There's quite a bit more certainty to our real estate planning than there is for oil and gas, which goes on a well-by-well basis oftentimes. Again, real estate is typically developed in more metropolitan areas, where oil and gas is oftentimes remote.

This was mentioned this morning to be remote, out of sight, out of mind. I would say it's not necessarily out of sight, out of mind, but we do have many decentralized remote locations. This makes it very challenging for storm water inspections and follow-up after a rain event.

Oftentimes we have a single-sided administration for real estate; whereas, with oil and gas with decentralization in multiple levels is a very scattered process for this industry, much different than oil and gas. Oil and gas is much different than real estate, and we believe that one rule does not necessarily fit all industries.

Just a little bit on cost figures. And I think the footnote here at the bottom of the slide best represents it. Pretty extensive analysis on cost and EPA is now also in the analysis phase of their cost and economics.

But in the neighborhood of 30,000 wells per year are drilled. And in our industry experience, we're seeing our cost running between 5,000 and 15,000 per plan for implementation and monitoring, sampling, testing, and installation of controls.

And this is going to add some burdens for government with additional manpower, recordkeeping, inspection, monitoring; also, for industry with the notice of intent process, the additional burdens of numerous notices of intent.

Right now there's a limited percentage that 30,000 is under notice of intent. And with the one-acre rule, this would put pretty much all 30,000 per year within the storm water rule process. So summaries of what we're trying to show on the oil and gas 101 slides today is that the intent of the storm water regulations are to protect surface waters from sediment and erosion runoff created by construction activities. I want you to keep that in mind. And we already covered, in the oil and gas process by storm water permits, storm water plans.

We see that there's a tremendous amount of difference between oil and gas and the real estate activities, and we want to make sure people understand the differences and distinctions. And the storm water regulations are a difficult process for oil and gas to manage, particularly when you get down into the one-acre size, below the five acres.

In conclusion, we're going to demonstrate a little bit later today an alternative process that we think is a better proposition for the storm water rules that would also protect the surface waters in the United States, and that the no-storm water-permit process for the one to five acres is still a strong applicable process and doable process with the implementation of RAPPS for oil and gas construction.

We're going to demonstrate and define what RAPPS is and hope that people understand that implementation of RAPPS for oil and gas construction is to protect the waters of the U.S. and give oil and gas a standard for construction practices.

Thank you very much. And with that, I'm going to lead into Tad Mayfield, who is going to come up and give you a better understanding of the leasing challenges.

MR. MAYFIELD: My name is Tad Mayfield.

I'm president of Goldston Oil Corporation. We are a smaller oil and gas exploration and production company. We are family owned and independently operated. And I appreciate the opportunity to speak with you today about what we feel are the implications and the effects of the storm water proposed rules for exploration and production activity.

We are mainly -- we mainly operate in Texas. We have some operations in Louisiana. I wanted to talk about impacts of storm water permitting on operators who do business primarily on privately held lands. We see the implications that -- we may incur lost leases; lost access to rigs; we have compliance issues; and this will result in lost production and reserves.

The following illustrates the leasing complexities, along with a current and live example of a typical exploration project. Leasing issues are complex, and I hope to show an example of why.

This is a recent article from the Gilmer Mirror in East Texas, and there are two folks on here, Ms. Effie Barksdale and Ms. Grace Duffie, who are being honored for their birthdays.

Ms. Barksdale is being honored for her 100th birthday, and she has 20 grandchildren, 30 great grandchildren, 55 great, great grandchildren, and 19 great, great, great grandchildren. That's a total of 124 grandchildren.

The reason that we have more problems today with leasing is that we have multiple owners, undivided interest owners of tracts that we need to lease prior to drilling a well. We need to acquire the rights to drill a well before we do so.

And to do that, we approach all the owners in the tracts involved in our exploration project and we individually negotiate leases with them that give us a contractual right to drill.

And here, with Mrs. Barksdale, if she owns a piece of property and she's the mineral owner and we want to lease those minerals, we give her an oil and gas lease and hopefully we can negotiate the right to drill on her property, along with any other owners on that properly as well.

However, hopefully a long period of time from now, some day she may have an estate that leaves her property to numerous owners, and instead of having one lease with her, we would have 124 leases to negotiate on that same tract of land.

To the right, Ms. Duffie is also a great, great, great grandmother, and she has more grandchildren than Ms. Barksdale. She has a total of 135.

So there are numerous individually negotiated leases on tracts of land with numerous undivided interest owners, and each one of these has different terms.

This is an actual live exploration project. It's very difficult. There are over 100 leases that we need to acquire for this to be ready to drill. And some of it is leased, which is shown in yellow. That's completely leased. There is a – two partially leased tracts showed [sic] in the red. And then the bottom green is held by production. We need to receive a farm out on that tract of land.

I'll go through the complexities of this particular prospect. This is a spreadsheet on tract one showing the leases that we have acquired. And you can see there are numerous people who own little bitty interests in tract one.

I may mention on tract one that none of the mineral owners own any of the surface. They're completely separated by ownership. And what we're interested in is acquiring leases on the minerals. And we are driven by the expiration dates of these leases.

We're particularly driven by ones that -- the leases that expire earliest, which there are 12 leases in here that expire by June 16th, 2006, unless prior commencement of drilling occurs. And we have been working on this tract for over three years to try to put it together so that we can drill a well on it.

This is the second page of tract one on the leases that are open. We have been researching the title and trying to locate the heirs of all these numerous owners. Leasing on this tract has taken years.

The bottom eight owners are the heirs of the estate of James S., who were located from a cousin Irene, who lives in Chicago. And she told us that the heirs live in North and South Carolina and we're now sending them leases and hopefully they will sign.

The top person, Allen, is in the hospital. He's institutionalized. We don't know that he's competent to sign a lease. We may need to find a guardian or perhaps get a court-appointed guardian to lease that tract if we're successful in doing so. So the total here, there's 40 leases taken, we need 24 leases.

This is tract two. There is a -- we've taken a total of 37 leases and we need an additional five leases. And just to show you the complexities on this one, James T., at the bottom, died entestate. That means he did not have a will. We are attempting to find all the heirs, then we will offer them leases. We may need to go through court for receivership. That may take three to five months. And if permitting delays cause the receivership leases to expire, we would then need additional court proceedings to lease once again.

Tract 3-A and 3-B contain leases that are held by production. That means there's another operator in production that's holding those leases by contract. To obtain this kind of lease, a farm out is required. Typical farm outs have a six-month or less drilling requirement. Company approval process may take two to five months or longer and storm water permitting delays may cause a loss of our farm out.

Tract four, we have been successful in leasing the three owners on that tract. In total, there are 317 acres, we have taken 80 leases, we need 29 leases and two farm outs.

I may add to that, there was one person that we just heard passed away and he has five new heirs that we need to go track down, so actually there are more leases that we need that aren't shown here. And we are hopeful that we can get this accomplished prior to June 16th of 2006. If we're lucky, we may have a short window in which to drill a well and any delays will disrupt this process.

Now, we may know and we may not know the current drill site location, because geological work is still being done. But even if we did know the drill site location, we would not disclose it until the leasing has been completed, and that's because of competition.

Competition from leases from outside operators or anybody else who may find where you are interested and will research the title around your drill site and start leasing, that could prove destructive to your exploration project or compromise mineral owner negotiations. If the mineral owner realizes that you are going to be drilling on their tract of land, they know that they have additional leverage, then they may be very difficult to deal with.

If you do not lease 100 percent of the drill site tract and most of the acreage around, then what if you -- outside parties can own part of your well without having to pay anything to drill and take the risk with you to find the oil and gas.

And I think, as many might know, that exploration is a risky business. Our first statistics says one out of nine wells is successful of exploration. It is risky and capital intensive. And so when we put up the money and time and effort to go after a project, we like to own that project. And the more outside ownership there is, the less reward, and it may not justify the risk for doing this project.

