S. HRG. 114–118

ENERGY SUPPLY LEGISLATION

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED FOURTEENTH CONGRESS

FIRST SESSION

ON

ENERGY SUPPLY LEGISLATION

TUESDAY, MAY 19, 2015

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Committee on Energy and Natural Resources

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ENERGY SUPPLY LEGISLATION

TUESDAY, MAY 19, 2015

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The Committee met, pursuant to notice, at 10:05 a.m. in room SD–366, Dirksen Senate Office Building, Hon. Lisa Murkowski, (Chairman of the Committee), presiding.

OPENING STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

The CHAIRMAN. Good morning. We will call to order the meeting of the Senate Energy Committee.

We are in the third of four legislative hearings related to the broader energy bill that we are putting together.

I want to thank my colleague, Senator Cantwell, and members of the Committee for their work as we craft what will hopefully be a bipartisan bill. We are building a strong foundation laid by members who continue to bring some good ideas to the table.

The 26 bills that we are looking at today will bring the total to 70 reviewed so far. Our topic today is supply. I think my views are pretty clear to folks on this Committee. It can be distilled to a bumper sticker. That bumper sticker reads, "Energy is good."

I believe it is in our national interest to make energy abundant, affordable, clean, diverse and secure.

Today's hearing, like the bill that we are assembling, is not designed to pit energy resources against each other, but instead to view energy supplies holistically and to find areas where we can come together.

When it comes to abundance, few states or even countries can compare to Alaska. With an estimated 46 billion barrels of conventional oil and more than 430 trillion cubic feet of natural gas, Alaska is a world class petroleum province by any measure. Those conventional resources are supplemented by unconventional resources like the estimated 590 trillion cubic feet of methane hydrates on the North Slope, much of which is under existing development.

In addition, we are the leader when it comes to everything else that is out there as well. I would challenge whether it is in the renewable areas with geothermal opportunities, marine hydrokinetic, ocean energy, biomass, wind, even with solar. People do not think about solar, but we truly are a state that has it all.

In terms of the conventional resources, today Alaska has produced and shipped more than 17 billion barrels of oil through the Trans-Alaska pipeline. We have exported 2.5 trillion cubic feet of

LNG to Japan. A lot of people forget that we have been engaged in this for decades, and 35 wells have already been drilled in the Beaufort and the Chukchi Seas.

I am oftentimes quite taken aback when I hear people ask basic questions as to whether or not we should allow drilling in the offshore, in the Arctic as if somehow or other drilling in the Beaufort or the Chukchi was something new. Exploration has occurred for more than 30 years. This was back in the 80s. It has been done safely, for all these years.

The only Federal production in Alaska comes from the North Star field. This is a development in the Beaufort that was discovered back in 1984. It has produced more than 150 million barrels of oil since 2001.

Despite the safe and successful development, all you hear is consternation in some of the press about how we cannot possibly be going offshore in the Chukchi. We cannot be going offshore in the Arctic. This is new and unexplored territory and the end of the world as we know it will likely come to pass.

In fact, 35 wells have been drilled up there. It did not make the news because there was no news to report other than that the exploration was successful. What happens then? Prices go down. It is difficult. It is expensive. That is part of Alaska's history. Given our history of safe and successful development, I think that it is time to expand Alaska's contribution to America's energy security.

My bill, S. 1278, provides for annual lease sales in the areas between three and six miles offshore, known as the 8G zone in both the Beaufort and the Cook Inlet. This area is adjacent to where the State of Alaska holds annual lease sales and is very close to existing infrastructure. It can deliver near term production from the Beaufort to maintain the Trans-Alaska pipeline which is critical as we look at the declining through-put and infrastructure that is less than half full. It can also deliver natural gas from the Cook Inlet to Alaskans around the state.

My legislation would also provide for more frequent lease sales than called for in the current five year plan and extend lease terms to accommodate the stringent regulatory requirements and short operating windows in the Beaufort and the Chukchi. The incapability of long development timelines in existing lease terms was identified as an issue in a recent National Petroleum Council study that was done at the request of the Department of Energy. I strongly believe that more predictable lease sales with more workable lease terms will provide more value for the treasury.

Offshore development must also benefit states and local communities, and that is why my legislation supports revenue sharing for Alaska. That is also why I thank Senators Cassidy, Warner and Scott for spearheading similar legislation for the Gulf and Mid to South Atlantic states.

Each area, I think we recognize, is different with specific needs and interests, but it is out of simple fairness that we should provide revenue sharing to all of them. In Alaska, supporting communities, science and workforce development are all critical components of a successful and vibrant offshore industry that meets our national energy interests.

While Alaska has abundant resources, Alaskans face some of the highest energy costs in the entire nation. For too many Alaskans energy is not diverse, secure or affordable. In fact, energy insecurity and energy poverty are the defining issues in many parts of my home state, and that is one of the reasons that I joined with Senator Scott from South Carolina to focus on this issue of energy insecurity.

In considering the importance of revenue sharing, I would ask all of my colleagues here on the Committee and in the Senate as a whole to consider the commitment that Alaska has made to invest the earnings from non-renewable resources into our renewable resources. Through just one program, for example, the state has allocated more than $250 million to more than 275 renewable projects to help unlock Alaska's vast wind, biomass and hydropower resources.

Among those renewable resources, one that is particularly important to me and to my state is hydropower. I have introduced legislation to recognize hydropower as a renewable resource throughout Federal programs. Recognizing hydro as a renewable resource is incredibly important as far as I am concerned. The Federal Government needs to improve the permitting process so that we can bring clean hydropower to more communities across Alaska and across the nation.

From producing energy on the Outer Continental Shelf to generating renewable hydropower in our waterways, we have got an outstanding opportunity to come together around some core principles and build a bipartisan supply title. I am optimistic that we can do this in a way that builds upon the American energy renaissance that we are currently experiencing.

We have a lot of bills on the agenda today, and I look forward to reviewing these to see which ones are going to meet the test as well as hearing our witnesses' perspectives on each.

With that, I will turn to my Ranking Member, Senator Cantwell. Good morning.

STATEMENT OF HON. MARIA CANTWELL, U.S. SENATOR FROM WASHINGTON

Senator CANTWELL. Thank you. Thank you, Madam Chair, for this important meeting, and I thank our witnesses for being at the hearing today.

Once again we have a bundle of various initiatives or legislative proposals before the Committee, generally related to the topic of energy supply. In setting the context for the discussion, I think it is helpful to once again review what we just heard recently about the current supply picture last month from the Energy Information Agency (EIA). First, growth in U.S. energy production—combined with modest growth in demand—will contribute to a decline in U.S. energy imports.

Second, energy use by residential consumers in the transportation sector is expected to continue to decline, driven by improvements in energy efficiency technology. Meanwhile the industrial sector is expected to post its strongest growth. We are making strides.

Third, electricity prices are expected to rise about 18 percent-driven primarily by fuel costs for natural gas and coal which are expected to rise 88 percent and 25 percent respectively.

But with renewable technology, the fuel is free. Even while EIA has been criticized for underestimating growth in renewable energy production, the agency does project a 72 percent increase in clean energy generation between 2013 and 2040, accounting for more than a third of new capacity.

Taken together, the set of findings suggests to me that the trajectory is generally positive from an energy security perspective. It is also a good reason that the first Quadrennial Energy Review, on which Secretary Moniz testified last month, focused so heavily on energy infrastructure.

To quote the Quadrennial Energy Review, "This focus was chosen because the dramatic changes in the U.S. energy landscape have significant implications for . . . infrastructure needs and choices. Well-informed, forward-looking decisions that lead to more robust, more resilient infrastructure can enable substantial new economic, consumer services, climate projection and system reliability benefits."

Based on the Quadrennial Energy Review, I think there is a very compelling case to be made that the most pressing issue for the Committee to address deals with modernizing our aging energy infrastructure. If there are specific priorities with respect to supply, they involve bending the cost curve even more sharply downward on carbon, given the tremendous costs our changing climate is already imposing on businesses and communities across our country.

From a competitiveness perspective, it also seems to me that we should be focused on supply-related policies that advance energy technologies that are going to be comparatively less expensive in the future.

According to the Department of Energy's 2014 Revolution Now Report, "... by 2014, rooftop solar panels cost about one percent of what they did 35 years ago, and solar PV installations were about 15 times less than what they were in 2008." The report outlined similar trends on wind.

The Department of Energy expects renewable costs to drop another 10 to 20 percent in the foreseeable future, and these projections do not even take into account the rapid technology changes that can further drive down the cost curve.

Another example from my home state is the innovation in regards to turbines that power our dams. BPA, the Army Corps of Engineers, and regional utilities have worked together on new designs that are optimizing fish survival rates and producing more power at the same time. Replacement turbines at one particular dam are achieving greater than 97 percent fish survival. And once all ten new turbines are updated, it is anticipated to result in enough power to serve an additional 12,440 homes. So energy efficiency is all across the board.

With these trends in mind, it is worth this Committee's time and attention to focus on policies and programs that help accelerate U.S. leadership in energy supply technologies that are becoming a greater proportion of the resource mix both at home and globally. But given the projections about domestic oil and gas production under current law, the need to legislate lease sales for Federal resources in the Outer Continental Shelf is not at all obvious to me. This is especially the case at a time when we are going to have a lot of choices to make. There will also be a lot of discussion on the rationale to lift the current ban on crude exports. But there are many lingering questions about the adequacy of our oil supply response capabilities and potential environmental impacts.

The Chair just mentioned this issue of revenue sharing. I want to note that the various revenue sharing proposals before this Committee would give producing states a larger portion of money generated from the development of federal resources on the Outer Continental Shelf. These are not new concepts.

But they are concepts that have brought this Committee to a standstill on multiple occasions, given a mix of concerns—fiscal policy concerns, concerns from Senators from interior states and concerns about adequate recovery of receipts on certain existing leases in the Gulf of Mexico. Already, the harsh budget realities at the Federal level are impacting the efficiency of the way we go about permitting energy infrastructure.

Among the findings in the Quadrennial Energy Review that has not yet received much attention is the fact that, "Federal agencies responsible for infrastructure siting, review, and permitting have experienced dramatic appropriations cuts and reductions in staff." As a result, "the overall effort to improve the federal siting and permitting processes have been stymied."

I do not discount the budget challenges that we face for a variety of reasons; but the budget challenges at the Federal level—which we are already impacting the way we permit energy infrastructure—additional revenue sharing is difficult to then pencil out.

I also want to take a moment to revisit something I mentioned earlier, which is the rising cost of coal. While coal costs are projected to go up 25 percent, coal exports are expected to increase 70 percent from 2015 to 2040. So I raise that again because it is worth noting: in the West, you can typically lease a ton of coal from the BLM for $1 or less. That is $1 or less. Taxpayers get $1. Then years later we have to deal with almost two tons of carbon dioxide from that one ton of carbon of coal. And the Government's current best guess is that two tons of carbon pollution will cost the American public over $70 in damages.

Our fossil fuel leasing laws were passed long before we knew all of this about carbon, but now we know. The fact that we are essentially subsidizing this coal that we will subsequently export fails a pretty simple test of common sense policies in the public interest.

With that said, we do have a broad set of proposals before us today about hydro relicensing, about energy workforce, about clean energy technology. I want to thank the Committee and the Chair for holding this hearing and for the many witness testimonies we are going to receive today.

Once again, I think we have a very broad hearing, and we will have lots to do to try to prioritize these various proposals before the Committee.

I hope that we can come together on focusing on infrastructure.

Thank you, Madam Chair.

The CHAIRMAN. Thank you.

Let us begin our panel this morning. We have a lot to talk about.

We are joined this morning by Ms. Abigail Ross Hopper, who is the Director of the Bureau of Ocean Energy Management at the U.S. Department of the Interior.

She will be followed by Ms. Susan Kelly, who is the President and CEO of the American Public Power Association.

Mr. Randal Livingston, who is Vice President of Power Generation with Pacific Gas and Electric Company, welcome.

Mr. Franz Matzner, who is the Director of the Beyond Oil Initiative with the National Resources Defense Council.

Followed by Mr. Erik Milito, who is the Group Director of Upstream and Industry Operations for the American Petroleum Institute.

Our final witness is a fellow Alaskan, Mr. Brent Sheets, who is the Deputy Director of the Alaska Center for Energy and Power at the University of Alaska Fairbanks.

Welcome to all of you. I would ask that you try to keep your comments to about five minutes. Your full testimony will be included as part of the record. Once you have concluded all of the presentations, we will have an opportunity to ask questions. So welcome to the panel.

Ms. Hopper, please start everybody off.

STATEMENT OF ABIGAIL ROSS HOPPER, DIRECTOR, BUREAU OF OCEAN ENERGY MANAGEMENT, U.S. DEPARTMENT OF THE INTERIOR

Ms. HOPPER. Sure. Thank you very much.

Chairman Murkowski, Ranking Member Cantwell and members of the Committee, my name is Abby Hopper, and I am the Director of the Bureau of Ocean Energy Management which we call BOEM. I am pleased to appear before you today.

I know that this hearing involves many bills that significantly affect a wide range of the Administration's energy programs and policies, and I am glad you share this Administration's belief that the Outer Continental Shelf, the OCS, which I'm sure we'll end up calling it, will continue to play a significant role in assuring America's energy future.

Three of the OCS bills directly affect my bureau, primarily in the areas of revenue sharing and expanded leasing for the Arctic, Atlantic and Gulf of Mexico offshore waters. My written statement provides more in depth observations on those bills.

Additionally I would like to note that the Committee will be receiving a written statement from the Bureau of Land Management regarding that bureau's position on many of the terrestrial bills under consideration this morning.

Chairwoman Murkowski, I recently had the pleasure of spending some time in your state including on the North Slope where they told me it was the coldest it had been all year when I was there. It was the coldest I've ever been and I met with many key stakeholders, including Alaska's native organizations and tribal governments as well as representatives from the state government of Alaska.

My conversations there reinforced the importance that BOEM has placed on carefully balancing leasing and potential exploration recognizing the significant environmental, social and ecological resources in the region and establishing high standards for the protection of this critical ecosystem, our Arctic communities and the subsistence needs and cultural traditions of Alaska natives.

For all five-year oil and gas leasing programs public input is a critical part of our process and we encouraged citizens and groups to provide comments to help guide our decisions. For this current five-year program that we're developing now we held 23 scoping meetings on the draft environmental impact statement around the country. We received over one million comments and anticipate robust dialogue with stakeholders in the coming months that will help us prepare a program that emphasizes protection of the marine environments and coastal economies and uses the best available science and technology to inform our decision making.

Regarding this revenue sharing provisions found in the bill submitted by Chairwoman Murkowski, Senator Cassidy and Senator Warner, the Administration is mindful of the long held view that coastal states should share the benefits of energy development that takes place off their shores. At the same time the Administration is also committed to ensuring American taxpayers receive a fair return from the sale of public resources, excuse me, and that taxpayers throughout the country benefit from the development of offshore energy resources owned by all citizens.

As an alternative to the multiple revenue sharing programs that benefit individual states, the Administration proposes to work with Congress on legislation to redirect existing revenue sharing payments to programs that provide broad, natural resource, watershed and conservation benefits to the nation, help the Federal Government fulfill its role of being a good neighbor to local communities and support other national priorities.

Senate Bills 1276, 1278 and 1279 would mandate additional lease sales off the coast of Alaska in the Atlantic and in the eastern Gulf of Mexico planning area during the 2017 to 2022 five year program.

The 2017 to 2022 draft proposed program which I'm sure we'll call the DPP, developed by the BOEM and approved by the Secretary includes potential lease sales in eight planning areas that contain nearly 80 percent of estimated undiscovered, technically recoverable oil and gas resources on the OCS. In total the DPP proposes 14 potential lease sales eight planning areas, 10 in the Gulf of Mexico, one in the Atlantic and three off the coast of Alaska.

The Outer Continental Shelf Lands Act, Section 18, does not allow for a sale or area to be added to the program without restarting the program preparation process at the state in which the sale or area was not included or deleted. So while Section 18 does not allow the Department to expand, obviously, Congress has the ability to mandate additional sales via the legislative process.

However, such legislation would mandate the Department conduct lease sales on the Outer Continental Shelf without regard for the consideration of the factors, the eight factors, under Section 18 which we believe, appropriately reflects the many equities involved in the leasing decision.

So based on those factors the Administration has concerns about bypassing the Section 18 OCSLA provisions. It's important to the

Department and my bureau that we explore ways to move forward towards energy independence by a safe and responsible domestic oil and gas production while ensuring that the American taxpayer receives a fair return for development of these Federal resources.

I look forward to working with the Committee and answering any questions you may have.

[The prepared statement of Ms. Hopper follows:]

STATEMENT OF ABIGAIL ROSS HOPPER
DIRECTOR
BUREAU OF OCEAN ENERGY MANAGEMENT
U.S. DEPARTMENT OF THE INTERIOR
BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
MAY 19, 2015

Chairman Murkowski, Ranking Member Cantwell, and members of the Committee, as the Director of the Bureau of Ocean Energy Management (BOEM) I am pleased to appear before you today to discuss S. 1276, the Offshore Energy and Jobs Act of 2015, S. 1278, the Alaska Outer Continental Shelf Lease Sale Act, and S. 1279, the Southern Atlantic Energy Security Act.

Taken together, these three bills would require lease sales offshore Alaska, in the South Atlantic and in the eastern Gulf of Mexico without Secretarial discretion to determine whether those areas are appropriate for leasing through balanced consideration of factors such as resource potential, State and local views and concerns, and the maturity of infrastructure needed to support oil and gas development, including response capabilities in the event of an oil spill. They would divert offshore energy development revenue from the Treasury, reducing the net return to taxpayers and adding to the federal deficit. We understand that the Department of Justice has constitutional concerns regarding S.1279 that they will convey separately. Accordingly, the Administration opposes these bills.

Today's hearing covers 26 individual bills that significantly affect a wide range of the Administration's energy programs and policies. Because the text for those bills was not made available to the Department until last week, the Administration has not had adequate time to conduct an in-depth analysis and the Department has not had adequate time to develop the detailed, thorough testimony that is appropriate for a hearing on these matters. I will therefore focus my testimony on the Administration's views on two broad themes presented in S. 1276, S. 1278, and S. 1279: revenue sharing and the Department's offshore oil and gas leasing program. My testimony will also address S. 1224, the Condensate Act, and S. 1280, the United States Exploration on Idle Tracts Act. Finally, in addition to my testimony, the Department will provide the Committee a statement for the record on the remaining bills subject to this hearing related to energy development on public lands onshore and other Departmental equities.

Introduction

The Administration is committed to promoting safe and responsible domestic oil and gas production as part of a broad energy strategy that will protect consumers and reduce our dependence on foreign oil. The Department of the Interior manages the federal waters of the Outer Continental Shelf (OCS) that provide resources critical to the Nation's energy security; is responsible for collecting and distributing revenue from energy development; and ensures that the American taxpayer receives a fair return for development of those federal resources.

Revenue Sharing

The Administration is mindful of the long-held view that coastal states should share the benefits of energy development that takes place offshore. Although coastal states clearly enjoy significant economic benefits from offshore development, there is also significant revenue that can be generated from offshore leasing and production in which coastal states assert an interest. Congress has addressed the interests of the coastal states in two ways. First, in 1953, the passage of the Submerged Lands Act, allowed coastal states to claim a seaward boundary up to three geographical miles from their coastlines (9 miles for Texas and the Gulf Coast of Florida). Second, in 1986, through the amendment of section 8(g) of the Outer Continental Shelf Lands Act (OCSLA), the Secretary of the Interior provides to coastal states 27 percent of all revenues collected on federal oil and gas leases within three miles of the seaward state boundary established pursuant to the Submerged Lands Act.

The Administration is committed to ensuring that American taxpayers receive a fair return from the sale of public resources and that taxpayers throughout the country benefit from the development of offshore energy resources owned by all Americans. As an alternative to multiple revenue sharing programs that benefit individual States and administration of a costly and cumbersome revenue allocation formula, the Administration proposes to work with Congress on legislation to redirect revenue sharing payments allocated by the Gulf of Mexico Energy Security Act of 2006 (GOMESA) to four Gulf of Mexico coastal States. The Administration proposes to redirect these payments, which are set to expand substantially starting in 2017, to programs that provide broad natural resource, watershed, and conservation benefits to the Nation; help the Federal government fulfill its role of being a good neighbor to local communities; and support other national priorities.

The Department takes seriously its responsibility to the public for the stewardship of our nation's natural resources and public assets that generate royalty revenue from federal leases. Revenue generated from leases on the federal OCS is directed to the U.S. Treasury and is used to fund federal conservation programs through contributions to the Land and Water Conservation Fund (LWCF) and the Historic Preservation Fund. The Administration strongly supports the core values of the LWCF and agrees that a portion of the proceeds from the sale of a public asset should be reinvested in something of lasting value for all Americans.

Previous and current revenue sharing proposals would ultimately reduce the net return to taxpayers from development of the federal resources generated on the OCS and would add to the federal deficit. Additional revenue sharing programs would likely result in a further reduction of billions of dollars in deposits to the Treasury. For these reasons, the Administration opposes new or expanded offshore revenue sharing.

Expansion of the Five Year Program

The OCSLA requires the Secretary to propose a schedule of offshore oil and gas lease sales every five years. This is referred to as the "Five Year Program." As specified by Section 18 of the OCSLA, preparation and approval of an oil and gas Five Year Program is based on the Secretary of the Interior's consideration of eight factors, which include balancing the potential for environmental damage, discovery of oil and gas, and adverse impact on the coastal zone, to determine the size, timing, and location of lease sales.

With the current Program ending in mid-2017, BOEM is preparing the 2017–2022 OCS Oil and Gas Leasing Program. In June 2014, the Department published a Request for Information and Comments (RFI) and received approximately 500,000 comments. On January 29, 2015, the Department published the 2017–2022 OCS Oil and Gas Leasing Draft Proposed Program (DPP) for public comment. BOEM simultaneously published a Notice of Intent to Prepare a Draft

Programmatic Environmental Impact Statement (PEIS), which will analyze the potential environmental effects of the Program. Twenty-three EIS scoping meetings were held in communities on the Atlantic coast, the Gulf of Mexico, and Alaska during the 60-day comment period. BOEM received over one million comments and is committed to integrating the critical information received during the comment period into the scientific, environmental, and social analysis that informs our decision-making. The Department expects to publish the Proposed Program and Draft PEIS in early 2016; the Department will invite public comment on both of these documents. Publication of the Proposed Final Program and Final PEIS will occur before the current program expires in 2017.

The 2017-2022 DPP includes potential lease sales in eight planning areas that contain nearly 80% of estimated undiscovered technically recoverable oil and gas resources on the U.S. OCS. In total, the 2017-2022 DPP schedules 14 potential lease sales for the 2017–2022 Program—10 sales in the Gulf of Mexico, one in the Atlantic, and three off the coast of Alaska. OCSLA Section 18 allows for proposed areas and sales in the DPP to be removed but not added to the program without restarting the program preparation process at the stage in which the sale or area was not included. For example, if an area was not included in the Draft Proposed Program (DPP), a new DPP would need to be developed to accommodate its inclusion. Even if the Eastern Gulf of Mexico moratorium as described in GOMESA were modified or lifted, no additional sales could be held in that area, nor could the sale area be expanded. Similarly, no additional sales in the Arctic or the Atlantic may be added to the 2017-2022 Five Year Program.

While Section 18 does not allow the Department to expand a Five Year Program without restarting the program preparation process, Congress has the ability to mandate additional sales via the legislative process. Such legislation would mandate that the Department of the Interior conduct lease sales in OCS Planning Areas without regard for the balanced consideration of factors under Section 18 of the OCS Lands Act, such as resource potential; equitable sharing of developmental benefits and environmental risks; the maturity of infrastructure needed to support oil and gas development, including emergency response; and input from local, state and federal stakeholders.

S. 1224, the Condensate Act

S.1224, the Condensate Act, would direct the Secretary of Energy to develop a standard definition of the term "condensate" and advise relevant Federal agencies to adopt that definition for purposes of clarifying energy policy. The bill would further require agencies within the Department of the Interior to consider condensate as a separate commodity. Therefore, in addition to the views outlined below, the Department defers to the Department of Energy with respect to the provisions directed to that Agency.

BOEM currently defines condensate as a very high-gravity (i.e., greater than 50 deg. API) liquid; it may exist in a dissolved gaseous state in the subsurface but liquefy at the surface. Both crude oil and condensate are reported jointly as oil in BOEM's Assessments of Undiscovered Technically Recoverable Oil and Gas Resources on the OCS. BOEM geoscientists and engineers conduct resource assessments in frontier areas that lack the empirical data necessary to define the condensate yield as a separate input into their Geologic Resource Assessment software model. Instead, assessors rely on the overall oil and gas volumes associated with analogue fields that are reported through publicly available industry sources and third party data service providers who do not report condensate separately from oil. This method instills confidence in BOEM's estimates of oil and gas as a whole and can be validated by information that is readily available. Therefore, without having any specific condensate data from analog fields, reporting condensate volumes separately in our undiscovered resource assessments may construe a false sense of precision and is not practical given the paucity of information. This proposed legislation is more applicable to reporting condensate in reserve estimates where empirical drilling and production information can be utilized. BOEM is willing to work with other federal agencies to define a working definition of condensate for the purpose of clarifying energy policy in the United States but is opposed to adopting a separate reporting convention for condensate in its assessment of Undiscovered Oil and Gas resources on the OCS.

The bill would increase uncertainty in U.S. Geological Survey (USGS) undiscovered petroleum resource assessments, especially estimates of natural gas liquids. The challenge is the lack of access to production data for condensate in hydrocarbon liquids (e.g., natural gas plant liquids vs. lease condensate, etc.). Industry, state, and national databases upon which USGS relies to estimate natural gas liquids do not include condensate as a separate item. If required to report condensate as part of USGS undiscovered resource assessments, USGS would have to report very uncertain condensate results alongside more reliable natural gas liquid estimates, for which abundant data are available. USGS also notes that, should a new definition be developed, inclusion into new assessments would be a multi-year process as data conforming to the new definition become available. USGS is open to working with stakeholders to develop a harmonized schema for classification and implementation of any new definition.

The Department's Office of Natural Resources Revenue (ONRR) foresees no significant impacts from proposed S. 1224 on its mission to collect, disburse, and verify Federal and Indian energy and other natural resource revenues. ONRR's production reporting and royalty reporting systems currently allow industry to report condensate separately from oil. If a definitive definition of condensate is developed, ONRR will instruct industry on the associated reporting requirements.

S. 1280, the United States Exploration on Idle Tracts Act

S.1280 directs the Secretary of the Interior to issue regulations establishing an annual production incentive fee for onshore and offshore oil and gas leases within 180 days after enactment of the bill. For offshore leases, the fee would be $4 for each acre of land from which oil and gas is produced for less than 90 days for each of the third, fourth, and fifth years of the lease. For the sixth year, this fee would be increased to $6 per acre, and $8 for the seventh year of the lease and every year thereafter. BOEM currently has in place a sliding-rental rate structure that prescribes increased rental rates per acre, per year, the longer a lease is held until production begins or until relinquishment. Use of a sliding scale rental system is designed to encourage exploration earlier in the lease term. In general, if a lease is drilled within the first five years of its initial period, escalating rentals can be avoided through either a discovery or through relinquishment. BOEM does not have any fees associated with incentivizing continued production on producing leases.

In the case of onshore leases, the fee would be $4 for each acre of land from which oil and gas is produced for less than 90 days for the first three years of the lease. This fee would be raised to $6 per acre in the fourth year of the lease, and $8 per acre in the fifth and every year thereafter.

Currently, the Bureau of Land Management collects annual rental rates onshore for both competitive and noncompetitive leases that are $1.50 per acre in the first five years and $2.00 per acre each year thereafter. Once the lease produces a paying quantity of oil or gas, rental payments cease and the leaseholder begins payment of royalties.

The Department supports incentivizing the diligent development of oil and gas leases. In lieu of S. 1280, the Department prefers its legislative proposal submitted through the 2016 President's Budget Request to establish a per-acre fee for all new leases that accrues each year that a lessee fails to drill a well as part of the Department of the Interior's Federal Oil and Gas Reforms package. The legislative proposal has been a component of the President's budget request since 2012, and recommends a fixed per acre fee to provide a financial incentive for leaseholders to bring their leases into production or relinquish them so that the tracts may be re-leased and developed by other parties. This fee would be in addition to rental rates charged by BOEM and BLM, thereby preserving the flexibility of each bureau to adjust rates as needed in future leases in order to continue to encourage appropriate diligent development by leaseholders. BLM is currently assessing whether to adjust the existing oil and gas rental rates. As with the current rental rates, the new fee would cease upon establishment of production and payment of royalties.

Conclusion

It is important to the Department and my bureau that we explore ways to move towards greater energy security via safe and responsible domestic oil and gas production while ensuring that the American taxpayer receives a fair return for development of those federal resources. I look forward to working with the committee and answering any questions you may have.

The CHAIRMAN. Thank you, Ms. Hopper.

Ms. HOPPER. Thank you.

The CHAIRMAN. Ms. Kelly, welcome.

STATEMENT OF SUSAN N. KELLY, PRESIDENT AND CEO, AMERICAN PUBLIC POWER ASSOCIATION

Ms. KELLY. Thank you very much.

Good morning, Chairwoman Murkowski, Ranking Member Cantwell and other Senators on the Committee. Thank you for inviting me to testify. I'm Sue Kelly, President and CEO of the American Public Power Association.

We commend your hard work putting together the first comprehensive energy package since 2005. While it may be hard to find consensus, APPA is ready to work with you to improve Americans' access to affordable, responsible, environmentally responsible and reliable electric power.

I'll discuss APPA's views on hydropower licensing, mandatory capacity markets and a federal, renewable energy standard.

Hydropower is a cornerstone of our nation's generation mix. It supports affordable and reliable operation of the power grid. 17 percent of the power that APPA members generate comes from hydropower. One hundred fifty public power utilities operate 159 FERC licensed projects with over 21,000 megawatts of capacity.

The current hydropower licensing process needs to be reformed. Right now public power and other utilities cannot increase their investment in emissions free hydropower without protracted resource agency reviews. There is significant potential for new hydropower at non-powered dams throughout the country. Hydropower could be substantially increased at existing facilities and at water distribution conduits and canals, but there are excessive regulatory barriers to doing so.

APPA therefore supports the concepts set out in Senate Bill 1236 which reforms the regulatory process for licensing hydropower projects. FERC should be the lead agency overseeing the process, and it should be able to establish and enforce deadlines for other Federal and state agencies involved in that process.

We also support the goals of Senate Bills 1058 and 1270. Increased Federal funding for research and incentives will help develop hydropower resources.

Second, I'd like to discuss the mandatory capacity markets in the eastern Regional Transmission Organizations which we call RTOs.

Senate Bills 1222 and 1272 address these regulatory constructs, which are often mislabeled markets. They're meant to make sure that generation and demand side resources will be there when needed to meet electricity demand. They have not lived up to that promise and they are constantly tinkered with, but they do account for a substantial share of electric bills that consumers and businesses pay each month.

APPA appreciates the interest that Chairman Murkowski has shown in this issue which Senate Bill 1222 shows. We're particularly pleased to see the legislation list among its objectives an enhanced opportunity for self-supply of electric capacity resources as well as a diverse generation portfolio and availability of transmission facilities. But we're concerned the bill may lack the teeth to achieve the needed reforms. We're concerned it does not include cost to consumers in the list of objectives which could force tariff amendments. Finally, we fear that owners of generation in regions without mandatory capacity markets could use Section 1222 to advocate for these constructs in their RTO regions.

We also appreciate Senators Markey and Warren's introduction of Senate Bill 1272. This legislation requires the GAO to answer the fundamental question that APPA has been asking for some time, whether these constructs produce just and reasonable rates as the Federal Power Act requires.

Both bills kick off a much needed dialogue, but we believe there's already more than enough information to support changes. We've recommended that FERC phase out mandatory markets over time and replace them with voluntary, residual capacity markets.

But in the meantime we propose two fixes. First, RTOs that have not yet implemented mandatory capacity markets should not do so without unanimous support of the states and their regions. Second, RTOs that already have mandatory capacity markets should not impair the ability of retail utilities or states to self-supply their own capacity obligations.

Finally, APPA has concerns with Senator Udall's legislation to establish a renewable electricity standard.

Many of you know that public power utilities strongly support renewable energy. We have been leaders in developing it. However, APPA believes that at this point there is no need for legislation to create a Federal renewable energy standard. State and local governments are best placed to implement these policies.

Moreover, the cumulative impact of various EPA regulations is leading to increased retirements of coal fired power plants in the United States. EPA's soon to be finalized regulations to reduce CO_2 emissions from fossil fired power plants are going to accelerate that trend. Utilities are already increasing the amount of electricity they generate from renewable resources and we're taking other steps to reduce CO_2 emissions. A Federal RES is therefore, unnecessary.

Thank you for the opportunity to appear today. I'm happy to answer any questions you have.

I know you have a whole slew of bills under consideration and some of them apply to our sector. We've reviewed those and we're willing to work with the Committee as you move forward.

Thanks again.

[The prepared statement of Ms. Kelly follows:]

Susan N. Kelly

President and CEO

American Public Power Association

Testimony before the Senate Committee on Energy and Natural Resources

Hearing on Energy Supply Legislation

May 19, 2015

The American Public Power Association (APPA) is the national service organization for the more than 2,000 not-for-profit, community-owned electric utilities in the U.S. Collectively, these utilities serve more than 48 million Americans in 49 states (all but Hawaii). APPA appreciates the opportunity to provide the following testimony for the Senate Energy and Natural Resources Committee's hearing regarding energy supply legislation.

APPA was created in 1940 as a nonprofit, non-partisan organization to advance the public policy interests of its members and their customers. We assist our members in providing reliable electric service at a reasonable price with appropriate environmental stewardship. Most public power utilities are owned by municipalities, with others owned by counties, public utility districts, and states. APPA members also include joint action agencies (state and regional entities formed by public power utilities to provide them wholesale power supply and other services) and state, regional, and local associations that have purposes similar to APPA.

Collectively, public power utilities deliver electricity to one of every seven electricity consumers. We serve some of the nation's largest cities, including Los Angeles, CA; San Antonio, TX; Austin, TX; Jacksonville, FL; and Memphis, TN. However, most public power utilities serve small communities of 10,000 people or less.

In terms of public power's generation portfolio, in 2013 these utilities generated 169.6 million megawatt-hours (MWhs) of electricity from coal; 76.9 million MWhs from natural gas; 62.78 MWhs million from nuclear; 69.8 million MWhs from hydropower; and 8 million MWhs from other sources such as non-hydropower renewable energy like wind, solar, and geothermal. It is important to note, however, that public power supplies approximately fifteen percent of electricity to end-users in the United States, but it only produces ten percent of the megawatt-hours generated. To make up the difference, public power utilities purchase power at wholesale from other entities such as investor-owned utilities, independent power producers, rural electric cooperatives, federal power marketing administrations, and the Tennessee Valley Authority.

Introduction

Energy supply conversations are occurring throughout the United States. APPA and its public power utility members are helping to lead these discussions, and are focusing on how to maintain reliable and affordable supplies of electricity. In this testimony, I will discuss APPA's views on several issues relating to the numerous bills before your Committee today. These issues include hydropower, capacity markets in regional transmission organizations, and the merits of a federal renewable energy standard, among others.

Legislation

Hydropower:

- S. 1058- Marine and Hydrokinetic Renewable Energy Act
- S. 1236- Hydropower Improvement Act
- S. 1270- Reliable Investment in Vital Energy Reauthorization Act ("RIVER Act")

Hydropower is a cornerstone of our nation's generation mix, and helps support the affordable and reliable operation of the nation's power grid. The option of hydropower generation is urgently needed to manage the very difficult choices that will be presented by the Environmental Protection Agency's (EPA's) proposed emissions guidelines for carbon dioxide emissions from existing fossil fuel-fired power plants under Section 111(d) of the Clean Air Act (commonly referred to as the "Clean Power Plan").

The current hydropower licensing process should be reformed so that public power and other utilities can increase clean, emissions free hydropower generation without unnecessarily prolonged resource agency review. For this reason, APPA supports reforms that will improve the hydropower licensing process. The Federal Energy Regulatory Commission (FERC) should be the lead agency overseeing the licensing process, with the ability to establish and enforce deadlines for state and federal agencies involved in the licensing process. Many of APPA's members are also members of the National Hydropower Association (NHA). One hundred public power utilities own FERC-licensed hydropower facilities, and in some cases they own multiple FERC-licensed facilities.

Making full use of the nation's hydropower resources is key to ensuring that the nation's grid remains reliable and resilient, and that utilities can meet emission reduction goals. Hydropower is a source of emissions-free base-load power which, unlike variable renewable resources, is generally available 24/7. Moreover, hydropower's "black start" capability makes it highly valuable from the standpoint of cyber and physical security; in instances of outages or disruptions to the grid, hydropower units can cycle back on quickly and help support full power restoration.

There is a significant potential for new hydropower to be generated at non-powered dams throughout the country, as well as for hydropower output to be dramatically increased in existing hydropower facilities and at water distribution conduits/canals. But there are excessive regulatory barriers to tapping this potential; we therefore ask this Committee to pass legislation that reduces those barriers.

FERC is currently the primary federal agency responsible for the licensing and relicensing of such non-federal hydroelectric projects. But given the involvement of multiple resource agencies, the licensing process can be lengthy, difficult, costly and uncertain for applicants. Under the Federal Power Act ("FPA"), FERC must establish requirements in conjunction with the license ("conditions") that give "equal consideration" to not only power needs, but also Endangered Species Act requirements, water quality issues, marine navigation, and other public interest concerns. FERC must carefully evaluate many aspects of a hydropower project, and we agree that it should do so. But under the current regime, other state and federal agencies can impose "mandatory conditions" that FERC cannot balance or modify in the public interest. While it is appropriate to consider a broad array of factors, this process must be streamlined and reformed. Critical new additions to existing hydropower facilities are languishing, caught up in bureaucratic and often contradictory processes that can span a decade or more or which simply become too costly to justify further pursuit of the license. FERC must be given more clear-cut authority to establish deadlines and fulfill its role under the FPA.

APPA therefore supports the concepts contained in S. 1236, the Hydropower Improvement Act, which reform the lengthy, duplicative and contradictory regulatory processes for licensing hydropower projects. APPA looks forward to working with the Committee to advance these ideas. Specifically, we strongly support the provisions in Section 35(b)(1) designating FERC as the lead agency for the purposes of coordinating all applicable federal authorizations, Section 35(c)(2)(A) directing FERC to establish a schedule for the issuance of all federal authorizations, and Section 35(b)(3) allowing FERC to consider any federal authorizations not issued by the applicable deadline as recommendations and not mandatory conditions needed before issuing a license. This list is merely illustrative, and should not be viewed as an exhaustive list of provisions in S.1236 that APPA supports.

APPA is also supportive the goals of S. 1058, the Marine and Hydrokinetic Renewable Energy Act of 2015, which seeks to promote research and development of marine and hydrokinetic hydropower technologies and S.1270, the Reliable Investment in Vital Energy Reauthorization Act (RIVER), which would reinstitute incentive payments to qualifying hydropower owners or operators. Increased federal funding for research and incentives will help to drive further improvement and development of our nation's hydropower resources.

Given the impact of a host of EPA regulations that are leading to the reduced use of coal-fired generation, it is important to adopt policies that will support and expedite the use of other base-load generation resources that are reliable and affordable.

Capacity Markets:

- S. 1222- A bill to amend the Federal Power Act to provide for reports relating to electric capacity resources of transmission organizations and the amendment of certain tariffs to address the procurement of electric capacity resources, and for other purposes.