I will say for the record, when the industry does take leases from mineral owners, the mineral owners do get paid royalties. I think our average royalty on this exploration project will probably be 20 percent. So 20 percent of the revenue will be going to the owners, and the rest of it is to help pay for the cost of the project.

Drilling and permitting must commence after the leasing and farm outs are acquired and prior to the expiration date, and so there may be a short window to get all that accomplished. We're worried about delays causing our leases to bust and our exploration project.

And overall, right now we have 67 percent of the interest leased on this project, we lack around 33 percent, and that's not enough to do the project. So we've got to get going and get this accomplished prior to the expiration date of our leases.

So I've shown why exploration projects have numerous individual leases with short time lines that may be easily derailed by delays. If leases are lost and reserves and production are lost due to abandoned exploration projects, costs lost forever are geological, seismic exploration, engineering, project financing, lease acquisition, title work, legal work, permitting, and environmental work.

And, believe me, this is a typical exploration project. We have ones that are much more complex than this and we have some that are less. I would describe this as being typical.

Additional concern with delays include the risk of losing a rig. A rig will commit to other jobs if the operator cannot keep on schedule. Once the rig is lost, the risk of losing leases and abandoning the exploration project is compounded.

It takes now four to six months lead time to get a rig. The market is so tight to not only acquire but to re-acquire one. So you have to plan ahead for that. And if you lose a rig, you're going to have substantial delays in your project until you get a rig again. You need to keep it working.

The rig mobilization costs vary, even more so than on here, but $70,000 to $100,000 is our experience, depending on the rig size. And if you lose a rig, to re-acquire it, to move it quite a bit of distance, costs a considerable, considerable amount more than it would just to be to drilling a new well.

Let's see. Drilling is required after final lease acquisition and prior to lease terminations. And lease clauses typically require continuous drilling to hold additional acreage. Typical continual drilling clauses are 60 to 90 days.

What that means is, if you are successful with your first well, that you may want to drill a second well on a particular lease. And you form a production unit that holds certain acreage, acreage outside a production unit, if it's on a similar lease, and that may require 60 to 90-day drilling to hold it.

So your plans are very fluid and unknown many times until you drill that well and have a successful well. And you may only have a few days left to go build another location and to drill another well or you lose leases. And with that added risk, if you know there's going to be delays, you may not want to undertake a project that is potentially as expensive as these are.

Compliance issues. I've broken this down for all operators, and then smaller operators a little more so. But the issues I have talked about before this I would say affect everybody, not just small or large operators. But here timing is an issue for everybody.

The substantial delays associated with permitting processes. Leases on privately owned land do not allow for permitting delays.

The need for user-friendly guidelines such as RAPPS, that Marilyn will be speaking about in just a little bit, are needed, not something that's complicated. If it's user-friendly, they're more apt to be followed.

The compliance issues for all operators we're discussing are the storm water permitting costs. The costs for all the regulatory compliance would be very expensive and especially more so for a smaller operator.

And then typically smaller operators hire third-party consultants because they do not have the environmental staff on hand to accomplish the work that needs to be done, so we hire outside folks to help do that.

And then the compliance issues mainly for smaller operators is that we basically don't do much on federal property. I mean, the smaller operators do some of that, but we don't. Because of the federal leases, we're less able to compete, and we have financial constraints, so we're mainly confined to privately held lands. My understanding on federal land there is some allowance for permitting delays where you don't lose your leases like you do on privately held land.

So in conclusion: The proposed storm water permitting requirements will cause delays, lost opportunities, and lost production; delays cause lost leases and rigs; lost leases and rigs cause abandoned exploration projects; abandoned exploration projects cause lost reserves in production for the U.S.; lost U.S. reserves in production will result in lost jobs, more imports, larger U.S. trade imbalance, more energy dependence on foreign countries, higher consumer prices, less federal, state and local tax revenue, and less clean-burning natural gas.

In Texas right now 87 percent of the U.S. drilling rigs are drilling for natural gas, so if we cut down on number of rigs that use -- try to find gas, then what are we going to replace that fuel with? I would say that is an environmental issue. Would it be perhaps coal or nuclear or more imports?

So we would like to see -- and lastly, the implementation of a RAPPS document is a better alternative as compared to the proposed storm water permitting requirements. It's user-friendly and addresses storm water runoff concerns and avoids delays and cost impact issues.

And thanks again for letting me speak about our issues.

MR. ELDER: Are there questions from the front table for Dave and Tad's presentation first?

MS. FISH: I don't want to put you on the spot, but can you give us an idea of what the cost is for the seismic and the geology and all the leasing costs that goes into a well like this? Since it's the typical well, just approximate, if it were successful.

MR. MAYFIELD: I would say that it varies wildly. But on a project like this, I would say that there are several hundred thousand dollars wrapped up in this project that could be destroyed by permitting delays.

MR. ELDER: Anyone else up here? Anyone from the audience? Okay. Great. We're doing a good job of staying on time. There are 24 additional people roughly that were walk-in registrants for the public meeting. There's a list of those in the back of the room. We'd like you to check the information that was provided to make sure that it was compiled properly before we have it incorporated into a master list.

And secondly, on the back table is also a list of the restaurants with some annotations, in terms of what the concierge has recommended. There are also two restaurants here in the hotel, The Bistro and the Colonial Bar & Grill. We're due to resume at exactly 1:30, so please be back at that time. Thank you.

(Lunch recess taken)

MR. ELDER: I hope y'all had a great lunch. We did. The agenda shows that David Baumgarten is going to speak first. But before we get to him, there's two other things I want to cover.

First of all, we had a slight misunderstanding with a gentleman from Fish & Wildlife Service, who's now at the front table, so I would like to give him the opportunity to introduce himself.

MR. CLOUD: My name is Tom Cloud. I'm here basically representing Region 2.

MR. ELDER: Thank you.

And, second, Casey Schneider, from Region 6, is going to give an ad hoc unscheduled brief presentation with a few slides, talk about some of her experiences as an inspector for Region 6.

MS. SCHNEIDER: I'm with Region 6 water enforcement. I do inspections and I do enforcement for the construction storm water program, particularly as it relates to oil and gas.

And this is ad hoc and unscheduled because of a comment or request we heard earlier about having EPA present here today and present to the oil and gas industry actual real site inspection photos that we have done over the last couple of years, so that's what we're doing. These locations again are all in Region 6.

This is a location actually in Oklahoma. Most of these sites -- I think all of them are going to be less than five acres, so they would not currently be regulated under the construction storm water program. However, three of them were inspected as a result of landowner complaints.

And you can see the silt fence. This operator had done, you know, a pretty decent job. He had the entire perimeter with the silt fence. And the mud pit is over here on this side. You can see some sediment that has escaped by the silt fence.

I think the next photo is an area that has been well maintained, so that's a good effort, but probably this operator needed to step up those efforts, particularly along the maintenance lines.

This is the area where the operator could've been paying a little bit more attention to the maintenance of the silt fence. And this is the kind of situation we see quite often. Some good well thought BMPs in place, but the maintenance becomes an issue.

They are remote locations -- I'm well aware of that since I did all these inspections – and so I know that keeping up with that becomes quite tasking.

This is another location. You'll see in a second the control technology that this operator chose to select was actually a sedimentation basin.

We talked about sedimentation basins earlier. Somebody mentioned them. It works in some locations better than others. It didn't work so well in this location. Again, this was a landowner complaint that we responded to.

The location is actually built immediately adjacent to receiving water body and the basin is actually on the receiving water body, so placement and well thought BMPs are very important.

Another location. This is actually an access road on the way to a location. And you can see that the shoulders of the road were not stabilized.

The well was already drilled by the time we did this inspection. The shoulders definitely needed to be addressed. And you can see some signs that the sediment is impacting the receiving water again immediately adjacent to a water body.

Another location where this operator chose to use hay bails in the -- in the drainage -- in a drainage ditch coming off of the location. I believe there's a very small creek here in the background.

Hay bails, used as velocity dissipaters, works okay. Certainly there are other ways that we discussed while we were on site to be more effective and to control the sediment transport from this location into that receiving water a little bit better but, you know, a good effort.

A larger location, not quite five acres, but a large cleared area. This is actually some of the topography that I'm imagining in the Rockies. And since I haven't done inspections out there, I don't know.

But this is a hilly location in Region 6, so probably very similar topography in Colorado and Montana and Wyoming, where you've got whole hillsides that are actually cleared to create the space for the location. Again, this location is right next to a receiving body, and this is erosion coming off of the north slope into that nearby creek.

Lastly, the location actually overrides most of the creek, and you can see where it's trying to make its way back to its natural course through the road through the access road.

One more location. This one was not the subject of a citizen's complaint, but it was nearby when we inspected so we decided to stop by.

They were drilling this well when we were on location, and the site had been constructed pretty recently prior to drilling the location; I want to say it was about 15 days.

This is on some flat farm land in Oklahoma. The reserve pit's back here. The area of concern that we had is actually up here.

You'll see in the next slide the operator did great job of putting a silt fence on the back side of the mud pit and controlling sediment coming off of that slope and down into the pasture and ultimately to receiving body, but this area here hadn't been addressed. And there was no silt fence on the back side over here. So, you know, another example of a good effort, but we certainly made some recommendations to better control sediment transport on this site. And there's kind of a close up of that area of concern I was just discussing.

And lastly, same location, the access road coming into that location, and we discussed this right here. This is actually a culvert, a creek crossing. This road goes across the creek crossing. There is a culvert. But this area here was the big concern and we talked about them grading that area.

Again, this is a location that was less than five acres so it would not be covered under the construction storm water regulations today, but certainly some BMPs are needed necessary to control sediment transport, particularly right here, into this creek right here.

So that's the off-the-cuff presentation of some inspection photos. Are there any questions?

AUDIENCE MEMBER: Casey, were any of these operators -- I was curious as to whether or not any of the operators of these sites were fined.

And as a kind of follow-up, even though these sites were less than five acres, the EPA does have authority to take action against operators because of runoff or sediment or other contaminants. I just wanted to state that case.

MS. SCHNEIDER: No. None of these sites were greater than five acres. Well, one of them was, but that was part of a different case so we won't get into that.

The rest of them, the other four, were not -- they were not subject to enforcement actions. Again, we were responding to landowner complaints.

When we inspected the sites, they all turned out to be less than five acres, not regulated under the Phase II program. We worked with the operators and the with landowners to go over those regulations, go over what kind of enforcement authority the EPA had in those situations, and to come to some kind of solution.

Any other questions?

MR. ELDER: Now for David Baumgarten.

MR. BAUMGARTEN: Good afternoon. My name is David Baumgarten. I'm the county attorney for the county of Gunnison in the western part of the state of Colorado. I appreciate the opportunity to make this presentation.

The topic that's identified for me is associated with oil and gas construction activities. I cannot presume to be an expert on that subject, nor can I presume to be an expert on Colorado experience, but I can speak to my local government's experience in Colorado and trust that it's helpful to us all.

It was a wonderful writer, May Sarten, that gave advice that is as central to the task in front of us as it is to our relations with other people. She said that we persuade, if we do at all, by being irresistible, not by demanding the impossible.

Now, I found that out too late in my last marriage, when my wife had to ask me one too many times to do the dishes, but it's advice I will pass on to you.

If it were the end of today and we had been successful, we would have persuaded each other that reasonable federal regulation of storm water discharge from small oil and gas construction is irresistible and that avoidance of that regulation by the federal government in the future is impossible.

It is most important for me to begin by clearly stating the intention of Gunnison County. That intention is identified in the first sentence of the first paragraph of Gunnison County's temporary oil and gas regulations.

It says that the goal of the Board of the County Commissioners of Gunnison County is to provide a framework for the responsible exploration and production of oil and gas resources in Gunnison County in a manner that conserves public natural resources, that is sensitive to surrounding land uses, and that mitigates adverse impacts to and protects the public health, safety, welfare, environment of Gunnison County.

What that means is that Gunnison County recognize that oil and gas are valuable natural resources that should be extracted and put to beneficial use. Gunnison County also recognizes that there are impacts, environmental and otherwise, caused by the extraction of those resources. And it's the intent of Gunnison that those who extract the resources reasonably and responsibly avoid or mitigate the impacts caused by the extraction.

Irresistible and appropriate regulation can be accomplished only by being attentive, to-the-core concerns of the industry, the environmental community, local government, the regulators tasked with responsibility to address public health safety and welfare, and the affected public.

Being quite direct, the industry needs assurance that regulation will provide three things, certainty, timing, and money; that is, it must be that exploration and production can be scheduled and conducted knowing that if one follows the rules one can and will obtain and comply with a permit in a reasonable time, at a cost that is proportionate to impacts, and that the permit can be administered without undue burden.

The environmental community needs assurance that oil and gas exploration and production will not violate the first law of ecology; that is, that the water that sustains and nurtures us reasonably be protected from degradation.

The environmental community also needs assurance that such protection will be enforced and will be implemented consistently.

Local government, from my perspective, must be responsible to a broad scope of local constituents on a daily basis. We must be mindful of production on split estates and public lands. And we must ensure a healthy local sustainable economy and environment.

Local government, again, please, from my perspective, is where theory meets reality and where public meets the industry and where the public meets the government. Often that happens at your kitchen table or in a field or on the telephone at 6:30 in the morning and somebody wants to address concerns, such as we've seen in the photographs.

Federal and state regulators need to address the concern of the industry and the environmental community, local government, and the public, consistent with accepted science, and translate into regulations that are clear yet flexible enough to make sense of diverse topography and climates.

There has been no question today that there are substantive impacts that need to be regulated. The EPA itself documented at least six years ago that discharges from construction activity impacts the biological, chemical, and physical integrity of receiving waters; that sentiment yields from smaller construction sites were as high or higher than 20 to 150 tons per acre per year that are measured at larger sites; and that siltation is the largest cause of impaired water quality and rivers and the third largest cause of impaired water quality in lakes.

The EPA likewise has recognized that storm water runoff from construction activities can have a significant impact on water quality because the storm water flows over construction sites and will pick up pollutants such as sediment, debris and chemicals.

Each phase of oil and gas development, whether on large or small sites, can have a significant chemical consequence. This is not an indictment of the industry; it is only the reality that we must recognize as consumers and regulators of oil and gas.

In the drilling in well completion phase, access roads that are constructed in western Colorado where I live, these roads are often miles long, and fragile environments above 7,000 feet in elevation are far from quick response and slow to rehabilitate.

Drill cuttings and drilling muds can contain mercury, cadmium and hydrocarbons. It's important to note that even if construction is short-term, that is less than the 30 days that might be proposed for an exemption, the storm water discharge opportunity and risk is much larger and longer, often years, due to the topography, climate, maintenance, and operation of the site.

During production, produce water may contain contaminants. If natural gas conditioning is performed on the site, the process may involve contaminants as well. These significant chemical runoff consequences at each step, coupled with the long-term vulnerability of sites to storm water discharge, suggest two things: One, that a waiver, if there is to be one, ought not be tied to a variable of construction time, because whether the construction takes 30, 40 or 50 days, the rehabilitation for construction can take much longer; and, two, that a prophylactic, upfront storm water control mechanism put in place before construction can have continuing efficacy throughout the resulting phases of the project.

It may be useful to recap the Colorado regulatory experience, at lease from Gunnison's perspective.

The Colorado Phase II storm water regulations were adopted by the Colorado Water Quality Control Commission in December of 2000 and went into effect in March of 2001. In that rule making, the Colorado Commission set a deadline of July 1st, 2002, for permit applications.

At the request of the oil and gas producers, the commission agreed to use enforcement discretions which extended that July 2002 deadline into March of 2003. In 2003, the commission acted to further postpone the deadline until March of 2005. And in 2005, there was proposed to the commission a third postponement. That state activity took place against the frame work of oil and gas production in Colorado.