- S. 1272-A bill to direct the Comptroller General of the United States to conduct a study on the effects of forward capacity auctions and other capacity mechanisms.

Background

S. 1222 and S. 1272 are directed at what are known as "capacity markets," which are currently operating in certain regions of the country with restructured wholesale electric markets. The intent of these "markets" is to ensure that resources will be in place and available when needed (i.e., there will be adequate capacity) to meet the demand for electricity. APPA and others have long had concerns with a specific type of capacity market – namely the mandatory capacity markets that are operated by Regional Transmission Organizations (RTOs) in the eastern wholesale markets (the PJM Interconnection, ISO New England and parts of the New York ISO). These administrative constructs account for a substantial share of the total electricity costs paid by consumers and businesses.

Unfortunately for electric consumers, these mechanisms have not demonstrated that they can achieve a reliable and diverse supply of power and incent the building of new generation where it is most needed. Instead, they have required consumers to pay billions of dollars in costs, with little concomitant benefit.

Because these mechanisms do not distinguish between technology types or between existing and new units, critical needs are not addressed, including: adequate flexible ramping capability (an operational requirement needed to match the variability of some renewable resources that come online when the sun is shining or wind is blowing, and go offline when they are not); reliability needs created by new environmental regulations and retiring coal plants; and the coordination of natural gas pipeline infrastructure needs with the increasing electricity generation from natural gas.

These mandatory capacity markets are not actually markets and are certainly not competitive. Instead, they are administrative constructs requiring elaborate rules and processes that have been in a constant state of flux as the RTOs continually tweak these rules. In practice, the constant rule changes have simply increased costs to consumers without addressing the fundamental flaw in the capacity markets -- that new generation generally requires long-term contracts to secure financing, as opposed to short-term, volatile capacity market prices and frequently changing rules. APPA studies have shown that 98 percent of new generation completed in recent years has been built with financing from ownership or long-term contracts. Moreover, in 2013 only 6 percent of new generation was constructed within RTOs with mandatory capacity markets. (There has been a recent increase in planned merchant natural gas plant capacity in the Eastern RTOs, but not all of this has actually been developed and, moreover, this capacity is being planned without consideration of fuel diversity or the impact on already constrained natural gas pipelines and natural gas prices. The speculative nature of these projects also leads to higher financing costs, which may drive up prices in the capacity markets.

APPA believes that continued reliance on mandatory capacity markets for resource development will not enable the development of needed resources in these regions to assure their energy future, especially in light of EPA's pending 111(d) rule for carbon dioxide emissions, as discussed later in this testimony.

These constructs persist because owners of existing generation resources have a strong financial interest in maintaining them. In recent years, these generation owners have successfully advocated for rules that reduce competition from new entrants and increase prices to consumers. Unfortunately, FERC has approved many of these rule changes.

Such recent restrictions on new entry and competition are the direct result of actions taken in states located within the Eastern RTOs. These states became frustrated with the lack of new power generation being developed in their states, given the billions of dollars being spent on capacity payments. They sought to take control of their energy resource future and protect their residents from high electricity prices and potential shortages. For example, New Jersey, Maryland, and Connecticut all took steps to establish competitive bidding processes for the procurement of new generation capacity through long-term bilateral contracts. Similarly, the New York Power Authority issued an RFP for new power supplies and subsequently entered into a long-term contract with a new efficient natural gas plant in the New York City area to displace an older, less efficient generation facility. Fearful of the *lower* prices that would result from the entry of new generation constructed under these state efforts, owners of existing power plants in the New York, New England and PJM RTOs sought to block this new entry through highly problematic new rules, or changes to or reinterpretations of existing rules that were approved by FERC. Such tariff rules involve what is known as the "minimum offer price rule" (MOPR) or "buyer-side mitigation" (BSM). While tariffs regarding MOPR or BSM differ slightly in the details among the three RTOs, the basic concept is to replace lower price offers to sell new capacity with administratively determined higher price offers, making it more difficult for these new plants to "clear" the capacity auctions. Such rules are based on a largely misguided fear of so-called "buyer-side market power." They produce results that have little to do with competitive markets and everything to do with the maintenance of existing seller-side market power.

The BSM rules greatly limit state control over generation resources in their own states and adversely impact not-for-profit public power and cooperative utilities. Because the capacity markets are mandatory, utilities that construct or contract for generation to meet their own customers' power needs still must offer such self-supply capacity into the annual or sub-annual capacity market auctions. If that capacity does not clear the auction, the utility nevertheless would be required to purchase capacity from the market to meet its capacity obligation—thus paying twice for capacity: once for its own power plant and again for the capacity obtained from the "market." The original rules of the capacity markets in PJM and ISO-NE contained provisions to ensure that self-supply would clear the auctions, avoiding this double-collection dilemma. But these exceptions for self-supplied generation were undone by FERC in subsequent rule changes. The revised capacity market rules now threaten a cornerstone of the business model for public power and cooperative utilities—their ability to self-supply their own customers.

Public power utilities have spent critical time and resources fighting to restore their self-supply rights. In PJM, lengthy negotiations among merchant generators, industrial customers, and public power and cooperative utilities in 2012 resulted in an agreement providing for, among other things, a MOPR exemption for self-supply resources, but only if such supply meets certain criteria. This exemption was approved by FERC in May 2013, but it is unclear whether it will in fact survive, given further litigation. State-sponsored resources are still not subject to any exemption.

Most recently, on May 8, 2015, the New York Power Authority, New York Public Service Commission, and New York Energy Research and Development Authority filed a joint complaint with FERC requesting that resources used for self-supply or the use of resources to meet an identified reliability be exempted from the MOPR applicable to certain capacity zones in New York. In their complaint, these entities note that "imposing imprecise or misdirected mitigation measures can pervert market outcomes and cause substantial deviations from the competitive equilibrium, much to the detriment of the social welfare."

Because the BSM rules also adversely impact the ability of states to procure needed generation or to make decisions on the types of resources they might need to meet their energy needs, the implementation of the EPA's proposed rules under Clean Air Act section 111(d) becomes even more complicated. EPA's proposed rule of necessity relies on state implementation, but the capacity constructs substantially impede state control of their own resource destinies. It is therefore difficult to see how the states will be able to carry out these new obligations. The capacity market rules could well exacerbate reliability problems and price increases as any final rule under section 111(d) is implemented.

Concerns about these constructs were encapsulated in a February 2014 joint letter to FERC from thirty entities, including APPA, publicly- and cooperatively-owned electric utilities, national consumer and low-income organizations, state public utility commissions, state consumer advocates, investor-owned utilities, industrial customers, and independent power producers. The letter listed the following core principles for capacity market reforms: a recognition that load serving entities (LSEs, which are entities that directly serve end-use customers), states, and local regulatory bodies have policy reasons to support specific types of resources so that barriers should not be erected to thwart resource decisions made by these entities; encouragement and support for long-term contracting and self-supply; and consideration of rate impacts on consumers.

S. 1222/S. 1272

Given this history, APPA greatly appreciates the interest shown in this issue by this Committee and by Chairman Murkowski as reflected in the introduction of S. 1222, the Continuity of Electric Capacity Resources Act. The legislation would: a) require RTOs to report on the status of capacity resources and reliability of the bulk power system; and, b) make tariff amendments if certain enumerated objectives are not being addressed by the capacity markets. We are particularly pleased to see that the legislation lists among those objectives "an enhanced opportunity for self-supply of electric capacity resources" as well as a "diverse generation portfolio" and "availability of transmission support services." This bill marks the welcome beginning of what we hope will be a fruitful consideration of the problems caused by mandatory capacity markets. We look forward to continuing to work with Chairman Murkowski, the Committee, and others who have expressed an interest in this issue to explore this and other legislative approaches to resolve these concerns.

In specific response to the provisions of S. 1222, given the extreme reluctance of the RTOs with mandatory capacity markets to acknowledge shortcomings of their markets and the strength of entrenched interests that have a vested financial interest in the perpetuation of the current regime, we are concerned that the legislation may lack the "teeth" to achieve the necessary reforms to these constructs.

APPA is also concerned that S.1222 omits the consideration of costs to consumers from the list of objectives which may force tariff amendments. In recent years, the Eastern RTOs have proposed increasingly costly rule changes under the guise of enhancing reliability. Ironically, these increased costs have been proposed to address the problem that capacity providers which have received capacity payments have not always been available during system peak times; *i.e.*, despite having been paid to provide capacity, certain generators have been unable to provide capacity when it was most needed. APPA agrees that such performance issues need to be addressed, but not with the costly and extensive rule changes these RTOs have proposed. Stakeholders recently sent members of Congress from the PJM region a letter addressing one such proposal—PJM's capacity performance proposal. The letter was signed by 14 public power utilities and associations, electric cooperatives, a group of large industrial customers, state commissions and consumer advocates, and states that PJM's capacity performance proposal "would dramatically increase electric costs without providing meaningful and necessary improvements in system reliability."

Finally, we are also concerned that S. 1222 could be used by owners of generation in regions without mandatory capacity markets to advocate for the imposition of these problematic constructs in their RTO regions. For example, generators in the Midcontinent Independent System Operator (MISO), which has a voluntary capacity market, have been continuously advocating for a PJM-style mandatory capacity market in that region despite widespread opposition from the state commissions, public power and others entities in the MISO region.

APPA also appreciates the introduction by Senators Edward Markey and Elizabeth Warren of S. 1272. This legislation would require the Government Accountability Office (GAO) to conduct a study on the effects of forward capacity auctions and other capacity mechanisms. This legislation rightfully focuses on the effect of these mechanisms on consumer prices, development of new generation, preservation of existing generation, and competition. More importantly, the legislation requires the GAO to answer the fundamental question of whether these constructs are producing rates that are "just and reasonable." APPA believes any such analysis would confirm our conclusions about these mandatory capacity market mechanisms and provide a basis for substantive reforms to these markets.

All of this said, we believe that there is currently more than enough information available to support immediate reforms. APPA has long recommended that these mandatory capacity constructs be phased out and replaced with voluntary, residual capacity markets, with primary resource procurement achieved through a portfolio of long-, medium- and short-term contracts and a diverse resource mix. While arguably such an overhaul may require the sorts of reports envisioned by S. 1222 and S. 1272, APPA believes a narrower near-term fix is already justified by what we know today.

Specifically, APPA would propose that:

A) RTOs that have not yet implemented a *mandatory* capacity market should not move to do so without unanimous support by the states in the region.
B) RTOs that have already adopted a mandatory capacity market should not impair (through rates, or rules, regulations, or practices affecting rates) the ability of a load-serving entity to meet its capacity obligations through a resource it owns, builds, controls, or for which it has a contract for capacity.

APPA believes legislation implementing these two changes would make common sense. A state should not be forced into a mandatory capacity payment mechanism when it wishes to meet its capacity obligations through some other means. Likewise, a load-serving entity should be able to meet its capacity obligations through self-supply (as discussed in S. 1222). As for whether such an approach might "risk" reliability, APPA members have been providing reliable service to their customers for more than a century. Moreover, load-serving entities would continue to be subject to resource adequacy and reliability obligations. Such an approach would simply allow our members and other load-serving entities to do so without being forced to pay billions of dollars for capacity they could more affordably supply themselves, and allow them to construct the diverse portfolios they need to protect their customers and better comply with coming EPA regulations.

In sum, APPA's members are absolutely committed to providing reliable electric power. We object, however, to being forced through mandatory capacity markets to squander billions of dollars for capacity payments which are not resulting in the building of new generation to meet capacity requirements that our members could better, and more affordably, meet through self- supply. As a result, we appreciate greatly the interest shown by this committee in this issue. We would hope that in drafting energy legislation this year, the Committee will recognize the impediments to an affordable, reliable and more efficient generation future posed by these mandatory capacity constructs and move to impose needed reforms to those markets, such as those proposed above.

Renewable Energy Standard:

- S. 1264- A bill to amend the Public Utility Regulatory Policies Act of 1978 to establish a renewable electricity standard, and for other purposes. (Udall)

Public power utilities are strongly supportive of renewable energy and have been leaders in the development of renewable energy resources. However, APPA believes that at this point there is no need for legislation to create a federal renewable energy standard (RES). Already, 28 states have RESs and eight have voluntary RESs or targets (National Conference of State Legislatures website -- State Renewable Portfolio Standards and Goals as of February 19, 2015, available at http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx). State and local governments are the in the best position to implement these types of policies and adjust them, if needed, to address changing circumstances. Furthermore, given the cumulative impact of various EPA regulations that are leading to the increased retirement of coal-fired power plants throughout the U.S. and the EPA's soon-to-be finalized regulations to reduce CO_2 emissions from existing fossil-fuel fired power plants, utilities are increasing the percentage of electricity they generate from renewable resources (or taking other steps to reduce CO_2 emissions) in any event. State and local policies promoting the greater use of renewables, along with EPA regulations to reduce CO_2 emissions are sufficient drivers for the increased use of renewable resources. A federal RES is unnecessary.

Furthermore, the creation of a federal RES could create a host of issues for utilities that are already subject to state RESs and are also trying to comply with state plans issued under EPA's final Section 111(d) rule that will be released in the summer of 2015. Not all states have access to sufficient renewable energy sources and under EPA's proposed Section 111(d) rule, utilities in a state that made investments in out-of-state renewables have no ability to get credit for those investments. EPA has thus far not stated whether it will address the out-of-state credit issue in its final rule, but given the system-based approach the agency took in developing individual state goals in the proposed rule, it is hard to see how the agency can fix this problem in the final rule. If a utility cannot get credit for out-of-state investments in renewable resources under a final Section 111(d) rule, it will be very difficult at best to comply with a federal RES of 30 percent by 2030, the same year the states must comply with their final goals under the Section 111(d) rule.

In addition, Senator Udall's legislation could have the unintended consequence of forcing public power, rural electric cooperative, and investor-owned utilities located in the same state to compete against one another for in-state renewable energy resources to meet the state goals set by EPA in its final Section 111(d) rule. While there may be some changes in the final 111(d) rule, EPA has clearly indicated it will retain the basic architecture of the proposed rule, including the four building blocks, of which building block three is renewable energy. Notwithstanding EPA's assertion that states do not have to use all the building blocks for compliance with a state's goal, most states will in fact have to use them all to meet the goal. In addition, there was very little guidance in the proposed rule on possible interstate trading of compliance measures, such as renewable energy credits. Thus, there may be little or no actual ability for utilities in one state to access substantial renewable credits from another state. Hence, utilities in one state may likely have to rely on in-state renewables from that state to meet the 111(d) goals and while some states are fortunate and have access to multiple types of renewable energy sources, others are not so fortunate given weather and topography. In states with limited renewable resources, competition for in-state resources could result in increased electricity prices, which for public power utilities, would be fully borne by customers. Competition could also result in public power utilities not having sufficient access to renewable resources to meet their obligations under state plans issued to comply with a final Section 111(d) rule. Given the complications a federal RES would very likely create with the implementation of EPA's final Section 111(d) rule, APPA opposes the creation of one in the energy legislation being formulated by the Committee.

Other Legislation

- S. 562- The Geothermal Exploration Opportunities Act
    - We would recommend support for this legislation as it would amend the National Environmental Policy Act (NEPA) to exempt exploratory work (seismic testing, test

wells, etc.) done on a small scale from environmental assessments or environmental impact statements under NEPA.

- S. 822- The Geothermal Production Expansion Act
  - This legislation would provide an incumbent developer first right of preference to develop adjoining lands. The legislation, however, could be used by an incumbent developer to discourage efforts by other developers to start projects in adjoining geothermal fields. Due to the potential unintended consequences, APPA would remain neutral at this point.

- S. 1057- Geothermal Energy Opportunity Act or "GEO Act"
  - The crux of this legislation is to create a self-funded program for development of geothermal resources, with royalty payments being held in a separate fund and disbursed by DOE to share costs for innovative projects. We would generally support the legislation, but strongly believe that the current royalty payments to affected counties should be maintained.

- S. 1304 – to require the Secretary of Energy to establish a pilot competitive grant program for the development of a skilled energy workforce, and for other purposes
  - APPA supports the goals of Ranking Member Cantwell's legislation to create a pilot grant program at DOE to support workforce training in the energy sector. Many changes are occurring in the electric utility industry that will require existing workers to learn new skills and necessitate new programs to educate and train new workers entering the field. A competitive grant program that would fund such job training and educational programs would very much benefit public power utilities and the communities they serve.

- S. 1282 – to amend the Energy Policy Act of 2005 to require the Secretary of Energy to consider the objective of improving the conversion, use, and storage of carbon dioxide produced from fossil fuels in carrying out research and development programs under that Act; S. 1283 – to amend the Energy Policy Act of 2005 to repeal certain programs, to establish a coal technology program, and for other purposes; and S. 1285 – to authorize the Secretary of Energy to enter into contracts to provide certain price stabilization support relating to electric generation units that use coal-based generation technology
  - APPA supports efforts to conduct more research and development on carbon capture and sequestration technologies that could help reduce the CO2 emissions from coal-fired power plants and preserve coal as an important source of affordable and reliable baseload generation. Collectively, the bills introduced by Senators Manchin and Heitkamp would prioritize CCS research at DOE and direct the department to conduct research and development, large-scale pilot projects, and demonstration projects to improve the "efficiency, effectiveness, cost, and environmental performance of coal use. Any future efforts to further develop the technology, however, must also look at the potential environmental consequences of long-term sequestration of CO2 and resolve the potential liability issues associated with long-term storage.

- While legislation is not currently pending before the Committee on this issue, APPA would nonetheless like to raise a strong concern about how the costs of safety improvements to federally operated dams are currently being allocated between the operating agency and the consumer-owned utilities that purchase the electricity produced at these dams through the respective federal Power Marketing Administrations. Shifting the costs of dam safety improvements from the operating agency -- whether it be the U.S. Army Corps of Engineers or the Bureau of Reclamation -- to not-for-profit customer-owned utilities is not only unfair, but contradicts the spirit of statutes such as the Flood Control Act of 1944 (16 U.S.C. §825s) and the Reclamation Project Act of 1939 (43 U.S.C. §485h(c)),which directs federally-operated dams to market power to preference customers at the lowest cost possible consistent with good business practices. This Committee has been a strong supporter of federal hydropower, and we wanted to alert you that the actions being contemplated by the U.S. Army Corps of Engineers to allocate dam safety costs to power customers could make that emissions-free, reliable and affordable hydropower uneconomic. APPA opposes such a non-sensical result.

Conclusion

Thank you again for the opportunity to testify before the Committee. I hope that the views expressed in my testimony will be fully considered by the Committee as you continue to develop the elements of an energy bill. APPA commends Chairman Murkowski, Ranking Member Cantwell, the other Senators on the Committee, as well as their staffs, for being fully committed to working together and finding a solution to our nation's 21st century energy challenges. APPA and its members look forward to working with you in the days ahead.

The CHAIRMAN. Thank you, Ms. Kelly.
Mr. Livingston, welcome.

STATEMENT OF RANDAL S. LIVINGSTON, P.E., VICE PRESIDENT, POWER GENERATION, PACIFIC GAS AND ELECTRIC COMPANY

Mr. LIVINGSTON. Good morning. Thank you.

My name is Randy Livingston. I serve as Vice President of Power Generation at Pacific Gas and Electric Company.

PG&E is one of the nation's largest combined electrical and natural gas utilities with more than 22,000 employees serving 16,000,000 customers in California. We are also the owner and operator of America's largest, investor-owned, hydroelectric system. With 26 FERC licenses we're always in the process of relicensing. Today we have seven projects and one phaser, in order of relicensing.

Our system generates nearly 3,900 megawatts of safe, clean, reliable and affordable power for millions of Californians, has been crucial in integrating other renewable energy sources. Additionally, it provides water supply, recreation, flood control, taxes and other benefits. Hydropower is an invaluable resource and it's one that our country can and should do more to capitalize on.

We appreciate the efforts made by past Congresses to advance hydroelectric generation. We believe this Congress has taken a very important step with the introduction of S. 1236, the Hydropower Improvement Act of 2015 and by holding today's hearing.

PG&E believes it's critical for hydroelectric power generators to be able to move through the relicensing process more efficiently and more affordably so we can implement the environmental protections, community improvements and facility upgrades more quickly than we can today.

We believe that S. 1236 accomplishes this fairly and effectively while maintaining important environmental protections and community interests. In particular, it does this by clarifying FERC's exclusive authority to enforce, amend or otherwise administer all aspects of a FERC issued license. It clarifies that mandatory conditions and prescriptions should have a clear and direct nexus to the project. It allows FERC to establish the schedule for federal authorizations and providing findings of fact by a FERC administrative law judge be binding on all participants in trial type hearings.

We believe these sensible and basic reforms can make hydropower licensing processes more efficient while keeping in place environmental protection and other benefits that we all agree are critical.

PG&E places a priority on using collaborative processes to relicense a facility as both understanding and incorporating the interests of stakeholders is critical. However, as it stands today, the current process is very complex and protracted leading to higher costs, delayed implementation of improvements and upgrades.

To put this in perspective, PG&E's recent experience that even for a medium-sized license it consistently takes over seven years to renew an existing license and often well over ten. The cost just to complete the process for continued operation of a facility can run over $50 million, and implementing the requirements of a new license routinely runs to $100 million. All these costs are ultimately borne by the energy consumer.

The relicensing process involves numerous Federal and state agencies and stakeholders with interests that may not always align, therefore, we believe the following processes should be improved.

We should assure that the environmental protections exist and we preserve hydropower at the same time, that we achieve the benefits of relicensing sooner, that we reduce cost and improve predictability and we enhance the collaborative process to be results and solutions oriented. S. 1236 would accomplish many of these objectives.

Given this focus of this Committee on crafting and advancing an energy policy for the 21st century you and your colleagues have an important opportunity to bring meaningful change to the hydropower relicensing process and to ensure that it is consistent with America's needs and opportunities today and for many years ahead.

PG&E looks forward to continuing our work with Congress. Thank you.

[The prepared statement of Mr. Livingston follows:]

Pacific Gas and Electric Company

Testimony

of

Randal S. Livingston, P.E.
Vice President, Power Generation
Pacific Gas and Electric Company

before the

Committee on Energy and Natural Resources

of the

United States Senate

on

Hearing: "Energy Supply Legislation"

May 19, 2015

Good morning Chairman Murkowski, Ranking Member Cantwell and members of the Committee. Thank you for the invitation to appear before you today as we consider S. 1236, the Hydropower Improvement Act of 2015, and the important opportunity to modernize and improve the hydropower licensing and relicensing processes.

My name is Randy Livingston, and I am here in my capacity as Vice President of Power Generation at Pacific Gas and Electric Company (PG&E).

PG&E is one of the largest combined natural gas and electric utilities in the United States. Based in San Francisco, with more than 22,000 team members, the company delivers some of the nation's cleanest energy to nearly 16 million people – or one in 20 Americans – throughout a 70,000-square-mile service area in Northern and Central California. In fact, more than 50 percent of the electricity we deliver to customers comes from greenhouse gas-free resources, a significant portion of which is attributed to hydroelectric generation.

PG&E owns and operates one of nation's largest investor-owned hydroelectric systems, which is built along 16 river basins and stretches more than 500 miles. PG&E's 67 powerhouses, including a pumped storage facility, have a total generating capacity of 3,888 megawatts (MW) – enough to meet the needs of nearly four million homes. The system relies on approximately 100 reservoirs located primarily in the higher elevations of California's Sierra Nevada and Southern Cascade mountain ranges.

PG&E's hydroelectric system consists of 26 federally licensed projects. Since 2000, PG&E has completed 10 hydropower relicensing proceedings representing 1,140 MW. PG&E has 7 "active" hydropower relicensing proceedings, which represent an additional 1,131 MW.

As required by federal and state regulatory agencies, PG&E evaluates and mitigates the projects' impacts on natural resources and the environment. We have made it a priority to work collaboratively with stakeholders, including federal and state agencies, local community members, environmental organizations, fishing interests and other recreationalists, and agricultural landholders, among others, during the relicensing process. Together, we work to assess the impacts of these projects, identify issues of importance, and develop plans to protect fish and wildlife habitat, enhance recreational uses, and improve water quality and flow management.

We believe this collaborative approach best serves the public interest, as we recognize that many entities and individuals rely on the watersheds in which our facilities are located. At the same time, we believe that the process currently in place could be substantially improved, allowing for the benefits of relicensing to the environment, the community and the consumer to be achieved significantly sooner than they are today.

Hydropower is an invaluable, renewable resource – and one that our country can and should do more to capitalize on. It is a greenhouse gas-free source of energy that provides important reliability benefits to the overall power system, particularly systems with significant amounts of intermittent renewable generation, such as solar and wind.

We appreciate all the efforts made to date by past Congresses to advance hydroelectric generation and we believe that, with the introduction of S. 1236, this committee is taking a very important step to continue this progress.

PG&E believes it is critical for hydroelectric power generators to be able to move through the relicensing process more efficiently and more affordably, so that we can implement environmental protections, community improvements and facility upgrades much more quickly than we do today. Essentially, delays in the relicensing process merely delay improvements and add costs, which are ultimately borne by the energy consumer.

We believe that S. 1236 includes common sense reforms, which would allow owners and operators of hydroelectric systems to function more efficiently, while providing – and accelerating – environmental protections and other benefits.

Hydropower: An Abundant Resource with Challenges

Hydropower is America's largest renewable energy resource. This safe, affordable and dependable natural resource is also by far the largest source of renewable electricity in the United States, at approximately 100 gigawatts of installed capacity.

In order to capitalize on hydropower's existing capacity and future potential, addressing key challenges within the existing hydropower licensing process is necessary. With respect to PG&E's system, the process to relicense existing hydroelectric projects requires extensive consultation with multiple state and federal agencies, consistently takes at least seven years, and frequently lasts more than ten years. For example, the relicensing of the Poe Project is now in year seventeen.

Meanwhile, the cost to PG&E customers to obtain a license renewal has routinely exceeded $20 million per license, and some current proceedings will exceed $50 million. When, and if, a license is approved and received, implementing the conditions of the license also routinely costs tens-of-millions of additional dollars.

To put this into greater perspective, the cost and duration of the process to relicense an existing hydroelectric project can be just as cumbersome and complex as seeking a license for a new, unbuilt hydroelectric project. In both cases, the cost and duration associated with licensing is typically far greater than any other established electric generation technology.

Congressional Action: Addressing Federal Regulatory Changes

PG&E applauds Congress for taking meaningful steps over the years to promote hydropower development, including taking swift action in 2013 to pass the "Hydropower Regulatory Efficiency Act of 2013" (now Public Law 113-23), and the "Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act" (now Public Law 113-24).

We also remain encouraged that the U.S. Senate and U.S. House of Representatives have expressed a desire – and are working now – to craft broad energy plans in the 114th Congress. PG&E fully supports the process and will remain an active voice in sharing our experiences during the development of potential legislation related to hydropower licensing, among other key issues.

Actions taken to provide a greater level of regulatory clarity and certainty for hydropower development and production, which are captured in S. 1236, serve as another example of the important work of the Committee on Energy and Natural Resources. Both the recognition of such licensing challenges in California – and across this country – as well as a bill providing solutions to these challenges, S. 1236 proposes, are very important to maximize hydropower's future potential.

Thus, there is no question that S. 1236 helps in many ways to improve the efficiency of the federal regulatory processes surrounding hydropower licensing. PG&E believes it responsibly reduces regulatory uncertainty across the nation, without sacrificing protections for the environment or jeopardizing the integrity of the licensing process.

Licensing Improvements for Hydropower

PG&E recognizes the right of and need for federal agencies to place license conditions upon the lands for which they have the responsibility to manage. Similarly, PG&E also understands that various federal agencies have different missions and different objectives, given their purview, and may therefore have different perspectives on the license conditions are needed. However, we believe that better coordination of these perspectives is necessary given how the process and agency interaction works today. In fact, today, if conflicting license conditions are placed on a project, they are left to the licensee to resolve. Instead, we believe the federal government should be in the position of resolving conflicting conditions from various agencies, not a licensee. While we recognize that the hydroelectric licensing provisions in the Energy Policy Act of 2005 tried to address this and similar issues, they unfortunately were not realized during implementation over the past decade.

The recommendations we advocate to modernize the process will: 1) help improve the timeliness and cost of renewing a license; 2) ensure all involved stakeholders use the same underlying data and studies, so that results can be compared, as well as follow the same schedule in exercising their authorities; 3) provide clarity of extent of authorities; and 4) provide a process for a single effective challenge opportunity before the Federal Energy Regulatory Commission (FERC) to resolve disputes regarding proposed license conditions.

Some specific actions Congress can take to overcome the existing challenges and maximize hydropower's potential, include addressing the following four areas:

- Improve coordination between federal and state environmental reviews;
- Better define the extent of authorities by federal agencies;
- Improve federal agency coordination and transparency; and
- Improve federal and state agency coordination and transparency.

To achieve these basic improvements, Congress should consider advancing legislation on the following four principles, which S. 1236 does in several cases:

- Establishing a defined process at FERC to resolve issues arising from overlapping or conflicting authorities, or overlapping and conflicting license conditions among federal agencies, as well as between federal and state agencies.

  S. 1236 accomplishes this recommendation through: 1) new Federal Power Act (FPA) section 35 (a) which defines "Federal Authorization" to mean any authorization required under Federal law including any license, permit, special use authorization, certification, opinion, consultation, determination or other approval; 2) new FPA section 35 (b) which designates FERC as lead agency for the purposes of coordinating all applicable Federal authorizations; and 3) new FPA section 36 (n) which states the Commission has final authority to resolve any inconsistencies between requirements imposed pursuant to Federal authorization (as defined in section 35(a)).

- When a preliminary condition is proposed by an agency, the relicensing process currently allows a licensee to propose alternatives that would meet the resource objective, but be superior from a licensees' perspective; and it allows for trial type hearings on the preliminary condition. However, the process does not allow for any challenge of a final condition; further, it does not require that the final condition resemble the preliminary condition or the outcome of the hearing. To that end, we suggest this be addressed.

  S. 1236 partially accomplishes this recommendation through new FPA sections 35 and 36 and revisions to Section 33. Proposed FPA Section 36 states any subsequent modified condition or prescription submitted by the Secretary in response to the trial-type hearing should reflect the findings of fact of the Administrative Law Judges (ALJ), and that the ALJ's findings shall be binding on all participants in the trial-type hearing. Alternatives may be submitted in response to a Secretary's submission of modified conditions or prescriptions. S. 1236 does not include a provision specifically allowing a party to request a trial type hearing on modified conditions or prescriptions, but there is no provision prohibiting it. Also, new Section 36 provides that after considering the modified condition/prescription and any alternative to the modified condition, the Commission shall include the modified condition, unless it determines that the alternative provides for the adequate protection and utilization of the reservation.

- Requiring the use of the same studies and data for both federal and state environmental analyses, including defining a disciplined schedule for all agencies and stakeholders to adhere to and empowering FERC to consider late filed conditions FPA 10(a) recommendations.

  S. 1236 accomplishes these recommendations by adding new FPA section 34 (a) (1), (2) and (3), which states FERC shall conduct an investigation into best practices, compile a comprehensive collection of studies and data accessible to the public and to the maximum extent practicable use existing studies and data to ensure such studies and data are not duplicated. Also, new FPA Sections 35 (c) (1) (2) and (3) establish timing for issuance of federal authorizations, that FERC shall issue a schedule for all such authorizations and that if a Federal authorization is not issued by the applicable deadline any subsequent submission shall be treated as a FPA 10(a) recommendation.

- Empowering FERC to be in a position of disallowing proposed license conditions if they do not have a clear nexus with the project being licensed or an effect on federal reserved land.

  S. 1236 accomplishes this by amending FPA section 4e to state that the mandatory conditions must pertain to "reservation land on which project works are located, have a clear and direct nexus to the project being licensed, as determined by the Commission." Also, FPA section 18 is amended to state fishways must be "necessary to mitigate effects of the project on fish populations" and "have a clear and direct nexus to the presence or operations of the project being licensed."

PG&E believes these common sense and much-needed improvements to the hydropower licensing process can be accomplished in a responsible and balanced manner that protects and preserves our fisheries and other natural resources, as well as the collaborative process in place today.

At the same time, such enhancements would bring consistency, predictability, and lower costs for projects that support the safe and reliable delivery of domestic hydroelectric power – benefiting utility customers, the environment, American jobs, energy infrastructure, and the power grid. For example, a license renewal typically results in enhanced habitat and species protections, more access to recreational areas and updated water resources measures. These are improvements that all stakeholders want, but unfortunately they often take too long to put in place. We believe a more timely process will not jeopardize the implementation of these benefits, but instead ensure that they happen sooner and at lower cost to energy consumers.

PG&E looks forward to continuing our efforts – and working with Congress to further address these important issues – as we strive to operate the safest and most reliable hydroelectric system in the nation.

Again, PG&E appreciates the opportunity to participate in today's hearing. We applaud the introduction of S. 1236, an important measure to help further realize the growth potential of the U.S. hydropower industry and its related benefits on our communities, the environment and generation systems.

PG&E stands ready to work with the Committee on Energy and Natural Resources, and other members of the U.S. Senate and U.S. House Representatives on finding reasonable opportunities to advance hydropower development, including embracing realistic reforms – such as those included in S. 1236 – to reshape and modernize the licensing process.

Thank you for your time and attention.

The CHAIRMAN. Thank you, Mr. Livingston.

Mr. Matzner, welcome.

STATEMENT OF FRANZ MATZNER, DIRECTOR OF THE BEYOND OIL INITIATIVE, NATURAL RESOURCES DEFENSE COUNCIL

Mr. MATZNER. Madam Chair and members of the Committee, thank you for the opportunity to testify today. I would also like to thank the Chair and Ranking Member for conducting such thorough bipartisan outreach ahead of these hearings.

Renewables and energy efficiency are the best long term solution to almost any energy resource question you can ask. Clean energy creates domestic jobs that can't be exported. It produces domestic energy that never runs out. It insulates consumers from the international price volatility that plagues other resources. It's the source of real national security. It promises to lower consumer costs and keep America internationally competitive. It requires less water usage and reduces toxic air emissions.

Clean energy cuts the carbon pollution that is driving dangerous climate change, the greatest environmental challenge of our time.

According to the overwhelming scientific consensus the U.S. must reduce emissions at least 80 percent by 2050 to avoid the worst impacts of climate disruption. Fortunately there is ample evidence that this is achievable if the proper choices are made. Clean energy from solar to wind to energy efficiency represents an abundant resource.

We're already using less energy today per capita than a decade ago. According to ACEEE, an expert efficiency group, even greater savings are possible, as much as 40 percent by 2050.

In 2012 the Energy Information Administration predicted we'd have three gigawatts of solar power in 2030. Three years later we already have more than three times that.

The story for wind is similar, doubling its capacity between 2008 and 2014, and the potential is enormous. Just one quarter of our nation's offshore energy potential would match our nation's entire existing fossil fuel based electricity generating capacity.

We've also turned a corner on gasoline use, reversing many decades of rising consumption, and policies already in place will further that trend.

This rapid expansion of clean energy is already providing more than 3.4 million American jobs, with more to come.

Policy proposals should be evaluated on whether they will accelerate this trajectory of success. Those that reverse course should be rejected. A good example of the kind of legislation needed to move forward is S. 1264, to establish a Federal renewable energy standard, a strong RES with significantly advanced renewable energy and cut pollution.

States that have embraced renewable energy standards have routinely met or exceeded the targets while growing jobs and reducing harmful pollution. A 30 by 30 target would secure America's place as a global leader in clean energy while reducing carbon pollution by 11 percent below business as usual levels in 2030.

On the opposite side of the ledger, opening new areas of our nation's Arctic and Atlantic coast to oil and gas drilling should be taken off the table for two primary reasons. First, new offshore drilling contradicts the international scientific consensus that the vast majority of known fossil fuel reserves must remain undeveloped, let along new reserves like the Atlantic and Arctic Oceans. Second, the risk of major oil spills is high and the impacts would be severe. In the Arctic alone the Department of Interior's own assessment finds a 75 percent chance of a major oil spill just from the existing Chukchi lease.

In the Atlantic drilling threatens coastal communities and economies up and down the eastern seaboard. Tourism and recreation are major contributors to the Atlantic Coast economy and they rely on healthy oceans. Communities in these regions should not have to risk their way of life or their economic health due to reckless offshore drilling.

The road map exists to craft meaningful energy legislation that will create jobs by cutting pollution and help create a safer, healthier, more stable future for all Americans. We urge that this road map be followed.

Thank you very much for the opportunity to speak. And I'm prepared to answer any questions the Committee might have.

[The prepared statement of Mr. Matzner follows:]

Testimony of

Franz A. Matzner

Director, Beyond Oil Initiative

Natural Resources Defense Council

U.S. Senate

Committee on Energy and Natural Resources

Full Committee Hearing on

"Energy Supply Legislation"

May 19th, 2015

Chairwoman Murkowski, Ranking Member Cantwell, and Members of the Committee: on behalf of NRDC's more than 1.5 million members and activists I want to thank you for the opportunity to testify today. Today's hearing considers a topic of vital importance to our nation and presents the committee with some clear choices. Some bills would accelerate our shift to a clean energy economy, combatting climate change, protecting health and our natural heritage, and create jobs. Others would aggravate climate change and the human and economic costs that come with it, and threaten our environment and public health.

In this testimony, I will focus on the proposed Renewable Energy Standard (S.1264) and the suite of proposed offshore oil and gas drilling legislation as examples of the clear choice facing this committee, Congress at large, and the nation.

The Climate Imperative

Climate change is the greatest environmental challenge of our time. On our current trajectory, we are creating for ourselves – and even more so for coming generations – a future of extreme and catastrophic risks from a dangerously disrupted climate. We must protect them from the worst impacts of climate disruption, and that means starting to cut carbon pollution now.

America has the world's best climate scientists. And America's climate scientists are sounding the alarm, as evidenced by the short, 8-page summary of scientific consensus published by the American Association for the Advancement of Sciences, called *What We Know: The Reality, Risks, and Response to Climate Change.*[1] The summary states:

The science linking human activities to climate change is analogous to the science linking smoking to lung and cardiovascular diseases. Physicians, cardiovascular scientists, public health experts, and others all agree smoking causes cancer. And this consensus among the health community has convinced most Americans that the health risks from smoking are real. A similar consensus now exists among climate scientists, a consensus that maintains that climate change is happening and that human activity is the cause. The National Academy of Sciences, for example, says that "the Earth system is warming and that much of this warming is very likely due to human activities."

This committee has the opportunity, on a bi-partisan basis, to heed these warnings before it is too late. Here is what the vast majority of climate scientists – 97 percent of those scientists – are telling us. They are telling us that the build-up of carbon pollution is having a wide range of dangerous consequences.

More heat in the atmosphere worsens other kinds of air pollution and leads to higher levels of natural allergens. Together, greater pollution and allergens triggers more asthma attacks and respiratory disease. And as the climate changes, disease-carrying insects and pests move into new territories, spreading illnesses to new populations.

More heat in the atmosphere contributes to more frequent, destructive, costly, and deadly storms and other extreme weather events. It also means deeper and longer droughts, like the one now afflicting California, with huge tolls on agriculture, and mortal threats to the water supplies that are the lifeblood of many of our western and southwestern states.

More heat in the atmosphere causes the seas to expand and ice to melt, raising sea levels on coastlines around the world. It is no exaggeration to say that the fate of Miami, or Virginia Beach, or New York or Boston, depends on the fate of the Greenland ice sheet. For all of human history, Greenland has safely stored enough ice on land to raise the level of all the world's oceans by 10 feet or more. And Greenland is melting at an unprecedented rate, releasing that meltwater back into the oceans.

And climate change is a national security issue. The AAAS paper *"What We Know"* cites Defense Department and National Academy of Sciences studies.