Oil and gas wells are widely distributed in Colorado and have significant volume. Two-thirds of Colorado counties, that is 42 of the 64 counties in the state, have wells located in them. Thirty percent of Colorado counties, that is 19 of 64, have at least 200 sites. Approximately 9,500 wells were drilled in the five years that implementation of Phase II was suspended for small oil and gas operations. The average pad size in Colorado, without the associated roads, is 1.2 acres.

Using these figures, more than 10,000 acres of oil and gas well pads were unregulated for storm water runoff in Colorado between 2000 and 2005. Using the EPA's estimate of between 20 and 150 tons per acre per year of sediment, one can quickly calculate that a number of millions of tons of sediment went unregulated into the waters in the state of Colorado.

Gunnison County decided to take action with regard to the exploration and production within our border. We passed a series of regulations, challenged, and wound up in state court.

In the state court action, which is entitled Board of County of Commissioners versus a particular company that will remain nameless, it lists the state of Colorado intervened.

The state, to date, has persuaded the state trial court that Colorado counties have no authority whatsoever to regulate impacts on water quality of oil and gas operations because it is only the state and the federal government that can do so.

We decided to take the opportunity of the third proposed postponement and try to get somebody, and it doesn't matter to us whether it's the state or federal government, we just want the impacts to be dealt with, and we used that opportunity of the proposed third postponement. And after that public hearing process, the Colorado Quality Commission made some findings that I think are very pertinent to our discussion today.

The Colorado Water Quality Control Commission found, quote, that if not properly managed, discharges from construction activity can impact the biological, chemical and physical integrity of receiving waters. They accepted evidence that included the EPA's analysis of water quality impacts from small construction sites in general and evidence of potential water quality impacts from specific oil and gas construction sites in Colorado.

The commission found that at the 2004 rate of permit issuance, a further 15-month delay of storm water permit requirements would result in substantial additional acreage disturbed by oil and gas and construction activities that would not be covered by the permits for storm water discharge. They found that delay would have a significant impact on water quality, that implementation of storm water permit program, along with appropriate planning and BMPs, could mitigate.

The commission explicitly found, quote, that there are no significant differences in oil and gas construction sites versus other types of construction sites that would affect the potential sediment yield from such disturbed areas.

They continue, quote, although the oil and gas industry is asking EPA to consider the short time frame for actual construction at most oil and gas sites, this does not take into account the time that it can take, up to several years, for revegetation of disturbed areas in Colorado.

The commission found in addition, quote, no evidence was presented that potential impacts on public health, beneficial use of water, or the environment for oil and gas construction activities are significantly different from other small construction sites to us to warrant special consideration.

The commission then went on and made additional findings, including: One, quote, no evidence was submitted quantifying unreasonable transaction costs of storm water permitting in Colorado for this industry; and, two, that evidence reflected a low storm water permitting cost to industry compared to the other cost of oil and gas development and compare to the water quality benefits of prompt implementation of permitting programs.

The commission concluded that the record for its rule making provided some scientific and technical evidence that establish a deadline for storm water discharge and permit application for oil and gas activities disturbing between one to five acres earlier than established by the EPA is, quote, necessary to protect the public health, beneficial use of water, and the environment of the state.

That Colorado experience suggests that in a vacuum of federal regulation, local and state governments will enact their own regulations. While those local and state regulations might satisfy some of the core interest that I identified before, it will also confront the industry and other communities, even communities that share the same oil and gas field with a dozen different flavors of regulation.

One solution is for the federal government simply to implement Phase II for small oil and gas sites.

Another potential solution has been articulated by the Independent Petroleum Association of America, and that is reasonable and prudent practices for stabilization, RAPPS, for oil and gas exploration. They are not prescriptive; that is, they don't attempt to identify one and only one solution for a problem, but are accepting of industry and are vitally informed.

Two, they're key to a various topographic types of the country.

Three, they're proactive.

Four, within each topographic area type analyses are presented based on vegetative cover and distance to regulated water bodies.

I suggest that the RAPPS deserve further attention and development. But again, from a local government perspective, a lot of care must be taken with regard to an enforcement mechanism.

Please, just a short conclusion, we have the opportunity in front of us to solve a significant problem, perhaps by consensus, that's being furthered by this hearing today. I trust that we'll be successful. The board thanks you and I thank you as well.

MR. ELDER: Are there any questions for David from the front table? From the audience?

David talked about RAPPS, and our next speaker is Marilyn Fish, who's going to talk about storm water management practices.

Marilyn.

MS. FISH: I am going to talk about reasonable and prudent practices for stabilization. And thanks for that introduction.

It has been mentioned several times today, but for those of you who don't know about RAPPS, I'm going to give you some information about what they are, how they were developed, and why they were developed, and then I'm going to work you through an example of how they work and show you how friendly they really are.

Okay. First of all, RAPPS were developed by industry representatives and personnel for various oil and gas companies and representatives of oil and gas industry associations. And the reason we did this was to develop a guideline for non-technical personnel.

We saw a lot of documents out there. Some were geared to oil and gas and some were not. But we wanted to compile control practices that were typically used in oil and gas and that were – and others -- that were suitable for oil and gas that may be used for other industries.

And when we did this, we actually got input from field people, so we would send these out occasionally with our drafts to field people. We sent those out to some of those people that did construction to let them try them out and see if they were user-friendly and to get their input, and we also did this with other small independent companies, so that we would end up with a document that was really useful.

So originally, like I said, the object of our group, to start with, was to compile a compendium of oil and gas practices for controlling sediment, erosion control, and to prevent the discharge of sediment into waters of the U.S. And as we did that, we decided that wasn't all we really needed.

We wanted to put it in a useful fashion so that construction people, the field people were out there really doing the work, could understand it and use it. So we were out to get a user-friendly document.

But in addition to that, as we were developing it, the question came up, Well, once they have these, how do they know when and where to use them? So we went on further than that and developed a methodology so people would know when to use controls, what types of controls would work best, and we put that together in the decision making process that's in the document. I think what we ended up with was a very good document, and I'll show you a little bit more about it.

First of all, it has been endorsed by several of the trade associations. And all of these organizations have endorsed the RAPPS. They publish it on their web sites. And it is something that's being made available to the industry as a whole, to every operator that knows about it. We're trying to communicate these through the different organizations, free to everybody, and we want it to become used as a voluntary guidance document for the industry.

Okay. So what is RAPPS? Well, RAPPS is a very short document, in reality. It's 21 pages. And in that is a group of flowcharts that cover different topographic areas that you work through, and you decide which controls you can use, and at the end of it it tells you which controls will work best in that particular type of environment.

And right at the beginning of the document, on about page 3 or 4, we have this information, steps one through eight, how to use this guidance document, because there are, like, two or three pages that tell about that. But again, we wanted to make it user-friendly. It's going to a construction person out in the field. They can go one through eight and get it done if they don't want to read two or three pages.

So step one, first you determine the geographic area that you're in, and you do this using figure one. Here is figure one. And these are general categories dividing the United States into six geographic areas. And so once you've decided where you are, then you go on to step two.

So for this example, I'm going to say, since Colorado is here, we're going to say we're in the Xeric Mountains, which is identified as XM on this map.

So step two, assure that that geographical area is the specific area where you're working, it fits the description of Xeric Mountains, and so we'll go to the page that gives further information on the Xeric Mountains.

And here it's described as generally mountainous area within the western United States, slopes exceeding 10 percent, variable vegetation, shallow rocky soils, and low to moderate annual precipitation.

So first of all, if that fits your site, then you want to use the flowchart for Xeric Mountains. If it doesn't, you want to go back to the other descriptions -- and there are only five others to look at -- and find the one that best fits your site.

And then there's some more information. Well, what -- it tells what to do. And again, it refers to the flowchart, but it says to -- there are certain things that you do. If you're more than 100 feet from a water body, you don't really need to put RAPPS in. Or if you are more than 75 feet from regulated water body and you have 75 percent vegetation -- that's probably rare in that area -- then you probably wouldn't need to install RAPPS; otherwise, you go to the flowchart. And the flowchart gets you to the same place.

Okay. So step three would be -- first of all, you have to look at your site, determine the slope, determine the distance to the U.S. regulated water body, and determine the approximate vegetation on that area. And again, we're looking at the area between your construction site and the nearest water body.

Once you've done that, you go to the decision tree for Xeric Mountains and you work through it. And in this example, we're going to say we have a vegetative cover of less than 25 percent; our slope is greater than 40 percent, which is pretty typical in this mountainous area; and the distance to water in this case is zero to 75 feet. So we've really got step slope, lightly vegetated area.

And when you get to the bottom of that, once you've worked through those distances, slopes and vegetations, you have a list of control measures that would work good with this particular site. And there's some abbreviations which tell which ones would work best in this case. And you don't use all of them. You look at your site, you look at the control measures, then you decide which ones and how many you really need to use for your site.

And at the bottom of this chart, it has a better description of what it is. BP up here -- BP down here is brush pile. And just to make sure we have as much information in one place as we can, if someone is working in one particular area, and construction people are typically in one area, then this is probably the only sheet that -- flowchart that that person will need, and he can carry it around in his pickup truck and have it when he needs it.

But again, it tells Xeric Mountains again, between 10, 15 inches of rainfall, and rocky soils with a lower erodability. So we put a lot of information in one place so they can keep referring back to it. We want to have it in several places.

So once you've looked at deciding which controls you want to use or you want to look at each control to see what it is and how it's installed so you can make your decisions about which one, you go to Appendix A, which actually has the control measures in them. And I've got here the control measures that were listed there for this particular area, so we can flip through these and see what one looks like.

For instance, the first one listed was rock berm. And you go to the sheet on rock berm and it talks about what a rock berm is and it describes the limitations, you know, where this won't really work, what are its limitations. If you have a lot of rock there, it may not be a good one to use.

And then also, we saw a lot of slides today that show maybe some silt fences that weren't properly installed. Well, we've thought it best to put in some information in here about how specifically to install it so that you make sure it's installed properly, so there's some information about installing it.

And again, just to repeat things, someone puts up this thing about rock berm, where can they use it, and we describe here where it works best, the types of facilities where you might use this it. And if someone is more visual, they like to see things rather than just read them, they can go to the diagram. The diagram gives them the same information about construction.

And I'll just flip through the others that are listed there. Diversion dike and a picture again of that; road surface slopes, and a picture of how that's done properly, or different ways you can be doing it depending on where you are; roadside ditches, the proper installation of roadside ditches to prevent erosion, et cetera.

Okay. So after all the routes are properly installed, of course you begin your construction, and then we start thinking about stabilization.

And again, the document is reasonable and prudent practices for stabilization of oil and gas sites. And that's where we want to get to. We want to get those sites stabilized and get on with our work.

And so we have provided some information in here about stabilization and what we think that makes for oil and gas sites.

And before we talk about stabilization, we felt like we needed to talk about what an actively disturbed site was. And it seems like it should be intuitive but we put it in here anyway so we make sure we have as much information as possible in this one document. Basically, it ends when the site is ready for its intended use and RAPPS have been selected and installed appropriately.

And so when are you through with that site? We say it's when you're applying base material, when you've added that base of material or it's been compacted. Were you don't install that base material, like on the edges of the roads, the ditches, the sides of the reserve pit, that's where you've achieved 70 percent of native vegetation or have control exceeding -- in place to achieve 70 percent of vegetation within three years. And that pretty much complies with the permit, I believe.

And then just some examples of what 70 percent vegetation looks like. It's not necessarily 70 percent of what could be there but what was there to start with. In this case, if vegetation is 50 percent to start with, it would be 35 percent or it should be 35 percent when you're finished and the area is stabilized.

Then we decided -- and this is actually in the controls for vegetative cover. The question was raised, Well, what do you mean by vegetation? And we thought, Well, what do we mean? Do we mean trees? Do we mean shrubs? Do we mean grass? What do we mean by vegetation?

And so we put this information in here and thoughts about how vegetation can be used as control and used properly.

And in here we say shrubs and trees may provide some means of controls, but really we're talking about low growing species, grass, and in one case I've seen crops used. One of our operators had asked the farmer to -- when he harvested his crop, that was around one of our oil wells, to leave a small area of the crop growing around the well pad, and it actually provided a great vegetative buffer, not natural but a crop, and it worked great for that particular site.

And then again, the limitations for vegetative cover, if it's something that's being installed, it's not native, how it should be installed properly, and just more examples of what it would look like.

And I think this was brought up today about stream crossings. We decided -- and this is in appendix B, I believe, how to properly install a stream crossing, and just some general information to start with.

Our first thought on that was, if you can bore under the stream, that's probably the best thing, to prevent disturbance nearby or in the stream. But there's some other information, if you have to cross the stream with construction, how to do it properly. And there's various diagrams in here that show proper installation in stream crossings.

That's the end of my presentation.

MR. ELDER: Any questions on Marilyn's presentation? Front table first.

MR. TEMPLET: You know, some of the comments we've heard today were about sediment control structure. Is there something in RAPPS or is that something we need to fix in RAPPS to address that?

MS. FISH: There's really nothing in RAPPS that talks about maintenance. It's mainly the construction of RAPPS. But I think the implication is there that once you install it properly then you can maintain it properly. But we can certainly add that into RAPPS if we needed to.

MR. ELDER: Anyone else?

AUDIENCE MEMBER: If I understand you correctly, this is publicly accessible. Can you provide us with the web site?

MS. FISH: You can go to the web sites for IPAA, Tipro, etc. It's readily accessible, it's free, and we want everybody to use it.

We field tested it. My company was part of developing it and we've had our construction people look at it. We've gone out to sites to see if it works, if the flowcharts are applicable, and we find, case after case, that it does work. It is a really good document.

AUDIENCE MEMBER: Marilyn, I have a question. Does RAPPS address any potential conflicts with compensation mitigation requirements associated with Army Corp. of Engineer permitting consideration?

MS. FISH: No.

AUDIENCE MEMBER: Hello. I'm with a El Paso Corporation, which is a subsidiary of Southern Natural Gas. And from looking at the different perspectives, because I work with transmission pipelines of natural gas, we have many projects that are one to five acres; however, we are regulated by the FERC. And we have -- FERC doesn't publish guidelines that are erosion control type documents. And they also have, you know, wetland water body mitigation and construction activity type. And it's kind of strange that we're in, generally, the oil and gas industry, but yet were any of these documents potentially looked at to be incorporated by the production side?

And then these are only -- RAPPS is applicable, as I'm understanding it, for states that don't have their own implementation of the different storm waters, and are you also looking at some of the other states for -- what do they do? Because I'm working in states and all of them have -- they implement storm water programs, one acre and larger.

So, yes, if I'm doing a project that's one acre, I've got to comply with Phase I. And then even if I'm doing a project that might be 25 square foot by 25 square foot but it's adjacent to wetland or water body, I'm not talking about water of the U.S., I'm talking about a state water, I've got to go through this whole notice of intent.

I mean, I'm overregulated, in my opinion. So there's a lot of stuff that's out there that I think you can also use as other tools to go through and apply just for RAPPS.

And the other thing about storm water pollution prevention plans is you also have a waste management program and spill prevention and that needs to be kind of addressed as well, I think.

You kind of -- the oil and gas industry is out there and I think there are many ways that you can improve it. Best management practices, BMPs, are not the same as erosion control devices. And we're regulated, like I said, by the FERC, and I never get in trouble for installing erosion control devices; I always get in trouble for not maintaining them.

So these are just some comments, and I'm free to talk afterwards. There's all sorts of agencies out there and organizations for erosion control and best management practices, and I would be more than happy to talk later with anyone afterwards about this.

MS. FISH: The control practices are not the new part that we have in the RAPPS. The control practices in RAPPS are things that are used in the oil and gas industry and other industries but the things we thing work best in the oil and gas sites.