For example: "Climate change could have significant geopolitical impacts around the world, contributing to poverty, environmental degradation, and the further weakening of fragile governments. Climate change will contribute to food and water scarcity, will increase the spread of disease, and may spur or exacerbate mass migration."45 In the context of other global dynamics that give rise to political instability and societal tensions, changes in climate are considered as potential threat multipliers or instability accelerants, according to the CNA Military Advisory Board—a panel of our nation's highest-ranking retired military leaders.46 Further, national security assets are often global first responders to humanitarian needs associated with natural disasters including typhoons, hurricanes, and flooding.

The AAAS paper cites one chilling example in particular: "There is a growing recognition that

the displacement of large numbers of people because of water scarcity and agricultural failure, as in the recent history of Syria, can exacerbate tensions that lead to civil unrest."[2]
We are already living with tangible climate disruption and its consequences. It will only get worse and worse, unless action is taken.

According to the overwhelming scientific consensus that means the world must reduce total emissions by at least 80 percent by 2050 to avoid inflicting these impacts on future generations.[3]

These reductions are achievable—if the proper choices are made. And as the single largest historical emitter, the United States has both the responsibility and the opportunity to continue leading the fight against global warming.

Under President Obama's leadership, the United States has already made significant strides. Fuel efficiency standards have reduced carbon emissions while saving consumers money at the pump. President Obama's proposed Clean Power Plan would reduce carbon emissions 30 percent below 2005 levels by 2030. It is also expected to result in reductions in smog and soot that will prevent 470,000 to 490,000 missed school and work days, 2,700 to 6,600 premature deaths and more than 140,000 asthma attacks in children by 2030.[4]

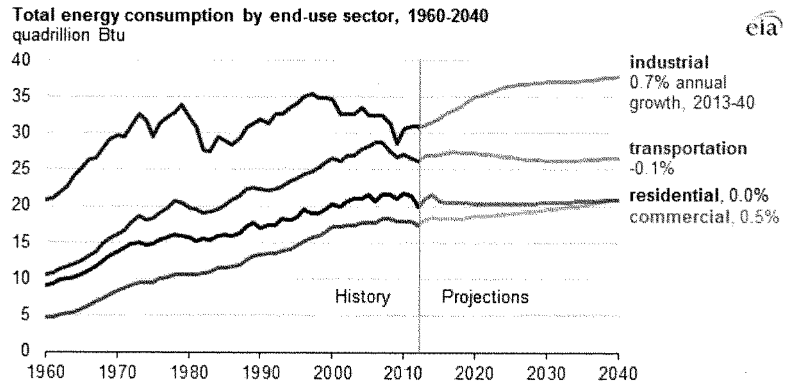
Much more can and must be done to build on this foundation and an essential part of the climate solution will be establishing federal policy that significantly accelerates the deployment of clean energy while making smarter choices regarding the source and extent of fossil fuel extraction.

Clean Energy is an Abundant Resource and Growth is Surpassing Expectations
Clean energy—from solar to wind to energy efficiency—represents an abundant resource, demonstrating a rapid growth and surpassing most expectations. Its potential is enormous.

Energy Efficiency

Energy efficiency is an energy resource capable of yielding energy and demand savings that can displace electricity generation from coal, natural gas, nuclear power, and other supply-side resources. Defining efficiency as a resource and integrating it into regulatory and policy decisions is critical as improving energy efficiency is the cheapest, cleanest and quickest way to meet our energy needs.

Total U.S. energy use peaked in 2007 and has trended downward since. Despite a small 2.8 percent uptick in 2013, total consumption was still below the level recorded a full decade earlier.[5] Any lockstep linkage between economic growth and total energy use ended almost 40 years ago. According to EIA's projections in the Annual Energy Outlook 2015, domestic consumption is expected to grow at a modest 0.3 percent per year through 2040, less than half the rate of population growth.[6]



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2015*

The American Council for an Energy-Efficient Economy estimates that efficiency improvements saved American consumers and businesses roughly $800 billion in 2014 and have also contributed to increased employment and economic growth, reduced energy imports, and a cleaner environment.

Federal programs are succeeding. The Department of Energy's appliance standards program, first authorized by Congress in 1987 and improved through numerous bipartisan bills over the years saved American consumers $58 billion on their utility bills in 2014 and $1.8 trillion on their utility bills through 2030 while cutting 2.3 billion tons of carbon pollution, equivalent to the annual CO2 emissions from nearly 500 million automobiles.[7]

Much greater savings are possible—a 2011 ACEEE report estimates that widespread use of energy efficiency technologies and practices can reduce US forecasted energy use by at least 40 percent by 2050. Studies by organizations such as the National Academies of Sciences (NAS) report that currently available technology has the potential to save 30 percent by 2035 and would save money compared to business-as-usual.[8] This is an extreme conservative estimate, an observation the study itself recognizes and discusses.

The country's energy efficiency resource is vast, and grows continuously as new technologies are developed. However, according to IEA projections to 2035, as much as two-thirds of energy efficiency potential will remain untapped unless policies change. The report also noted the many barriers to investment that necessitate these policies, such as lack of information or financing.[9]

Energy efficiency is one of the fastest growing sectors of the U.S. economy. It creates jobs that require a broad range of homegrown expertise, including for electricians, heating/air conditioning installers, carpenters, construction equipment operators, roofers, insulation workers, industrial truck drivers, construction managers, and building inspectors. Many of these jobs cannot be exported and represent an important and dynamic driver of new economic opportunities.

Making improvements that increase building efficiency is an even bigger job creator. Between 2009 and 2020, the consulting firm McKinsey found that energy efficiency building retrofits could create between 600,000 and 900,000 American jobs. This job growth would be spurred in two ways – from labor-intensive retrofits in the residential and commercial sectors, and from implementation and enforcement of energy efficiency codes and standards.

All this illustrates that energy efficiency represents a major untapped supply to meet our energy demands.

Solar and Wind

The renewable energy industry has experienced explosive progress over the past 6 years. Costs are plummeting, capacity is skyrocketing, and technological advancements are occurring at a rapid pace. In fact, current U.S. utility-scale solar PV capacity has already *surpassed* the Energy Information Agency's AEO 2012 estimates for 2030– by 227 percent[10 11]. Total solar capacity has increased at an astronomical rate from less than 1 GW in 2008 to over 20 GW in 2014. Since 2009, the cost of electricity from utility-scale solar PV projects has declined by nearly 80 percent.[12] Meanwhile, a new Deutsche Bank report predicts that distributed solar power will be cheaper than average retail electricity prices in 36 states by the end of 2016.[13] NREL estimates that the technical resource potential of solar power is enormous,[14] and with costs falling precipitously, there is no reason not to tap into this clean, abundant, and increasingly cost-competitive resource.

Wind's success story is similar, as is its potential. Between 2008 and 2014, installed wind capacity has grown dramatically from about 25 GW to nearly 66 GW.[15] Wind prices have also sharply declined. The capital cost of developing onshore wind has dropped from $2260/kW in 2010 to $1750/kW on average in 2014, and performance improvements have further increased the competitiveness of wind power.[16] NREL has recently announced funding to try to scale turbines up to 140 m (from an average of 80-90 m today), which it estimates would result in an additional 1800 GW, or 237,000 sq. miles, of wind resource potential nationwide, and would significantly expand the geographic diversity of wind resources.[17] Additionally, the resource potential for offshore wind in the United States is vast and adjacent to many metropolitan areas with high electricity demand. The Department of Energy recently found that providing 35 percent of our electricity from wind power (combination of onshore and offshore) is not only technically achievable, but also economically beneficial – creating jobs and lowering pollution at little to no cost to consumers.[18] Further illustrating its potential, just one quarter of our nation's offshore wind potential would match our nation's entire existing fossil fuel-based electricity generating capacity[19].

2014 marked a major milestone as wind and solar energy made up about 55 percent of all new installed capacity in the U.S.[20] This is not an anomaly – many industry analysts predict that wind and solar will become increasingly competitive with new NGCC plants and will make up a major market share of new U.S. demand.[21, 22, 23]

Importantly, recent analyses also show that high penetrations of renewable energy can be integrated into our existing grid at little to no additional costs. Detailed analyses performed on the PJM grid (the nation's largest grid operator), the Eastern Interconnect, and Western Interconnect have all found that renewables can provide up to 30 percent of total generation with only minor adjustments to the existing grid and proper system planning.[24,25,26]

Renewable Energy on Federal Lands

In short order our nation has also witnessed a sea change in the amount of clean energy that has been permitted and sited on our public lands. Starting from scratch in 2009, the nation has now six utility scale solar projects operating on federal lands. These six operational plants along with a number of newly constructed wind and geothermal plants will soon be joined by an additional eight solar projects under construction that will in total produce 4.7 gigawatts of clean energy.[27] And this is just the start. The Department of Interior making significant strides in meeting the goal of permitting 20,000 megawatts of renewable energy on federal land by 2020.[28]

But as our nation strives to meet its clean energy goals, it is imperative that wind, geothermal, and solar development go forth in a manner that safeguards our natural resources, while still allowing the recreation and tourism that sustains local communities. Congress should consider additional measures that will further modernize clean energy development on public lands and provide tools and guidance necessary to meet our growing demand for clean energy in an environmentally responsible and efficient way. But unlike other pieces of legislation being contemplated by the Committee, the permitting and management of renewable energy on federal lands lack the financial mechanisms and assurances that are necessary to address and mitigate the impacts of development to local communities and natural resources. Absent legislative intervention, this imbalance will further undermine the widespread adoption of these promising technologies.[29]

Fuel Efficiency and Clean Vehicles

The U.S. has started to reverse a dangerous, decades-long trend of rising oil consumption and accompanying carbon pollution by the transportation sector. From 1985 to 2005 U.S. oil demand rose approximately 32 percent, driving up greenhouse gas emissions in the sector.

However, cars and trucks are consuming less fuel and belching less pollution in more recent years thanks to clean vehicle and fuel efficiency standards. Since 2005, gasoline consumption has decreased 8 percent and the average efficiency of new U.S. automobiles is up 25 percent.[30] When fully implemented, the federal 54.5 mpg fuel efficiency standards are expected to save 12 billion barrels of oil over the life of vehicles made between 2012 and 2025.[31] We can do more. By continuing to advance efficiency and implement new transportation policies designed to reduce driving and accelerate electric vehicle sales, the U.S. could save nearly 4 billion barrels of oil annually by 2035.[32] Notably, that's almost the same amount of oil, in a single year, as the Interior Department estimates can *ever* be recovered from drilling all our offshore waters from Florida to Maine.[33]

Renewable Energy Standard: A Critical Tool for the Clean Economy

S. 1264 to establish a Renewable Electricity Standard (RES) would put in place key tools in the fight to cut carbon pollution, by transitioning from fossil fuels to clean energy sources like wind, solar, and geothermal energy. The RES will continue to build our clean energy future by setting a national target of 30 percent renewable energy by 2030 (30x30).

The legislation also provides additional support for distributed resources. The RES offers three times the Renewable Energy Certificates (RECs) for electricity generated by distributed resources such as solar photovoltaics (with administrative adjustments over time) and two times the RECs for renewable electricity on tribal lands. Depending on location, clean, distributed renewable resources offer benefits to both the local electric grid and local air quality.

The 30x30 RES will promote clean energy source that cut carbon pollution, further expand our powerful clean energy economy which currently employs hundreds of thousands of American workers, drive innovation, and provide a strong market signal that the future lies in renewable energy developed here in America.

State-level success stories

Renewable portfolio standards have been critical to driving the recent growth of the wind and solar industries. Across the country, 29 states and D.C. have mandatory renewable energy targets in place, providing strong market signals to drive investments in clean energy. Seven more have non-binding goals. Between 1998 and 2013, approximately 68 percent (51 GW) of non-hydro renewable capacity additions have occurred in states with binding renewable portfolio standards.[34] A recent analysis by the Lawrence-Berkeley National Laboratory (LBNL) found that many states are on track to successfully meet their *2035 requirements* within the next few years.[35]

State-level renewable energy standards have been found to generate a wide range of benefits, including emissions and human health benefits, wholesale price suppression, and job creation, while the cost impacts have been minimal (1-1.5 percent of retail rates).[36] In fact, a recent analysis from DBL Investors found that there is no correlation between increased renewable energy penetration and retail electricity prices, with many of the leading clean energy states experiencing lower electricity price increases than the rest of the country over the past decade.[37]

Michigan is a prime example of a state that is beginning to seize the economic opportunities and benefits of a clean energy economy. The state's Renewable Portfolio Standard has spurred more than $2.3 billion in new investments and created new clean energy jobs since its enactment.[38] Michigan ranked seventh among the states for wind-related jobs in 2014, employing between 2,000 and 3,000 permanent workers.[39] A poll of 600 Michiganders in December 2014 found that 75 percent support *tripling* the renewable energy target from 10 percent in 2015 to 30 percent by 2035.[40]

Colorado also has very strong renewable energy potential and state policies have helped to begin to capitalize on this potential. Colorado was the first state to pass a voter-approved Renewable Portfolio Standard (RPS). After recent amendments, the RPS is now set at 30 percent for investor-owned utilities and 20 percent for electric cooperatives by 2020 – the second highest standard in the nation.[41] The RPS has already helped create 10,000 jobs – including between 6,000 and 7,000 wind jobs at 22 manufacturing plants, 29 operating wind farms, and many other companies up and down the sprawling supply chain and it's brought in millions from lease and property tax payments for rural communities.[42, 43]

Montana is yet another state with outstanding renewable energy potential – it is ranked 3rd in the nation for wind potential, 2nd for geothermal potential, and 15th for solar potential.[44] Montana has taken steps to tap into this large potential, establishing a Renewable Portfolio Standard of 15 percent by 2015, which has already been met.[45] So far, 650 MW of wind has been installed in Montana – enough to power about 200,000 homes – bringing with it $1.6 billion in new investment, 1,500 high-paying construction jobs, and over 100 permanent jobs in rural communities. In addition, the leases for these wind turbines bring in property tax payments of $2 million annually.[46]

Similar success stories can be found all across the country, as 29 states and D.C. have shown leadership in promoting clean, zero-carbon energy, while bringing significant economic benefits into their states.

The Federal 30x30 RES

Implementing a federal renewable electricity standard would expand on the success of state-level policies across the country and ensure that our entire nation reaps the benefits of a clean energy economy. A strong federal RES would also secure America's place as a global leader in clean energy, providing policy certainty and a transparent market signal to drive investment in American companies and manufacturers.

Recent analysis from the Union of Concerned Scientists demonstrates the significant benefits of a federal RES. Specifically, the analysis found that renewable energy generation would increase 265 percent over today's levels, driving $294 billion in cumulative new capital investments in the United States. By increasing the amount of clean, zero-carbon energy in our electricity mix, the electricity sector CO_2 emissions would decrease 10.8 percent below business-as-usual levels in 2030.[47]

And consistent with the experience of 29 states and D.C., all of this could be accomplished with little impact on electricity prices compared to business-as-usual – the UCS analysis found that the maximum national average incremental increase in electricity prices in any given year would be only 0.2 percent. Combined with lower fuel prices as a result of less reliance on natural gas, UCS found that consumers would actually *save* $25.1 billion (0.5 percent) in cumulative electricity and natural gas bills between 2015 and 2030, as a result of the RES.[48]

Importantly, to fully capture these benefits any final RES legislation must recognize the importance of ensuring that the nation invests in truly low-carbon alternatives, by requiring that all biomass is responsibly sourced and meets greenhouse gas emissions standards as determined by the best available science.

Offshore Drilling: Dirty, Dangerous, Unnecessary

Proposals to incentivize and expand offshore oil and gas exploration have no place in any final energy legislation. More offshore drilling is dirty, dangerous, and unnecessary. It will keep our nation tethered to the fossil fuels of the past and threaten the health and economies of our coastal communities. These offshore areas are owned by the public and should not be developed at the behest of the fossil fuel industry in detriment to this and future generation's health and economic well-being.

S. 1276 would open additional areas in the Gulf of Mexico to drilling, bring offshore drilling closer to the Florida coastline, include Florida as a Gulf producing state and mandate three lease sales (in 2018, 2019 and 2020). It also would increase revenue sharing caps for several states, creating additional incentives for states to drill off of their coasts, introducing more risk to their coastal economies and quality of life. It is important to note the proposed legislation would also undermine multiple bedrock environmental laws such as the National Environmental Policy Act (NEPA) and the Marine Mammal Protection Act (MMPA). It severely undercuts NEPA and would force the National Marine Fisheries Service to meet unrealistic deadlines when reviewing applications to harm marine mammals under the MMPA, threatening its ability to provide fundamental protections to marine mammals.

S. 1278 would mandate oil and gas development in some of the most pristine and ecologically vibrant portions of the Arctic Ocean. It would also establish a revenue distribution scheme diverting funds from the Federal Treasury to various other sources.

S. 1279 would open up the Atlantic coast to drilling (from Virginia through Georgia) for the first time since 1983, mandate a minimum number of lease sales, and establish a revenue distribution scheme which would divert funds from the Federal treasury while creating perverse incentives for states to drill of their coasts. In addition, it will exacerbate climate change, threatening coastal communities and their economies which rely heavily on tourism, fishing and recreational industries.

Below are 7 reasons all of these proposals should be rejected:

Contradict Climate Science: New offshore drilling contradicts the international scientific consensus that in order to avoid the worst impacts of climate change, the vast majority of known fossil fuel reserves must remain undeveloped.[49] Let alone the oil and gas in the Atlantic and Arctic oceans. Illustrating this point, a study in the premier scientific journal, *Nature,* specifically found developing Arctic Ocean oil and gas incompatible with efforts to stay within our global carbon budget[50].

Further, oil industry claims that Arctic oil may be needed 30 years from now assume continued oil-dependence scenarios that the International Energy Agency says will result in an average global temperature increase of at least 6 degrees Celsius—three times what science state the planet can sustain.[51] To avoid increased rates of asthma attacks and respiratory disease, degraded air quality, and more frequent, costly, and deadly extreme weather events we must protect--not drill--the Arctic and Atlantic coasts.

Risk Devastating Oil Spills: The risk of major oil spills is high and the impacts severe. In the Arctic, the Department of Interior's own assessment finds a 75 percent chance of a major oil spill should drilling under existing leases in the Chukchi Sea proceed[52]. And in the likely event of a spill, none of the three primary oil spill response methods - mechanical containment and recovery, *in situ* burning, or dispersants - have been proven effective in harsh Arctic conditions. In fact, in even far less challenging environments, less than 10 percent of the spilled oil has actually been recovered.

Almost no infrastructure exists in the Arctic to support emergency response. There is no backup in the American Arctic when systems fail. The nearest source of additional clean-up equipment is 2,000 miles away in Seattle. There are no major ports or landing strips near the lease sites, and bringing rescue crews and equipment to the Arctic would be a staggering challenge.
If you knew there was a 75 percent chance risk that someday you'd have a devastating accident

that neither you nor first responders were equipped to deal with, wouldn't you start looking hard at alternatives?

A major oil spill off our Atlantic coast would also be devastating. The BP Gulf oil disaster impacted over 1,000 miles of coastline – an equivalent disaster in the Atlantic could coat beaches stretching from Savannah to Boston. A spill off Virginia's coast could threaten the Jersey Shore. From Miami Beach to Hilton Head to the Chesapeake Bay, many of America's most beloved beaches would all be vulnerable to the catastrophic effects of an oil spill.

Reflect No Revisions of Safety Laws: The BP Deepwater Horizon disaster demonstrated that spill impacts are both environmentally - and economically - devastating. The oil spill contaminated more than 1,100 miles of coastline, at least 1,200 square miles of the deep ocean floor, and 68,000 square miles of surface water. The Gulf of Mexico commercial fishing industry was estimated to have lost $247 million as a result of post spill fishery closures. One study projects that the overall impact of lost or degraded commercial, recreational, and mariculture fisheries in the Gulf could be $8.7 billion by 2020, with a potential loss of 22,000 jobs over the same timeframe. Following that spill, President Obama established the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. The Commission found that "the central lesson to be drawn from the catastrophe is that no less than an overhauling of both current industry practices and government oversight is now required."[53] Yet there have been no major revisions to the law to increase safety since that disaster, throwing into severe doubt any claim that expanded drilling is "safe".

Threaten Costal Communities, Economies, and Wildlife: Drilling off the Atlantic coast has been off the table since 1983. Tourism and recreation are major contributors to the Atlantic coast's economy and they rely on healthy oceans. In 2012, those two sectors alone generated $40 billion in the Mid- and South-Atlantic regions[54]. Communities in these regions should not have to risk their way of life - or their economic health - due to reckless offshore drilling.

The Atlantic region is home to extensive and diverse fish and shellfish populations. In 2012, the Mid-Atlantic and South Atlantic seafood industry supported over 244,000 jobs; fisherman landed over 850 million pounds of fish and earned more than $650 million for their catch. Ocean tourism and recreational industries supported 76 percent of all Mid-Atlantic and 84 percent of all Southeast Atlantic ocean sector jobs in 2012. These regions host important and sensitive marine species, including endangered whales. Opening the Mid and South Atlantic would sacrifice economies, coastlines and fragile marine and coastal environments.

While the Arctic is sparsely inhabited, a major spill there would be no less disastrous. Some of the most productive marine ecosystems on Earth are found in Alaska's Arctic waters.[55] They are also among the most pristine.[56] The waters of the Beaufort and Chukchi Seas are home to one-fifth of the world's polar bears, as well as ice seals, millions of migratory birds from virtually all continents, bowhead and gray whales, belugas, walrus, and much other marine life.[57, 58] Among the many species they support are numerous threatened or endangered species and both seas have numerous areas of heightened ecological significance.[59, 60] An oil spill in the Arctic Ocean would decimate this rich ecosystem and the unique way of life it supports. Impacts would savage the Arctic's vulnerable food chain. Seals and seabirds would be coated in oil. Blowholes of endangered whales would clog. And pristine beaches - potentially including the Arctic National Wildlife Refuge - would be fouled. Poisoning the seabed on which all marine life in the Arctic depends - particularly if dispersants that spread a toxic oil-dispersant cocktail throughout the water column are used – would threaten one of the most unique, pristine places on the entire planet. Cascading consequences would extend to human residents as well because "biodiversity and the natural environment remain integral to well-being of Arctic peoples, providing not only food but the everyday context and basis for social identity, cultural survival and spiritual life."[61] These foods also lower the risk of metabolic diseases in Alaska Natives.[62]

Embrace the Folly of Revenue Sharing: The proposed offshore drilling legislation under consideration today creates perverse financial incentives that exacerbate the above risks by directly incentivizing increased drilling, in some cases even sending funds directly to states or coastal areas that pursue drilling closer to shore. Moreover, these schemes are often justified by arguing the funds are needed to mitigate the impacts of drilling, which some proponents argue don't exist in the same breath. We should not be incentivizing coastal states and local governments to allow increased and more environmentally damaging drilling. Encouraging additional risky drilling invites disasters for our beaches, coastal economies and marine life. Offshore ocean areas beyond state waters are owned by all of the people of the United States, which was confirmed by the Supreme Court in 1947.[63] As we saw with the BP oil disaster, offshore drilling can create extensive environmental and economic devastation that requires quick response. The federal government was responsible for addressing the BP disaster precisely because it occurred in federal waters. Revenue collected from federal waters funds federal departments and agencies that deal with such disasters when they occur. It would have been impossible for Louisiana to deal with the BP spill on its own - even if it had received additional funds from drilling. Incentivizing more drilling while simultaneously diluting the ability to respond to the inevitable spills is doubly irresponsible. The proposed revenue sharing schemes encourage drilling with less of a safety net, provide fewer resources from the federal government in the event of a disaster, and provide sweeteners that keep states and nation hooked on dirty energy.

Unnecessary for Energy Security: As the above sections summarized, the clean energy economy is booming. Even if Arctic and Atlantic offshore oil and gas were made immediately available, there is no current demand due to a global oil glut. In the midterm, its development is countermanded by the explosive growth in clean energy and effective fuel efficiency and clean vehicle policies. And over the long term, the only possible justification for exposing these unique ocean environments and vibrant coastal economies to the risk of devastating oil spills is to assume a total failure in addressing climate change. A responsible coastal plan would preserve the Arctic as our last pristine ocean and focus any Atlantic development on unlocking the vast potential of offshore wind, providing sustainable, clean energy that does not threaten the integrity of existing business or the health of our communities.

Overlooks Widespread Opposition: Across the country the public has expressed its opposition to increased offshore drilling, preferring clean solutions over more dangerous, dirty, and unnecessary drilling. According to a running tally maintained by Oceana, more than 500 national, state and local elected officials have taken a public stance against offshore oil exploration and/or development, including more than 50 coastal towns, cities and counties that passed resolutions opposing or voicing concern.[64] The environmental community, which collectively represents millions of members, provided more than 550,000 comments via email and petition drives. These comments were delivered electronically and in person on March 30th to a BOEM representative. Finally, a 5-state poll (including Fl and VA) conducted by American Viewpoint and Hart Research Associates found that the public prefers federal investment in clean energy over dirty energy proposals like offshore drilling by an almost 2-1 margin.[65]

Conclusion

There is an abundant supply of domestic clean energy that is already improving our nation's health and economy. Clean energy's remarkable growth in just the last decade has far surpassed what many estimated was achievable decades from now. Smart policies like federal fuel efficiency standards, tax incentives, and state-level Renewable Electricity Standards were integral to this explosive innovation and deployment. There remains an enormous potential to do much more. The choice before this committee, the Congress, and the nation is whether to put in place the policies that will further unlock this bountiful supply and harvest the economic and health benefits that flow from it, or remain tethered to the dirty fossil fuels of the past. For the sake of our climate, economy, and long-term security, the choice is obvious.

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[63] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling Final Report, p. 58." http://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf

[64] Oceana's tally available at: http://usa.oceana.org/seismic-airgun-testing/grassroots-opposition-atlantic-drilling

[65] Views on Environmental Regulations, *Key findings from five statewide surveys conducted December 2014 for the Natural Resources Defense Council by American Viewpoint and Hart Research Associates, available at http://docs.nrdc.org/legislation/files/leg_15012201a.pdf*

The CHAIRMAN. Thank you, Mr. Matzner.

Mr. Milito, welcome.

STATEMENT OF ERIK MILITO, GROUP DIRECTOR, UPSTREAM AND INDUSTRY OPERATIONS, AMERICAN PETROLEUM INSTITUTE

Mr. MILITO. Morning, Chairman Murkowski, members of the Committee, I'm Erik Milito, Upstream Director at the American Petroleum Institute. Thank you for the opportunity to testify on the importance of energy supply to our nation's economy and our energy future.

We are pleased to see the Committee moving forward with a robust debate to move the country toward a comprehensive energy strategy. We, as a nation, truly need a comprehensive approach to energy shaped by reason, common sense and experience. As the Committee considers and debates the pillars of infrastructure, supply, efficiency and accountability, the U.S. is well positioned to lead the world in the production of all energy sources and particularly in the production of oil and natural gas.

As both the U.S. and global economies grow, the U.S. with its abundant supplies can effectively provide economic and energy stability to domestic and global markets through continued and expanded development of oil and natural gas. To successfully pursue this path, we must plan for the future. And the most sensible approach is to pursue safe and responsible energy development here at home.

Given the expected global economic and population growth, more total energy will be needed both in the U.S. and globally in the decades to come. The Energy Information Administration forecasts that U.S. energy demand will grow by nine percent between 2013 and 2040 with more than 60 percent of the energy demand expected to be met by oil and natural gas as is the case today. Fundamentally the facts in our energy reality demonstrate that our economy will rely on oil and natural gas for decades to come.

Globally the change in energy demand is much greater, and when it comes to liquid petroleum products the U.S. competes on a global basis for these resources. Recent forecasts by the EIA estimate that growth in the global economy from 2014 to 2040 will require additional oil production of about 28 million barrels per day. That is an increase roughly equivalent to the current consumption of the U.S., Canada, Mexico and Japan, combined.

Despite significant and much needed growth of renewable energy and improvements in energy efficiency, more than half the world's energy demand will be met in 2040 by oil and natural gas. Again, as is the case today.

Government policy plays a substantial role in the ability of the U.S. to tap its own supplies and help meet the projected growth in U.S. and global demand. The dramatic increase that we have seen in oil and natural gas production is occurring today on state and private lands. Production of oil and natural gas, when taken together, has decreased in areas under Federal control. The lack of growth and production on Federal lands is a result of policies that have effectively discouraged investment in those areas or simply taken opportunities for investment off the table.

Fortunately three of the supply bills that are being discussed today will effectively move us past these self-imposed energy prohibitions. Senate Bills 1276, 1278 and 1279 would open highly promising areas in Alaska, the Gulf of Mexico and the Atlantic Outer Continental Shelf to energy exploration and production. It is these types of legislative proposals that acknowledge that we will need oil and natural gas for decades to come and recognize our strong capacity to safely and responsibly produce those resources here at home.

These bills embrace a long term, comprehensive approach to energy policy because steps like these will help ensure we have got the necessary energy for our citizens, five, ten, fifteen and more than twenty years down the road. To be sure, the offshore energy that we produce today is available because of smart policy decisions made ten to fifteen years ago.

Over the past 6 years we have seen increasing U.S. oil and natural gas production drive economic growth, global energy security and ensure affordable energy supplies. Moving forward we will need all the energy sources to meet our growing demand—solar, wind, air, nuclear, hydro, coal, but also oil and natural gas. Oil and gas development and the oil and natural gas supply chain are expected to create 1.3 million job openings over the next 15 years.

We now need smart policy decisions today to secure these job opportunities and to secure our path to energy security for the decades ahead. This hearing and many of the proposed bills are constructive steps forward.

Thank you. I look forward to your questions.

[The prepared statement of Mr. Milito follows:]

Testimony
Senate Committee on Energy and Natural Resources
Energy Supply Bill Hearing

Erik Milito
Group Director, Upstream and Industry Operations, API
May 19, 2015

Good morning Chairman Murkowski, Ranking Member Cantwell and members of the committee. I am Erik Milito, Upstream Director at the American Petroleum Institute.

API has more than 625 member companies and represents all sectors of America's oil and natural gas industry. Our industry supports 9.8 million American jobs and 8.0 percent of the U.S. economy. It also provides most of the energy we need to power our economy and way of life and delivers tens of millions of dollars a day in revenue to the federal government. On the upstream side of the industry, we have successfully developed and advanced technologies to allow us to safely and responsibly explore for and produce the oil, natural gas, and natural gas liquids that are vital to every aspect of our economy. In fact, because of American ingenuity and engineering prowess, the U.S. is now firmly established as a global energy superpower.

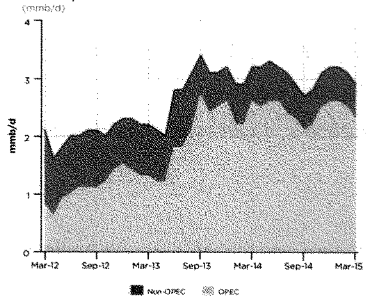
We are pleased to see the Senate Energy and Natural Resources Committee moving forward with a robust debate to move the country toward a comprehensive energy strategy. We as a nation truly need a comprehensive approach to energy shaped by reason, commonsense and experience – an approach based on competition in the marketplace and state-of-the-art technology. As the committee considers and debates the pillars of infrastructure, supply, efficiency, and accountability, the U.S. is well-positioned to lead the world in the production of all energy sources, and particularly in the production of oil and natural gas. As both the U.S. and global economies grow, the U.S. – with its abundant supplies – can effectively provide economic and energy stability to domestic and global markets through continued and expanded development of oil and natural gas.

Our nation can and should be producing more of the oil and natural gas Americans need here at home. This would strengthen our energy security and help put downward pressure on prices while also providing many thousands of new jobs for Americans and billions of dollars in additional revenue for our government. According to the Energy Information Administration (EIA), we produced about 5 million barrels of oil a day in 2008, and we are now producing more than 9 million barrels per day. Simultaneously, we are reducing the amount of oil that we import. But we can and should do more.

As we have seen throughout this current energy renaissance, increased production of U.S. oil and natural gas drives many benefits for the country, including billions of dollars in capital investments, creation of thousands upon thousands of well-paying jobs, continued improvement in our balance of trade, and increased energy security for the U.S. and our allies abroad. Unplanned supply disruptions in the global crude oil market have grown in recent years, peaking at 3.3 million barrels a day in September 2013 and again in May 2014. According to the Energy Information Administration, this is the highest level of supply disruption since the Iraq-Kuwait War (1990-91), when prices spiked to new highs. By April 2015, the amount taken off the market had fallen to 3 million barrels per day.

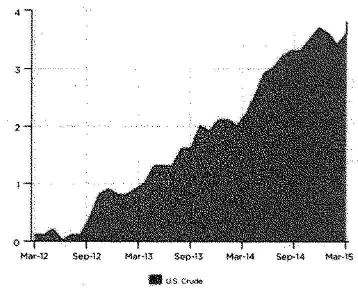
U.S. production growth has made all the difference. It has largely offset the loss from unplanned production outages around the world and put downward pressure on prices to the great benefit of American consumers and businesses. See the graphs below for more information on this key, positive impact of U.S. energy production.

Growth in Global Oil Supply Disruptions
(mmb/d)



Source: EIA.

Growth in U.S. Oil Production*
(mmb/d)



Source: EIA.
*Includes hydrocarbon gas liquids, biofuels, and refinery processing gains.

Fundamentals of economics are quite evident in oil and gas markets, with growing U.S. supplies putting downward pressure on the price of oil and natural gas. The Henry Hub price of natural gas has remained at $6.00 per mmBtu or less since December 2008, with most months since then with an average price in the $2 to $4 range. Abundant supplies of natural gas in the U.S. and the ability of U.S. producers to efficiently produce these resources has led the EIA and other analysts to predict that natural gas prices will remain relatively low for many years. The low price of natural gas led IHS to conclude that the average household had $1,200 additional disposable income in 2012, expected to increase to $3,500 in 2025.

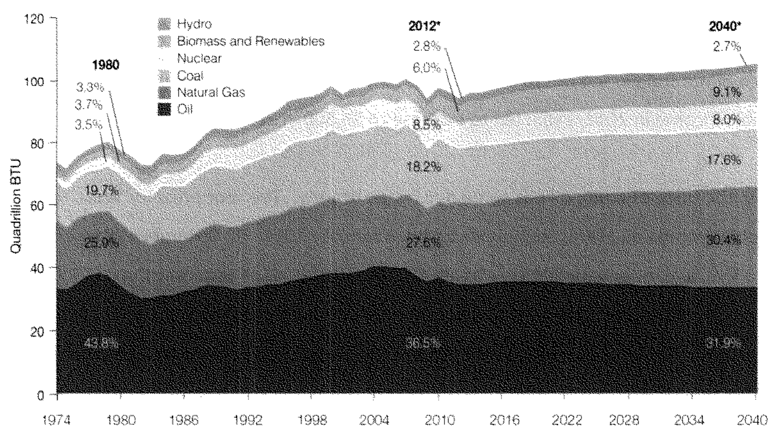
Similarly, the price of crude oil has come down significantly. The spot price for West Texas Intermediate crude oil averaged $95 per barrel in January 2014. By December 2014 it was down to $59, and in January 2015 it was at $47. According to The Economist in its "Sheikhs vs. Shale" article: "Cheaper oil should act like a shot of adrenaline to global growth.... A typical American motorist, who spent $3,000 in 2013 at the pumps, might be $800 a year better off – equivalent to a 2% pay rise." Affordable energy helps drive the economy, and affordability comes with increased access to U.S. oil and natural gas supplies.

The U.S. energy boom has also been a catalyst to resurgent manufacturing and petrochemical sectors, which rely on low cost energy to fuel operations and on natural gas and natural gas liquids as feedstock for production. For example, the American Chemistry Council (ACC) identified 225 chemical industry investment projects valued at $138 billion that have been announced as of March 2015. According to ACC, during peak investment years, these projects could support 383,000 jobs, $266 billion in new economic output and $19 billion in new tax revenue by 2023.

To maintain these benefits, we must plan for the future, and the most sensible approach is to pursue safe and responsible energy development here at home. Given expected global economic and population growth, more total energy will be needed both in the U.S. and globally. The EIA forecasts that U.S. energy demand will grow by 9 percent between 2013 and 2040, with more than 60 percent of the energy demand expected to be met by oil and natural gas, as is the case today. The graph below provides this data.

Future U.S. Energy Demand

The U.S. will require 12 percent more energy in 2040 than in 2012.

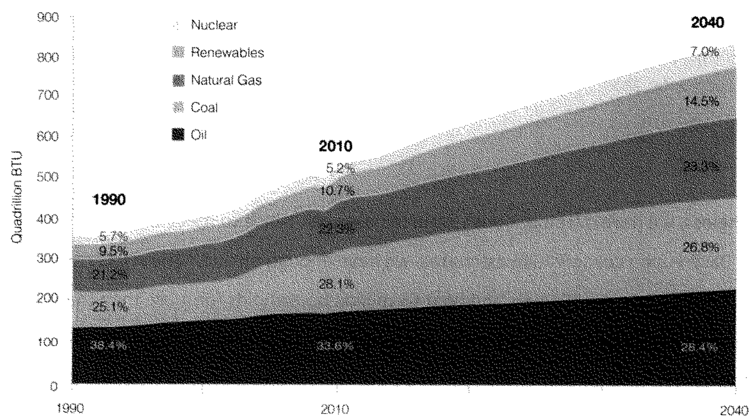


*Excludes non-biogenic municipal waste and net electricity imports. Source: EIA, *Annual Energy Outlook 2014*, Tables A1 and A17.

Globally, the change in energy demand is much greater, and when it comes to liquid petroleum products, the U.S. competes on a global basis for these resources. Recent forecasts by the EIA estimate that sustaining a 3.6 percent annual growth in the global economy from 2014 to 2040 will require an expansion of about 28 million barrels per day in global oil supplies. That is an increase roughly equivalent to the current consumption of the U.S., Canada, Mexico and Japan. The growth in demand for natural gas worldwide is expected to be even larger, increasing by 64 percent from 2010 to 2040. Despite significant growth of renewable energy and improvements in energy efficiency, more than half the world's energy demand will be met in 2040 by oil and natural gas, as is the case today. The graph below provides this data.

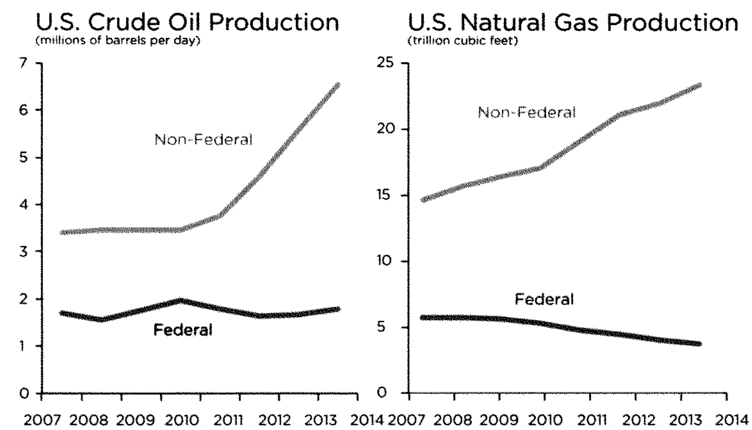
Future Global Energy Demand

The world will require 56 percent more energy in 2040 than in 2010.



Source: EIA, *International Energy Outlook 2013*.

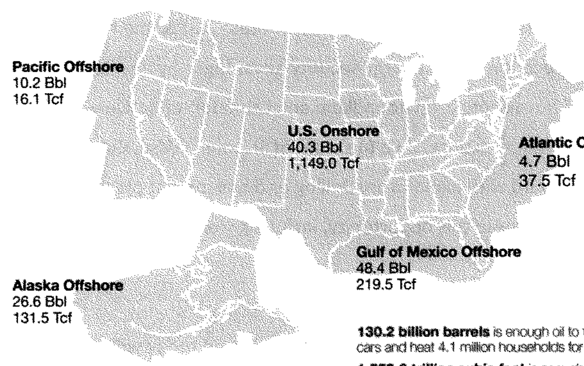
Government policy plays a substantial role in the ability of the U.S. to tap its own supplies and help meet the projected growth in U.S. and global demand. The effect of government policy on energy production is strikingly evident when comparing production on federally controlled lands and production on state and private lands. The dramatic increase that we have seen in oil and natural gas production is occurring on state and private lands. Production of oil and natural gas has decreased in areas under federal control. The lack of growth in production on federal lands is the result of policies that have effectively discouraged investment in those areas. See the graphs below.



Source: CRS, "U.S. Crude Oil and Natural Gas Production in Federal and Non-Federal Areas," April 3, 2015 and February 28, 2013.

Nevertheless, we have a tremendous resource base with which to meet our growing energy needs. Based upon conservative estimates, we have enough oil and natural gas resources to fuel 93.7 million cars for 50 years and heat 66 million households for more than three centuries. And there is very likely much more oil and natural gas than previously known in areas where the industry has been unable to explore, and new technologies allow us to access resources previously thought unreachable. The graphic below demonstrates the geographic diversity and abundance of undiscovered, technically recoverable resources in the country.

U.S. Undiscovered Technically Recoverable Crude Oil and Natural Gas Resources
(billion barrels - Bbl and trillion cubic feet - Tcf)*



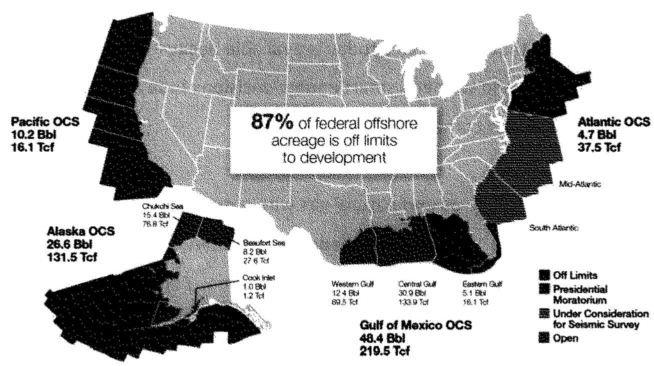
130.2 billion barrels is enough oil to fuel 93.7 million cars and heat 4.1 million households for 50 years.

1,553.6 trillion cubic feet is enough natural gas to heat all 66 million households that use natural gas heating for 314 years.

*Figures may not add exactly to total due to rounding.
Source: U.S. Geological Survey and BOEM.

The U.S. Outer Continental Shelf (OCS) is estimated to contain some of the greatest quantities of undiscovered oil and natural gas resources. Unfortunately, the federal government has placed most of the OCS – approximately 87 percent of it – off-limits to oil and natural gas development.

U.S. Offshore Undiscovered Technically Recoverable Federal Oil and Natural Gas Resources
(billion barrels – Bbl and trillion cubic feet – Tcf)



Source: The Bureau of Ocean Energy Management (BOEM).

The U.S. has kept areas like the Atlantic off-limits while our neighbors continue to move forward in an effort to develop oil and gas off their shores. Just to the North, Canada has secured tremendous economic and energy security advantages by developing oil and natural gas off the coasts of Nova Scotia, Newfoundland and Labrador, effectively reviving seaports that were considered "near-extinct," like the town of St. Johns. Also, Cuba and the Bahamas have both moved forward with exploratory drilling or development planning. And the rest of the Atlantic continues to seize this opportunity, including Norway, the U.K., Venezuela, Brazil and Nigeria.

Fortunately, three of the supply bills that are being discussed today will effectively move us past self-imposed energy prohibitions. S. 1276, S. 1278, and S. 1279 would open highly promising areas in Alaska, the Gulf of Mexico, and the Atlantic OCS to energy exploration and production. Provisions are also included to provide revenue sharing to coastal states, much like the revenue sharing currently provided to those states that see federal onshore production within their borders. It is these types of legislative proposals that acknowledge that we will need oil and natural gas for decades to come and recognize our strong capacity to safely and responsibly produce those resources here at home. These bills embrace a long-term, comprehensive approach to energy policy, because steps like these will help ensure we have the necessary energy for our citizens five, ten, 15 and more than 20 years down the road. To be sure, the offshore energy that we produce today is available because of smart policy decisions made ten to 15 years ago. And we need smart energy decisions today to provide energy stability for the generations to come.

Moreover, the ability to produce oil and natural gas within our own borders reverberates prominently around the globe. The positive geopolitical and national security implications of America's emergence as a global energy superpower are huge. Fundamentally, the more oil and natural gas that the U.S. produces here at home, the less the U.S. and the rest of the world need to buy from unfriendly regimes that often use energy as a political weapon. General

Martin Dempsey, Chairman of the Joint Chiefs of Staff, had this to say during a hearing of the Subcommittee on Defense Appropriations in the U.S. House of Representatives in March 2014:

> An energy independent [U.S.] and net exporter of energy as a nation has the potential to change the security environment around the world – notably in Europe and the Middle East. And so, as we look at our strategies for the future, I think we've got to pay more and particular attention to energy as an instrument of national power. And because it will very soon in the next few years potentially become one of our more prominent tools.i

Our allies in places like Central and Eastern Europe and in Southeast Asia have a significant policy interest in seeing the U.S. produce and export more oil and natural gas. On the oil side, the U.S. is importing far less because of increased domestic production. The trade balance, which can weigh heavily on the economy, has improved and less oil is purchased from foreign nations. On the natural gas side, the fact that the United States is not importing significant quantities of natural gas means that there is substantially more on the global market, giving nations around the world access to a greater diversity of supply from which to choose.

Unfriendly regimes rely upon their own oil and natural gas to fund their governments and militaries and to exercise power over neighboring countries. This is particularly true for much of Eastern Europe, which is almost fully dependent upon Russian natural gas, while the rest of Europe is tied to that market as well. According to a January 10, 2013 editorial in the Wall Street Journal, "in Europe, American LNG exports will be a welcome source of diversification to cut energy dependence on Russia."

With respect to oil, both increased supplies and the decrease in the price resulting from America's energy boom weigh heavily on certain oil producing regimes. According to The Economist's editorial "Many winners, a few bad losers" published on October 25, 2014, "For those governments that have used the windfall revenues from higher prices to run aggressive foreign policies… things could get uncomfortable. The most vulnerable are Venezuela, Iran and Russia." According to The Economist, Iran requires oil prices of $140 per barrel, Venezuela requires $120 per barrel, and Russia too requires high prices to meet government budgets. The U.S. energy revolution has helped to drive prices well below those levels.

The energy renaissance has put the U.S. in a better geopolitical position than few could ever have imagined. Increased U.S. production alone is having a significant impact on the balance of global power. By opening up its borders to the free trade of oil and natural gas, the U.S. could have an even greater impact, and we would be responding directly and positively to the pleas of our allies. Exports of these commodities will not only serve our natural security interests as described by General Dempsey, but they will also allow for greater production of oil and natural gas in the United States, spurring additional spending and job growth throughout the country. However, applications to export LNG linger in government bureaucracy, and crude oil exports are subject to a 1970s era ban that has long outlived any purpose it may have served. It is in the best interests of the nation to make the necessary decisions to expedite exports of both oil and natural gas. Fortunately, we have seen positive movement on the legislative front and leadership from the members of this committee to advance these critical free trade policies. But time is of the essence.

In conclusion, what is needed today are policy choices to increase, not decrease, energy production. Barriers to oil and natural gas production only contribute to volatile energy prices, slower economic growth, and lost American jobs. Our history is replete with short-term energy "fixes" and false promises of "silver bullets" to solve our nation's energy problems. Today, we need to take positive steps to ensure that we will meet America's energy needs in the decades ahead. These policy decisions should include a commitment to the following:

- Increase, not decrease energy production by promoting all sources.
- Encourage energy efficiency.
- Encourage investment in advanced energy technologies and long-term energy initiatives.

- Allow market forces to allocate products and adjust to changing conditions.
- Refrain from new taxes that make it more expensive to develop domestic supplies.
- Support participation in global energy markets.

Over the past 6 years, we have seen increasing U.S. oil and natural gas production drive economic growth and global energy security. We now need policy decisions to secure this path for the decades ahead. This hearing and many of the proposed bills are constructive steps forward.

Thank you again to the Chairman and to the Committee, and I look forward to your questions.

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[i]*See Wall Street Journal*, A Gas Export Strategy, March 19, 2014.

The CHAIRMAN. Thank you.
And let's finally go to Mr. Sheets, welcome.

STATEMENT OF BRENT SHEETS, DEPUTY DIRECTOR, ALASKA CENTER FOR ENERGY AND POWER, UNIVERSITY OF ALASKA FAIRBANKS

Mr. SHEETS. Thank you, Chairman Murkowski and the other members of the Committee for having me.

My name is Brent Sheets, and I'm the Deputy Director for the Alaska Center for Energy and Power. We've submitted our written testimony, and in there is a description of what we do.

For many Americans, Alaska is the crown jewel of the nation's wilderness resources, but it's also the crown jewel of America's energy resources both renewable and non-renewable. But despite that energy abundance the state's lack of infrastructure and its distributed population contribute to extremely high energy costs for our citizens. The majority of the State lives off road, and unless you happen to live on the road system you are paying the highest energy costs of anywhere in the nation.

Energy issues are where the national interests and where Alaskan interests intersect. The nation needs the energy security that is afforded on the conventional and unconventional fossil energy resources on the North Slope, and they need to be developed.

Also, Alaskans need energy security, and for most of our villages that means access to reliable and affordable technology that allows the development of local energy resources, generally renewable, in a way that it can be used for electricity and heat generation in an environmentally responsible manner.

Recognizing this need, the Alaska legislature has appropriated over $700 million in FY'14 alone. Much of that has gone for demonstration projects in geothermal and biomass and in river hydrokinetics, and to a lesser degree the state stands ready to assist in the development of methane hydrates by having some land set aside ready for a production test should that event ever happen.

But the work that's being accomplished in Alaska, especially in the renewable side and in the investment, is gaining international and national recognition.

For example at the Alaska Center for Energy and Power, we have been working to develop a technology that helps overcome some of the hurdles of developing the in river hydrokinetic energy. We've had visitors from various countries to our site. We've had contracts with commercial vendors to help develop their technology and to demonstrate it at our site, all without Federal investment. And then recently in January of 2015 we were excited when the Northwest National Renewable Energy Center which is partially funded by DOE invited us to join.

Two of our scientists are also on an international standards committee setting the standards for in river hydrokinetic technology or marine technology overall.

And in addition to that the State of Alaska has invested in over 29 biomass demonstration projects around the state.

And finally, with some support from the Department of Energy, the Alaska Center for Energy and Power has worked to develop ways to assess geothermal resources in remote, hard to get to areas and done so successfully.

As a former Department of Energy employee I can say that I believe that Alaska is the nation's energy laboratory. They're actually investing. They're putting their money where their mouth is. They're developing things. They're making a difference.

We have industry at the table. We have other countries at the table. We have other Arctic nations at the table.

What seems to be missing in a lot of our discussion is the Federal Government. They don't seem to be at the table where we are in Alaska.

I'm here to support the efforts of this Committee to expand the portfolio of energy options that are available to our nation, both renewable and non-renewable. For our communities we believe that renewable energies over the long term can provide energy costs that are less susceptible to the uncertainties inherent with relying solely on fossil energy which is what our communities do now.

Demonstration projects for hydrokinetic energy, for low temperature geothermal, for biomass energy and for methane hydrates hold the potential for developing advances in technology that can lead to lower energy costs for all the citizens of the nation. Alaska does have world class energy resources, renewable and non-renewable, but we lack the technology to economically utilize them. Let's change that.

Thank you. I look forward to your questions.

[The prepared statement of Mr. Sheets follows:]

Brent J Sheets
Deputy Director
Alaska Center for Energy and Power
University of Alaska Fairbanks

Written Testimony before the
United States Senate Committee on Energy and Natural Resources

May 19, 2015

Madam Chair, Ranking Member Cantwell, and Committee Members, thank you for the opportunity to testify before you today. My name is Brent Sheets, I am the Deputy Director for the Alaska Center for Energy and Power. Our mission is to develop and disseminate practical, cost-effective, and innovative energy solutions for Alaska and beyond. The Alaska Center for Energy and Power is a statewide, university-led, applied research program based at the University of Alaska Fairbanks. We make every effort at being responsive to immediate and long term needs of residents, industries and agencies; and we focus on research related to community and industry-scale power generation that has the potential for providing reliable and affordable energy, especially in instances of islanded micro-grids. Those markets are found throughout rural Alaska where a regional transmission system does not exist, in developing nations, and increasingly in the lower-48 where some institutions are recognizing that the national transmission system is becoming increasingly unstable and are seeking energy security by developing microgrids that can be "islanded," that is isolated from the regional grid system, if that should become advantageous for continuing to operate their facility.

There are some cities in Alaska, namely Barrow, Anchorage, and several communities in the Kenai Peninsula, that have access to affordable natural gas, and many Southeast Alaska communities have affordable hydropower generated from small dams; but much of the rest of Alaska relies on expensive diesel fuel for generating electricity and home heating; fuel that is delivered once a year by barge during the summer months when the rivers are flowing. This is a costly way to provide power and heat to these communities, and the state of Alaska has invested millions of dollars seeking alternatives to the status quo. One form of state investment has been through grant programs administered by the Alaska Energy Authority, the Renewable Energy Fund and Emerging Energy Fund. Some of those outlays have been in support of advancing hydrokinetic, geothermal, and biomass technologies.

As a result of Alaska's investment in emerging energy technologies, and also the University's investment in establishing the Alaska Center for Energy and Power, Alaska has emerged as a leader in innovative microgrid power systems that incorporate renewable energy. The Alaska Center for Energy and Power works closely with the Alaska Energy Authority, various communities, utilities, and technology developers to demonstrate technology or control systems that enable renewable resources to displace some of the diesel currently used for power or heat generation.

We have also been fortunate to partner with the US Department of Energy and its labs in several technology areas, including wind, geothermal, hydrokinetic, and several other technologies not necessarily germane to our discussion today. We have also successfully competed for an award through the DOE EPSCoR program with a project entitled, "Sustainable Village Energy: Integration of Renewable and Diesel Systems to Improve Energy Self-Reliance for Remote Rural Alaska Communities" which we believe has benefited the state tremendously by adding to the body of knowledge and helping the state to develop additional expertise and capabilities.

Alaska also supports research to develop its unconventional fossil energy resources. In April 2013, the US Department of Energy entered into an MOU with the Alaska Department of Natural Resources concerning development of methane hydrates, a vast and important energy resource found on the North Slope of Alaska. Under the agreement, DOE's Office of Fossil Energy will be responsible for developing R&D opportunities in Alaska and providing scientific expertise and resources in support of projects. Alaska has set aside acreage for potential methane hydrates production testing, and will coordinate permitting and regulation where appropriate. The state further supports methane hydrate technology development by participating in periodic reviews of all scientific data and reports collected or created during the course of the MOU. Needless to say, Alaska strongly supports research into technology that will lead to the safe and commercial production of methane hydrates.

Because of my experience with a variety of energy technologies and resources in Alaska, I am here today to address several energy sources abundantly available in Alaska: hydrokinetic energy, low temperature geothermal, biomass, and methane hydrates.

Hydrokinetic

Many of Alaska's remote communities and technology developers are interested in river hydrokinetics because some studies suggest that power production during summer months in Alaskan rivers are capable of producing as much energy as tidal turbines (on an annualized basis) because of the periodic ebb and flow of tidal currents compared to the steady currents of rivers. But for the majority of villages in Alaska, river debris will be a major hazard for in-river turbines. Other considerations include sediment, river turbulence, ensuring that operation of turbines does not harm Alaska fisheries, and integration of hydrokinetic energy into the utility grid.

Access to funds for demonstration projects are vitally important to further the development of this technology. There have been several notable attempts to harness the kinetic energy found in the rivers of Alaska. In the summers of 2008 through 2010, a 5 kW turbine was deployed in the Yukon River near the community of Ruby. This project was sponsored by the Yukon River Watershed Tribal Council and funded with a grant from the Administration for Native Americans. In 2010, a 25 kW turbine was deployed in the Yukon River in Eagle by the Alaska Power and Telephone Company, primarily funded with a grant from the Denali Commission, but requiring considerable match component. Both demonstration projects were modestly successful generating power for a short period, but those early deployments also demonstrated that deploying such devices is not as simple as it might first appear.

There were some initial issues with the transmission and integration of the generated power into the utility systems. Some of these issues were easily solved, and others required additional investigation before a permanent solution could be identified. But there were other significant challenges that required more consideration. Working on the floating platform that suspends the turbine into the river proved challenging, and at times outright dangerous for the maintenance workers, thus making some solutions for addressing transmission and integration issues difficult to implement.

One of the most significant challenges illustrated by both Ruby and Eagle deployments was management of woody debris. Debris buildup on the various anchor lines and on the floating platforms proved so significant that in the course of one night, debris sometime gathered up in a significant enough amount to partially submerge the floating platform. In the case of Eagle, a 12 man crew was once required to work for a full day to clear debris. In addition, both surface and subsurface debris damaged turbines and platforms on multiple occasions. These are the sorts of things that technology developers do not think about until such problems are encountered in the "real world."

Subsequent testing of hydrokinetic devices avoided the problem by deploying in debris-free settings, namely in the Kvichak (Kwe-jack) River in Igiugig, Alaska. Two companies deployed turbines at that location during the summer of 2014, and those demonstration projects further illustrated the difficulty, expense, and unforeseen problems associated with deploying a system in a remote rural community, even in the absence of debris, and the problem of integrating with the local grid. Both devices were able to produce power for a brief period of time, and much was learned from these demonstrations projects and documented so that everyone in the industry can benefit from their experiences. Modeling and testing in flumes will take the industry only so far, but it is trial and error testing in the environment that will expose the weaknesses of this emerging technology.

At the Alaska Center for Energy and Power, our faculty and staff recognized that the major problems facing the hydrokinetic industry included river debris, meeting regulatory requirements to demonstrate no harm to fish, special needs for deploying and operating in remote areas, determining the optimal sites for turbine locations, and grid integration. Our experts developed methods to characterize river hydrokinetic potential, designed and deployed reliable anchoring methods and debris diversion technology, developed a test site on the Tanana River at Nenana, conducted fish population studies, and have tested the performance of "river in-stream energy conversion" technology. In the summer of 2014, the University's test site was used to evaluate the performance of Oceana Energy's turbine over a three-week period. The device was protected from debris using the University's debris diversion device. Oceana Energy will return to the test site in July of 2015 for extended river testing. They will also be working with ACEP's Power Systems Integration lab to address the challenges of integrating with a local grid system.

Because of its innovative work with respect to debris diversion technology, river hydrodynamics, fish populations and their interaction with turbines, and performance testing of river energy converters, the Alaska Hydrokinetic Energy Research Center, a component of the Alaska Center for Energy and Power, is attracting national and international attention. Two of our research faculty are hydrokinetic subject matter experts serving on the International Electrotechnical Commission establishing standards for assessing the hydrokinetic potential of wave, tidal, and river locations so that hydrokinetic energy converters will have consistent standards to enable comparisons between the various technologies. They also lead the US shadow committee representing US interests to the International Committee. Shadow committees are national committees consisting of subject matter experts and industry representatives who provide input to the national technical committees. Finally, AHERC is advising some companies on ways to improve designs to reduce their susceptibility to debris impacts.

During the summer of 2014 the Alaska Center for Energy and Power had a visitor from Chile tour our Tanana River Hydrokinetic Test Site, and we expect to be working more closely with a Chilean partnership in the coming months. We also hosted representatives from the Inter-American Development Bank to explore possible collaborative opportunities that could be facilitated by them in other Central and South American countries. And this summer, we will be hosting a delegation of engineers from a west African country who are interested in developing hydrokinetic technology for deployment in their region.

Other research centers are also interested in partnering with us, including Canada's leading research center for in-stream tidal energy, the Fundy Ocean Research Center for Energy. But it is our partnership with the Northwest National Marine Renewable Energy Center, NNMREC, that we are the most excited about. Created in 2008 through funding from the U.S. Department of Energy to Oregon State University and the University of Washington, NNMREC expanded in January 2015 to include the University of Alaska Fairbanks. NNMREC is now funded by a variety of federal agencies including the Bureau of Ocean Energy Management, the National Science Foundation, and the Department of Defense. Our network of industry partners includes many of the US leaders in tidal, riverine and wave energy: Ocean Renewable Power Corporation, Verdant Power, Columbia Power Technologies, M3, Oscilla Power, Resolute Marine, and Oceana Energy. Between the three universities, test sites are available for industry use to demonstrate full-scale wave energy devices, tidal devices, and river devices. Test sites are located off of the Oregon coast, in Puget Sound and Lake Washington, and in the Tanana River in Alaska. They are fully permitted for testing, supported by academia who are able to collect data and provide analysis that benefits the industry and regulators, and who have shown that testing at sites such as these is cost effective and more efficient than expecting each company to permit and develop their own proprietary test sites.

Taken together, these test sites represent the critical infrastructure that this country needs in order to provide the foundation for building the wave, tidal and river hydrokinetic industry. If we can successfully demonstrate this technology on a small scale, then it should be a relatively easy matter to scale it up so that it can also begin to provide renewable energy for larger populations as well. We hope to see deployment of river systems throughout remote Alaska during the summer months so that diesel generators can be turned off for a time, and we also expect larger versions of the same technology to be deployed in bays and oceans producing power for both coasts of the United States.

Tapping into the rivers to produce power has been a dream for many of Alaska's citizens over the years. That dream is closer to becoming a reality, in large part thanks to pioneering work made possible with research dollars to fund hydrokinetic power generation technology development and demonstration projects. Those research dollars have largely come from the federal government, and in the case of Alaska, from the state government as well. Several companies are partnering with Alaskan entities such as the one I represent, the University of Alaska Fairbanks' Alaska Center for Energy and Power, with National Marine Renewable Energy Demonstration Centers, and even a few regulatory agencies. Federal dollars are an enabler for developing this technology.

Geothermal

Alaska's potential for geothermal energy is high, but largely undeveloped. There are many locations with accessible geothermal energy in Alaska. The obvious ones are found in the Aleutians where proximity to volcanoes also provides some world-class geothermal opportunities. But there are also low-temperature geothermal resources in some areas of the Interior and Southeast Alaska where geothermic "hot spots" lie close to the surface and are easily accessed to draw up heat.

One site in the Interior of Alaska that has capitalized its low-temperature resource is Chena Hot Springs Resort. In 2006, Chena Hot Springs Resort installed a 400 kW geothermal power plant designed and manufactured by United Technologies Corporation. Chena Hot Springs was the first to develop commercial power from a resource of 165° F, about the temperature of a hot cup of coffee. This pushed the lower temperature limits down quite a bit, and was made possible by the cold water (and cold air during the winter months) that provided the necessary temperature differential between the hot and cold sides of the Organic Rankine Cycle generator. (The greater the temperature differential, the greater the efficiency of the generator.)

The Alaska Center for Energy and Power and its partners were funded by the Department of Energy to prove an inexpensive remote sensing technique capable of reducing the cost of geothermal exploration in remote areas, specifically Pilgrim Hot Springs which is approximately 60 miles from Nome. This was followed by a drilling program which resulted in slightly more than 60 shallow gradient holes of depths ranging from 80 to 500 feet, as well as three deeper confirmation holes that drilled to bedrock and were used to locate the source of the thermal fluids.

Today we know that the maximum downhole temperature at Pilgrim Hot Springs is 195° F, though the estimated reservoir temperature is considerably higher – likely approaching ~300 °F. This means the resource could be capable of sustaining approximately 2 MW of power generation, which could be used locally or delivered to Nome or a nearby mining operation via a transmission line. (Nome has an average electrical load of about 4 MW.) Because of the investment in this resource by DOE and additional financial support from multiple partners, including the Nome Joint Utility, Nome Chamber of Commerce, the Alaska Energy Authority, and the local native corporations to list but a few, there is now a private developer interested in potentially developing the resources and providing power to the community of Nome, thus reducing its dependence on diesel fuel.

Low temperature geothermal is often overlooked by developers in favor of traditional geothermal with its higher temperatures and higher pressures. But with additional research to help lower the cost of the technology, including exploration and drilling technologies, then the economics of remote mines or communities who rely on imported diesel fuel for power generation might be improved.

Biomass

The heat requirement for Alaska far surpasses the electricity requirement, and while a majority of the state's communities use diesel fuel to meet their heat demand, woody biomass is often a more economical solution, especially in communities separated from the road/rail connected system. Diesel is imported into communities by barge and airplane, and is sold as heating fuel at between $3.50 and $12 per gallon. Conversely, in many communities, especially in the Interior region of Alaska, abundant woody biomass exists in the local forests. Permitted harvesting is available on land owned by state, tribe, community, and private entities with allowable harvest limits determined through resource assessments and harvest plans. Using this locally available fuel can be economically beneficial to a community by creating jobs where employment opportunities are limited, and retaining the monies spent on local fuels in the community and thereby increasing the economic sustainability of the community.

Alaska has demonstrated many successful applications of biomass energy for community heating, including completed installations in over 29 communities throughout three major geographical regions of the state (Southeast, Interior, and Western). Assessment of candidates occur annually through the Alaska Wood Energy Development Task Group's (AWEDTG) pre-feasibility grant applications. These applications rank the community's readiness and compatibility for community scale biomass energy installations using criteria including: wild fire threat, beetle-killed trees, diesel fuel cost and offset, building energy efficiency audits, and lastly the willingness of the community to engage in a labor-intensive employment to maintain and operate the biomass systems.

The 2013 funding of Alaska's State Wood Energy Team by the US Department of Agriculture has enabled a wider range of pre-feasibility assessments, including allowing commercial buildings to be assessed for the economic feasibility of biomass system installations. This opens the door to wider adoption of the locally available resource. Many successful candidates who complete the pre-feasibility applications of the AWEDTG either pursue the biomass heat installations on their own, or they use their assessment to apply for grant funding from other sources. The state-funded Renewable Energy Fund has funded approximately 50 biomass energy assessments, designs and construction projects since the inception of the grant program in 2008. Despite funding cuts in the Alaska state budget, biomass energy projects remain alive in the 2016 budget approved by the state legislature.

The biomass systems selected for installation in Alaska are selected for efficiency, reliability, and low emissions. Alaska, despite its remote location, is often affected by high-emissions from low quality biomass systems that burn inefficiently, lack emission controlling components, and are used in conjunction with wet, green wood. Many days throughout the winter months, some Alaska communities fail to meet EPA mandated $PM_{2.5}$ fine particulate air quality standards. Educating the public about proper wood drying and appliance maintenance is a large component of biomass energy in Alaska, and the Alaska Wood Energy Conference is one method of delivering valuable information for lowering the emissions and increasing the efficiency of these units.

"Biomass readiness" is incredibly important for Alaska, especially where many of the energy systems installed are found in very remote areas with limited air transport. These communities must maintain the operation of their energy systems usually troubleshooting without much guidance. To help the new generation of boiler operators, a biomass energy training workshop was held in the community of Tanana in 2015 in which participants from nine different communities were trained on the operation, maintenance and repair of the systems. This training is the first of many that prepares communities funded to receive new biomass system installations to become familiar with the system and meet other operators to share knowledge and troubleshooting. This first 3-day training was overwhelmingly successful, and we are encouraged by the participant's dedication to understanding their systems.

The Alaska Energy Authority recently received funding through the USDA to create a "Community Sustainability Handbook: Best Practices for a Biomass-Heated Greenhouse at your Alaska School." Several school districts in Alaska have used the savings realized from heating with wood to build greenhouses adjacent to their schools. Today the children at the Thorne Bay School and Tok Schools eat salad every day as part of their lunch, and soon the students at three other schools (Kasaan, Coffman Cove and Naukati) will have their greenhouses up and running. The students are also involved in growing the plants in the greenhouse. Other schools in Alaska would like to do the same. Additionally, this handbook could be used by Alaska tribes and other publicly managed facilities that have existing biomass heating systems. And of course the private sector could benefit as well.

Alaska does not have a large wood processing industry, and thus lacks inexpensive waste fuel that could be used for biomass energy. The harvesting of whole trees for use as biomass fuel is generally not cost-effective in other states, but due to the high cost of diesel fuel, the harvest of trees for biomass does make economic sense in some regions of Alaska. And, there is a constant threat of wildfire to communities with large, highly-flammable spruce forests. As a way to alleviate this fire threat, many communities including Tok, Alaska, (a road accessible community of 1,300 close to the Canadian border) cut a large fire protection perimeter around their community. The wood from Tok's mitigation effort is used to fuel the state's first biomass-fueled combined heat and power system at the Tok School. This unique system, and the only one of its kind in Alaska, produces 5.5 MMBTU and up to 52 kW per hour. In response to excess heat produced, the school installed a year-round greenhouse supplying fresh produce and an educational tool for the students. This system is uniquely suited to Tok where there is an abundant, and subsided, source of wood from Alaska's state forestry fire mitigation efforts.

A small wood-to-electricity gasification unit (GEK 10 kW) has been installed in the Matanuska Experiment Farm, part of the University of Alaska Fairbanks. This system will be used by UAF engineers to determine the best use of this batch-load system using Alaska's resources. A small 10kW electricity generator could be used in some communities to offset a portion of their electricity generation from diesel. The money saved from offsetting diesel would stay in the remote community, enhancing the local economy and providing funding for employment.

Despite small steps towards using biomass to generate electricity, heat still remains the highest use of energy in Alaska, and biomass energy is best used to attempt to meet the thermal energy demands of residents and communities. And, the labor-intensive nature of woody biomass ensures that employment opportunities will always exist, and keep local money in the community. Alaska supports research that could lead to lower energy costs for its citizens, and we believe that more research in to lower the costs associated with biomass systems would be helpful, especially to the degree of lowering heating costs.

Hydrates

So far my testimony has been centered on renewable energy sources, which are important for a variety of reasons, but from my Alaska-centered perspective, investment in this technology is desirable in order for the technology to mature to the point where it becomes a reliable and affordable option for our communities that struggle with the high cost of energy. Use of local resources also puts local people to work, and enables cash to circulate inside of the community. And while renewable energy sources hold much promise for the country, and for the residents of Alaska, we cannot overlook the abundant fossil energy resources found only in Alaska, either.

A significant amount of our nation's conventional oil and gas resources remain on Alaska's North Slope and in offshore waters. This region contains more oil than any comparable region in the Arctic, including Russia, with approximately 40 billion barrels of technically recoverable oil and more than 250 trillion cubic feet of conventional gas, according to the EIA database. These numbers are likely dwarfed by Alaska's unconventional resources, such as shale oil, heavy and viscous oil, and methane hydrates.

While we are currently in a time of renewed oil and natural gas production within the borders of the United States, and American consumers are seeing some relief at the gas pumps, we cannot forget that the time to be investing in future fuel supplies is now so that they will be technically recoverable when the pendulum begins to swing toward high-priced energy again.

Continuing investment research is needed in order to enable the safe and economic production from methane hydrates. There have been some field tests funded by the US Department of Energy, and its federal, private, and international partners, that validated hydrate system concepts, and shown we can indeed detect, characterize, drill and produce hydrates from some types of hydrate reservoirs using carefully tailored applications of existing technology.

Despite these recent accomplishments, there are still challenges. One of the chief unknowns is whether the resource can be produced in a manner that meets environmental and commercial expectations. This will require a long term production test. The most obvious candidate for such a test is the North Slope of Alaska where there is existing infrastructure available to support such a demonstration project. As noted earlier, DOE entered into an MOU with the state of Alaska to cooperate on hydrates development, and since 2013, the state has set aside acreage for the purpose of conducting a hydrates production test on the North Slope.

Methane hydrate research is an obvious demonstration of the importance of government involvement in early, high risk research that has the potential to yield substantial benefits to the public. This large, untapped, energy resource has the potential to become the next "game-changer" similar to shale gas production which was transformed from uneconomic to viable based demonstration projects initiated by the newly formed Department of Energy in the 1970's. The state of Alaska is very supportive of continued methane hydrate research and urges this committee to support this vitally important research.

Conclusion

Speaking for the Alaska Center for Energy and Power, we support the efforts by this Committee to expand the portfolio of energy options available to our nation. For our communities, we believe that renewable resources, over the long term, can provide energy at costs that are less susceptible to the uncertainties inherent in relying solely on fossil fuels provided to our communities at considerable expense because of the remoteness of their locations. For our nation, Alaska has many unconventional fossil resources just waiting for the technology to produce them, methane hydrates is chief among them.

Demonstration projects for hydrokinetic energy, low temperature geothermal, biomass energy and methane hydrates hold the potential of developing advances in technology leading to lower energy costs. Alaska has world-class energy resources, renewable and non-renewable, but we lack the technology to economically utilize them. Let's change that.

Thank you again for the opportunity to testify before this committee. I would be happy to answer any questions you may have.

The CHAIRMAN. Thank you, Mr. Sheets. I am going to be going out to Egegik in about six weeks looking at some of the new technology they are putting in the water. So as you say, we are the technology lab for a lot of interesting things going on. Thank you for your presentation and being here today.

I wanted to focus on offshore for my initial round of questions, if I may, and I will start with you, Ms. Hopper.

As you know, we have the proposed Arctic rule, obviously just one example of regulation affecting the offshore oil and gas industry. We also have other regulations that are out there. We have got the well control, blow up preventer rule. We have got the proposed changes in the evaluation of oil and gas and coal that would be significant for our offshore facilities.

Senator Cassidy has introduced a bill that would require that the GAO report on the cumulative impact of regulations on offshore development. Does BOEM consider the cumulative impact of these rules, not just on the operations, but on the value of the lease sales and the bonus bids?

Ms. HOPPER. Thank you for the question, Madam Chairwoman.

We do, and when we issue our proposed rule there is a regulatory impact analysis that is included with those rules and we look at the impact of that rule. I do not believe that we look at the cumulative impact of all the rules together.

The CHAIRMAN. So it would be important then with Senator Cassidy's measure to look at that cumulative impact because I do think that is something, again, we deal with on a daily basis whether it is talking about things like the hydropower licensing and some of the overlay that we have with these regulations. I think this is where some of the costs and the delays come from.

Ms. Hopper, I was discouraged with your comments about the revenue sharing issue. Secretary Jewell came before this Committee in 2013 and she pretty much made a commitment to work with us to put together a bipartisan proposal with respect to revenue sharing that would bring everybody together.

She said, these are her words, "I'd be delighted to work with members of this Committee on that important proposal. I think revenue sharing is clearly a very important topic that deserves some attention from the Department of the Interior as well as this body."

So to hear your comments that, effectively, the way that you want to work with this is to redirect existing revenue payments from the revenue sharing plan that is in place for the Gulf, not to the states that are impacted, but basically to pull the rug out from underneath the promise that was already made is disconcerting.

We are going to have to have some serious discussion about how we can make good on the Secretary's promise to work with members of this Committee to make sure that issues like revenue sharing are meaningful and do work for the people that are impacted while at the same time allowing for that benefit to the taxpayers.

Mr. Milito, I listened to some of the comments from Mr. Matzner about the concern about new drilling. Again, as I mentioned we have been out in the Beaufort and the Chukchi since the 80s with some 35 wells are already in place, and no headlines.

The concern was raised that there is a 75 percent chance of a large oil spill. Looking at BOEM's fact sheet they make it very, very clear that what we are talking about here is that if we have a hypothetical scenario over the course of more than three quarters of a century of oil and gas activities, there is a 75 percent chance of one or more spills of more than a thousand barrels of oil. Again, put it into context, 75 years. How much are we talking about?

BOEM's actual statement here is no. Is it accurate to say that if Shell's Chukchi Sea exploration plan is approved there is a 75 percent chance of a large oil spill? No. I do think it is important to get the facts on record.

This came from the National Petroleum Council's study that was just released at the request of the Department of Energy, and the study looks at different exploration and development timelines, particularly in these defined and closely monitored windows. Chukchi and Beaufort are different than anywhere else, probably, on the planet.

Do you agree with the National Petroleum Council study that lease terms in the Beaufort and in the Chukchi need to be different to accommodate an operating environment that is different and, in my view, the additional regulatory demands proposed by BSSE in the proposed Arctic rule?

Mr. MILITO. Absolutely. When you have additional time in your lease terms it gives the industry a greater amount of flexibility and the ability to put more planning into the operations, and it allows us to look at energy development from a long term standpoint.

We know that we are going to need oil and natural gas for decades to come, and we know that when you are moving into new areas like this it takes a long time to get from exploratory activity to production. Bills like yours are a sensible approach to making sure that we are not ignoring these opportunities, but rather seizing these opportunities in a more constructive way.

The CHAIRMAN. I think people forget that it is not like drilling in the Gulf. You have got a window, basically you get the go ahead to get in the water in July and you have to be out by September. If ice comes in, you are out. If whales come early, you are out. It is an entirely different environment.

I think it is quite telling that President Obama actually agrees with much of what you have said about a transition process, that we will eventually need to transition off fossil fuels. It is going to take some time and until then, we are going to be using fossil fuels. So, as he says, would it not be better that we produce our oil and gas rather than importing it from others?

My time has expired. Senator Cantwell is not here, so let's go next to Senator King.

Senator KING. Thank you, Madam Chair.

In preparing for today's hearing I realized I had a lot more to learn than to contribute. So I am going to pass on the questions and listen and learn.

There is a famous saying of Golda Meir that Moses tramped all over the Middle East for 40 years and settled in the one place without oil. The people who founded Maine, in effect, did the same thing.

So I am going to learn about the issues of production today, and I appreciate you are having this hearing. Thank you.

The CHAIRMAN. Thank you, and I think it is also fair to note that in your state of Maine you are pioneering some good things when it comes to ocean energy. We have got some joint relations between Alaska and Maine with some of the technologies that we are looking forward to utilizing as coastal states that have some significant tides too. So thank you for also being a technology pioneer there.

Let us go to Senator Portman, sitting there patiently at the end.

Senator PORTMAN. Thank you, Chair Murkowski.

The CHAIRMAN. Thank you.

Senator PORTMAN. I have been here since 10 soaking it all in.

I appreciate the great testimony and the fact that this is our third opportunity to put together a comprehensive series of energy policies, and I appreciate the Chair and Ranking Member doing that. I think these have been great hearings, and the witnesses today did a terrific job laying out the supply issues. I have worked with a lot of you on different issues.

Franz, thank you for being here and working with us on the efficiency bill and helping us get that moving again and back to the Floor, maybe in a comprehensive way as opposed to the legislation we did get through a couple of weeks ago.

On supply, one of the things I heard this morning a lot about and particularly interesting was the question of permitting again, and we had got into that actually last week a little bit also.

But I would focus, if I could, Ms. Kelly, on your testimony. I found particularly interesting your discussion of the hydropower licensing process.

One of your members, AMP, came to me about five years ago when I was first elected to give me the stories about the Ohio River hydro frustrations. They were trying to build three hydroelectric plants on the Ohio River at that time. All of them would have been terrific, relatively inexpensive, renewable energy, but they have been delayed for years by an inefficient and redundant Federal permitting system. And that got us off on this issue.

I know that there are a number of you who have talked about this in a broader context. But if you could, in your experience, is AMP's story unique or are many of APPA members having to wrestle with this inefficient Federal permitting system? Also if you could comment on whether it goes beyond your hydro projects? I know you also have other sources of energy within your membership.

Ms. KELLY. Thank you for those questions.