We've reviewed a lot of documents. I'm not sure we reviewed the one you're referring to, the FERC document. But we've received state guidance documents, other industry guidance documents, a lot of them, to come up with what we thought were the best and most effective for oil and gas and put them in there.

And we're not trying to regulate anything. We're trying to make it easy for operators to determine what works best for them and to install it and install it properly so it works.

But the different thing about RAPPS that you don't see in a lot of best management practices documents was -- is that flowchart, that helps you decide what to use, if any RAPPS are needed, and which ones to use, and has it all together in one document.

MR. ELDER: Sir?

AUDIENCE MEMBER: You said this RAPPS system has been field tested. Did this field testing extend to giving the information to a non-technical person, having them design, install a system, and then after it was done, have an inspector come in, like a state inspector, and say, yeah, this is cool?

MS. FISH: No, we haven't. We have given them to field people and have them decide what they need from the RAPPS and what kind of controls to use and how to install them properly, but we haven't had inspectors come behind them to see that it's done properly.

MR. ELDER: Anyone else?

MR. FLEMING: I was going to comment that Tipro had several of our smaller operators field tested, a small operator with non-technical staff, or frankly no technical staff, besides consultants.

And I think that's a point that needs to be made about the RAPPS document, was that it is geared towards E&P operations, so I don't know its applicability. Others can speak to whether it's applicable to midstream or downstream activities.

But it's principally an E&P document and it was designed to be user-friendly, easy to use. And the principal reason for that is so that we can have greater compliance and greater use of these practices by operators who don't have environmental staffs to work through them. So it's a tool that's been designed to have, in fact, greater compliance and greater ease of use. I just wanted to make that comment.

MR. ELDER: All right. Last chance. All right. Marilyn, thank you.

Our next speaker is Lori Wrotenbery. She's going to talk about the potential role of STRONGER, Inc.

And while she's coming up here, the stenographer asked earlier, if any of the people that gave written statements this morning or gave verbal presentations, if you do have a written statement you would like to have submitted for the record, please give it to her before you leave today. Thank you.

MS. WROTENBERY: While we're getting set up here, I might just mention that I did bring copies of my remarks with me and those are going around the table now and they contain some attachments that provide more information about STRONGER.

I am Lori Wrotenbery. I'm here on behalf of two organizations today, the Oklahoma Corporation Commission, for one. I am director of the Conservation Division of the Oklahoma Corporation Commission. In that role, I'm involved with regulating oil and gas exploration production operations in the state.

Oklahoma has roughly 130,000 active oil and gas and ejection wells. In addition to that, we are currently issuing permits to drill and re-enter or re-complete wells at a rate of over 5,000 a year. So we have quite a bit of activity.

One thing about Oklahoma is most of our operators and their operations are quite small, so we do have to be very sensitive to compliance costs when we're working in developing regulations for oil and gas operations from the state of Oklahoma.

Mike Decker of our general counsel's office already spoke to you a little bit earlier today. He pointed out that the Corporation Commission has taken a very clear stance on the question of the scope of the exemption for oil and gas exploration production operations under the Clean Water Act.

The Commission considers these construction activities to be part of the exploration and production operations that are covered for the exemption for uncontaminated storm water.

I don't need to go further on that particular point. What I did want to say is that we do intend to continue to work with EPA and the oil and gas industry and other interested parties to address whatever environmental threats are posed by the improper management of storm water during the construction of oil and gas locations and to avoid the discharge of contaminating storm water that might trigger NPDES permitting requirements.

In that spirit, we have participated in a work group that was set up by STRONGER, which is developing guidelines for state-level programs for the management of oil and gas storm water, and that's what I'm going to focus on here for the rest of my comments today.

STRONGER stands for State Review of Oil & Natural Gas Environmental Regulations. It is a nonprofit organization that is led by a board that has equal representation from the oil and gas industry, from environmental and public interest groups, and from state regulatory programs.

There are three board members from each of those groups. The state board members are designated by the Interstate Oil & Gas Compact Commission through the state review committee of that organization, and I am one of those state board members.

I've served on STRONGER since it was founded, but it got going in 1999 and I've worked on it since. I am currently the vice chair and so I'm very pleased to be here and talk to you about the activities of STRONGER and how it might tie in with some of the efforts to address the storm water management issues.

I wanted to point out, too, that we have a number of members of the STRONGER board that include EPA and the Department of Energy and the Bureau of Land Management and the Interstate Oil & Gas Compact Commission, so a number of the people who are represented in this room participate very actively in STRONGER activities.

As I said, I attached some materials that summarize STRONGER activities, but I'd like to run through just a quick PowerPoint presentation. The packet also includes a copy of the slides.

The state review process got underway, I guess, about the same time that the storm water management program started.

In this instance, though, it grew out of the discussion of the scope of the oil and gas exemption under the Resource Conservation & Recovery Act.

If you'll recall, EPA did a study back in 1986 and 1987 of the waste that generated in exploration and production operations to determine how those wastes should be regulated and whether they should be regulated as hazardous waste or subject to regulation.

In 1988, on the basis of that study, EPA issued a regulatory determination finding that the exploration and production waste should not be regulated under the hazardous waste program, found that state and federal regulation was generally adequate. Although, EPA did identify, through the study, gaps in some areas and some questions about the consistency and effectiveness in enforcement activities.

And so EPA proposed, as an alternative to the subtitle C regulation, a three-pronged approach to managing oil and gas exploration and production waste. What we're going to focus on here today was the part about working with states to improve their programs.

And in that arena, EPA and the Interstate Oil & Gas Compact Commission joined forces and established a council on regulatory needs back in 1989 that developed a set of guidelines for state oil and gas waste management programs and then put together a process to conduct reviews of state programs under the guidelines. These reviews were conducted by stakeholder teams that consisted of the same stakeholders that now make up the board of STRONGER, Inc.

The review teams would go in and visit, in most cases, for a full week with the states, would evaluate the state programs against the guidelines, and then develop a report that summarized both the state programs and also made recommendations for improvements in the state programs.

I don't have a copy on the PowerPoint presentation, but in the packet there is a map showing the number of states that have been reviewed to date. I believe there are 19 state programs that have been reviewed so far, and a number of those -- I think it's nine of those -- have not only an initial review but also a follow-up review.

And today STRONGER is continuing to administer the program and will be conducting more follow-ups and initial reviews of the state programs in the coming years. To date over 90 -- the states that have had reviews represent over 90 percent of the production of oil and gas in the country.

Funding for the state review process has come primarily from EPA and EOE and it also has had contributions from API. Plus, I must mention that there's a significant incoming contribution that we get from the various participants in the state review process, from the states and industry and environmental representatives.

This slide just summarizes the purposes of the state reviews and to evaluate the programs against the published guidelines, measure the effectiveness of program implementation, document program strengths, identify recommended areas for improvement.

I just thought I might mention, because it's relevant to our topic of discussion today, that Oklahoma had its initial review in 1994, I believe it was. I was working in another state at the time and I happened to be a member of the review team.

And the review team in that particular report made a number of recommendations for improvement. The state has been working on those recommendations in the years since and it's made quite a few changes in the state program as a result of those recommendations.

One of the recommendations concern storm water management, and as a result of that recommendation, the Corporation Commission worked with the extension service at Oklahoma State University and developed a pollution prevention document/brochure for exploration and production operations that was one of the materials that was referenced in the RAPPS document.

So there are very concrete recommendations that come out of these reviews and very concrete steps are taken in response to those reviews.

The reviews also give the states opportunity to exchange information about innovative program activities. It's also just a good forum for increasing understanding generally among all of the participants in the process, the states, the environmental public representatives, and the industry representatives of the various regulatory issues.

And then finally I might mention that these reviews promote consistency among state programs and ensure the strength of the state programs. At the same time, it allows flexibility for states to address their unique circumstances.

And that's a very important point or aspect of the state review process that has application, I think, in our discussion about storm water management.

Because state-level programs have the ability to tailor their requirements and approaches to address regional variability in topography and other factors that affect the level of environmental risk.

The latest version of the guidelines was issued in 2000. There have actually been, I believe, to date -- the guidelines were originally issued in 1990, and then there have been two revisions since then. One is currently in progress.

This is just an outline of the 2000 guidelines. The original version of the guidelines focused on waste management issues. Over the years, the guidelines have been revised to address other issues that have arisen, like abandoned sites. And, as I mentioned, the guidelines are currently under revision. These are some of the areas that are being addressed in the current revision.

There's some general updating and clarification in the guidelines that has come about as a result of the use of the guidelines. In the state review process we've learned where the guidelines need some clarification and what points maybe were not addressed thoroughly enough.

In addition, there's emphasis in these revisions on three new areas, got a new section dealing with spill risk management, and greatly expanded the section dealing with performance measurement to ensure that the state programs are actually achieving their objectives of protecting the environment, and then a particular note for today's meeting, we've got a new section on storm water management.

This just outlines the new section on storm water management. And I should emphasize that these are draft guidelines at this point. We did put together a stakeholder team that worked up these revisions. That is one thing that you probably heard through the course of my presentation.

All of the work groups teams and other groups that are involved that work on any aspect of STRONGER involve representatives from all of the stakeholder groups.

There is a copy of the section on storm water in the handout there. One thing I might want to emphasize again, this is a focus on state level programs for storm water management.

And there's an emphasis on providing system flexibility to allow the state to develop requirements that are appropriate for the particular circumstances of the state. The state programs may be rule-based or may rely on operator specific or I should say site specific plans as well.

And in the context of developing these guidelines, STRONGER has also had some discussions – I think we'll follow through about that -- about serving as a clearinghouse for information on prudent practices and best management practices for storm water, perhaps by putting links on the STRONGER web site to various documents, like the RAPPS.

This is a timetable for the guidelines revision. The draft guidelines were just published earlier this month. STRONGER is requesting comments by June 17 and plans to revise the draft in time for it to be reviewed by the Interstate Oil & Gas Compact Commission at its meeting in September, and then the plan is to implement the new guidelines beginning with the state reviews that are conducted in 2006.

We do encourage you -- we ask you to review the guidelines document and provide us your comments. We'd like to get as much feedback as possible on the proposed revisions.

And then this final slide just summarizes the strengths of the state review process. I'll just emphasize that -- that one of the strengths of the program is that we have a process in place for following up on the reviews of the state programs, both through specific in-state follow-up reviews, and then also we've quite a bit of work over time the IOGCC; for instance, to compile information about the changes that have been made in the state programs as a result of the review.

So we can document the benefits of this process and the improvements that have occurred in state programs.

Also consider this process as a model for evaluation of other environmental regulatory programs. We have partners with the groundwater protection council in some states. This is a state option. But we have incorporated review of the underground control programs into the state process. And that has worked very, very well in a couple of different states.

We continued to explore opportunities for collaboration efforts with other organizations, and we've been visiting about the possibility of addressing some of the storm water management issues through the state review process.

We are currently considering the possibility of reviewing the RAPPS document by going to another stakeholder work group to evaluate that document and provide some feedback and some recommendations.

As I mentioned earlier, we're considering the possibility of providing links to various best management practices on our web site.

And then the proposed revisions to the guidelines may present other opportunities for collaboration. So we'll be pleased to discuss those possibilities with participants of this meeting and with the EPA.

I want to thank you for giving me the opportunity to share this information with you. And please feel free to contact me or any of the STRONGER board members if you wish to discuss STRONGER.

Thank you.

MR. ELDER: Any questions for Lori?

MS. BUCCINO: I was just wondering if you could clarify whether there are any states that have -- that are moving forward with the permit requirements in the absence of EPA's permit requirement other than the action that's been initiated by Colorado.

MS. WROTENBERY: I don't know I could give you a complete listing, but other states have addressed storm water issues, some through permitting programs, others through various best management practices approaches under state law.

MS. BUCCINO: Specifically on implementing, I guess, the construction general permit for Phase II, I was not aware of any states that have moved forward with that in the absence of EPA's action. I just wanted to clarify that.

MS. WROTENBERY: Other than Colorado.

MR. TEMPLET: Montana and Wyoming.

MR. CARL: West Virginia has a general permit. And I'll mention Louisiana and Kentucky, they all have implemented regulations to deal with that issue, storm water. It's not in response to Phase II. It's something that they recognized many years ago and they dealt with it at the time.

MR. ELDER: Any other comments or questions? Thank you.

Okay. Going into the general additional issues and comments, and Angie Burckhalter, from Oklahoma, wanted to speak, so now would be an excellent opportunity for her to come up here.

MS. BURCKHALTER: My name is Angie Burckhalter and I represent the Oklahoma Independent Petroleum Association. OIPA has approximately 1500 small to large independent crude oil and natural gas producers that will be directly impacted by EPA's action.

We appreciate the EPA holding this public meeting today and allowing the oil and gas industry the opportunity to discuss the impacts, storm water requirements on our industry, and also allowing us the opportunity to provide a more workable alternative using the RAPPS guidance document rather than a permit.

We think that the RAPPS guidance document will minimize the impacts from the oil and gas industry while, at the same time, provide benefit to the environment. We do have written comments, and I did provide those, but I will also give the reporter here a copy a well.

The U.S. Department of Energy has established that the impacts to -- or the impacts of EPA storm water requirements on our industry. They are significant and they are real.

We think that the non-permit option is a viable approach for EPA to take. Through the non-permit option, we think that the storm water runoff concerns can be addressed through the flexible management process using the RAPPS guidance document.

Marilyn described all the details of that document just a short time ago, but these are based on terrain and rainfall. They can be easily utilized to which increases the compliance among many small operators. It's a practical and cost-effective manner that provides environmental protection. OIPA is another association that has this document readily available on our web site as well.

Once again, we appreciate EPA holding this public meeting and giving us an opportunity to discuss our issues and some other solutions using the RAPPS guidance document.

Thank you.

MR. ELDER: Okay. So we have plenty of time set aside for open discussion. Again, first, I'd like to give people at the front table the opportunity to make some additional comments or ask questions of one another or other speakers, so if anybody would like to begin.

MR. ANDERSON: We have looked at the RAPPS document. It is a very nice and easy-to-use format that puts together some good control measures.

One thing that we would like to make sure that happens is, in pointing to BMP-type document, like the RAPPS, many companies have been implementing these type of control practices for many, many years and have their own documents that they have developed and used.

One of the things that I would have to state about ours is ours is not quite as easy to use, but it is something that we use and we're knowledgeable about. We'd like to make sure that it's kind of a RAPPS or equivalent-type document, type controls, because RAPPS, as was stated earlier, or FERC has guidelines, or a lot of the oil companies have their own guidelines. We don't want to point just to one document and say, that is the only thing that you can use. We want to make sure that the equivalent language is in there so that it legitimizes other approaches to the same problem.

MR. ELDER: Understood.

Anyone else at the front table? How about people from the audience?

Okay. I've been told that the final attendance list is not going to be available until approximately 3:30, so unless you want to wait until then, you can request it by e-mail.

Please, sir, come up to the microphone.

AUDIENCE MEMBER: I listened to Bill Clinton at the -- well, through TV at the National Convention thank George Bush and the Republic Party for all the tax benefits they were going to get, and I feel a little bit in the same boat here, thanking the EPA for funding my graduate degree in environmental engineering and allowing me to go to work for a major oil company.

I would ask that the EPA and the rest of the participants at this meeting think about the presentations and the data that was presented here today and to go back and clarify the facts and what is going on, what is applicable, et cetera, and that would be to all of us.

One thing that struck me this morning when we were talking about operations, oil field operations in the west, and I believe it was in a particular county in Colorado down in the southern part of the state and with regard to translating the number of truck or amount of truck traffic by mile, et cetera.