Of course every hydro project is a little bit like a snowflake. They're all a little bit different. They all have their own issues, their own environmental concerns, and they all have to travel the licensing process. But you are correct that AMP's four run of the river projects on the Ohio have been a long travail for them, and it's been incredibly frustrating because number one, these are run of the river projects. And number two, these are intended to provide clean, renewable, non-CO_2 emitting resources, you know, power and to be used in RTO market regions.

They have had a lot of issues with the hydropower licensing process. I think they're finally coming to the, you know, hopefully, will be coming to the end of that. But it's been very protracted and has added to the years on the project and the cost.

In addition I should note that after having gone through all that they are now facing changes in the capacity markets in PJM that may diminish the value of that capacity to them. So the investment that they thought they were getting for that project, they may find that they are not going to get the full benefit of those resources.

So, it's—you were talking, Senator Murkowski, about the cumulative impact of different sets of regulations. And this is a perfect example of that. We have the long travail to get these four wonderful projects sited and built, created a lot of jobs, a lot of, I think it's 12 different states, 60 contracts. I mean, it's really been a win/win in many ways.

And now as we finally get towards the end we find we may not be able to get the full benefit out of those projects. So you're absolutely right, and thank you for the question.

Senator PORTMAN. Susan, I suspect you have also had some permitting issues with some of your transmission and natural gas projects?

Ms. KELLY. Yes. The transmission siting can be very long and very protracted especially if it's on Federal lands. Our members in the West have really experienced those concerns as well.

But transmission siting is really more of a state and local issue right now. There was an attempt to, kind of, federalize it with backstop siting in the Energy Policy Act of 2006. That was, frankly, eviscerated by a court appeal from the Fourth Circuit. So we don't really have strong, Federal siting of transmission at this moment.

Senator PORTMAN. When AMP came to me we worked with them on trying to figure out what the best way was to address their problem and found out it was this broader problem on energy projects, but also construction permits, generally and came up with this legislation that was reported out just about a week ago, S. 280 which is the Federal Permitting Improvement Act.

As you know, we now rank down 41st in the world now in terms of greenlighting projects. I know, Franz, you have worked with us on this and others, but I do hope we can get that legislation moving. I think it would affect energy projects in very direct ways as well as other construction projects. It has deadlines that have to be set. It also helps in terms of the litigation risk, and we think it would be appropriate to consider it as part of this package as well. It came out of the Homeland Security and Governmental Affairs Committee by a 12-to-1 vote, by the way, after working with the Administration on it.

Just quickly I've got five seconds left, but let me just say I would love for the record, Mr. Milito, if you could give us a little more information about how long it takes to get necessary permits to drill a well or natural gas well. As you know in Ohio with Utica and Marcellus we are interested in that. If you could just give us a little sense of the permitting on the natural gas and oil side for the record, that would be terrific.

Mr. MILITO. Yeah, on state and Federal, I mean, on state and private lands in states like Ohio and Pennsylvania, we have a permitting process that's fairly reasonable and effective. Companies are able to get their permits, generally, within a 30-day time period.

When you move to the Federal lands it can take 200 to 300 days depending upon where you're getting the permit from based upon where the BLM's office is. So efficiency is key to maintaining and expanding our energy production.

Senator PORTMAN. Thanks for what you can give us on the record on that. We'll actually submit a question to you.

Mr. MILITO. Great.

Senator PORTMAN. A question to you for the record and like to get some more information on that.

Senator PORTMAN. Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator Portman.

Ms. KELLY. Would you mind if I just could mention that I've been informed by wiser heads than mine that while I did not study up on your bill for this hearing, we support it.

Senator PORTMAN. Great. Thank you, Susan, I appreciate it.

The CHAIRMAN. Very good.

Senator Heinrich.

Senator HEINRICH. Thank you, Madam Chair.

Ms. Kelly, you mentioned FERC backstop authority and the effort in the past to create that. That obviously is not in place now due to the litigation that you alluded to. Would APPA support FERC-based backstop authority for regional transmission lines, transmission lines that cross multiple states?

Ms. KELLY. We would obviously want to take a look at the details of that legislation as a trade association composed of units of state and local government.

Senator HEINRICH. Sure.

Ms. KELLY. You know, we don't take federalization lightly.

Senator HEINRICH. Nor should you.

Ms. KELLY. We came to support that section of EPACT 2005 because of the really substantial problems we saw in siting transmission.

Senator HEINRICH. Right.

Ms. KELLY. So we certainly would be open to considering that, but the details would matter.

Senator HEINRICH. Have you got a chance to look at the legislation I introduced to do that? It basically tries to accomplish the same thing as the EPACT provisions but with a different basis in law that would be less subject to challenge in the courts.

Ms. KELLY. I will probably, if it's alright with you, have to get back with you on that for the record. But the more you're coloring inside the lines of the legislation that we previously supported, the more likely it is we would.

Senator HEINRICH. Right.

Ms. KELLY. But I don't want to commit without talking to my members.

Senator HEINRICH. I understand. I would appreciate it, and we look forward to working with you on that.

I also wanted to ask you about your position on national renewable portfolio standard. You mentioned that APPA believes that that's not necessary. Given the substantial climate challenges that we face at this point, what is APPA's plan to reduce our carbon pollution profile and to meet those climate challenges?

Ms. KELLY. Well it's not necessarily APPA's plan, but the EPA has a plan for us. It's called 111D. The third building block in there calls for increased use of renewables. The state targets that have been set out under that incorporate that increased use of renewables. So assuming that survives in some version of the final rule and that those state limits are enforced, we will be doing that as part of that.

This, again, gets back to the issue of cumulative impacts of regulations that Senator Murkowski mentioned earlier. I mean, we're just seeing so many different mandates piled on us that it makes it increasingly difficult for us to do what we feel needs to be done.

Senator HEINRICH. So, there are some conservative voices who have said, let's get rid of 111D in its entirety, replace it with some sort of carbon fee that would be revenue neutral on the budget as a whole.

Have you given any thought to that kind of an approach as a potentially less regulatory based approach that would be more purely economically driven?

Ms. KELLY. Our association does not have any policy on that right now. We have been focused on the 111D proposal. We filed very extensive comments on that proposal. We raised both legal and practical and technical issues with it, but right now we are attempting to do the very best we can to work with the EPA and with other agencies such as FERC to get a livable, final 111D rule.

Before I became CEO I was an appellate attorney for over 30 years. I've spent a lot of time litigating cases in the DC circuit, and I don't necessarily count, even if I think I have a winning case, on actually winning in the end.

So I think we have to live in the world of the possible and have to assume that this may be implemented in some way and we have to work forward to try and make it the most livable regime we can.

Senator HEINRICH. Mr. Livingston, while I've still got a couple of seconds here. I wanted to ask you a little bit, a couple of questions based on the fact that PG&E has several decades now of history managing now energy storage, historically in the case, in your case, pumped hydro. That has a lot of value, I think, to share with those of us looking at how we utilize storage more broadly moving forward, especially in a world where energy sources can be intermittent.

Can you talk a little bit about how you use that storage in your daily operations? What opportunities you see moving forward for adding additional storage in PG&E system and whether or not you will be able to meet the 580 megawatt storage requirement called for by 2024 in California?

Mr. LIVINGSTON. Yeah, thank you.

Our Herald Pump Storage unit is 1200 megawatts. It pumps at 900 and generates at 1200. There's three units there. Those units have been absolutely superb in helping to manage the overall electrical system in California, especially during the energy crisis as supplies were more intermittent. But even more so today as we see much larger portions of wind and solar come in that we're balancing in the whole side.

All of our hydro resource helps play in that arena and helps provide the ancillary services to do that, but importantly pump storage is one that's a large and proven resource. It's one that there's technological advances that could make it even better, and is one of the few very large, large, proven technologies that can meet what is becoming very large demands for that type of service.

And as far as meeting our requirements under increasing the storage requirements, those are all small blocks of storage and generally, you know, more suited towards development of batteries and so on. We do not see a problem with meeting those requirements.

The CHAIRMAN. Thank you, Senator Heinrich.

Senator Cassidy.

Senator CASSIDY. Thank you, Madam Chair. Thank you for holding this meeting today related to energy supply.

I will first begin speaking about Senate Bill 1276, the Offshore Energy and Jobs Act, that I am introducing along with Senators Cornyn, Vitter, Cochran and Wicker. This bill provides new access to frontier acreage in the Gulf of Mexico within areas 50 miles from the Florida coastline by redefining the Eastern Gulf moratoria in 2017.

According to current law the moratoria is scheduled to expire in 2022. This directs the Department of the Interior to hold three new lease sales in the Eastern Gulf by 2020. Our legislation is supported by national energy and manufacturing organizations. In addition, the Florida State Hispanic Chamber of Commerce, the Florida Transportation Builders Association and the Florida Retail Federation have all called for the inclusion of the Eastern Planning Area in the Administration's 2017 through 2022 offshore leasing program.

According to the Energy Information Administration, in 2014 about 27 percent of the petroleum we consumed as Americans was imported from foreign countries. We, as a nation, need greater access to fossil fuels to strengthen our energy security and independence. In fact, President Obama said last week, we are "going to be using fossil fuels and when it can be done safely and appropriately U.S. production of oil and natural gas is important." Hopefully we all agree with that.

In addition to preserving energy access, Senate Bill 1276 brings greater equity in revenue sharing for the Gulf States that host offshore energy production. According to the Department of the Interior, royalties from crude oil production in the offshore Gulf of Mexico for Fiscal Year 2014 was $4.6 billion. In the same year $3.4 million was shared with coastal states.

Ms. Hopper mentioned how there is a commitment by the Congress to share with the coastal states. The Federal Government gets $4.6 billion. We get $3.4 million. Now that is about .07 percent. My children would be very unhappy with that level of sharing.

To put this in perspective revenue shared from energy development on Federal shores onshore the state gets 50 percent of the royalties. Obviously it is different for coastal.

For Louisiana revenue sharing is not only about fairness, it is about our survival. Louisiana is experiencing unparalleled land loss due to Federal engineering decisions that for nearly a century have channeled the lower Mississippi for the benefit of inland ports. Louisiana's 2,300 square miles of land loss is largely attributed to this channelization along with the placement of Federal levees along the river system.

Louisiana, by our state constitution, uses this revenue sharing to restore our coastline. Now that is important, again, for the rest of the nation. Five hundred tons of water borne cargo pass through Louisiana's system of deep water ports and navigational channels every year. If present land loss rates continue more than 155 miles of waterways and several of the ports will be exposed to open water within 50 years.

Similarly, one fourth of our nation's energy supply depends upon the support facilities in South Louisiana while working coasts create significant value benefitting the entire country. America cannot afford to lose what is perceived as only Louisiana's resource.

To that end, Mr. Milito, just a couple questions for the record. Based on the recent API study what is the increase in Federal Government revenue estimated to be derived from the development of the Eastern Gulf of Mexico?

Mr. MILITO. If we move forward with development of the Eastern Gulf over an 18 year period, we'd be looking at about $70 billion going to the Federal Government.

Senator CASSIDY. How much?

Mr. MILITO. $70 billion.

Senator CASSIDY. $70 billion. So when folks suggest that this bill will increase the nation's deficit you have to, kind of, chuckle, $70 billion more.

Mr. MILITO. Yeah, this is all additive revenues coming into the Government.

Senator CASSIDY. How much additional revenue would be allocated to the Land and Water Conservation Fund if the GOMESA revenue sharing paradigm applied to the Eastern Planning Area?

Mr. MILITO. Twelve percent of a?

Senator CASSIDY. A lot. Billions?

Mr. MILITO. Yeah.

Senator CASSIDY. Yeah, fair statement.

Mr. MILITO. $10 billion or so.

Senator CASSIDY. Yeah, that is not bad.

Ms. Hopper complained that my legislation takes away secretarial discretion on the appropriateness of leasing in the Eastern Gulf of Mexico when a number of factors, including resource potential and infrastructure are needed to support oil and gas. Can you tell us what the resource potential in the Eastern Gulf of Mexico is?

Mr. MILITO. I'm sorry——

Senator CASSIDY. Can you tell us what the resource potential is in the Eastern Gulf of Mexico?

Mr. MILITO. Yeah, we'd be looking at, over time, a million barrels of oil equivalent per day for many years.

Senator CASSIDY. A day? A million a day?

Mr. MILITO. Yeah.

Senator CASSIDY. And is there sufficient infrastructure to support the oil and gas development in the Eastern Gulf?

Mr. MILITO. Absolutely. You're neighboring the existing development we have in the Western and Central Gulf which is driving economic development——

Senator CASSIDY. I'm out of time. I am going to interrupt you just to say that this legislation would create 230,000 working class jobs for Americans who currently are underemployed or unemployed, $70 billion in new revenue, $10 billion or so for the Land and Water Conservation Fund while providing access to America's oil and gas for Americans. What's not to like?

I yield back.

The CHAIRMAN. What's not to like?

Senator Franken. Maybe he'll tell us.

Senator FRANKEN. I'll tell you. [Laughter].

I appreciate the Senator from Louisiana's perspective. We talked about this during the vote-a-rama, and I understand that those offshore drilling jobs are good jobs, for middle class jobs and we want to build those.

And I know that the Chairwoman talked about economic and energy security in offshore drilling and including in the Arctic.

I also am very cognizant of the fact that we have climate change. When we had the hearing on the Arctic, something struck me as kind of ironic and that is what I used to do for a living. I used to identify those things, and it was that we have the Arctic now melting. And because of the melting more fossil fuels being available for drilling offshore and that climate scientists are telling us that the vast majority of known fossil fuel reserves need to actually remain in the ground if we want to avoid the worst impacts of climate change.

So that is what I found ironic which is that we are going to be able to get to more fossil fuel in the ground even if it is under the ocean because of climate change.

So Mr. Matzner, how much CO_2 would be released in the atmosphere if we exploit and burn the oil and gas reserves in the Arctic Ocean?

Mr. MATZNER. Thank you, Senator Franken.

About 16 billion tons of CO_2 would be emitted into the atmosphere. That's the equivalent to the emissions from all of U.S. transportation modes in the U.S. over a nine year time period. That's clearly a significant number.

And what that illustrates is the point that you, yourself, raised is that if we're really serious about tackling climate change we have to make smarter decisions about where and to what extent we use, particularly public resources, too. And the best available science we have is that we've already discovered four times as much fossil fuels as we can safely burn if we're going to avoid the worst impacts of climate change and that doesn't even account for these new undiscovered, unproven reserves.

So if we're really serious about this we're going to have to take something off of the table, and I can't think of anywhere better than places where there's also high risks, other ecological values or ways of life.

Senator FRANKEN. And what are the other risks in terms of——

Mr. MATZNER. Well, whether you're focused on the Arctic or on the Atlantic, there's risk of severe oil spills and we've seen what happens when we have those major oil spills. The impacts are economically severe, ecologically severe and they're persistent.

Senator FRANKEN. Okay. So, that's what's not to like. I mean, that's just, in answer to the question, which is so we have choices to make. I think that's fair to say.

On the other hand, what positive impacts do we see if we focused on meeting energy needs by developing clean energy technologies instead such as say, combined heat and power which I think the Chair and I agree on and energy efficiency and using energy efficiency technologies?

Sir, you don't have to answer that, I think.

But I want to move on to, sort of, using combined heat and power and also using district energy use by using hazardous fuels in our forests because we are seeing also increased wildfires and longer seasons, et cetera.

In my state of Minnesota, District Energy St. Paul was recently recognized for its leadership in using wood waste to generate heat and electricity for downtown St. Paul while providing its customers with stable and competitive energy prices and reducing CO_2.

Mr. Sheets, I will get right to the question because I have four seconds. I know that more and more Alaskan communities are turning to biomass as a local, reliable and clean source of energy. Can you talk about some of the benefits that your communities are seeing as a result of these biomass energy projects?

Mr. SHEETS. Yeah, certainly and very briefly. There's over 29 communities that have invested in different biomass projects. Some have been successful. Some have been unsuccessful.

The successful ones demonstrate a commitment to the increased manpower that's associated with that. And then within the communities it provides local jobs cutting down the trees, delivering them, stacking them and in many of the rural communities unemployment is huge. So any cash that you can keep in the economy is good.

So we have found that augmenting our other sources of power with heat from wood keeps cash in the community a little bit longer and circulating. So those are some of the benefits.

Senator FRANKEN. Okay, well I want to pursue that, but on my time and I am out of it. So, there.

The CHAIRMAN. Thank you. In deference to my colleague from Minnesota, I think some in the North, many in the North, believe that the irony is that the people of the North would be denied jobs, economic opportunities, the opportunity to access a resource responsibly, safely, to the benefit of the country and national security while people 4,000 miles away lock them up and put them effectively in a snow globe making them wards of the state and nation. That is where they feel the irony is.

Let us go to Mr. Gardner.

Senator GARDNER. Thank you, Madam Chair. Thank you, Chairwoman Murkowski and the Ranking Member Cantwell, for holding this hearing and thanks to all of you for being here today. I think Senator Daines and I, at least, and I am sure others have been going back and forth between a couple of different committees. So I apologize for attending a fun hearing on air traffic controlling for a while before being able to come back to this Committee.

Just a couple of questions for you.

My legislation, S. 1720, the RIVER Act, is included in today's hearing. Of course, the RIVER Act stands for the Reliable Investment in Vital Energy Reauthorization Act. I was hoping we could name it something like driving America's manufacturing but I didn't like the acronym for that. I thought it would be fun to have one that said that.

Included in today's hearing S. 1720 is a proposal to reauthorize Section 242 and 243 of the Energy Policy Act of 2005. These sections were designed to promote the conversion of non-powered dams into hydro facilities and accelerate the addition of new generation at existing hydro plants.

According to the new Department of Energy reports there are 12 gigawatts of untapped hydropower development using the nation's existing dam infrastructure. These are dams with no power houses today. In my home state of Colorado there are approximately 30 megawatts of untapped hydropower development potential.

This program was initially authorized, 242 and 243, initially authorized back in the EPA of 2005, but the Department of Energy hydropower program only recently received Federal appropriations in Fiscal Year 2014 and the first round of awards are expected to be released any day now and they have not even been released as of yet.

So just as this program is beginning to finally take off, it is set to expire later this year, and there is a little bit of urgency in the passage of the RIVER Act.

So to Susan Kelly, Senate Bill 1720, the RIVER Act, reauthorizes the hydraulic production and efficiency improvement incentives. Could you comment on the value of hydropower to the grid, especially as utilities grapple with implementation of the EPA rule 111D and early retirement of coal plants?

Ms. KELLY. Yes, sir. I'd be happy to. We think hydropower is a very valuable resource to have in the portfolio as we move to comply with 111D.

One of the reasons for that is that it is a clean, renewable resource and yet it has characteristics that some of the other ones, for example, wind and solar, do not. It can assist with what we call black start which is restoration of the system when there's a blackout. It is much more controllable.

So if it's needed to back other resources like wind and solar, you can do that. You know, as their production goes up and down you can release water from over the dams to account for that. So it's a good complement to these other resources.

So we strongly believe in hydropower, and we support your act. That's in my written testimony.

Senator GARDNER. Thank you very much.

You mentioned, Ms. Kelly, that hydropower is renewable energy. Is there anybody on the panel today that disagrees that hydropower is not a renewable energy source? So I guess the record will reflect that everybody on the panel today agrees that hydropower is a renewable energy source.

Mr. Matzner.

Mr. MATZNER. I think we would not categorize it as a renewable energy resource, but as an important clean energy source.

Senator GARDNER. Not renewable? Why is that?

Mr. MATZNER. Well, it doesn't have some of the characteristics of renewable energy and that, you know, we, sometimes are—others clearly affected by water shortages and droughts and we have to make sure that we're being careful about our conservation of water as well.

Senator GARDNER. What is not renewable about hydropower?

Mr. MATZNER. One of the things that we're concerned about is how hydroelectric power interrelates with other renewable resources. So I guess to clarify my point, it's just about how it's treated under standards like the renewable electricity standard.

Senator GARDNER. Okay. So it is not so much that it is not renewable, it is just how it is defined by law. Is that right?

Mr. MATZNER. Yes, that's correct. So I will clarify my comment in the record as well.

Senator GARDNER. Okay, very good. And I have a letter from the Western Small Hydro Association. If I could have it entered into the record talking about our efforts.

[The information referred to follows:]

Western Small Hydro Association
PO Box 1646
Telluride, CO 81435
www.smallhydro.co
970-729-5051

May 18, 2015

TO: Senator Cory Gardner
Senate Energy and Natural Resources Committee

FROM: Kurt Johnson
Western Small Hydro Association

RE: Support for Gardner Legislation to
Reauthorize Section 242 Hydro Incentives

On behalf of the Western Small Hydro Association (WESHA), I am writing to thank you for your leadership in introducing legislation to reauthorize the Section 242 program.

As has been documented in recent federal and state studies, Colorado has significant potential for development of new small hydropower which could benefit from consistent federal support for the 242 program.

A recently completed study by the Colorado Department of Agriculture highlighted the potential for development of approximately 30 megawatts of new agricultural small hydro, which could benefit enormously from the 242 incentives. See the attached press release as well as the following recent *Denver Post* article:

http://www.denverpost.com/environment/ci_28046145/colorado-begins-3-2m-effort-save-ag-water

In addition, as you get further along in developing the legislation, I would like to respectfully suggest adding additional legislative language to create a preference for small hydro, which has disproportionately high development costs as a percentage of total project costs.

The previous version of the 242 legislation imposed a payment cap. The most likely interpretation of the reason for this cap was that Congress foresaw the problem that large projects could potentially consume most of the limited available 242 incentive funds.

A payment amount of 2.3 cents/kWh is economically meaningful and will incentivize new development. However, if the program is oversubscribed, a simple pro rata system yielding substantially reduced payments for all program

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applicants will not fulfill clear congressional intent to incentivize new hydro development.

In an oversubscribed situation, DOE has a choice between implementing an incremental payment mechanism favoring small hydro which could result in a meaningful payment (2.3 cents/kWh) for some applicants, or a limited payment to all applicants under a pro rata system which could be ineffective at incentivizing new development.

An incremental payment system favoring small hydro would be automatically self-adjusting, providing an economically meaningful payment of 2.3 cents/kWh to as many projects as possible, given limited available funds.

An incremental payment system favoring small hydro first would implement Congressional intent to incentivize new development and ensures the greatest benefit for the greatest number of applicants; with payments to recipients that are meaningful for incentivizing new development.

I would be happy to provide additional suggested legislative language in order to implement this suggested improvement to the 242 program.

Thank you for your consideration.

Attachment
COSHA press release about new Colorado agricultural hydro program

Senator GARDNER. I just want to finish with a comment that you made about jobs in the West.

Recently a court decision in Colorado has basically called into question the permit for a mine in the Colowyo Mine. This is not the topic of today's hearing, but this court decision which was brought an unbelievable eight years later, has the potential to wipe out two communities in Northwestern Colorado.

Two hundred twenty jobs directly at the mine, millions of dollars in tax revenues, 220 jobs and two communities in Western Colorado, gone.

That is the impact that some of these regulations have. That is the impact of litigation, and I hope that as we talk about moving forward on energy that we will recognize that these jobs, these mines, are important. If we just treat them as pieces of paper in litigation we are doing a lot of damage to our fellow members of the community.

I thank you, Senator Murkowski, for that.

The CHAIRMAN. Senator Daines.

Senator DAINES. Thank you, Madam Chair, and thank you also, Ranking Member Cantwell, for holding this hearing on a very important topic, America's energy supply.

I associate myself with Senator Gardner's comments. Certainly I scratch my head. Having spent 28 years in business, trained as a chemical engineer, this was the first place I ever stumbled across that defined hydropower as not being a renewable source of energy. So I appreciate the question, Senator Gardner, and I think, hopefully we can have sound science drive this discussion versus the political science as we look at our all of the above energy portfolio.

Montana faces challenges to developing its vast energy sources on both Federal and tribal lands. Bills before us today help address some of these challenges.

I firmly believe we truly must pursue an all of the above energy strategy in the U.S. In fact, Senator Gardner and I, along with Leader McConnell and a few other Senators were over in the Middle East several weeks ago meeting with leaders in Israel, in Jordan, in Iraq, in Afghanistan and coming back, I think one of our conclusions was the importance of continuing to develop an all of the above energy portfolio and more made in America energy, both in terms of our future economic security, but certainly from a geopolitical and national security perspective.

There are two Montana hydro projects under review by FERC. One is called the Clark Canyon Dam and the other, the Gibson Dam. They have been facing uncertainty in the permitting process, though Senator Murkowski's hydropower Improvement Act will address these challenges on a broader scale.

Two bills on the agenda today that I introduced, Senate Bill 1103 and Senate Bill 1104, would provide short term relicensing and extensions to these two important hydropower projects. I can tell you if you talk to a rancher or a farmer in Montana and ask him if they believe hydro is a renewable, I think common sense prevails and they will say, absolutely, yes.

I introduced these bills with my colleague from Montana, Senator Jon Tester, my Idaho colleagues, Senators Risch and Crapo, and also my counterpart in the House, the lone representative from the

State of Montana, Ryan Zinke. My bills would allow FERC to extend licenses for non-Federal, hydropower development on existing dams in Montana.

The first bill would extend for three years a contract for hydropower development on the Clark Canyon Dam in Dillon, Montana. It would allow for construction and operation for a project that will power about 1,200 homes per year, replace 18,000 metric tons of carbon each year, create 30 to 40 jobs during construction and generates $611,000 in state and Federal taxes and $37,000 in property tax contributions over the next five years.

The second would provide a six year contract extension for non-Federal hydropower development on the Gibson Dam near Augusta and Choteau, Montana. Once completed the project will provide decades of stable tax revenues for Teton and Lewis and Clark Counties, the State of Montana and the Federal Government. It will benefit the environment as its FERC license requires the dam incorporate measures that would enhance fish and wildlife resources.

I think one of the untold stories as an avid fly fisherman myself is a tremendous benefit. Frankly, the fisheries that we have with some of these tail water fisheries allow the water to stay cooler so in the hot summer months that we have in Montana where the waters increase in temperature and actually can create hardship for the fish. A dam, when built correctly to proper ecological standards, is a way to continue to enhance our fish and wildlife resources.

It will replace 40,000 tons of carbon per year. It will strengthen area irrigation by providing a portion of the power sales to Greenfields Irrigation District to support irrigation improvements, operations, water conservation and urge enhancements.

It generates $4 to $5 million in wages during construction and provides $200,000 per year in revenue for the Sun River Cooperative. I can tell you those are big numbers in rural America, in the rural counties we have in Montana.

Hydropower development must be a key component of our all of the above strategy to meet our nation's energy needs. These bills have received robust support from affected local communities.

I ask unanimous consent to submit letters of support from Sun River Electric Co-op, the Sun River Watershed Group, Greenfield Irrigation District, Clark Canyon Hydro, Toll House Energy and Beaver Head County Commissioners certifying these bills will improve the environment and help sustain local communities for decades.

The CHAIRMAN. They will be entered into the record.

Sun River
ELECTRIC COOPERATIVE INC.

May 15, 2015

Senator Steve Daines
Russell Senate Office Building
Courtyard 1
Washington DC 20510

RE: Senate Bill 1104

Dear Senator Daines:

As the President of the Sun River Electric Cooperative board of trustees, I am writing to you to convey the Cooperative support of the Gibson Hydroelectric Generation Project.

Hydroelectric power is perhaps the best example of renewable energy and this project fits that criteria.

We ask your support in pursuing the FERC license extension requested by the project in Senate Bill 1104.

Thank you.

Sincerely,

John Burgmaier

John Burgmaier
Board President

A Touchstone Energy® Cooperative
310 1st Avenue South • PO Box 309 • Fairfield, Montana 59436
Phone (406) 467-2526 • 1-800-452-7516 • Fax (406) 467-3108
WWW.SUNRIVEREC.COM

GREENFIELDS IRRIGATION DISTRICT
105 West Central Avenue
P.O. Box 157
Fairfield, Montana 59436
Phone: (406) 467-2533
Fax: (406) 467-2705

May 18, 2015

Honorable Senator Steve Daines
Russell Senate Office Building
Courtyard 1
Washington, DC 20510

Dear Senator Daines,

As District Manager of the Greenfields Irrigation District (GID) and on behalf of the Board of Commissioners and GID waterusers, I am writing to express our collective support for the Gibson Hydroelectric Generation Project. The Gibson Hydroelectric Project is an important project for GID as it represents a significant source of income to help us offset the growing cost of repairing and/or replacing our nearly 100-year old irrigation infrastructure. The revenue from this environmental-friendly, renewable energy will also contribute greatly to the local tax bases of the State of Montana and the counties of Teton and Lewis and Clark. Our local electric co-op, Sun River Electric, will also benefit from proposed infrastructure upgrades.

Our partners as well as other local stakeholders have been working tirelessly to continue moving this project forward and recently have made great strides towards eventually commencing construction. This project has involved many challenges and we have systematically been addressing public and regulatory concerns and requests.

Unfortunately, our current permit license from the Federal Energy Regulatory Commission (FERC) mandates a construction start date of January 12, 2016. Due to the dynamics of the project and the challenges, we will fall short of our deadline. Therefore we ask for your leadership and support in securing the FERC license extension requested for Gibson Hydroelectric in Senate Bill 1104.

Please call if you have any questions.

Respectfully,
Greenfields Irrigation District

Erling A. Juel

Erling A. Juel, P.E.
District Manger

C: Gus Papadakis, Tollhouse Energy
GID Board of Commissioners
Robin Baker, Sen. Daines Great Falls office

Tollhouse
Energy
Company

May 15, 2015

The Honorable Lisa Murkowski
Chairman
Senate Committee on Energy
and Natural Resources
304 Dirksen Senate Office Building
Washington, DC 20510

The Honorable Maria Cantwell
Ranking Member
Senate Committee on Energy
and Natural Resources
304 Dirksen Senate Office Building
Washington, DC 20510

Dear Chairman Murkowski and Ranking Member Cantwell,

Tollhouse Energy supports S. 1104, a bill that would authorize the Federal Energy Regulatory Commission "FERC" to extend the construction commencement deadline for a proposed 15 MW project on the Bureau of Reclamation's Gibson Dam, a non-powered federal irrigation dam in Montana. Since 2005 Tollhouse Energy, an independent power producer based in Bellingham, Washington, has been developing a new hydroelectric facility with our partner the Greenfields Irrigation District in Fairfield, Montana. Together we formed the Gibson Dam Hydroelectric Company, LLC. After many years of stakeholder engagement, FERC issued the project a 50 year license on January 12, 2012. We are required to commence construction by January 12, 2016.

The project requires upgrading an existing power-line that crosses a federal easement. We are resolving the easement issues, however, we require more time to do so.

As a broad rule of thumb the entire development process takes 10 years from a projects' beginnings to commercial operation. Additionally, a proponent risks several million dollars and many years to navigate the extensive licensing process to satisfy local, state and federal requirements. Importantly, we have worked continuously and in good faith to meet all the requirements in a timely manner. Because our project is in its final stages, we are committed to ensuring a successful outcome. S. 1104 would provide the needed time to secure final permits and acquire the necessary easements prior to commencing construction.

We have earned broad support from stakeholders in the area. Our project will strengthen the Greenfields Irrigation District and provide a new source of income for the Sun River Electric Cooperative. After the project is built, local grid reliability will improve and area environmental factors will be enhanced. The project will create a new source of sustainable federal, state and local revenue for decades. Gibson Hydro answers the congressional call to add hydroelectric generation to existing federal infrastructure. The project will also diversify American energy supply, a key national interest. We need S. 1104 to pass to make it all happen. Please support S. 1104.

Sincerely,

Thom A. Fischer

Thom Fischer
CEO Tollhouse Energy

1800 James Street | Suite 201 | Bellingham, Washington | 98225
Phone 360-738-9999 | Fax 360-733-3056

Statement of Alina Osorio, Manager
Clark Canyon Hydro, LLC

Before the
U.S. Senate Energy and Natural Resources

May 19, 2015

Chairman Murkowski, members of the Senate Energy and Natural Resources Committee, thank you for the opportunity to submit testimony in support of S. 1103—A bill to reinstate and extend the deadline for commencement of construction of a hydroelectric project involving Clark Canyon Dam.

I am also grateful to Senators Daines, Tester, Crapo and Risch for introducing this legislation providing an opportunity for the Clark Canyon Hydro project to come to fruition and provide benefits to the people of Montana and Idaho.

The Clark Canyon Hydro project will provide jobs, reliable and renewable electricity, tax revenue for Montana and power during the hottest months of the year when electricity demand is high. The hydro project being developed on the Clark Canyon Dam located in Montana, draws on the existing dam owned by the Bureau of Reclamation. The project is for a net capacity of 4.7 MW supplying an estimated 17,900 MWh of clean, renewable electricity per year, enough to power approximately 1,770 average homes per year. As you know, hydro power is stable, reliable and a renewable resource whose assets typically last for 50 to 100 years. Unlike some other forms of renewable electricity, hydropower has a number of ancillary benefits which helps to provide stability to the electric transmission and distribution system.

Environmental benefits include reducing an estimated 18,000 tonnes/year of CO_2 and supplementing the dissolved oxygen into the Beaverhead River below the dam. The Beaverhead River has ongoing challenges with low oxygen levels, the Montana Department of Environmental Qualify has provided 401 water quality certification for the project. The Bureau of Reclamation owns and operates this dam which was built in 1964, the project draws on already existing potential power without creating adverse impacts to the Beaverhead River.

Economic benefits include, creating 30 to 40 jobs during construction and 1 to 2 full time operating jobs for the life of the project, which is anticipated to be 50 or more years. In addition to the job benefits, state and federal tax revenues that will be realized during the first five years will be approximately $611,000. Because the electricity is considered renewable, the renewable electricity credits (RECs) will be an additional economic value.

Clark Canyon Hydro LLC (CCHL) acquired the project from a former developer who was not able to complete the. The delays that occurred were due in large part by the former developer's mismanagement and neglect to file the necessary updates and project plans in a timely fashion to the Federal Energy Regulatory Commission (FERC). Despite the prior developer's errors, the FERC Commissioners continue to support development of the project and uniquely expressed that support in the FERC Order terminating the license:

> *Although we are required to terminate the license, we are sympathetic to efforts to develop the project – indeed, the Commission previously issued Clark Canyon a license because the Commission concluded that the Clark Canyon project was in the public interest – and those efforts need not end with our holding here. In a number of instances, Congress has, at the request of developers of projects that failed to timely commence construction, enacted legislation authorizing us to reinstate terminated licenses and grant additional extensions of the time to commence construction*[1].

We are grateful that the Senate Energy Committee is expeditiously considering the extension of the license as suggested by FERC.

Other interested government entities with jurisdiction over the Clark Canyon Hydro project also support the project completion. The Bureau of Reclamation has been extremely cooperative with CCHL since the company took over the project by providing guidance and recommendations such that the project design will quickly achieve final approval. The Montana Department of Environmental Quality (DEQ) in November 2014 published a report indicating the Beaverhead River, which feeds the Clark Canyon Dam and ultimately the hydro turbines, is low in oxygen which hurts native aquatic species. (As stated earlier, the Montana DEQ provided water quality certification for the project.)

Clark Canyon Hydro LLC looks forward to the opportunity to complete this project and deliver all of the anticipated environmental and economic benefits to the people of Montana and Idaho.

Madame Chairman, thank you again for the opportunity to submit testimony on behalf of Clark Canyon Hydro, LLC in support of S. 1103.

Respectfully submitted,

Alina Osorio
Manager
Clark Canyon Hydro, LLC

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[1] 150 FERC ¶ 61,195, United States of American Federal Energy Regulatory Commission, Clark Canyon Hydro, LLC Project No. 12429-013, Order Terminating License (Issued March 19, 2015)

Sun River Watershed
a non-profit organization benefiting all water users in the basin
816 Grizzly Drive Great Falls, Montana 59404 406-727-4437

May 14, 2015

The Honorable Steve Daines
United States Senate
Washington, D.C.

RE: Gibson Hydro Project

Dear Senator Daines:

The Sun River Watershed Group (SRWG) is writing this letter of support S. 1104 to extend the Gibson Hydro project license for another six years. This project will diversify our country's energy supply, boost rural vitality, create job opportunities, and increase rural income while protecting our environment.

For more than 20 years the SRWG has worked with many partners to find win-win solutions to complex natural resource issues. Two key components of our long-term goals is the sustainability of the local agriculture economy while improving our natural resources - which the Gibson Hydro project does both. What better way to find these win-win solutions than to utilize an existing facility to generate clean electricity that will also protect and enhance natural resources.

The SRWG considers what the Sun River Watershed will look like in future years when evaluating the pros and cons of most projects. So with the Gibson Hydro project will it: 1) protect water supplies for future generations to meet all needs - YES; 2) protect water quality for wildlife and people - YES; 3) improve the our local agriculture economy - YES; 4) improve other sectors of our local economy - YES; and 5) does not appear to have negative effects to anyone or anything. So with all these key points considered, the SRWG supports the Gibson Hydro project moving forward.

Please help us improve our teamwork in the Sun River Watershed by supporting this project. Call Alan Rollo at 406-727-4437 if you have any questions concerning our support for this project.

Sincerely,

John Chase, President
Sun River Watershed Group

Cc: GID

Beaverhead County Commissioners
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April 20, 2015

The Honorable Steve Daines
U.S. Senate

RE: Clark Canyon Dam Hydroelectric Project.

Dear Senator Daines:

The Beaverhead County Commissioners strongly support the Clark Canyon Dam Hydroelectric Project at Clark Canyon Reservoir.

Symbiotics, LLC, on behalf of Clark Canyon Hydro, LLC has evaluated the entire project area. The Symbiotics Report addresses the topics of concern and lists a detailed conclusion. The Report states that there will be no impact to the recreation industry.

The Hydroelectric Project will not affect the annual set irrigation season releases or the winter releases from the dam outlets.

The Clark Canyon Dam Hydroelectric Project is a welcome addition to the County's economic base as it is an example of the multi-use of our natural resources.

The Beaverhead County Commissioners support a bill to reinstate and extend the deadline for commencement of construction of the Hydroelectric Project at Clark Canyon Dam.

Sincerely,

Garth L. Haugland
Chairman

Michael J. McGinley
Commissioner

C. Thomas Rice
Commissioner

:pto

Senator DAINES. Thank you, Madam Chair. FERC has also submitted a statement on these bills stating that they do not oppose.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

May 18, 2015

OFFICE OF THE CHAIRMAN

The Honorable Lisa Murkowski
Chairman
Committee on Energy and Natural Resources
304 Dirksen Senate Office Building
Washington, D.C. 20510

RE: S.1103 and S.1104

Dear Chairman Murkowski:

This letter is in response to a request from your staff for my views on S.1103 and S.1104. S.1103 would require the Federal Energy Regulatory Commission to reinstate the license for the proposed 4.7-megawatt Clark Canyon Dam Hydroelectric Project No. 12429, to be located at Reclamation's Clark Canyon Dam on the Beaverhead River in Beaverhead County, Montana. The bill also would require the Commission to extend the commencement of construction deadline for the project for a three-year period. S.1104 would authorize the Commission to extend, for six years, the commencement of construction deadline for the proposed 15-megawatt Gibson Dam Hydroelectric Project No. 12478, to be located at the U.S. Department of the Interior, Bureau of Reclamation's (Reclamation) Gibson Dam, on the Sun River, in Lewis and Clark and Teton Counties, Montana.

The Commission issued an original license for the Clark Canyon Dam Project on August 26, 2009. The license required that commencement of project construction begin by the maximum allowable two-year deadline, August 25, 2011. At the licensee's request, the Commission extended the deadline for two years (i.e., until August 25, 2013), which is the maximum allowable by section 13 of the Federal Power Act. The licensee was not able to commence construction by that date and, as required by section 13, the Commission terminated the license, by order dated March 19, 2015. The Commission explained that the licensee could file a new license application and that Commission staff would work with the licensee to determine whether portions of the Commission's regulation could be waived to make the new license proceeding as expeditious as possible.

The Commission issued an original license for the Gibson Dam Project on January 12, 2012. The license provided that the company was required to commence project construction within two years of the date of the license, which again is the maximum period permitted by the Federal Power Act. The Commission subsequently granted the maximum allowable two-year extension of the commencement of construction deadline. Accordingly, the deadline for the commencement of construction is now January 12, 2016. Section 13 of the Federal Power Act provides that, if construction does not timely commence, the Commission must terminate the license. It is my understanding that the licensee is encountering difficulty obtaining lands, subject to a U.S. Fish and Wildlife conservation easement, that are needed for construction of the project's primary transmission line, such that the licensee believes that it may not be able to commence project construction by the statutory deadline.

The last several Commission Chairmen and I have taken the position of not opposing legislation that would extend the commencement of construction deadline no further than 10 years from the date that the license in question was issued. Where proposed extensions would run beyond that time, there has been a sense that the public interest is better served by releasing the site for other public uses. Because S.1103 and S. 1104 provide for commencement of construction deadlines that do not exceed 10 years from the dates that the respective licenses were issued, I do not oppose these bills.

If I can be of further assistance to you on this or any other Commission matter, please let me know.

Sincerely,

Norman C. Bay

Norman C. Bay
Chairman

Senator DAINES. With that, I yield back my time.

The CHAIRMAN. Senator Barrasso.

Senator BARRASSO. Thank you so much, Chairman Murkowski. Thank you for holding today's hearing on legislation to boost America's energy supply.

Last month Senators Manchin, Heitkamp, Hoeven, Enzi and I introduced S. 1026, the North American Alternative Fuels Act. It is a bipartisan bill that would promote the production of alternative transportation fuels here in North America and help reduce our nation's reliance on energy from overseas.

Specifically our bill would repeal a provision enacted in 2007. This provision prohibits the Government from purchasing transportation fuels which emit more carbon than conventional petroleum fuel. While the authors of this provision were surely well intentioned, they have left us with a policy that makes little sense.

In effect, the policy compels the U.S. Government, including the U.S. military, to favor energy produced in the Middle East and other hostile regions of the world over energy produced here in North America. So I think most Americans would find this absolutely absurd. That is why Senator Manchin and I are working to change this policy.

We believe Congress should, at the very least, allow North American energy to compete on a level playing field with energy from overseas. We believe Congress should allow U.S. oil, gas and coal producers to sell the fuel range of their products to the U.S. military. This will enable oil, gas and coal producers to increase investments in jobs here in the United States. It will also allow the U.S. military to access additional energy resources here in North America which will enhance our nation's energy security.

Mr. Milito, would you explain how Sections 526 of the 2007 Energy Act favors energy from Middle East and other hostile regions of the world over energy produced in the United States?

Mr. MILITO. Yes, Senator. Fundamentally, Section 526 simply limits the flexibility of the military to purchase its fuels from reliable partners like Canada. And then by doing that, you're taking those partners off the table and turning the demand to other parts of the world, including the Middle East. So fundamentally, it's extremely problematic.

Senator BARRASSO. And could you explain how this Section 526, if it is not repealed, could actually increase transportation fuel costs for the military?

Mr. MILITO. Yes. Anytime you're limiting supply the fundamentals of economics are going to lead you to a position where you could increase the costs of the fuels to the purchaser, in this case the military. You know, the military is the Government's largest consumer of fuels, and prohibiting the use of Canadian oil jeopardizes our national security and could increase those fuel costs for our military and it restricts the Pentagon's ability to get the reliable energy it needs to fight the war on terror. I think the last thing we should be doing is limiting the ability of our military to get the necessary fuels for readiness, training, as well as operational needs.

Senator BARRASSO. So it will also impact our ability to get reliable and secure sources of energy?

Mr. MILITO. Absolutely. And if you look at the recent Quadrennial Energy Review, there was a great focus in there about looking at energy from a North American standpoint and making sure that we're looking holistically at both Canada and Mexico and working together to really create that energy security we need. 526 does the opposite, that's why we need passage of S. 1026 so we can get over these hurdles and create the stability our military needs.

Senator BARRASSO. In your testimony you also note that General Martin Dempsey, Chairman of the Joint Chiefs of Staff, has acknowledged that geopolitical benefits of energy exports. Could you tell us a little bit and discuss what those benefits might be?

Mr. MILITO. Yeah. Last year in March, General Dempsey testified before House Appropriations and was asked about U.S. production and U.S. exports. He specifically stated that U.S. production and U.S. exports are a prominent tool as we move forward from a geopolitical standpoint, and we've seen that in the past four to five years where the key factor counterbalancing global supply disruptions has been our production.

Our production has gone up over three million barrels a day. Global supply disruptions have been about three million barrels a day, so we've been able to counterbalance that. And we've gone beyond just counterbalancing by putting downward pressure on the price of oil as well as gasoline and creating huge benefits for consumers.

So it's having a tremendous benefit, and it's impacting the ability of regimes like Iran, Russia, Venezuela to fund their own governments and militaries.

Senator BARRASSO. Alright, thank you very much.

Thank you, Madam Chairman.

The CHAIRMAN. Thank you, Senator Barrasso.

Senator Manchin.

Senator MANCHIN. Thank you, Madam Chair and thank all of you.

I'm so sorry. I was in a Commerce Committee meeting and that made me late for this hearing, but I appreciate you all being here.

Last week my good friend, Senator Heidi Heitkamp from North Dakota, and I introduced a package of five bills to set a clear path forward for coal. I am happy to have three of these bills considered here today.

The first of these would establish a new program to ensure the continued use of domestic coal resources by developing technologies that will improve the efficiency, effectiveness, cost and environmental performance of coal. The program would work to preserve low cost electricity, diversify our nation's energy supply by keeping coal competitive and with other low carbon energy sources and speed up efforts to develop carbon emission reducing technologies.

The second of these bills which is also sponsored by Senator Whitehouse, myself and Senator Whitehouse, would ensure carbon capture use and storage is a priority for the Department of Energy across the fossil program. CCUS is not just a coal technology but one that will be used across the fossil energy sector.

The third bill, led by Senator Heitkamp, would give the Secretary of Energy the ability to help secure long term certainty for clean coal technology utilities and workers by allowing the Secretary to enter into private pricing stabilization agreements that keep the clean coal market price viable. This simple fix would create more incentives for public/private investment in carbon reducing clean coal projects and help remove barriers of uncertainty surrounding development of these critical technologies.

I think you all know me. Coming from West Virginia we have an all in energy policy. We have been blessed with a lot of coal, blessed with gas, natural gas, Marcellus shale gas. We have hydro. We have wind farms. We are trying everything. We are just not picking and choosing. We are basically trying to make sure this country is energy secured, and we think the security of our energy basically secures our country and keeps it safer.

With that, Ms. Kelly, if I could ask, how do members of your organization view the use of coal in their future generation portfolio and what technology would they recommend be pursued to maintain coal as a future option? Because I've talked to the Department of Energy, EIA, it is in the mix for the next three to four decades.

Ms. KELLY. Well, first of all we do definitely want to keep coal on the table as a viable option for us. Every time an option is taken off the table we have a diminished ability to have a full array of resources to use to provide the most economical, reliable and environmentally responsible power.

Senator MANCHIN. Do you believe that the country can make it without coal right now in the mix?

Ms. KELLY. Not right now.

Senator MANCHIN. It's not reliable. Won't be affordable, right?

Ms. KELLY. It's too, well at this moment it's too large a portion of our generation mix. I mean, if you just look at the numbers. We see reducing that over time.

We support the bills you've noted, by the way.

Senator MANCHIN. Yeah.

Ms. KELLY. Because we do believe that with new research and development we can find better ways to use it. And we are, but let me just note one thing which is if we are going to go the sequestration route we need to think about the impacts of the sequestration and the potential liability for those people who do do that.

But yes, I agree with you that in the short run, you know, it's part of the mix.

Senator MANCHIN. I would like to go on record basically saying I have spoken to all the utilities, major utilities of the United States of America. Not one of them told me that the portfolio they have, the diversity of their portfolio, is one they would accept as a good business practice. They are all concerned of what they are being forced to do by regulations and by the different directions of this Administration.

To Mr. Hopper, if I may? Has the Bureau of Ocean Energy Management worked with the DOE to access the ability of storing CO_2 in offshore geological reservoirs?

There is a lot of oil and gas being produced, as we know, and developed offshore. Have you looked into potentially using those depleted sites as a medium for storing CO_2?

Ms. HOPPER. Senator, I'm going to have to get back to you on that. I don't actually know the answer to that question. But I will get back to you on that.

Senator MANCHIN. Okay. The only thing that we are trying to do is find a sensible way. Myself and Sheldon Whitehouse, that you would not suspect coming from two different spectrums. We both agree that we have a responsibility as humans for the climate and that basically they've got to find a balance between the economy and the environment. And we're trying to do that with legislation.

I have been to Rhode Island and seen basically the algae that they have been using from CO_2. We think that is doable. We think that can be expanded tremendously.

Senator Whitehouse has been to West Virginia to see what coal has done for the country and what we continue to do and what we are asked to do every day. We are just finding it very hard in West Virginia working with a hostile environment in Washington.

Ms. KELLY. Can I just say?

Senator MANCHIN. Yes.

Ms. KELLY. That, you know, our job as utilities is to provide reliable, affordable and environmentally responsible power supply. And we have to balance those three factors every day as we move forward. So I appreciate the bipartisan nature of the work——

Senator MANCHIN. We try.

Ms. KELLY [continuing]. You're doing with Senator Whitehouse. And we really do support those kinds of efforts.

Senator MANCHIN. Thank you very much.

The CHAIRMAN. Thank you, Senator.

Senator King.

Senator KING. Madam Chair, I did discover something I knew something about.

The CHAIRMAN. I knew you would. [Laughter].

Senator KING. I helped permit my first hydro project in 1983. It was a massive 1.5 megawatt on the Cobbossee Stream in Gardiner, Maine. So I have been working, I have worked in hydro permitting for many, many years. Any permitting program that takes seven to ten years and costs $50 to $100 million is not a permitting program, it is an annuity for lawyers and consultants. [Laughter.]

I want to just associate myself in the discussion of this Committee on the hydro relicensing provisions because it definitely needs to be fixed. So I want to commend the Chair for making that part of this discussion.

Hydro is an enormous resource in America. Clean, renewable and it is one that, I think, we have to clear away some of these issues that make it such a lengthy and expensive process.

One other point on this. We can talk about a $50 million process in seven years. What we do not know are the projects that never come forward because of that. It is the opportunity cost of companies who say, we cannot afford this.

By the way, that is high risk money because you can do seven years, spend $50 million, not get one of the necessary permits and you have nothing. So I believe that the country is losing potential resources because of the in terrorem effect of an uneconomic, unpredictable and untimely permitting process, particularly in the field of hydro.

So, I look forward to working with the Committee on this issue. Thank you.

The CHAIRMAN. Well, Senator King, thank you for that, and I look forward to working with you on this.

It is fascinating to me when we talk about hydro it seems that the assumption or the stereotype of hydro is some massive Hoover Dam. In Alaska most of our dams are small facilities. They provide for the needs of one community. They intertie with others to provide support in Southeast Alaska to a considerable degree. About 25 percent of our renewable energy comes from hydro in Alaska.

But it is not the big projects. It is probably more akin to what you helped permit there. Again, when you think about the time that is involved and the time value, then that's money that adds to the cost. It does put off the possibilty of some projects that could help make a difference, bring down our costs, which is particularly important in our more remote areas.

I wanted to ask you as a follow on to this, Mr. Livingston and then I will ask you, Mr. Sheets, about Alaska specifically. We did reforms back in 2005 in EPACT to require trial type hearings to allow the consideration of alternative condition and prescriptions, but what we understand is the reforms either did not take or they were not sufficient.

I agree with you, Senator King. When you are talking about a relicensing of a project, not licensing first time around, a relicensing taking eight to ten years, costing $50 to $100 million, it just does not work.

I believe you said, Mr. Livingston, that you felt that S. 1236 does take what we attempted to do, I guess, back in 2005 and really does address the concerns that Senator King has raised and that we have identified. Do we, in fact, now move closer to a reform that will actually be meaningful for the licensing and the relicensing of these hydro facilities?

Mr. LIVINGSTON. Yes, it does. I think the EPACT 2005 created some reforms which, you know, in use today the ILP process works, especially at the beginning of the process but in between two things happened.

One of those is how the regulations of EPACT 2005 were put into place. They allowed trial type hearings on preliminary conditions but not on final conditions so that the final conditions can actually look different and be submitted to FERC than what your trial type hearing outcome was. So that's one of the things that is a fix here.

There was also a court case that left lack of clarity in the extent of the condition and authority of the agencies so that as you think about where a condition might apply, should it apply to just the Federal lands within the FERC license?

Nobody doesn't think that the Federal Government for work done on its lands shouldn't have a say and shouldn't direct how those lands are treated. But right now should those conditions apply to private lands outside the boundary of FERC? Should they apply to third party lands outside of the boundary of FERC? Should they have a clear nexus? And those are the things that need better definition in the process because without that clarity to those conditions, those mandatory conditions, can become fairly far ranging.

So I think your bill does a fine job of making sure we achieve the balance of looking at the process.

We've got hard working people all trying to do the right things on this that helps fix the process issues we have today, takes a lot of things that happen sequentially and puts them parallel and helps better define the box. So we can get a five year relicensing.

So that those hydro projects that today are relatively small and couldn't afford a relicensing can go into licensing with greater certainty. And for those new projects coming along, they can be permitted in a way that at least we can get to a decision, one way or another, yes or no, earlier in the process and with a lot less money.

The CHAIRMAN. Well, we would like to think that we are going to get it right this time.

Mr. LIVINGSTON. Yeah.

The CHAIRMAN. Which is key, it is critical for that.

Mr. Sheets, I wanted to give you an opportunity this morning to speak to some of what we are seeing. You mentioned it briefly in your opening statement. You did not say that we are the incubator or the guinea pig for energy projects, but I like to think that we really are that testing ground for some very innovative energy technologies on the renewable side.

We are pioneering what microgrids are all about. When you recognize that most of the communities in the state are not attached to any grid and how you have to figure it out on your own, the resiliency that comes from being in a remote place and a high cost energy state, challenges us to be ever the more innovative.

I would like you to speak specifically to our opportunities within geothermal. We have great prospects out in Nome. What more can we be doing around the state to encourage that but also to take this model and replicate it elsewhere?

Also, given the fact that we have got policies back here that consider traditional geothermal to be this, so called, mature technology and as such, it is perhaps not eligible for certain Federal assistance. We have issues going on with our low temperature geothermal. We have some research and development projects going on with low temperature that in other parts of the country they would have said, it is not possible to even do what you are doing. Yet we know that in places like Chena, we have taken low temperature geothermal and we have powered a little resort. We have made it possible, but can we take what we have learned in Alaska and replicate that elsewhere?

Mr. SHEETS. Yes, yes, Madam Chairman, thank you for the opportunity to speak to that.

Alaska is blessed with a lot of low grade geothermal, meaning low temperature geothermal. In other states that are blessed with a high grade geothermal they can build large power plants that feed into the grid system. In Alaska we have very remote locations, and it's often hard to even characterize the geothermal resource that we have because in some of our areas that are permafrost. There are hot seeps, not necessarily hot springs in some of those places.

So conventional ways of determining the geothermal potential involves going out there, having a flow test, if you will, for a spring that's identified or some flowing hot water, that doesn't exist in some parts of Alaska. It's very marshy, and the whole region can be very warm and pinpointing where the source of that hot water is very difficult in those circumstances.

So we've had the opportunity to develop some technologies that allow us to fly over that area with FLIR, forward looking infrared cameras, and kind of help define the basins. And then by measuring nearby lands we can figure out how much heat it takes in that hot area to heat the ground temperature to that level.

So these are some innovative ways of just, kind of, reassessing these remote resources that we believe could work around the world in other situations that perhaps are underexplored for geothermal.

Another area for us that's really key, as the Senator pointed out, was making things smaller. We have a small population. We have small microgrids. We need to integrate these resources into the communities that we have.

We can't do anything with five megawatts of power. That's like ten times the size of many of our communities need. We need small technology that enables us to convert those local resources into useable energy, and the technology for that doesn't exist and the lower 48 could care less about it because they do have the grid system that they can rely on.

And so in Nome, for example, we have done quite a bit of work to de-risk that resource. We've done quite a bit of work to see if it's economic to string 60 miles of transmission wire into Nome. Nome, if you recall, just a few years ago ran out of diesel fuel, and we had to bring in the ice breakers to help them. They need local resources. You talk about energy security. That's energy security for Nome.

What happened in our case was we got to the point where now the private sector has taken notice and is interested in possibly pursuing that further. Maybe we'll see an IPP come in and develop that resource and sell it to the community of Nome, thereby providing reliable energy year round.

But it's not just low grade geothermal too. We're doing that in small photovoltaics. Several years ago when Galena, if you recall, was flooded and nearly wiped out, there was quite a bit of emergency money coming to that community. A lot of folks looked at it as an opportunity to put PV on every rooftop, if you will. You know, when we rebuilt the community let's go ahead and do that.

Well, the problems that you have with that is again, if you put too much renewable into a small grid system and a cloud comes over, suddenly you've destabilized that grid. So you still need conventional forms of energy to provide that base loader to follow. In our case we're using diesel generators, small diesel generators. And as the Senator pointed out, there are communities throughout the State of Alaska that have to make these microgrids work.

At our center we do a lot of research on integrating renewables with the conventional resources in microgrids. That is catching the attention of the nation because the nation is losing confidence in the reliability of its grid sources. So you see military bases, you see hospitals, you see, you know, critical infrastructure going to the microgrid format where they're installing diesel generators so that if they become islanded by choice or by happenstance, if they become isolated from the grid, they can make things work.

Alaska has had to do that for pretty much its entire life as a state. And so, that's why I, you know, I didn't use words like incubator because we're doing things. We are leading it. Now what we want to do is export that knowledge to the rest of the states and to the rest of the world, and invite them to see what we've done.

We're not really looking for Federal handouts. We're just looking, you know, maybe for the Feds to come alongside of us and help us figure out on those projects that weren't successful but they were just really, really close. It'd sure be nice to see a little bit of investment to find out why we're that close and we just can't quite get there yet.

The CHAIRMAN. Yeah, yeah.

Mr. SHEETS. So that's where we try to focus our attention is what can we do to get that extra little step? That's where, I think, a partnership like the demonstration projects that are listed in some of these bills are so important, and that's why I'm here today.

The CHAIRMAN. Well, I thank you for that, and I did not want to cut you off from your answer because I think the information that you are providing is so important.

Senator King and I are the co-chairs of the Arctic Caucus here in the Senate. One of my hopes is that while the United States is Chair of the Arctic Council for these next two years, one of the things that we lead on, that we help set the agenda on, is discussing and moving forward with some of the energy issues that, particularly, are lacking in the remote areas of the Arctic.

The European Arctic for the most part, they have got their energy infrastructure grids that are built out. Not so much in Canada, the U.S., and Russia. How we can take some of these technologies and as you say, this is not just research and development. This is on the ground. Sometimes it is a little bit of duct tape and just the crazy inventor out there. But when you don't have——

Senator KING. Sounds like something Maine and Alaska have in common, duct tape.

The CHAIRMAN. Maine and Alaska would really get together well here on some of these because again, you have got challenges with your cold. You have got challenges with not having anybody else to rely on. This is something that again, when we talk about technologies and public/private partnerships, we have such an opportunity here.

I have got a couple more questions.

I will just let the witnesses know that it is not because of lack of interest that Senator Cantwell is not here this morning. As you know, we have TPA on the Floor and Senator Cantwell has been very involved with that, so she has been pulled away to deal with issues on the Floor, otherwise I know that she would be here asking questions as well.

I would like to try to wrap up within the next couple minutes, but I wanted to ask you, Mr. Milito, we have had a lot of discussion here in this Committee about the prospect for LNG exports and what we might be able to do from just a process perspective to ensure that we are able to share the abundance of our natural gas resource with friends and allies around the world. Now that subject is moving to the export of oil. Senator Cantwell brought it up in her opening statement. When we are talking about workforce issues and the nation's growing energy portfolio, what potential for challenges, I guess, or maybe there is greater opportunity there, do we see with a qualified and trained workforce if we are successful in advancing opportunities for lifting the ban on oil exports which would ultimately increase production?

Can you just speak to the workforce piece of it because we really have not had that conversation here this morning?

Mr. MILITO. Absolutely, and it's a great topic that we need to discuss. I mentioned how the industry is looking at 1.3 million new jobs, excuse me, over the next 15 years, but that's going to be tied to access on the one side, making sure that we have the opportunity to develop oil and gas so we can secure those jobs. But on the other side, making sure that we are putting our young people and our college-age students in a position to be able to move into those jobs from a qualified standpoint.

So we are working very hard with your office and other offices in trying to make sure that we're engaged in this dialogue. We've created a website called oil and gas workforce.com. So anybody can go there and look at the type of jobs that are available.

But in that study we noted that over 60 percent of the jobs are blue collar which is great. They're all well-paying. They pay double, triple the national average in terms of looking at the Bureau of Labor statistics data.

But we need to make sure that we're putting qualified people in those positions, so working with community colleges, working with universities, working with our companies and kind of bridging together. And part of our effort is also creating outreach to African American, Hispanic communities to make sure that we're creating a diverse workforce which is the way the U.S. is moving. We're becoming more and more diverse and we have to really create these opportunities for all the communities out there who have a stake in this.

So it's a critical issue, and the only way we're going to be able to be successful is making sure that we move forward in a strategic way to develop this qualified workforce. It's the great crew change that's occurring, and we need to fill that void with good people so they have the good paying jobs.

The CHAIRMAN. Thanks, I appreciate that.

Senator KING. Madam Chair, before we leave the hearing.

The CHAIRMAN. Senator King.

Senator KING. One important point for the record in our discussion about hydro relicensing and the licensing and permitting process, neither you nor I nor I think anybody else here is talking about lowering environmental standards.

The CHAIRMAN. Right. Right.

Senator KING. We're talking about the process.

The CHAIRMAN. Absolutely.

Senator KING. My goal in Maine was that we would have the highest environmental standards in the country and the most timely, efficient and predictable environmental process. And I don't think those two goals are in any way in conflict.

So I think it is important that we emphasize we are not talking about cutting environmental corners. We are talking about establishing a process that makes sense and does not impede the development of these important resources.

So I just wanted to——

The CHAIRMAN. Yeah.

Senator KING [continuing]. Make that comment for the record.

The CHAIRMAN. No, I appreciate you doing that, and know that I concur. Again, I want to work with you on some of these hydro issues.

My last question is going to be for you, Ms. Kelly. As you know, I have focused a lot in this Committee about the concerns that I have in so far as making sure that there is a reliable infrastructure, that there is reliability and affordability within our energy sector here. You have not only in your comments but in fielding different questions here this morning, talked a fair amount about the RTO rules and the requirements for public utilities to participate in capacity markets to supply their own capacity, trying to find this balance forward.

You spoke relatively favorably of my bill, S. 1222, which would among other things, require the RTOs to make filings with FERC to satisfy a set of resource adequacy objectives and moving then towards the self-supply. So just hopefully very quickly, would you agree that base load plants are critical for reliability?

Ms. KELLY. We need all types of plants to ensure reliability. We need base load. We need shoulder, what we call shoulder units. We need peaking units. And in order to comply with coming environmental regulations, we need to have a diverse fleet as well.

The CHAIRMAN. Yes.

Ms. KELLY. For example, one of the problems we know are that some new nuclear, you know, old nuclear units have difficulty operating. They have a proper place in our fleet.

We have new nuclear units that we would like to construct. We have members that are doing four new nuclear units. They're in Georgia and South Carolina because they cannot be supported in these capacity markets which are too short term in nature to permit that.

So yes, we believe there needs to be all kinds of resources. We prefer, as I said in our discussion with Senator Manchin, that we have all options on the table to do that because we need that to meet the, kind of, triple play of reliable, affordable and environmentally responsible.

The CHAIRMAN. I would assume further that you would agree that base load plants in RTO markets should have the opportunity to earn a reasonable rate?

Ms. KELLY. Yes, they should have the opportunity to earn a reasonable rate.

The CHAIRMAN. Then while self-supply may not be the answer that most of your members prefer as their first choice, it may provide a basis for enabling your members to join with others who care about preserving base load nuclear and other plants in the RTO markets. I am assuming, again, that this is where your members would like to go?

Ms. KELLY. We have an abiding interest in being able to self-supply our resources. In the three eastern RTOs where these mandatory markets operate, most other utilities no longer have an obligation to serve their customers. That has been undone through retail access.

So our business model is actually the minority model. We still supply our member's resources. We still try to do that at the lowest reasonable cost with a diverse portfolio of different kinds of resources.

But that's not the business model for some of these others and for most of the other entities in these RTOs. That's why we want to be able to self-supply because we want to be able to serve our own loads, with our own resources, at our own economics. When these markets were first introduced we negotiated those provisions, especially in ISO New England and PJM. We made that deal, but then later those provisions were revised and taken away from us. So that, you know, we feel there's substantial overarching problems with these markets but we also want to be able to self-supply our own members because our business model is different than everybody else's. I hope that's helpful.

The CHAIRMAN. Yes, that is helpful. Thank you.

Ms. KELLY. And we can comment for the record if you wish as well.

The CHAIRMAN. You know, I would appreciate that.

I mentioned in the first round of questioning the BOEM fact sheet as it related to oil spill risk in the Chukchi Outer Continental Shelf. This was in reference to a comment that Mr. Matzner had made about a 75 percent figure, and I am going to include that fact sheet in the record itself.

I think it is important to note that in the BOEM fact sheet their numbers assumed 500 wells producing 4.3 billion barrels of oil over 77 years. So through the year 2092, .00002 percent of the oil produced might be spilled. 99.99998 percent would be delivered safely to Americans while creating jobs, generating revenue, improving trade balance and increasing security throughout.

Again, I want to make sure that when we talk about the figures that are out there that we give full definition to where those numbers came from. That BOEM fact sheet will be included as part of the record.

[The information referred to follows:]

BOEM | FACT SHEET
BUREAU OF OCEAN ENERGY MANAGEMENT

Oil Spill Risk in the Chukchi Sea Outer Continental Shelf

The 75-percent figure: What does it mean?

BOEM manages the responsible exploration and development of offshore energy and marine mineral resources on the U.S. Outer Continental Shelf (OCS). The bureau supports energy independence, environmental protection and economic development through responsible management of these offshore resources based on the best available science. All offshore exploration has potential benefits and potential risks. Our goal is to maximize benefits and minimize risks – to people, wildlife and to the environment.

In February 2015 the Bureau of Ocean Energy Management published a Supplemental Environmental Impact Statement examining the potential environmental impact of oil and gas development in the Chukchi Sea, off the northwest coast of Alaska (see: www.boem.gov/ak193).

Following its publication, one figure in particular has attracted attention in the media and from stakeholders: The estimate that future development brings with it a 75-percent chance of one or more spills of more than 1,000 barrels of oil.

What follows is a short FAQ designed to clearly explain what this 75-percent figure means -- and doesn't mean.

Frequently Asked Questions

Q: Is it accurate to say that "If Shell's Chukchi Sea Exploration Plan is approved, there is a 75-percent chance of a large oil spill?"

A: No. First, the 75-percent chance figure does not apply to plans of any particular operator; it applies to a hypothetical long-term exploration and production scenario created by BOEM analysts (see below) over the full life of all leases issued in the Chukchi Sea. Second, Shell has to this point proposed only an exploration program. Even in BOEM's hypothetical scenario, the data suggest that a large spill in the exploration phase is very unlikely. In the exploration phase, wells are drilled to discover the location of oil or natural gas. In the production phase, wells are drilled to extract the oil or gas from beneath the seabed.

Q: How can BOEM analyze environmental impacts without knowing more specifics about the development in question -- how many wells, operating for what length of time, etc.?

A: To analyze potential effects of development, BOEM must first create a hypothetical scenario and model. The scenario involves eight production platforms with more than 500 wells producing 4.3 billion barrels of oil over the course of 77 years. BOEM then examines the potential environmental impacts associated with this scenario. BOEM estimates the likelihood of a spill by first looking at oil spill data from other portions of the Outer Continental Shelf. We then consider how factors unique to the Arctic (harsh weather, climate, and the length of the drilling season, for example) may additionally affect spill rates.

Q: In the hypothetical scenario created by BOEM, what do the models suggest about the likelihood of a spill?

A: The historical data suggested that, in the hypothetical scenario we used, there would be -- over the course of more than three quarters of a century of oil and gas activities -- a 75-percent chance of one or more spills of more than 1,000 barrels of oil.

Q: What do the data say is the most likely number of such spills?

The data suggest that, in this hypothetical scenario, the most likely number of such spills is one. However, in examining the likely environmental impacts of development -- which, as you remember, is our original question -- we assumed two such spills, just to make sure we weren't inadvertently understating the likely environmental impacts. This is in keeping with the Administration's cautious approach in the Arctic.

Q: And how large would such spills be?

A: To estimate the likely size of these spills, we again looked at the historical data for "large" oil spills (that is, spills of more than 1,000 barrels). This data indicated median spill sizes of 5,100 barrels (from a production platform) and 1,700 barrels (from a production pipeline).

Q: Can you put that into historical perspective?

A: The impact of any spill should not be minimized. Our analysts report that impacts from such spills can be significant depending on timing and location of such spills. However, the spills modeled by BOEM are very unlikely to be the catastrophic historical events one might think of when we think of oil spills. For historical perspective, the 1989 Exxon Valdez spill is estimated to have been from 257,000 to 750,000 barrels; the 2010 Deepwater Horizon spill is thought to have been 3.19 million barrels.

To learn more about oil spill risk analysis conducted by BOEM, see the latest BOEM Ocean Science Journal at this link.

For information about recently proposed Arctic regulatory standards, visit this link.

For more information: www.BOEM.gov

Last updated April 2015

The CHAIRMAN. I think it is important for people to recognize, and I know that my colleagues on the Committee recognize that when we said we were going to do a supply hearing it was not just supply as may come out of the State of Alaska. Although, as I have listened to all of you, everything that you have touched on comes from my state. So again, I think it goes to prove the point that we do have a little bit of everything and a lot of a lot of things.

My purpose in focusing on supply as a title is not to say that we are going to focus on renewables at the expense of fossils or we are going to focus on nuclear at the expense of coal or natural gas. It is to appreciate and understand that in this country we have an abundance of supply when it comes to our energy assets, and that is something worth celebrating because not every country has this.

We see this from our friends and neighbors. The reason that I am pushing for oil exports is because we have friends that are truly being held hostage because they do not have a source, a safe source of supply that they can turn to.

Murkowski pays attention to what goes on in Poland. Poland is 96 percent dependent on Russia for their oil. We have an abundance of supply so why would we not work to encourage that production in this country where our environmental standards are second to none, that will allow for jobs and economic opportunity and at the same time with that wealth of supply help our friends and our allies?

So part of what we are trying to craft here in this Committee is a view of the energy sector that is fair and balanced and does have, truly, a little bit of everything, all of the above. People are getting tired of that phrase, but I think it does denote what it is that we have here.

If we choose to sit on it or to close it off or to lock it up, then I think we need to answer for that. If we are going to lock up our oil and gas resources in Alaska's North Slope whether in ANWR or NPRA or offshore are we going to be satisfied then that we will continue to receive that resource from somebody else who does not have the same environmental standards, who will continue to provide supply?

My colleague speaks of the irony that he sees with us accessing our resources in the North. I do not think that any of us would find it ironic when a Senator from Colorado says we need to access our shale gas or when a Senator from Minnesota says that we need to access our biomass. We have resources within the regions that we all represent.

I think the challenge for us is how we access it safely, responsibly and for the benefit of the people who are engaged in that economic opportunity. That is what I am trying to do here within the Committee.

I appreciate what you all have contributed here this morning with your views and your perspectives. I thank you for taking the time to travel here to Washington.

Certainly, Mr. Sheets, you have come the furthest, but again, I thank you for helping to educate not only my colleagues here, but others around the country about some of the extraordinary opportunities that we have when we are challenged. I think we can rise to the occasion, do well and perhaps even surprise some folks with our abilities.

So, with that, I have held the Committee over longer than I intended. I thank you for your time and again for your resources here today.

The Committee stands adjourned.

[Whereupon, at 12:12 p.m. the hearing was adjourned.]

APPENDIX MATERIAL SUBMITTED

U.S. Senate Committee on Energy and Natural Resources
May 19, 2015 Hearing: Energy Supply Legislation
Questions for the Record Submitted to Ms. Abigail Ross Hopper

Questions from Chairman Lisa Murkowski

Question 1: The proposed Arctic rule is just one example of regulations affecting the offshore oil and gas industry; there is also the well control/blowout preventer rule, proposed changes to the valuation of oil, gas and coal that would be significant for offshore facilities. I greatly appreciate Senator Cassidy's inclusion in S.1276 of a requirement for a GAO report on the cumulative impact of regulations on offshore development — does the Bureau of Ocean Energy Management consider the cumulative impact of these rules, not just on operations, but on the value of lease sales and subsequent bonus bids?

Response: Regulatory impact analyses should monetize forgone benefits to the extent possible, as described in OMB Circular A-4. The analysis conducted by BOEM and the Bureau of Safety and Environmental Enforcement (BSEE) of potential costs and benefits of the recently proposed Arctic Rule do not anticipate that the proposed requirements, or their associated costs, would prevent lessees and operators from conducting exploratory drilling on their leases. Therefore, BOEM did not evaluate the impacts on the value of lease sales and bonus bids in the proposed rule. However, pending review of the information included in public comments on the proposed regulatory impact analysis, BOEM may include such costs in the final rule.

Question 2: On March 7, 2013, during a full Committee hearing, I asked Secretary Jewel for a commitment to work with us to try to put together a bipartisan proposal with respect to revenue sharing that could bring together, all across the country, communities where there's Federal land and Federal water – Secretary Jewell stated: "Senator, I'd be delighted to work with members of this committee on that important proposal. As I met with a number of the Senators that are present here, I appreciate the different perspectives on revenue sharing. I appreciate the importance of a strong economy in our communities that feel both the impacts as well as the economics of oil and gas development and other mineral developments. I think revenue sharing is clearly a very important topic that deserves some attention from the Department of Interior as well as this body." Instead of attention and collaboration, I have seen simply opposition. What have you done at BOEM to follow up on the commitment Secretary Jewel made during her confirmation?

Response: As stated by the Secretary in a response to a Question for the Record from the March 7, 2013, hearing, "I believe that the Department, as steward of our public lands and waters and through rigorous dialogue with stakeholders, must strike the right balance of meeting the interests of local communities and the public owners of these resources as we advance the President's ''all of the above'' energy strategy." The goal is to direct offshore energy revenue to programs that provide broad natural resource, watershed, and conservation benefits to the Nation; help the Federal government fulfill its role of being a good neighbor to local communities; and support other national priorities. This goal does not exclude affected states from receiving shared revenue.

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Specific to BOEM, the bureau has worked with Members of the Committee and Congress to provide useful information on potential revenue sharing proposals, including the development of hypothetical maps and revenue projections under various revenue sharing scenarios.

Question 3: Ms. Hopper, in your testimony you stated that the Department of the Interior cannot support any of the three Outer Continental Shelf bills discussed at the hearing because they do not provide, "Secretarial discretion to determine whether those areas are appropriate for leasing through balanced consideration of factors such as...State and local views and concerns." Please clarify if it is, in fact, the position of the Department of the Interior that unelected agency officials are better suited to consider state and local interests than duly elected Members of Congress?

Response: Pursuant to Section 18 of the Outer Continental Shelf Lands Act, there are eight factors that the Secretary must consider in determining the size, timing, and location of leasing, one of which is the laws, goals, and policies of affected States. As required by Section 18(c)(1), BOEM sent letters to the Governors of all 50 states requesting their suggestions and asking them to identify any relevant state laws, goals, and policies for the Secretary's consideration in developing the 2017-2022 Oil and Gas Leasing Program. Additionally, BOEM has received comment letters from Members of Congress throughout the early development of the 2017-2022 Program. Each comment from a Member is reviewed and officially recorded to ensure their comments remain an active part of the process. Concurrently, BOEM has conducted many scoping meetings in affected states to gather valuable input from all stakeholders. The three Outer Continental Shelf bills discussed at the hearing call for circumventing this important provision of Section 18.

Questions from Senator Joe Manchin

Question 1: Has the Bureau of Ocean Energy Management worked with DOE to assess the ability of storing CO2 in offshore geologic reservoirs? There is a lot of oil and gas being developed offshore – have you looked into potentially using those depleted sites as a medium for storing CO2?

Response: Yes. A BOEM study published in 2012, titled *Analysis of the Costs and Benefits of CO2 Sequestration on the U.S. Outer Continental Shelf*, incorporates data and assessments found in DOE's National Carbon sequestration database and geographic information system (NATCARB). OCS Study BOEM 2012-100 can be found at http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Energy_Economics/External_Studies/OCS%20Sequestration%20Report.pdf

June 4, 2015

U.S. Senate Committee on Energy and Natural Resources

May 19, 2015 Hearing: Energy Supply Legislation

Susan N. Kelly Responses to Questions for the Record

Questions from Chairman Lisa Murkowski

Question 1: Should a diverse generation portfolio also include resources providing ancillary services (i.e., reactive power supply and voltage control, regulation and frequency response, energy or generation imbalance, and operating reserves both spinning or non-spinning, as applicable)?

APPA Answer: A diverse generation portfolio as the term is generally used means a portfolio of resources of different fuel types (*i.e.*, coal, natural gas, nuclear, hydro, wind, and solar) and technologies, in different locations, which taken together can meet the power supply needs of retail customers in each electric utility's service territory over short and long term time horizons. A diverse generation portfolio also minimizes the risk of being dependent on one fuel source or on an intermittently available resource. Diversity can also reflect a variety of financial arrangements, including ownership, long-, medium-, and short-term contracts, as well as spot-market purchases, which reduce the financial and reliability risks to customers and allow the utility to respond to evolving community expectations, such as increased reliance on renewable resources and distributed generation.

Many of these resources are capable of providing ancillary services. Moreover, new technologies, such as battery storage, also hold the promise of being able to provide such services. Balancing authorities and transmission operators employ such resources to ensure operational reliability of the bulk power system, often at the regional level. It is therefore necessary to have resources capable of providing ancillary services when and where they are needed by system operators, but not every utility or load serving entity needs to own or operate resources capable of providing ancillary services. Thus, ancillary service capability may or may not be part of the discussion about portfolio diversity for a particular utility.

If the portfolio owner is seeking to self-supply its own ancillary services or is seeking to reduce the risk that the ancillary services may not be provided or may not be provided at a reasonable cost by a third party, then it would want to ensure that such resources are included in its portfolio.

Question 2: I appreciate APPA's support for S. 1236, my Hydropower Improvement Act, that would empower FERC to be the lead agency in the hydro licensing process, with the ability to establish and enforce deadlines for agencies responsible for required Federal authorizations. There are some who object to these provisions as divesting the resource agencies from imposing mandatory conditions they believe are necessary to protect federal lands. Why do you believe these reforms in the Hydropower Improvement Act are necessary?