I think there was fracs per well or an average that struck me as being very strange. And that might be true in a very small discrete part of the United States. But I called, over lunchtime, our senior management over our southern Colorado operations, in charge of all of our southern Colorado drilling, and I must say that, based on that result, the number of fracs per well, for example, is overstated 80 to 90 percent, in that typically, on our operations anyway, we do frac wells generally once, occasionally twice, and that's it.

The other thing is that the last I looked is that the storm water regulations still fell under the Clean Water Act. And while we're not here to debate what's going on with that definition, et cetera, it clearly states that it impacts waters of the United States. Of course, there's a lot going on with that.

But if I think back to situations or photographs or actual events on the high plains, especially West Texas, New Mexico, Kansas, Oklahoma, and parts of Colorado and New Mexico, that oftentimes we will have runoff from a particular location and it will run off 10 feet or 20 feet or 30 feet and then it will collect and it will sit there.

And I would argue to you that a lot of pictures and things could be taken that show some runoff and some deposition is there, and over geological time or through floods of biblical proportions it could eventually make it into a current water body of the Gulf of Mexico, similar to the fact that Western Kansas, at one time, was effectively the Gulf of Mexico, and it will run off, as will Pike's Peak and the rest of the Rocky Mountain chain. But clearly, to have some connection to the storm water regulations, we need to have some connection and direct points discharge into waters in the United States.

MR. ELDER: Okay. Other comments? Anybody want to ask a question?

AUDIENCE MEMBER: I have a question.

MR. ELDER: Okay. I don't want to hold you here against your will.

AUDIENCE MEMBER: What's particularly been, you know, proposed regulations, draft regulations, one of the things that struck me, is there anything being considered about influx of water to the location and building barriers against that?

I saw some evidence of, possibly in some documentation about, snow melt, things of that nature. That doesn't run across my line of work so much because I'm not in the Rocky Mountain area.

MR. ELDER: Someone from EPA want to take that one on?

MR. FAULK: Yeah. I mean, we definitely want to talk about storm water control talk about both runon control as well as runoff and taking steps necessary to protect your site so that that runon doesn't then become runoff.

I don't know if the RAPPS specifically deals with that issue. I think some of our older guidance mentions it but probably not in that much detail, and there are probably certain areas of the country where it's more applicable, so if that helps...

AUDIENCE MEMBER: I just have a couple of clarification questions of the EPA. I'm not in the exploration or production, but as I understand it, these exemptions are for states that don't implement their own program, is that correct, or if it's on federal property, as I understand it, projects that are one to five acres. Is that correct?

MR. HANLON: Basically the December 1999 rule we talked about earlier affected -- let me back up a little bit.

With the 1987 amendments to the Clean Water Act that made it clear that EPA was to move forward with the storm water regulatory program, Phase I in the early 1990s and then the Phase II rules in 1999 set national standards for managing storm water.

For the states that are authorized to implement the program, their obligation is to adopt conforming state regulations to be implemented within their states.

For states that are not authorized to implement the program, the EPA implements the program and that's why a lot of the focus is on the five not authorized states, New Hampshire, Massachusetts, New Mexico, Idaho, and Alaska, and also Oklahoma and Texas, because those two states, they have not been authorized for oil and gas. So for those seven states, EPA implements oil and gas regulatory activities, including storm water.

So when we talk about the exemption, what EPA has said is that we are not requiring states to move forward because we're still considering how that December 1999 rule affects small oil and gas construction, but that when that decision is made the authorized states will be required to move forward with conforming state regulations and EPA would implement that in the states where we implement oil and gas permits.

AUDIENCE MEMBER: All the states I work in unfortunately do implement that.

MR. HANLON: That's why the Region 6 people are here to help. So if the states implement it, then basically what would happen is when a decision is made, in terms of what the federal standard is, then those states would have an amount of time to adopt conforming state regulations.

AUDIENCE MEMBER: I guess in the southeast all of those states do implement a storm water program, some kind of -- you know, I can't turn around and say that my project is for transmission are not covered by your permit because I have to comply with their program, one to five acres. I can't waive this exemption and say, I've got an exemption on transmission pipeline and, you know, I'm less than five acres therefore, I'm not under your jurisdiction.

I guess I just wanted to clarify that because it's been a little bit of a confusing -- everybody here practically is production and exploration and I'm actually downstream transmissions. So am I interpreting that incorrectly, that when it says transmission, we're not actually talking about interstate pipeline?

MR. HANLON: Our reading of the exemption would be for oil and gas transmission lines that are covered by -- from one to five acres, they're covered by the current exemption.

MR. FAULK: I think I know what you're getting at, is that, for example, we have this deferral set, two years you don't need to get permit coverage, but, in fact, in South Carolina or Florida they don't have that exemption.

AUDIENCE MEMBER: Correct.

MR. FAULK: What some states have done is actually -- and I don't know if they did it through rule making or informal enforcement discretion, have come out with statements that said, we're not going to require those types of activities to get permit coverage until whether it was March of 2005 or June of 2006.

I don't know specifically, in that part of the country, if any of those states have made that same decision. So, in fact, they have -- they've drafted their regulations or enacted promulgated regulations that said construction one to five acre needs permit coverage.

AUDIENCE MEMBER: That's what they've done.

MR. FAULK: And they never came back out and said that we're going to abide by EPA's decision to defer for oil and gas.

AUDIENCE MEMBER: Except possibly Louisiana, which somebody else mentioned earlier. They actually do recognize it. But for our benefit, we just comply with it because we're always getting hit in Louisiana. In the southeast we get lots of rain, can't turn a corner without a wetland or water body, might as well do the permitting.

I actually will be presenting back to my industry -- I'm one of the guys who talks about storm water, so coming here was gathering information to apply back towards my industry.

You know, we're all kind of in the same industry, just one is regulated and one is not, and I'm just trying to get clarification.

MR. FAULK: Someone from Region 6, if you can talk about how your --

AUDIENCE MEMBER: Most of our states have gone ahead and basically are not moving ahead of EPA. Of course, the state does have the authority to go faster than us if they choose to do so, but we're not going to make them move ahead of it.

MR. FAULK: But they didn't revise the regulations, did they?

AUDIENCE MEMBER: A couple of them did, in emergency rules, to address the delays. I'm not sure, but I think some of the states have.

AUDIENCE MEMBER: Like the example of the state of Georgia, you have to take six months to get upstream buffer bearings. I mean, we're, in my opinion, way overregulated. But they see us as definitely being part of this requirement to follow this. I can't go to them and say, you know, we're exempt from y'all, because I don't think they even know about it or recognize it. They've got that program in place and we've got to follow it. And that's the simple guidelines they tell everybody. If the state has a program in place, you follow.

MR. HANLON: As Colorado has done, the state, under state law, has the authority to move forward and implement programs, and the Clean Water Act makes it clear that they have that authority. So you're right. Basically, if a state has adopted a regulatory requirement, your best advice is to work with your state permit.

AUDIENCE MEMBER: And that's what we do. And the rest of the industry that's here, they do have a lot of concerns about how are the states going to implement, you know, the notice of intent process requirement of having to provide a storm water pollution prevention plan time frame.

Nobody mentioned a permit fee, which can be exorbitant. Yes, it's a real hassle working on a state level effort, and then you have you multiple states possibly that you're working in.

I wish there was only one -- in the oil and gas industry, I wish there was only one general permit through EPA so that I could tell these other states, you don't recognize me for my industry, you're regulating me as a subdivision builder or a Wal-Mart, you're regulating me as if I'm going to do permanent changes to topography and vegetation, whereas I'm not. And I guess that's one of my biggest concerns.

And that's one of the things that when I go back to the Southern Gas Association or the American Gas Association, these are things that we talk about how we overcome through the different states across the nation, how we deal with this.

Thanks for your time.

MR. ELDER: Anyone else? Going once, twice. Okay. Appreciate everybody coming today and appreciate the constructive comments from everyone and wish the EPA luck in making their deadlines.

(END OF PUBLIC MEETING)