APPA Answer: FERC is the primary federal agency responsible for the licensing and relicensing of non-federal hydroelectric projects, but the involvement of multiple resource agencies often makes the process long, expensive (sometimes prohibitively so), and plagued with uncertainty for applicants. Under the Federal Power Act ("FPA"), FERC must give "equal consideration" to power and non-power needs, the latter of which include Endangered Species Act requirements, water quality issues, marine navigation, and other public interest concerns. Moreover, state and federal agencies can impose "mandatory conditions" that FERC cannot balance or modify in the public interest. APPA believes, while it is appropriate to consider a broad array of factors when licensing or relicensing a hydropower facility, the process needs to be streamlined. Your legislation, S.1236, preserves the authority of state and federal resource agencies to provide their expert input during the license consideration while creating a sensible framework and timeline for the process. Without reform, additional clean electricity generated by hydropower facilities will remain an untapped resource.

Question 3: You testified that the option of hydropower generation is "urgently needed to manage the very difficult choices" that will be presented by EPA's proposed Clean Power Plan for existing facilities. You also noted that a federal Renewable Electricity Standard (RES) at this time is unnecessary, would create a host of issues for utilities that are already subject to state RES requirements, and would be nearly impossible to comply with given EPA's Clean Power Plan regulation.

a. How is hydropower treated under the proposal to impose a federal RES mandate?

   APPA Answer: S. 1264, introduced by Senator Udall would impose a 30 percent federal renewable electricity standard on retail electric suppliers, which are defined as persons that sell "electric energy to electric customers that sold not less than 1 [million] megawatt hours of electric energy to electric customers for purposes other than resale during the preceding calendar year." Retail electric suppliers would be required to obtain set annual percentages of their electricity from renewable energy resources, which are defined as including "solar, wind, ocean, tidal, geothermal energy, biomass, landfill gas, incremental hydropower, or hydrokinetic energy." Incremental hydropower is defined as "additional generation that is achieved from increased efficiency or additions of capacity made on or after—(A) the date of enactment of the…[bill]; or (B) the effective date of an existing applicable State renewable portfolio standard program at a hydroelectric facility that was placed in service before that date."

The legislation essentially treats hydropower differently than other renewable energy resources by only giving credit for incremental hydropower, and completely precluding compliance with the federal RES through use of electricity generated from existing hydropower facilities. There are no similar restrictions for other renewable energy sources, such as wind or solar. Therefore, retail electric suppliers could obtain electricity from an existing wind farm or solar facility to meet the federal RES, but they are precluded from meeting the federal RES with hydropower from an existing facility. It is unclear to APPA why the legislation only counts incremental hydropower under its definitions of eligible resources. Many states with renewable portfolio standards allow for the inclusion of existing small hydropower facilities up to at least 30 MW of capacity (a few allow even larger existing facilities to count). No rational reason exists to treat hydropower differently than other renewable energy resources—it produces low-cost, emissions-free electricity. Furthermore, unlike many other renewable resources, it provides important base-load power.

b. Why doesn't a one-size-fits all renewable mandate mesh with existing state plans and with the expected finalization of EPA's Clean Power Plan?

APPA Answer: According to the National Conference of State Legislatures, as of February 19, 2015, 28 states have RESs and another eight have voluntary RESs or targets. Generally, states that have adopted these programs have designed them based on what they think can be achieved by utilities operating in their borders, with input from stakeholders.

A cursory review of individual state programs shows they can vary considerably based on the overall percentage requirements, what qualifies as a renewable energy source, and percentages that must be achieved from specific sources (*e.g.*, 10 percent from solar). States and localities have been clear leaders in the establishment of RESs, and are in the best position to implement such policies and adjust them if needed. They do not need the federal government imposing a one-size-fits-all approach that may not use resources optimally, or worse, cause problems with their existing programs.

Furthermore, as I explained in my written statement, given the cumulative impact of various Environmental Protection Agency (EPA) regulations that are leading to the increased retirement of coal-fired power plants throughout the U.S. and the EPA's soon-to-be finalized regulations to reduce carbon dioxide (CO2) emissions from existing fossil-fuel fired power plants, utilities are increasing the percentage of electricity they generate from renewable resources (or taking other steps to reduce CO2 emissions) in any event. State and local policies promoting the greater use of renewables, along with EPA regulations to reduce CO_2 emissions are sufficient drivers for the increased use of renewable resources. A federal RES is unnecessary.

In addition, the creation of a federal RES could create a host of issues for utilities that are already subject to state RESs and are also trying to comply with state plans issued that will issued subsequent to EPA's issuance of a final Section 111(d) rule. As proposed, the rule essentially requires each state to achieve its emission reduction goals through implementation of four building blocks—(1) efficiency improvements at electric generating units, (2) more use of natural gas, (3) more use of renewable energy sources, and (4) more use of demand-side energy efficiency programs. In figuring the element of each state's goal that could be achieved through the use of increased renewable energy (building block 3), the EPA looked at the various state-level RPS's in effect in different regions of the country. It then developed a proxy level of achievable renewable use for each state in the region by averaging the RPS's in those regions. The resulting numbers were applied even to states that do not have their own RPS. In other words, EPA effectively developed and imputed a regional RPS.

EPA has clearly indicated it will retain the basic building block architecture of the proposed rule in its final rule. And notwithstanding the EPA's assertion that states do not have to use all the building blocks for compliance with a state's goal, most states will, in fact, have to use them all to meet the goal.

An additional wrinkle is that under EPA's proposed Section 111(d) rule, utilities in a state that made investments in out-of-state renewables have no ability to get credit for those investments. Assuming the final rule does not address this issue, utilities will be forced to obtain electricity from renewable energy sources within the states they operate (unless those states enter into multi-state plans or enter other type of arrangements to allow for the trading of credits). The inability to receive credit for out-of-state investments in renewable resources under a final Section 111(d) rule, layered with a federal RES of 30 percent by 2030, the same year the states must comply with their final goals under the Section 111(d) rule, would make it very difficult to comply with such a federal RES.

Questions from Ranking Member Maria Cantwell

Question 1: The mandatory capacity auctions that some of your members are subject to in Eastern RTOs do not allow public utilities to self-supply. What are some of the specific costs to your members of these policies approved by FERC that can force public utilities to ignore generation resources already built (or under construction) and owned by their consumers?

Are there RTOs that have found a better way to manage capacity auctions and allow the public power model to co-exist with investor-owned companies?

APPA Answer: Generally, mandatory capacity auctions do not explicitly prohibit self-supply. Instead the applicable market rules erect barriers to the ability of such self-supply resources to "clear" the relevant auctions. In these mandatory markets, a utility with its own retail customers that develops generation -- either through ownership or contracts -- still must offer such "self-supply" capacity into the auction. If that capacity does not clear the auction, the utility nevertheless would be required to purchase capacity from the market to meet its capacity obligation—thus paying twice for capacity: once in the purchase of its own power plant and again in its payment to the capacity market.

The three RTOs with mandatory capacity auctions – the PJM Interconnection LLC, ISO New England, and the New York ISO – have what are known as "minimum offer price rules" (MOPR) or buyer-side mitigation rules. Under such rules, the RTO can replace an actual cost-based price offer from public power utility seeking to qualify a new generating resource for an auction with a higher offer. RTOs can do this if the actual price offer is below a certain threshold. Replacing the actual price offer with a higher price offer makes it more difficult for these new plants to "clear" the capacity auctions. The faulty logic of such provisions is that they will prevent a utility from using a lower price self-supply offer to reduce the price of additional resources that the utility might need to purchase in the auction. However, there is no evidence that any of the entities subject to the MOPR rules in fact have intended to use a self-supply offer to drive down prices or, in the case of smaller public power utilities, that their self-supply offer was large enough to significantly affect prices. Public power utilities or other entities subject to the MOPR, such as the states, are focused on procuring sufficient resources to meet their customers' load. To the extent that prices were lower after new supply is introduced, that is exactly how a market is expected to function.

The original rules of the capacity markets in PJM and ISO-NE contained provisions to ensure that self-supply resources would be guaranteed to clear these auctions and not be subject to the MOPR. But in response to complaints from merchant generators wishing to restrict new entry and raise prices, two FERC orders in 2011 removed these exceptions for self-supply. Self-supply is therefore now subject to the MOPR in these RTOs. In PJM, the rule applies to new natural gas plants and in ISO NE the rule applies to all resources, including renewable energy (other than a small exemption). These rules also apply to resources subject to state-sponsored procurements, reducing the ability of states to control their energy resource needs.

In PJM, negotiations among merchant generators, industrial customers, and public power and cooperative utilities in 2012 resulted in an agreement providing for, among other things, a limited MOPR exemption for self-supply resources, but only if they meet certain criteria. This exemption was approved by FERC in May 2013, but it is unclear whether it will, in fact, survive, given further litigation. State-sponsored resources are still not subject to any exemption.

In New York City and the lower Hudson Valley, the New York ISO can also use buyer-side mitigation (BSM) rules to raise the offer price of a new resource. As in New England, these rules cover all resources, including renewable resources. In 2015, FERC approved a "competitive entry exemption" for resources that are offered into NY ISO auctions, but that receive no payments from bilateral contracts. The New York Power Authority, the New York Public Service Commission, and New York State Energy Research and Development Authority recently filed a complaint with FERC requesting additional exemptions from the BSM, including a self-supply exemption and an exemption for resources needed for reliability.

Your question about costs is a good one, but it is not simple to answer. The costs are not easy to quantify because the full impact of the self-supply restrictions has not been felt. APPA members in PJM and ISO New England have not yet faced the prospect of a new resource not clearing. Offer floors have, however, been applied to the Astoria II plant in Queens, NY, under contract with the New York Power Authority. APPA has not been privy to calculations of the increased costs that have resulted from that action.

We can say that three types of costs result from these limitations on self-supply clearing the market. First, there are the (higher) costs incurred by the public power utility for the purchase of the same amount of capacity from the market as would otherwise have been provided by the self-supplied unit. Second, to the extent that new supply is discouraged or constrained then the capacity market prices would increase for all purchasers of capacity. Third, to the extent that the mitigation of a plant's bid results in additional risks to clearing, there is a chance that the financing cost could increase to address the greater risk.

Not all RTOs have chosen to rely on these problematic markets for resource adequacy needs. In the Midcontinent Independent System Operator (MISO), there is a voluntary capacity market. Public power, cooperative and most vertically integrated utilities may choose to build or contract for new resources without the necessity of such resources clearing the capacity market. But the market does exist if there is a need for a public power utility to purchase or sell incremental amounts of capacity. Similarly, merchant-owned generation can either sell capacity via a bilateral contract or into the capacity auction if they choose. Unfortunately, those utilities that do choose to rely on MISO residual market to obtain their capacity can get badly burned, due to the questionable bidding strategies of sellers in that market, as the recent complaint filed by Southwestern Electric Cooperative Inc. against MISO and Dynegy in FERC Docket No. EL15-72 vividly shows. (This is available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13891589)

The California ISO and Southwest Power Pool do not have capacity markets, although the California ISO is considering a voluntary market. Boston Pacific, the market monitor for SPP, recently concluded: "For SPP states and others like them, they may be wise to avoid capacity markets altogether and maintain jurisdiction over resource adequacy and new generation."[1]

APPA supports the voluntary capacity markets model, so long as those markets are adequately policed to prevent the exercise of generation market power, coupled with long-term integrated resource planning and the procurement of needed resources through an array of bilateral contracts of varying lengths as well as utility ownership of resources.

Question 2: The energy industry faces a continuing demand for skilled workers, particularly as more energy workers reach the age of retirement. The average age of a utility worker is 47 years old and 55 percent of the workforce is expected to retire in the next decade. Many companies have stated that they face a "skills gap," in that potential employees do not have the needed abilities and training for open positions. What skills do you think are most critical in developing a trained workforce for the energy sector and as more workers retire, what can Congress do make the investments needed to train new workers in the energy sector?

APPA Answer: APPA agrees that the energy industry faces difficulties in attracting and training the workforce that will be essential in the coming decades. Compounding the problem, utilities are set to experience significant turnover from retirements while undergoing a technological change that requires new and diverse skill sets. APPA has been working with its membership to encourage utilities to prepare for this transformation through outreach, education, articles, presentations, and developing best practices programs such as APPA's Reliable Public Power Provider (RP3) program. Information on APPA's RP3 program is available at http://www.publicpower.org/Programs/Landing.cfm?ItemNumber=31003

Based on data from the 194 utilities designated in 2014/2015 by APPA's RP3 program, an average of 24 percent of the utility work force is eligible to retire in the next five years. At the same time, the data indicates that almost 75 percent of these utilities have succession plans in order to address this changeover of workforce.

APPA believes there two distinct areas of need. The first is the lack of workers in the skilled trades. As the utility industry moves to a future filled with new emerging facilities such as solar on rooftops, automated metering infrastructure, and energy storage, the skills required to work on distribution systems will change. Congress can help the industry prepare for this change by providing funding incentives for local training and recruiting programs from high schools, junior colleges, and other educational and vocational programs.

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[1] Southwest Power Pool Annual Looking Forward Report: Strategic Issues Facing The Electricity Business, Boston Pacific Company, Inc., April 20, 2015, http://www.bostonpacific.com/content/uploads/2015/04/Boston-Pacific-2015-Looking-Forward-Report.pdf

The second area is in the STEM disciplines. When it comes to Science, Technology, Engineering and Mathematics degrees, the utility industry is competing against all other technology fields for personnel recruitment into careers in energy. At the same time, power systems engineering programs at U.S. universities have dwindled, and recruiting from universities has been replaced with recruiting from other utilities (the personnel equivalent of robbing Peter to pay Paul). This is not a long term solution. Congress could help by funding programs that work with universities in STEM disciplines to educate the new technical workforce on system modeling, renewable energy, connectivity of the future, and other multi-technical discipline majors.

Questions from Senator Joe Manchin

Question 1: How do members of your organization view the use of coal in their future generation portfolio? What technologies would they recommend be pursued to maintain coal as a future option?

APPA Answer: APPA members strongly believe they should be able to generate electricity from a diverse portfolio of resources, including coal. Among members that currently own coal-fired power plants or contract for power generated from such plants, there is a strong concern that the Environmental Protection Agency's (EPA) New Source Performance Standards for New Fossil Fuel-Fired Power Plants under Section 111(b) of the Clean Air Act, and other air, waste, and water regulations aimed at coal-fired power plants, will effectively preclude the construction of new coal-fired generation. There is an even stronger concern that EPA's final rule to reduce carbon dioxide (CO_2) emissions from existing fossil-fuel fired power plants will force public power utilities to prematurely retire existing coal plants, leading to stranded costs and increased electric bills for customers.

APPA has supported programs funding the research and development of carbon capture and sequestration technologies. However, given the current state of the technology, APPA is skeptical it will be a viable option for electric utilities to use for the construction of new coal power plants in the near future (and even less so for existing power plants). Enhanced oil and gas recovery operations do not adequately demonstrate sequestration. While CO_2 has been recycled in the oil and gas sector for almost 40 years, the idea of permanently sequestering it is novel. CO_2 gas functions like a solvent to move oil and gas more effectively than water flooding. The CO_2 currently used in the oil and gas sector in the U.S., Norway, Australia, and Canada is recycled, not permanently stored. Recycling of the gas is far different than permanently storing it underground for thousands of years. The oil and gas sector typically stores the gas for days, weeks, and sometimes months and usually removes and transports it by specialty pipeline for use at the next oil and gas recovery location.

Furthermore, the non-air, public health and environmental impacts of long-term sequestration need to be addressed before CCS could be commercially viable. Issues that need to be resolved include, the impacts to soil of injecting CO_2 (an acid gas) underground; potential surface water contamination; Endangered Species Act implications; liability implications of underground leakage; and state trespass laws, among others. For a more detailed explanation of these issues, please see APPA's testimony before the House Science Committee from March 10, 2014, available at https://science.house.gov/sites/republicans.science.house.gov/files/documents/HHRG-113-SY20-WState-SMiller-20140312.pdf.

Question 2: If funds were made available through the program that would be authorized in S. 1283, do you think APPA member companies would consider hosting or supporting a DOE sponsored CCS pilot project at one of their facilities?

APPA Answer: Several APPA members have already participated in CCS projects—Jamestown Board of Public Utilities (New York), Holland Board of Public Works (Michigan), and City Utilities of Springfield (MO). All three CCS pilot projects these public power utilities were involved with were discontinued when the sequestration of captured carbon was found not to be feasible for a variety of reasons. For a summary of City Utilities of Springfield's experience with the Missouri Carbon Sequestration Project, please see APPA's testimony before the House Science Committee from March 10, 2014, available at https://science.house.gov/sites/republicans.science.house.gov/files/documents/HHRG-113-SY20-WState-SMiller-20140312.pdf.

In spite of our members' experiences with these discontinued projects, I do believe there would be interest to participate in future pilot projects. Our members would like this technology to be developed and commercially demonstrated. However, we do believe that far more research and development on the technology is needed to address the unresolved issues we have raised in our comments to EPA on the proposed Section 111(b) rule and in testimony to the House Science Committee.

Questions from Senator Elizabeth Warren

Question 1: In order to make sure that our generation capacity will meet our electricity needs as they occur, several regions across the country have implemented forward capacity markets – auctions where generators bid to receive incentive payments in exchange for committing to provide a certain amount of future energy capacity. In New England, the forward capacity auction procures capacity three years in advance of when it will need to be in place.

A significant amount of generation capacity in New England will go offline soon, including the 1,528-megawatt Brayton Point power station in Somerset, MA that is scheduled to close in 2017.

a) What has been the impact of the planned closure of Brayton Point power station and other generation capacity on forward capacity auctions in New England, particularly with regard to auction prices?

Answer:

APPA Answer: In Forward Capacity Auction (FCA) 8, held in February 2014, to procure capacity for the 2017/18 delivery year, auction prices increased to $3 billion from an average of about $1 billion in the prior seven auctions. This auction saw the retirement of over 3,000 MW of generation, including the 1,544 MW Brayton Point generating facility. These retirements represent the loss of generation that could supply about 2.4 million homes. Brayton Point had been previously sold by Dominion to EquiPower Resources, which is owned by Energy Capital Partners (ECP), in August 2013. Brayton Point filed a non-price retirement request with the ISO NE in October 2013. The week before, the Vermont Yankee nuclear plant, had also filed a retirement request. Because of the reliability problems that would be caused by the retirement of Brayton Point, the ISO NE began to negotiate a cost-of-service agreement to allow the plant to remain in service. ECP did not accept the offer for an agreement and pulled Brayton Point out of the auction in January 2014. This produced a shortfall in capacity and triggered what is known as the insufficient competition rule (ICR), which provides for a higher default payment to existing resources. This default payment had just been increased by FERC in a docket initiated by a complaint by the New England Power Generators Association, a trade association that represents the merchant generation owners in the region. These higher payments resulting from the implementation of the ICR will financially benefit other resources owned by ECP that are still operating in ISO NE and that did participate in the auction.

When the results of the February 2014, capacity auction were submitted to FERC, the four Commissioners then sitting were unable to reach agreement on approval of these results, meaning that the auction's outcome automatically took effect by operation of law. Commissioners Bay and Clark did not vote for approval of the auction. Below is an excerpt from their Joint Statement issued in September 2014:

> "The ISO-New England's (ISO-NE) forward capacity market (FCM) is unique in that the auction results are subject to Commission review under the just and reasonable standard. This review process was part of a carefully negotiated settlement meant to allay stakeholder concerns over the market's design. Here, there is evidence suggesting the exercise of market power, and it is uncontroverted that the market power, if it existed, was not mitigated. In the words of ISO-NE, prices resulted from a 'non-competitive auction.' To the extent any portion of those prices was attributable to an exercise of market power; the auction will have imposed unwarranted costs upon consumers. Moreover, it is possible that ISO-NE may have violated its Tariff in the way it conducted the auction. On this record, we do not believe that ISO-NE has carried its burden of establishing that the auction results are just and reasonable."

b) How and why has this occurred?

APPA Answer: The dramatic increase in prices from $1 to $3 billion in one year is not just a result of the actions of the Brayton Point owners, but rather reflects the flaws in the underlying structure of the capacity market. First, the market provides a single price to all capacity within a certain zone and the ownership of capacity is often highly concentrated within the zones. Therefore, the bidding activity of one unit can influence the prices paid to other capacity under the same ownership, providing a perverse incentive for merchant generation owners to keep supply constrained. Second, the ISO's Minimum Offer Price Rule (MOPR) further constrains the supply and increases the prices in the auction. The MOPR prevents owners of resources (or those with contracts with resources) from offering those resources at "too low" a price. MOPRs are discussed more fully in my response to Question No. 1 asked by Senator Cantwell. In the absence of a MOPR, the procurement of resources by public power and cooperative utilities or by the states could alleviate such supply constraints and moderate price increases.

Question 2: The stated goal of forward capacity auctions is to ensure that sufficient capacity is available to meet future demand.

a) Has the forward capacity market in New England stimulated new capacity?

APPA Answer: The table below shows the total capacity clearing each of the nine ISO New England capacity auctions and the portion that was new generation and new demand response. Other than the auction held to procure capacity for the 2012-13 time frame, when the percentages of new resources was 6 percent, new resources accounted for between about one and four percent of the total. New generation ranged from 0.1 percent to 5 percent.

Period of Capacity Procurement	Total Capacity Cleared (MW)	New Generation	New Demand Response	Subtotal New	% of Total Cleared
2010-11	34,352	40	860	**900**	**2.6%**
2011-12	37,442	1,157	448	**1,605**	**4.3%**
2012-13	32,228	1,670	309	**1,979**	**6.1%**
2013-14	32,127	144	515	**659**	**2.1%**
2014-15	37,040	42	263	**305**	**0.8%**
2015-16	36,326	79	314	**393**	**1.1%**
2016-17	36,220	800	245	**1,045**	**2.9%**
2017-18	33,712	27	355	**382**	**1.1%**
2018-19	34,695	1,060	367	**1,427**	**4.1%**

Of the 1,060 MW of new generation resources that cleared in the most recent Forward Capacity Auction, 245 MW is located in the Southeast Massachusetts/Rhode Island capacity zone and will be paid the administrative cap price of $17.73 per kW-month. (In other words, because of a capacity shortfall in this region, these resources would have been needed no matter what their bid price.) The other 815 MW are located in Connecticut and will be paid $9.55 per kW-month. These resources consist of two projects. One is a dual-fuel combined cycle project that has been under development for the past 10-15 years. The other is a 90 MW expansion at the site of an existing gas-fired peaking project. APPA's members in the area have advised that these are unusual situations that may not be relevant for future auctions.

b) Have capacity markets outside of New England stimulated new capacity?

APPA Answer: With regard to other mandatory capacity markets, in PJM, there is also available data on the new generation, but demand response and energy efficiency are not broken down between existing and new. In that capacity market, new generation accounted for between 0.5 and 4 percent of the cleared resources over the 10 auctions held to date.

However, not all of the new resources can be attributable to the capacity market. Simply because a new generator is constructed within the geographic boundaries of an RTO with a mandatory capacity market is not an indicator that the market was the reason this new generation was developed. A significant portion of the new capacity clearing the auction is actually owned, either by a utility or customer, or receiving direct payments under a long-term contract. An APPA analysis of all new capacity built nationwide in 2013 found that just 2.4 percent of the new capacity was built for sale into any of the RTO markets without a contract or ownership. The 2.4 percent includes new facilities for which no information could be found about the contracts. When broken down geographically, only 6 percent of all capacity constructed in 2013 (including capacity built under long-term contracts or ownership) was built within the footprint of the RTOs with mandatory capacity markets (ISO New England, PJM and parts of the New York ISO). Moreover, the mandatory capacity market constructs do not ensure stability and certainty with regard to resources that clear the auctions. For example, according to an affidavit filed with FERC in late December by Michael Kormos, PJM's executive vice president for operations, only 3,800 MW of new generation will be available for the 2015/16 delivery year out of a total of 5,346 MW that cleared the BRA for that time period.

c) Have auction rules played a role in hindering the development of new capacity?

APPA Answer: The mandatory capacity markets place restrictions on self-supply and state-sponsored resources through MOPRs or "buyer-side mitigation" (BSM) rules. While tariffs regarding the MOPR or BSM differ slightly in their details among the three RTOs, the basic concept is to replace lower price offers to sell new capacity with administratively determined higher price offers, making it more difficult for these new plants to "clear" the capacity auctions.

Because the capacity markets are mandatory, utilities that construct or contract for generation to meet their own customers' power needs still must offer such self-supply capacity into the annual or sub-annual capacity market auctions. Such rules may act as a deterrent to new supply development. For example, the MOPR in PJM was significantly strengthened after both New Jersey and Maryland established procurements for new natural gas facilities to develop additional supply in constrained portions of PJM. These procurements were conducted after the states experienced a lack of needed new power generation despite the billions of dollars being spent on capacity payments. In the absence of such MOPRs, states would have the ability to address capacity shortfalls when the markets are ineffective in doing so.

Question 3: Do you have any specific recommendations to stimulate new affordable generation?

APPA Answer: Yes. APPA has proposed that FERC mandate a transition away from mandatory capacity markets to voluntary residual markets. (APPA notes in this regard that only three RTOs have mandatory capacity markets; other RTO regions employ other mechanisms to ensure adequate capacity.) Primary procurement of capacity would be conducted by utilities (including public power and cooperative utilities) and states through bilateral contracts and development of needed generation and demand-side resources. This new paradigm would replace an irrational mandatory, centrally administered construct and allow states and their utilities to determine the optimal mix of resources. They could structure a portfolio of contracts for supply and demand-side resources of varying lengths and terms, or direct ownership that would lower costs to consumers, maximize reliability and provide environmental benefits. Residual markets would be available to absorb short-term surpluses and alleviate temporary shortfalls in capacity.

In the interim, APPA believes a narrower near-term fix could be helpful. Specifically, APPA would propose that:

- RTOs that have not yet implemented a mandatory capacity market should not move to do so without unanimous support by the states in the region; and

- RTOs that have already adopted a mandatory capacity market should not impair (through rates, or rules, regulations, or practices affecting rates) the ability of a load-serving entity to meet its capacity obligations through a resource it owns, builds, controls, or for which it has a contract for capacity.

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Questions from Chairman Lisa Murkowski

Question 1: In your estimation, will goals for the increased development of hydropower be impacted by long-term droughts in some regions of the United States?

PG&E RESPONSE: This is an important question because increased development of hydropower is needed to achieve our country's environmental protection goals and to improve integration of other forms of renewable energy into the electric grid. As you know, the successive years of drought are impacting California in many ways. Similarly, changing weather patterns create uncertainty about just how much power would be produced from new facilities, which makes it difficult for investors to forecast hydropower generation output and therefore return on investment.

PG&E is working diligently to steward our water resources in a responsible manner and work with key stakeholders. We continue to work closely with water agencies, first responders and regulatory agencies to address concerns and develop mitigation measures for limited water deliveries, increased fire danger, and environmental impacts drought conditions may have.

In our hydroelectric system, we are strategically generating less hydropower now, so that we can save water in our reservoirs for generating power during the summer peak periods, when demand for power is higher. Hydropower also enables us to better integrate wind and solar generation with the grid. In parallel, PG&E is actively collaborating with appropriate regulatory agencies and other stakeholders to reduce the required water releases from our reservoirs in order to lessen the drought's impact on the environment, as well as prolong availability of water for downstream users' needs. PG&E is continually analyzing reservoir and stream conditions, and is working closely with stakeholders to seek variances.

From a national perspective, regional droughts may have positive or negative impacts on hydropower development. As we have seen in California, drought has increased the pressure to build new dams and increase the capacity to store more water when it is available from precipitation. With more dams, there would certainly be the opportunity to include construction of new hydropower facilities. Any expansion projects must be developed thoughtfully, however.

Some of the water storage projects being contemplated in California could actually decrease hydroelectric production through inundation of existing hydropower facilities. If in constructing or operating any new or modified water storage project the federal government reduces or eliminates the capacity or generation of any existing non-federal hydroelectric project by inundation or otherwise, the federal government should balance these actions in the following ways: 1) Provide the owner of the impacted hydroelectric project with a right of first refusal to construct, operate, and maintain new hydroelectric generating facilities at the new or modified water storage project; and 2) The federal

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government should construct, at its own expense, any water conveyance facilities as may be necessary to convey water to any new powerhouse constructed by the affected owner in association with said new hydroelectric generating facilities.

Question 2: I appreciate PG&E's support for S. 1236, my Hydropower Improvement Act, that would empower FERC to be the lead agency in the hydro licensing process, with the ability to establish and enforce deadlines for agencies responsible for required Federal authorizations. There are some who object to these provisions as divesting the resource agencies from imposing mandatory conditions they believe are necessary to protect federal lands. Why do you believe these reforms in the Hydropower Improvement Act are necessary?

PG&E RESPONSE: The water, fisheries, lands and other resources involved in hydropower licensing are treasured resources of the nation, and thoughtful regulation is appropriate and necessary. PG&E believes S. 1236 responsibly improves the efficiency of the licensing process and reduces regulatory uncertainty across the nation, without sacrificing protections for the environment or jeopardizing the integrity of the licensing process. Furthermore, we appreciate and recognize the right of and need for federal agencies to place license conditions upon the lands for which they have the responsibility to manage. Similarly, PG&E also recognizes and appreciates that different federal agencies have different missions and may therefore have different perspectives on what license conditions are needed. However, better coordination of these perspectives is greatly needed given how the process and agency interactions work today.

As I stated during the May 19 hearing, the cost and duration of the process to relicense an existing hydroelectric project can be just as cumbersome and complex as seeking a license for a new, unbuilt hydroelectric project. In both cases, the cost and duration associated with licensing is typically far greater than any other established electric generation technology.

Finally, the proposed modernization of the licensing process would preserve the existing mandatory conditioning authority of federal agencies and the state agency responsible for enforcement of the Clean Water Act. It would also require such agencies to participate in development of a reasonable schedule for the process, resulting in greater regulatory clarity and certainty. Should such agencies submit conflicting or redundant mandatory conditions, we believe FERC should be allowed to ultimately resolve any inconsistencies.

Questions from Ranking Member Maria Cantwell

Question 1: Due to the growing need for skilled workers in the energy sector the PG&E's Power Pathway has partnered with many different educational and community partners for workforce development. How important is the collaboration between the

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community colleges, labor, and industry in the development of a skilled energy workforce?

PG&E RESPONSE: PowerPathway is a collaboration between local colleges, the public workforce development system and unions to enlarge the talent pool of qualified candidates for entry-level opportunities in the utility industry. We believe that this collaboration is key to the ultimate success of PowerPathway. We are working with these other entities to expand the program into new geographic areas and new job classifications, as well as to engage military veterans who are transitioning into the private sector and energy-related careers.

All of our partners share a high level of commitment to establish career programs, especially in underserved communities. PowerPathway strengthens one of PG&E's core values of diversity by ensuring a reliable pipeline of qualified candidates in the communities we serve. This effort starts locally, with local leaders identifying local opportunities through local employers.

As new opportunities for sustainability, efficiency and reliability continue to emerge, both prospective and current employees need new skills and additional training. Programs developed by PowerPathway and our training partners are designed to help both new and experienced workers grow and develop along several skilled craft and apprenticeship career paths in both gas and electric operations.

Question 2: In the energy sector an estimated 2 million workers will be needed over the next 5 years. Apprenticeship programs are a proven tool for workers to learn new and advanced skills that make them much more productive in our increasingly innovative economy. Apprenticeships have worked well in my state of Washington, where a recent study by the Washington State Workforce Training and Education Coordinating Board found that those completing apprenticeships earned nearly $4,300 more per quarter. Are there specific examples that you can think of that illustrate the importance of apprenticeships developing a skilled workforce in the energy sector?

PG&E RESPONSE: PG&E believes apprenticeships are critical in the utility industry in preparing workers for the future to be safe and efficient. PG&E currently has 35 active apprentice programs ranging from one to four years in duration, with 628 indentured apprentices, 10% of which are veterans. PG&E is in the process of expanding that number to 38 in 2015 and to 41 in 2016. Employees entering into an apprentice program at PG&E will earn hourly rates of approximately $31.00 and $44.00 before attaining a higher journey level rate respective to the collective bargaining agreement. Programs such as Lineman, Meter System Technicians and Welders will earn journey hourly rates of approximately $53.00 to $55.00 (lineman), $49.00 and $50.00 respectively.

Due to the need to develop workers more rapidly, but as at the same time ensuring that the apprentice is receiving the required formal training and hands-on practice, PG&E has

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shifted our apprenticeship training design model from a heavily dependent On the Job Training to a much more balanced program that includes intensive formal instruction in conjunction with On the Job Experience. This accelerated training model is essential to offset the need for a demographic cliff (attrition), as well as account for the rapid advancement of new technologies that are impacting the energy sector. As apprentice programs are updated to reflect industry best practices, new technologies and other factors, we are finding an expansion of 3% to 20% in overall duration and increasing complexity by 5% to 20%, which places a strong emphasis on pre-apprentice programs and identifying highly capable candidates.

To hire an apprentice off the street and employ them until they reach journey level, the total investment will range from $140,000 to $1.2 million per employee, depending on the program duration. With hundreds of employees needing to be employed and trained to a level of competency necessary to run our gas and electric system, the total investment will be in the hundreds of millions of dollars over apprentice program duration. PG&E's initial financial analysis, given that apprentices are performing productive work on the job, indicates a positive Return on Investment (ROI) for employers. This is largely due to best-in-industry apprentice program design principles and a strong administration of the programs to ensure the program is effective and functioning as designed. It is important to note that the investment to build and sustain effective apprentice programs is significant and apprenticeships only represent the beginning of the career path when it comes to sustaining a qualified workforce. Qualifications and refresher training programs continue to expand as rapidly as the apprentice programs mainly due to high rates of change in technology, work procedures and regulations.

PG&E's overall program completion rate reported May 2014 is 90.2% as compared to the State of California average of 55.4% during 2014.

Question 3: In your testimony you pointed out that license renewals for hydroelectric dams routinely exceed $20 million for PG&E and can take as long as licensing a brand new dam. Who ultimately pays for those renewal costs, and what alternative investments could PG&E be making on the grid if those costs were lowered?

How can we make relicensing more timely while continuing to respect the ultimate responsibility of federal agencies other than the Federal Energy Regulatory Commission over the resources they manage?

PG&E RESPONSE: The length and expense involved with today's licensing process continue to create daunting impediments for hydropower operators and developers. Companies needing to license projects typically face the prospect of five to ten years of back-and-forth among multiple federal and state agencies. The price tag routinely crosses into the tens of millions of dollars, expenses that nearly always flow through to end-use energy customers.

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To put this into greater perspective, the cost of relicensing ranges from $100,000 to $1.3 million per megawatt. The relicensing process often stalls when agencies with mandatory conditioning authority do not act within deadlines imposed by FERC. Furthermore, delays cost our customers because we accrue interest on the substantial costs expended during relicensing; interest on a single license proceeding can be over $2 million in a single year. Recently, our costs to obtain a Water Quality Certification for one project were approximately $10 million, and over ¾ of that cost was interest on the relicensing costs. Delays also impact the environment because the new license conditions that have been negotiated are not implemented until the license is issued.

Broadly, Congress can facilitate progress by focusing on actions in several areas. These include eliminating redundancies and improving coordination among federal and state agencies, clarifying lines of authority and jurisdiction, and defining clear processes for parties to reconcile conflicting or confusing direction received from different agencies. These steps can substantially reduce unnecessary complexities, bring consistency and predictability, and lower costs and speed up project timelines – without sacrificing protections for the environment or jeopardizing the integrity of the licensing process.

Question 4: The energy industry faces a continuing demand for skilled workers, particularly as more energy workers reach the age of retirement. The average age of a utility worker is 47 years old and 55 percent of the workforce is expected to retire in the next decade. Many companies have stated that they face a "skills gap", in that potential employees do not have the needed abilities and training for open positions. What skills do you think are most critical in developing a trained workforce for the energy sector and as more workers retire, what can Congress do make the investments needed to train new workers in the energy sector?

PG&E RESPONSE: Getting ahead of the "skills gap" requires a sustained, consistent long-term message targeting the next generation of the utility workforce. The literal gap is reflected in challenges in recruiting experienced skilled-craft professionals (i.e., welders, line workers and others). The key to bridging the gap lies in career awareness campaigns and investments within our schools. Employers must be able to articulate their long-term needs, build industry coalitions and amplify the possibilities to tomorrow's workforce.

PG&E's PowerPathway program is one way the company is addressing the short-term "gap" by proactively training individuals for positions within the company. PowerPathway helps PG&E increase the skills, diversity and industry know-how of the local talent pool, and creates opportunities for hiring workers from supported programs. For example, each year PG&E hires six to ten apprentice welders from the Capstone to Utility Welding program at Butte College. Together with its partners, PowerPathway provides a reliable pipeline of skilled workers that PG&E and other industry employers can count on to get the job done.

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In addition to PowerPathway and PG&E's broader commitment to skills training and workforce development, PG&E has been a leading partner with the Obama Administration over the last two years on the following initiatives:

- Long-Term Unemployment: PG&E made a commitment to address challenges faced by the unemployed and veteran populations with the creation of two PowerPathway workforce development programs in California's Fresno region.
- Small Business Supplier Financing Initiative: PG&E was one of the first companies to sign on for this program to expedite payments for goods and services and promote better access to financing—all with the intent of creating jobs.
- Leading Forward: As part of the White House initiative on "up-skilling", Leading Forward was recognized as a best practice to help workers gain skills to advance into better paying jobs.

Finally, building off the Workforce Innovation and Opportunity Act of 2014, which was signed into law, Congress should advance legislation which would provide much-needed federal guidance and a framework for workforce development programs for the utility industry – an industry that employs nearly one million people nationwide and is facing a critical shortage of skilled workers necessary to maintain our country's electric and natural gas infrastructure.

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Questions from Chairman Lisa Murkowski

Question 1: You've testified in support of S. 1264, legislation to establish a Renewable Electricity Standard. S. 1264, however, includes an exemption for public power entities even though public power utilities, such as municipally-owned systems and rural electrical cooperatives, provide approximately 15 percent of electricity to end-users in the United States. Does the NRDC support the exemption of public power utility providers from a national RES? Please explain fully.

We support S. 1264 as a good step forward while noting that there are issues that should be resolved in any final legislation.

We would prefer a national RES that included public power entities at the same levels as investor-owned utilities and welcome the opportunity to engage with the Committee and other stakeholders to discuss the appropriate requirements for public power entities.

Another issue with S. 1264, identified in our written comments, is its broad inclusion of biomass as renewable energy. It is critical that any final legislation provide standards that ensure that biopower is also low-carbon, by requiring that all biomass meets greenhouse gas emissions standards as determined by the best available science. This has been included in several previous RES proposals, and NRDC urges the Committee to reinstate this provision in any future versions of S. 1264.

Question 2: At the May 19 hearing, Sue Kelly, President and CEO for American Public Power Association, testified that "the creation of a federal RES could create a host of issues for utilities that are already subject to state RESs and are also trying to comply with state plans issued under EPA's final Section 111(d) rule that will be released in the summer of 2015." Do you agree with this statement? If not, please detail how a utility can simultaneously comply with a state RES (or equivalent goal), a federal RES, and the EPA's Clean Power Plan requirements.

No, NRDC does not agree with this statement. Federal RES credits, which will often be more narrowly defined than state RES credits and thus could easily be adopted for compliance with any state RES. State RESs and the federal RES compliance obligations would not in any way be incompatible. The federal RES would simply serve as a floor which all utilities would have to meet.

Far from being a challenge, the federal RES would actually facilitate implementation with Clean Power Plan requirements by providing a ready-made one portion of a utility's compliance plans. Pending EPA guidance, in a rate-based plan a federal RES credit would likely be submitted to EPA as an eligible credit for 111(d) compliance without any additional administrative burdens. In fact, in our comments to EPA we recommended that a REC tracking system should be part of minimum criteria for any state plan. The development of such a system as part of a federal RES implementation could ease the burden on state officials.

In a mass-based plan, in many cases the purchase of renewable energy and the associated RECs can serve to displace carbon emissions from other in-state power plants, leading to progress towards a utility's compliance. If a utility chooses to purchase out-of-state RECs to comply with its RES requirements, then this may not contribute towards compliance with its mass-based targets, but it is simply one option available in the market and does not create "a host of issues" as suggested.

Question 3: You noted in your testimony that 29 states plus the District of Columbia already have mandatory renewable energy targets in place. Will a federal RES supersede those existing state plans? For example, if a state mandate contains timetables, targets, and allowable resources that differ than the federal plan, does the federal standard become the floor that utilities must meet? Or will utilities be subject to a state RES (or the equivalent) and the federal RES even if the requirements differ?

Yes, the federal standard targets would become the floor that utilities must meet. As mentioned in our response to Question 1, the federal RES should prioritize the procurement of low-carbon energy, and these requirements should hold even if the state plan defines allowable resources more broadly.

Question 4: Ms. Kelly further noted that "under EPA's proposed Section 111(d) rule, utilities in a state that made investments in out-of-state renewables have no ability to get credit for those investments. EPA has thus far not stated whether it will address the out-of-state credit issue in its final rule, but given the system based approach the agency took in developing individual state goals in the proposed rule, it is hard to see how the agency can fix this problem in the final rule. If a utility cannot get credit for out-of-state investments in renewable resources under a final Section 111(d) rule, it will be very difficult at best to comply with a federal RES of 30 percent by 2030, the same year the state must comply with their final goas under the Section 111(d) rule." Do you agree that this out-of-state issue is a problem? If so, how do you propose to address it? If this is not a problem, please explain why not.

In the final guideline, EPA will be able to include provisions that allow entities in one state to obtain credit for renewable investments made in another state. In the proposed rule, EPA stated: "The EPA is proposing that, for renewable energy measures, consistent with existing state RPS policies, a state could take into account all of the CO2 emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states." 79 Fed. Reg. 34830, 34,922 (June 18, 2014). EPA also noted that its approach is consistent with the approach that states have taken with respect to renewable energy credits and sought comment on how to

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ensure that states did not double count the same renewable energy. Id. We believe that EPA can resolve the question of counting out-of-state renewables by providing that each state plan must ensure that Clean Power Plan renewable energy credits are not double-counted and that it can establish a national system for tracking such credits.

Questions from Ranking Member Maria Cantwell

Question 1: Senator Cassidy's bill (S.1276) requires the Secretary of the Interior to begin leasing all planning areas of the Gulf of Mexico, including areas in the Eastern Planning Area currently under Congressional moratorium until 2022. This bill also accelerates the review of incidental harassment approvals under the Marine Mammal Protection Act of 1972 and includes language changing the air emissions guidelines for the Eastern Gulf. Combined, these changes will both increase the amount of the Gulf of Mexico that is affected by oil and gas production and reduce the protections afforded to fragile marine species and the environment. What are consequences, long-term and otherwise, with opening additional areas in the Eastern Gulf of Mexico?

The immediate and long-term consequences of exposing additional areas in the Eastern Gulf of Mexico to oil and gas exploration and drilling could be severe, in terms of direct harm to the region. These risks are both inherent to high-energy seismic surveying and offshore drilling and inextricably linked to the still damaged state of the area's ecosystems and coastal communities. The Cassidy legislation would open up the Eastern Gulf to drilling despite the fact that Congress has refused to revise the Outer Continental Shelf Lands Act since the BP spill, leaving drilling still dangerous and the public on the hook to pay most damages if there is another major oil spill. It would open large areas to riskier drilling, lift an existing moratorium, increase disruptive seismic surveying in already degraded habitat, expose the Florida coasts to additional risk, all while reducing protections for marine mammals among many other problematic provisions. In sum, the bill absolutely ignores both the history and persistent damage incurred by the BP *Deepwater Horizon* disaster that we are still just beginning to understand, and fails to acknowledge that no meaningful reform legislation has been passed to prevent the conditions that allowed the disaster to occur in the first place.

On April 20, 2010, BP's *Deepwater Horizon* oil rig exploded in the Gulf of Mexico, killing 11 workers, injuring 17 others, and initiating one of the worst environmental disasters in America's history. While we still don't know the full extent of the damage to the Gulf's ecosystems, wildlife or coastal communities, what we do know is shocking.

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The oil spill contaminated more than 1,100 miles of coastline, at least 1,200 square miles of the deep ocean floor and 68,000 square miles of surface water. Some 22,000 tons of oil washed up on the shores of the Gulf Coast.[i] Nearly 1 million coastal and offshore seabirds are estimated to have died as a result of the oil spill.[ii] Oyster harvests in Louisiana are one-third of pre-spill levels.[iii] These are just some of the impacts that this region is still enduring. The environmental impacts extend far beyond this, and as scientists continue to study the area, over time we will learn the full extent of the disaster.

The impacts of the *Deepwater Horizon*, and the potential impacts of new leasing in the Eastern Gulf, are particularly severe for marine mammals. Since the blowout, more than 1,300 bottlenose dolphins have been found dead on beaches reaching from Louisiana to Franklin County, Florida, in what NOAA biologists have rightly characterized as an unprecedented die-off of the species. A new peer-reviewed study, conducted by NOAA scientists and released just last month, concluded that "[r]esearch now links this unusual mortality event to the massive *Deepwater Horizon* oil spill."[iv] To make matters worse, the die-off appears to be devastating the Gulf's celebrated near-coastal dolphin populations, small dolphin communities that live in the region's bays and estuaries and are icons and magnets for tourism. A previous NOAA study on the *Deepwater* spill found that dolphins in heavily-oiled Barataria Bay, Louisiana, were suffering from adrenal toxicity and moderate to severe lung disease, with poor prognoses for survival.[v]

Opening up the Eastern Gulf, and expanding lease sales to the west, would not only intensify the impact on coastal dolphins, but would risk the Gulf's desperately small population of Bryde's whales, the region's only resident baleen whale. This population numbers fewer than 50 whales and appears limited to a single habitat: the upper reaches of the DeSoto Canyon, an erosional valley that off Alabama and Florida. A recent NOAA study found that this small population is evolutionarily unique, distinct from all other known Bryde's whales, and may well represent a separate species; if so, it would be one of the most endangered species of whales on the planet.[vi] Bryde's whales, as well as bottlenose dolphins and the Gulf's other marine species, are at risk both from expanded drilling and from the increased high-energy seismic exploration that would precede it, an activity that is known to disrupt foraging, communication, and other vital behaviors of marine life on a large geographic scale.[vii]

Coastal communities have been devastated as well. The Gulf of Mexico commercial fishing industry lost an estimated $247 million as a result of post-spill fisheries closures.[viii] In 2010, as a result of post-spill fishing closures, shrimp landings decreased by 32 percent in Louisiana, 60 percent in Mississippi, 56 percent in Alabama, while menhaden landings in Louisiana decreased by 17 percent. Estimates of lost tourism dollars were projected to cost the Gulf coastal economy up to $22.7

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billion through 2013.[ix] These are real impacts to communities that should not be saddled with additional risk.

President Obama's National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling found that "the central lesson to be drawn from the catastrophe is that no less than an overhauling of both current industry practices and government oversight is now required."[x] Yet no major revisions to the OCS Lands Act have been made since this tragedy, making new drilling still dangerous and the chance of a major oil spill a real risk. In the event of an oil spill, the liability of the offending company for economic and environmental damages remains staggeringly low at just $134 million dollars, with taxpayers on the hook for all additional damages. But it's worth noting that the effects of offshore drilling are not limited to catastrophes like the BP disaster. Louisiana loses a football field's worth of wetlands every 45 minutes due largely the infrastructure of pipelines and canals necessary to support offshore drilling.[xi] Furthermore, around 1,500 small oil spills are reported in Louisiana each year, spilling an average of 330,000 gallons annually.[xii] These statistics are more than just that- they are real-life impacts that should inform how many more communities and valuable ecosystems we are willing to risk. This legislation would expose far more coastlines and marine systems to this damage.

The proposed amendment to the Marine Mammal Protection Act ("MMPA"), accelerating NOAA's review of incidental harassment authorizations, would undermine NOAA's ability to protect marine mammals. The authorizations it would affect are not trivial. Harassment under the MMPA encompasses a wide variety of impacts—e.g., large-scale disruptions in feeding and breeding, loss of hearing, and physical injury—which, as NOAA, BOEM, the National Research Council, and numerous other authorities have observed, can have dire impacts on marine mammal species over time. Effective management of these impacts depends on careful review during the MMPA's authorization process. Yet as even a cursory review of comments from the U.S. Marine Mammal Commission (the independent agency charged by Congress to assess MMPA implementation) indicate, applications submitted by the oil-and-gas industry, *e.g.*, for high-energy seismic surveys, are frequently incomplete and inaccurate.[xiii] Forcing NOAA to work to unrealistic deadlines, as this legislation proposes, would result in poor analyses, undermining the conservation of species that, in the wake of the *Deepwater* spill, are already profoundly vulnerable. It would also have the effect of shifting the resources of NOAA's small permitting staff away from other activities, such as military training, that may require priority. Notably, the amendment would apply not only to offshore oil-and-gas activities in the Gulf of Mexico, but would undermine marine mammal protection in every region the offshore industry operates.

Producing oil and gas at sea is an inherently dangerous industrial operation. There is no way to make it safe—a fact driven home by the recent spill off the coast of Santa Barbara. Instead, we must do all we can to reduce those risks, starting with reducing the amount of ocean we expose to high-energy seismic testing and drilling. And we

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have to reduce our reliance on oil, gas and the danger and damage they bring by focusing our Federal policies and resources on advancing clean solutions like enhanced fuel economy, electric vehicles, and renewable resources.

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June 4, 2015

Honorable Lisa Murkowski
Chairman, Senate Committee on Energy and Natural Resources
304 Dirksen Senate Building
Washington, DC 20510

SUBJECT: API Answers to Questions for the Record, Senate Committee on Energy and Natural Resources, Energy Supply Hearing

Chairman Murkowski,

Thank you again for the opportunity to testify before the committee on the game-changing opportunity that we have before us through the development, use and export of domestic oil and natural gas. The application of the proven technologies of horizontal drilling and hydraulic fracturing have allowed the United States to become the global leader in natural gas production, and we are on our way to becoming the global leader in oil production. However, we as a nation must do more to secure our energy future. We must move forward as global leaders in developing oil and natural gas resources by exploring for and producing energy resources in areas that have been thus far off-limits to production. Specifically, we must expand the domestic development of resources in the U.S. Outer Continental Shelf and in Alaska. This will enhance our energy security tremendously, considering that the U.S. will rely on natural gas and oil for decades to come for energy consumption, and the world will require significantly more natural gas and oil. The overall benefits of expanded access are very compelling: it would strengthen our energy and national security, help put downward pressure on prices, provide many thousands of new jobs for Americans, and generate billions of dollars in additional revenue for our government. According to the Bureau of Labor Statistics, jobs in the oil and natural gas exploration and production sector pay on average more than $100,000 per year, more than twice the national average. As we move forward with this important debate, we must ensure that we move down a path that fosters this important economic and job growth through responsible development of these resources. The following are answers to the questions for the record that I received following the hearing. Please do not hesitate to reach out to me should you have any follow-up questions.

Questions from Chairman Lisa Murkowski

Question 1: Promoting offshore oil and gas development is a key part of our national energy policy and I have seen studies that suggest that increased leasing and development could, by 2035 create nearly 840,000 jobs, raise more than $200 billion in revenue for the government and increase U.S. energy production by 3.5 million barrels – those are staggering numbers. With lower oil prices today and corresponding struggles in the service sector, Do you believe that offshore development, with longer timelines than onshore unconventionals and a greater scale of capital commitments, provides a key countercyclical opportunity to support jobs and investment in America's oil and gas industry?

Response to Question 1: Yes. America's oil and natural industry has a strong commitment to investing in both onshore and offshore projects here in the U.S., as can be seen by continued and robust capital expenditures on diverse energy projects. Offshore projects are long-term and capital intensive, generating economic and employment opportunities that sustain both large-scale investment and long-term, stable employment for the coastal regions and beyond. The positive economic impacts are felt throughout the supply chain and provide significant opportunities for companies of all sizes, including small businesses. Through the implementation of an energy policy that embraces geographic and technological diversity by promoting development of resources in onshore, offshore and arctic regions, the U.S. will be able to effectively enable strong countercyclical opportunities to support jobs and investment.

Question 2: LNG exports are moving forward and there are some in Congress, myself included, who are interested in exporting oil. What potential challenges does the industry face in having a qualified and trained workforce to do this safely?

Response to Question 2:

Moving forward, the oil and natural gas industry faces challenges in attracting, hiring and retaining a talented workforce to develop the domestic oil and natural gas resources that will effectively provide affordable energy supplies to both domestic and global markets. The oil and natural gas industry is certainly up to this challenge and API has taken positive steps to ensure that we have both the opportunities for employment and the talent to fill those positions as we move forward into our energy future.

As we look at the changing demographics in the country and the future workforce needs of the industry, it has become clear that we as an industry must broaden our recruitment efforts to attract and retain talent in an increasingly diverse workforce. API has done research on the opportunities for women and minorities in the industry and their perceptions of the industry, and has found that one of the major barriers for those groups coming into the industry is a lack of awareness and understanding about the opportunities available. API has engaged in targeted outreach efforts to generate interest and build relationships with women and minorities to ensure that they are aware of the opportunities we have. For example, last year API did an 8-city tour, going to cities around the country to talk about our research on minority and female employment opportunities and engage with the African American, Hispanic, Asian, and Native American communities on ways to work together and help prepare them for jobs in our industry. We are undertaking similar efforts with veterans.

As we look to employ more women and minorities, we recognize that these candidates must first have education and training for industry occupations. API has conducted research on education trends that show the low incidence of women and minorities in degree areas that traditionally feed into oil and gas jobs (e.g. engineering degrees, geophysical and earth sciences). Based upon this research, we are moving forward with a targeted effort to drive our youth to science, technology, engineering and math programs (STEM), and to help them gain an interest early on in STEM fields and to understand and appreciate the important role our industry plays in the global economy.

The IHS Minority and Female Employment study that API sponsored projects nearly 1.3 million job opportunities available through 2030 in the oil & gas and petrochemical industries, with 408,000 projected for African American and Hispanic workers, and 185,000 projected to be filled by women. This study is provided for the record. Those projections are based on current and projected trends in things like labor force participation rates, educational attainment, unemployment rates, population growth rates, etc., and should not be considered a ceiling. We are hoping that with our outreach efforts, targeted to address specific groups by what matters most to them, we can have an even more diverse workforce.

API is also doing events around the country this year to engage in a dialogue that focuses on recently conducted research related to employment opportunities in industry for women, so that we can help get more women into the industry and make it a better place to work for the women already here.

Questions from Senator Jeff Flake

Question 1: In your written testimony you highlight that the domestic oil and gas revolution over the past decade is primarily a result of exploration on non-federal land. I am particularly concerned that the "lack of growth in production on federal lands is the result of policies that have effectively discouraged investment in those areas." To what extent are the policies you point out limitations on the number of acres available for production and to what extent are they an extended permit process? What are the most significant impediments in the permit process?

Response to Question 1: The lack of growth in production of oil and natural gas resources on federal lands is the result of a combination of policies that serve to discourage investment and therefore production on federal lands. We are also providing for the record a flow chart of the process for receiving permits and approvals for oil and natural gas development on federal lands, which clearly demonstrates a byzantine and overly-bureaucratic system for moving forward with investments on BLM-managed properties. In terms of offshore opportunities, the federal government currently keeps 87 percent of the federal Outer Continental Shelf off-limits to oil and natural gas operations. This is occurring while we see neighboring countries like Canada and Cuba move forward with offshore oil and gas operations. Canada in particular has achieved substantial success in developing oil and natural gas in the Atlantic region.

In terms of onshore opportunities, we have seen the opportunities for leasing on BLM-managed lands impacted by new policies that create additional regulatory layers to remove multi-use lands from leasing opportunities. It is important to note that the lands in question are designated as multi-use and specifically for oil and natural gas leasing, and are not wilderness or national park areas. Major problems with development of resources on BLM-managed lands related to the pace of approvals for permits to drill and the number of permits that are process each year. The recent report of the Congressional Research Service shows a study decline since 2006 in the number of permits processed per year (the report is provided for the record):

Table 6. Onshore Oil and Gas Drilling Permits (FY2006-FY2014)

Fiscal Year	New APDs Received	Total APDs Processed	APDs Pending at Year-End
2014	5,316	4,924	4,121
2013	4,757	4,892	3,546
2012	5,240	5,861	3,683
2011	4,728	5,200	4,108
2010	4,251	5,237	4,603
2009	5,257	5,306	5,589
2008	7,884	7,846	5,638
2007	8,370	8,964	5,600
2006	10,492	8,854	6,194

Source: DOI/ BLM, *FY2016 Budget Justification* for years FY2011-FY2016. For earlier years, see DOI, *Oil and Gas Utilization, Onshore and Offshore*, May 2012.

Timing is a key factor in the ability to profitably develop oil and natural gas resources, and the slow process for securing permits from BLM is in stark contrast to the permitting timeline for securing similar permits from state regulators.

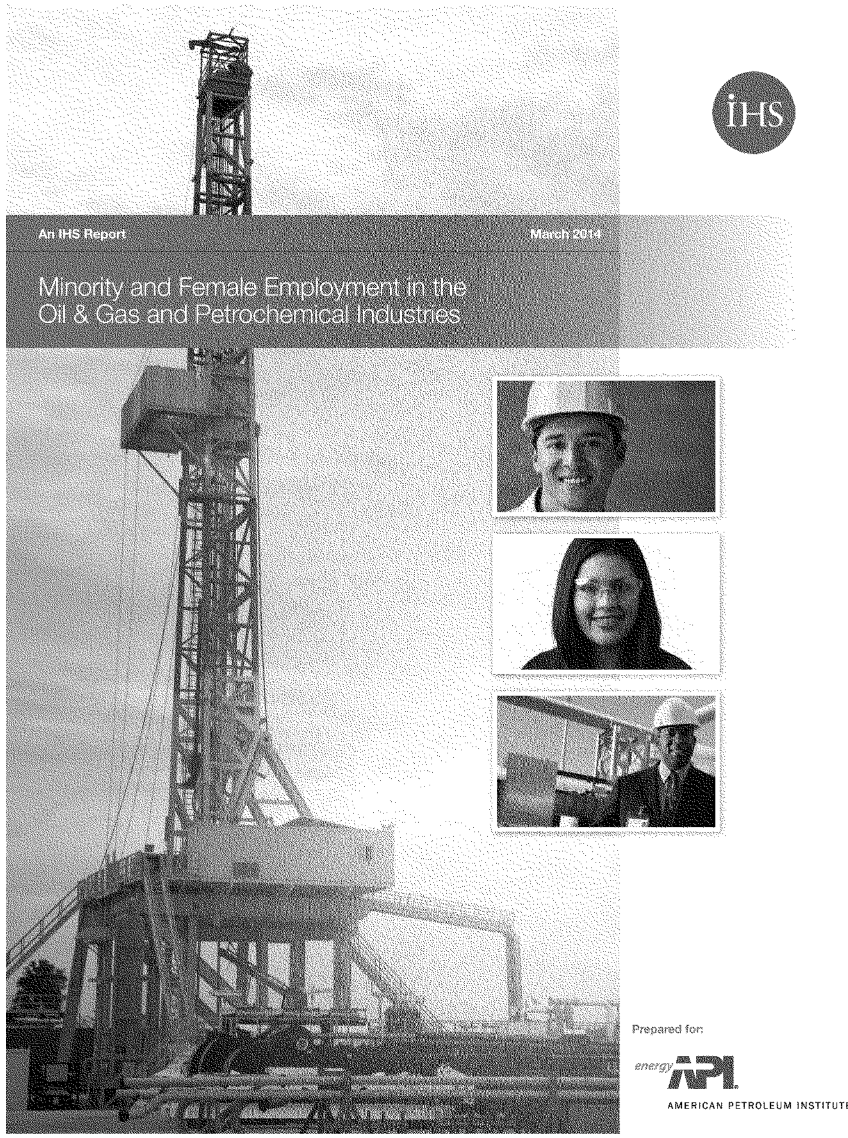
The environmental review process under the National Environmental Policy Act is another layer of red-tape that discourages and impedes oil and natural gas production on BLM-managed lands. In 2012, the Western Energy Alliance and SWCA Environmental Consultants released a study on the economic impacts associated with delays in the NEPA review process. This report provides a detailed analysis of the number of projects and thousands of wells that have been held up in the NEPA process. Most importantly, this report provides comprehensive data on the thousands of jobs and billions of dollars in wages and government revenues that have been foregone because of NEPA delays. This report is provided for the record.

Question 2: The BLM is considering consolidating the Arizona and New Mexico state offices. A number of users of BLM land in Arizona have expressed concerns about the effects of consolidating two states with extensive BLM land holdings. Are you aware of any concerns by your members in New Mexico regarding the proposed consolidation? If so, please share those concerns.

<u>Response to Question 2:</u> API's members have expressed serious concerns about the ability of the BLM to adequately resource oil and natural gas activities in the State of New Mexico under this proposed consolidation. As described in the response above to Senator Flake's first question, the regulatory process associated with developing resources on BLM-managed lands is already layered with red tape and delays. Any efforts by BLM in Arizona and New Mexico should be focused on ensuring that BLM-managed activities in both states are sufficiently resourced and have the organizational capability and efficiency to manage all BLM responsibilities, including oil and natural gas activities. The industry is concerned that regionalization of these two offices will lead to a loss of managerial and agency responsiveness to oil and natural gas management and responsibility. Also, the oil and gas program is a primary source of appropriations for BLM. Combining the states could erode that oil and gas budget by having to support additional overhead and less funding for leasing, permitting, reservoir management, and inspection and enforcement. The industry supports an effective BLM regulatory regime that is cost-effective and provides for timely permitting and approvals. The industry also supports adequate staffing and funding for BLM to carry out its regulatory and enforcement function. As it relates to this particular question, the efforts of BLM should focus on creating efficiencies and certainty in the process so that we can see investment in oil and natural gas projects increase on federal land, as increased investment will ultimately lead to increased production, government revenues and energy security.

Thank you again for the opportunity to testify and to provide responses to these questions.

Best regards,



iHS

An IHS Report

March 2014

Minority and Female Employment in the Oil & Gas and Petrochemical Industries

Prepared for:

energy API

AMERICAN PETROLEUM INSTITUTE

Minority and Female Employment in the Oil & Gas and Petrochemical Industries

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Executive Summary

This report examines the employment outlook of African American and Hispanic workers and employment by gender in the oil and natural gas and petrochemical industries over the period 2010 to 2030. Four types of job opportunities are considered:

- New jobs that are projected to be created under a baseline forecast of the expected growth of these industries,
- Job opportunities that will likely be created due to the need to replace workers who retire or otherwise leave these industries over this period,
- Jobs created by projected capital investment in the transportation and storage infrastructure of the oil & gas industry and in the petrochemical industry, and
- Jobs that would be created under a scenario for more accelerated development of the upstream oil and gas industry.

The report first presents data on employment by occupation, race/ethnicity, gender, and region in the upstream, midstream and downstream segments of the oil & gas industry and in the petrochemical industry in the base year of our forecast period (2010).[1] Principal findings of this analysis are as follows:

- The three segments of the U.S. oil & gas industry and the petrochemical industry together employed a total of 1.2 million people in 2010.
- The upstream segment, with employment of 721 thousand, accounted for 60% of the total, followed by the downstream segment with 23%.
- African American workers held 98 thousand jobs in these industries in 2010, accounting for 8.2% of total employment.
- Hispanic workers held 188 thousand jobs across all four industry segments – 15.7% of the total. They accounted for a higher share of employment in the upstream segment than in the other segments.
- Women accounted for 19% of total employment in the combined oil & gas and petrochemical industries. Their shares are higher in the downstream and petrochemical segments (25%) and lower in the upstream and midstream segments (15-16%).

We next present forecasts of the employment outlook in these industries by occupation, race/ethnicity and gender; we also consider job opportunities associated with replacement demand. The forecasts presented here rely on projections of the growth of

[1] The upstream segment includes oil and gas exploration and production; midstream is pipeline transportation; and downstream includes refining, wholesale distribution and petroleum products manufacturing. Note that we do not include retail gasoline stations in our analysis of the downstream segment – an industry with employment of over 800 thousand in 2010.

population, labor force and employment for these two minority groups through 2030 that we produced in our 2012 report for API, taking into account expected trends in their labor force participation rates, educational attainment, and unemployment rates. We supplement that analysis here with an analysis of trends in female employment by occupation, in total and in the two minority groups. We present only direct employment impacts in this report. If indirect and induced effects were considered, the total job impacts would be significantly larger. Our principal findings are as follows:

Projected Job Growth in the Oil & Gas and Petrochemical Industries

- We project a total of nearly **1.3 million direct job opportunities over the 2010-2030 period**, considering all types of job growth.
- Of those job opportunities, we project that African American and Hispanic workers will account for nearly 408 thousand jobs, or 32%, in 2030.
- We project women could account for 185 thousand of these job opportunities in the oil & gas and related industries through 2030 when growth through pro-development policy is combined with baseline growth, replacement requirements, and the impact of capital investment.

Projected Job Opportunities in the Oil & Gas and Petrochemical Industries*

	African American	Hispanic	Minority	Total Jobs	Female
Increment 2010 to 2020					
Baseline (Growth, Replacement Requirements, and Capital Expenditures)	53,709	138,198	191,907	664,036	100,586
Total (Baseline plus Pro-Development Policy)	73,440	202,408	275,848	955,359	142,932
Increment 2010 to 2030					
Baseline (Growth, Replacement Requirements, and Capital Expenditures)	78,584	218,738	297,322	941,535	142,600
Total (Baseline plus Pro-Development Policy)	100,228	307,310	407,538	1,264,138	184,970

*"Minority" here and throughout the study refers to the sum of African American and Hispanic. African American, Hispanic, Minority and Total columns include females.

Job Opportunities for Minorities

- Hispanic employment growth in the oil & gas industry is projected to show larger gains due to the faster growth of the Hispanic population and the higher labor force participation rate and lower unemployment rate of Hispanics relative to African Americans over the forecast period.
- African American and Hispanic workers are projected to make up nearly 20% of the management, business, and financial job opportunities through 2030.
- There will be tremendous opportunities for workers in blue collar occupations as these jobs will make up the bulk of job opportunities through 2030.
- The share of minorities employed in the upstream, midstream, and downstream oil and gas and petrochemicals industries is rising. Minority employment will rise from one-quarter of the total in 2010 to one-third of the total in 2030.

Female Employment Growth in the Industry

- Women will share in the growth of more skilled white collar jobs in the industry. Opportunities will exist for female petroleum engineers, managers, and other professionals, with the number of job opportunities projected for women in these areas growing by almost 70 thousand from 2010-2030.
- The already-low shares of women in the semi-skilled and unskilled blue-collar occupational groups are projected to decline further, which will hold down the overall increase in female employment in the industry. However, there is significant potential for female blue collar employment due to the large number of job opportunities projected in blue collar positions; interest and training need to exist to increase female participation in these areas.
- The share of women in the traditionally female-dominated 'Office and Administrative Support' (OAS) category in the oil and gas industry will fall over the forecast period, although this category remains a large source of potential job opportunities for women
- Nearly as many jobs will be added for women in the 'Management, Business and Financial' and 'Professional and Related' occupational categories as in the OAS category over this period.

Job Growth by Occupation

- Our estimates of job growth by occupation suggest that 63% of all job opportunities created over the forecast period will be blue collar jobs. This suggests tremendous opportunity for workers with a high school diploma and some post-secondary training.
- A significant share of the potential jobs—about 23%—would be in scientific and managerial occupations, e.g., petroleum engineers, most of which require a college degree.

Total Projected Minority and Female Job Opportunities in the Oil & Gas and Petrochemical Industries, 2010-2030, by Broad Occupational Category*

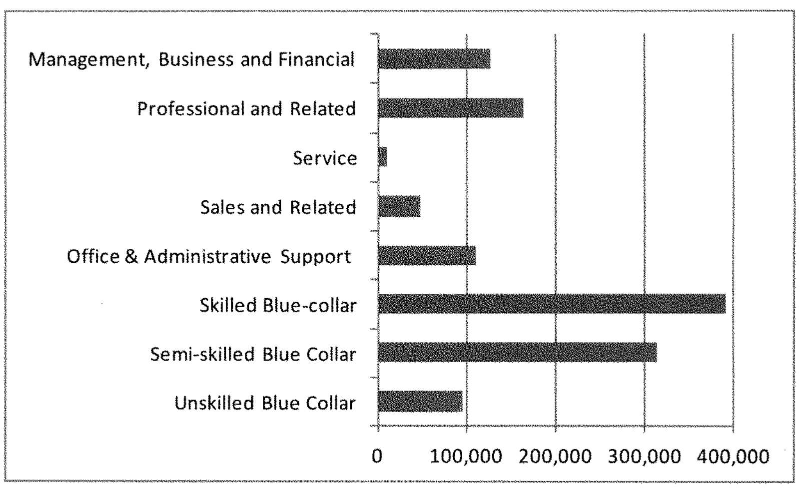
(Combining Pro-Development Policy with Baseline Growth, Replacement, and Capital Investment)

	African American	Hispanic	Total	Female
Total	100,228	307,310	1,264,138	184,970
Management, Business and Financial	7,876	15,433	127,157	34,863
Professional and Related	10,006	16,792	164,946	33,965
Service	1,684	2,769	11,912	3,135
Sales and Related	3,325	6,350	48,043	9,782
Office & Administrative Support	12,633	22,062	110,293	73,362
Skilled Blue-collar	25,769	100,197	391,434	8,133
Semi-skilled Blue Collar	28,863	92,721	314,861	16,382
Unskilled Blue Collar	10,072	50,986	95,492	5,348

*African American, Hispanic and Total columns include females.

Projected Job Opportunities in the Oil and Natural Gas and Petrochemical Industries, 2010-2030, by Broad Occupational Category

(Combining Pro-Development Policy with Baseline Growth, Replacement, and Capital Investment)



Specific occupational categories with the largest number of jobs in the oil & gas and related industries are listed on the following page. Job descriptions for these occupations are provided in Appendix G.

Top Occupations in the Oil & Gas and Related Industries

Management, Business and Financial	**Skilled Blue Collar**
General and Operations Managers	First-Line Supervisors of Constr. & Extraction Workers
Construction Managers	Carpenters
Engineering Managers	Cement Masons and Concrete Finishers
Cost Estimators	Paving, Surfacing, and Tamping Equipment Operators
Accountants and Auditors	Operating Engineers & Other Constr. Equipment Operators
Professional and Related	Electricians
Architects	Plumbers, Pipefitters, and Steamfitters
Surveyors	Derrick, Rotary Drill and Service Unit Operators
Civil Engineers	Mobile Heavy Equipment Mechanics, Except Engines
Electrical Engineers	Industrial Machinery Mechanics
Mechanical Engineers	Maintenance and Repair Workers, General
Petroleum Engineers	Petroleum Pump System Operators, Refinery Operators
Engineers, all other	Crane and Tower Operators
Architectural and Civil Drafters	Pump Operators and Wellhead Pumpers
Civil Engineering Technicians	**Semi-skilled Blue Collar**
Surveying and Mapping Technicians	Roustabouts, Oil and Gas
Geoscientists	Helpers, Extraction Workers
Geological and Petroleum Technicians	Welders, Cutters, Solderers, and Brazers
Service	Inspectors, Testers, Sorters, Samplers, and Weighers
Security Guards	Truck Drivers, Heavy and Tractor-Trailer
Janitors and Building Cleaners	Excavating and Loading Machine and Dragline Operators
Sales & Related	**Unskilled Blue Collar**
Sales Representatives, Wholesale & Manuf.	Construction Laborers
Office & Administrative Support	Fence Erectors
First-Line Supervisors, Office and Admin. Support	Freight, Stock & Material Movers, Hand
Bookkeeping, Accounting, and Auditing Clerks	
Secretaries and Administrative Assistants	
Office Clerks, General	

I. Introduction

In 2012 IHS Global Inc. (IHS) prepared a report for API on the number and types of jobs that could be created by the accelerated development of North American hydrocarbon resources over the next 20 years for African American and Hispanic workers. That analysis focused on the upstream oil and natural gas industry. In this report, we expand that analysis to include the midstream and downstream segments of the oil and gas industry, the petrochemical industry, and the employment impact of capital investment in the transportation and storage infrastructure for the oil & gas industry and in the petrochemical industry. In addition, we develop estimates and projections of employment by gender in all segments analyzed.

We consider four types of job growth:

1. New jobs that are projected to be created under a baseline forecast of the expected growth of these industries. We present projections of employment by occupation, race/ethnicity, and gender in three industry segments: upstream oil and gas industry, midstream oil and gas industry, and petrochemical industry. We present estimates of current (2010) employment but no projections for the downstream oil and gas industry, because employment in this segment is expected to be stable.
2. Jobs that will likely be created due to the need to replace workers who retire or otherwise leave these industries over this period. We present projections of replacement requirements for the upstream, midstream and downstream oil and gas industry and for the petrochemical industry. (Since we estimate only net new job creation when we analyze the employment impacts of capital investment in various sectors, analysis of replacement requirements is not relevant in these instances.)
3. Jobs created by capital investment in the transportation and storage infrastructure for the oil and gas industry and in the petrochemical industry. In each case, we project employment by occupation, race/ethnicity, and gender in the industries that contribute directly to these capital expenditures.
4. Jobs that would be created under a scenario for more accelerated development of the upstream oil and gas industry. We present estimates that were developed in our 2012 report for API on occupational employment in the oil and natural gas industry and extend that analysis with projections of employment by gender.

Our analysis and projections of employment in the oil and gas and related industries spans six industry segments. However, as is evident from the summary above, not all four types of employment estimates are made for each industry segment.

The six industry segments and the data we present for each are as follows:

Upstream oil and natural gas industry:
- estimates of base-year (2010) employment
- projections of baseline employment growth through 2030
- projections of replacement requirements through 2030
- projections of additional jobs that would be created under a scenario for more accelerated development of U.S. oil and natural gas resources

Midstream oil and natural gas industry:
- estimates of base-year (2010) employment
- projections of employment growth through 2030
- projections of replacement requirements through 2030

Downstream oil and natural gas industry:
- estimates of base-year (2010) employment
- projections of replacement requirements through 2030

Petrochemical industry:
- estimates of base-year (2010) employment
- projections of baseline employment growth through 2030
- projections of replacement requirements through 2030

Capital Investment in oil and natural gas transportation and storage infrastructure:
- projections of employment growth from 2015 through 2030

Capital Investment in the petrochemical industry:
- projections of employment growth from 2015 through 2030

In the following section, we provide an overview of the sources and methods used in the analysis. This is followed by sections devoted to the base-year (2010) estimates and the employment projections to 2030. Additional detailed results are presented in appendices to the report.

II. Sources and Methods of Employment Estimates

The employment estimates presented in this report include only the direct employment in oil & gas and petrochemical industry operations and the direct employment stimulated by capital expenditures in these industries. If indirect and induced effects were considered, the total job impacts would be significantly larger.

Our benchmark employment estimates for industries that comprise the various segments of the oil & gas and related industries are drawn from government surveys of establishments and, thus, exclude the self-employed. In the upstream oil and gas industry in particular, including the self-employed would boost employment totals. Employment figures include both full-time and part-time workers.

Definition of Industry Segments

Each of the segments of the oil and gas and related industries analyzed in this report is defined as a group of industries based on the North American Industry Classification System (NAICS). To develop estimates of employment by occupation, minority group and gender for the three segments of the oil and natural gas industry and for the petrochemical industry, we first gather data on total employment, nationally and by region, in the industries that make up that industry segment for 2010 – the base historical year for data presented in our 2012 report for API.

The primary source of these 2010 employment data is the IMPLAN model. However, IMPLAN employment in each industry was also cross-checked against the Bureau of Labor Statistics' (BLS) Quarterly Census of Employment and Wages, and where IMPLAN industry definitions are not sufficiently detailed to measure an industry segment, we use the BLS data.

We then use data from the 2007-2011 public-use microdata file of the American Community Survey (ACS) to estimate the distribution of employment by minority group and gender within occupations in each NAICS industry within a segment of the oil and gas industry. The composition of employment across these demographic dimensions generally changes only slowly, and this five-year database provides a very large survey sample, which is necessary in order to estimate employment in narrowly defined cells of the labor force like those we seek to measure.

The IMPLAN model and the ACS both use industry classification systems that are based on the NAICS, but each uses its own industry numbering system, and they define industries at different levels of detail (e.g., 4-digit, 3-digit and 2-digit NAICS). Below we list the NAICS industry definition for each industry segment and indicate the ACS Census Bureau industry code that we use to estimate the distribution of employment by occupation, race/ethnicity and gender.

The identification of the NAICS industries used to define each industry segment was guided by several other studies of the impact of oil and natural gas industry activity. For all industry segments, the projections of employment by occupation, race/ethnicity, and gender that we develop are linked to projections of total employment at the industry level from one of these economic impact studies. The discussion of each segment below identifies the source of these industry level employment estimates and projections.

1. Upstream Oil and Gas Industry

- NAICS 2111, Oil and Gas Extraction
  - Census Code 0370 in ACS
- NAICS 2131, Support Activities for Mining [Drilling Oil and Gas Wells (213111), and Support Activities for Oil and Gas Operations (213112)]
  - Census Code 0490 in ACS
- NAICS 2389, Construction, Site Preparation Contractors (23891)
  - Census Code 0770 in ACS
- NAICS 5413 Architectural, Engineering, and Related Services [Engineering Services (54133) and Geophysical Surveying and Mapping Services (54136)]
  - Census Code 7290 in ACS

All estimates and projections of employment in the upstream oil and gas industry reported here, except data on employment by gender, are drawn from our 2012 occupational employment report for API. There, we developed employment estimates consistent with a baseline forecast of employment growth in the upstream oil and natural gas industry and an alternative forecast based on a scenario for accelerated development of oil and natural gas resources, which were projected in a study conducted by Wood Mackenzie for API in the fall of 2011.[2]

Note that the analysis in our 2012 report for API included two industries where there are indirect employment impacts of oil and gas industry development – "Mining and Oil and Gas Field Machinery Manufacturing" and "Maintenance and Repair Construction of Nonresidential Structures." Data for these two industries are not included in this report. As noted above, we present only direct employment impacts.

2. Midstream Oil and Gas Industry

- NAICS 486, Pipeline Transportation
  - Census Code 6270 in ACS

[2] Wood Mackenzie, *U.S. Supply Forecast and Potential Jobs and Economic Impacts (2012–2030),"* September 7, 2011.

In a recent study for API, IHS developed comprehensive estimates and projections of the investment in oil and gas transportation and storage infrastructure that will be required through 2025 to support the expected growth in U.S. natural gas, natural gas liquids, and crude oil production over this period.[3] We extended these projections of capital investment in transportation infrastructure to 2030 for this report. We then developed forecasts of employment in pipeline operations in selected years through 2030 based on the growth of pipeline capacity that will result from the projected capital expenditures.

3. Downstream Oil and Gas Industry

- NAICS 32411, Petroleum Refineries
    - Census Code 2070 in ACS
- NAICS 32412, Asphalt Products, and 324191, Miscellaneous Petroleum Products
    - Census Code 2090 in ACS
- NACIS 4247, Petroleum and Petroleum Product Merchant Wholesalers
    - Census Code 4490 in ACS
- NAICS 45431, Fuel Dealers
    - Census Code 5680 in ACS

Industries that make up the downstream oil and gas industry are identified in an economic impact report prepared for API by PWC.[4] In our analysis, we exclude retail gasoline stations – an industry with employment of over 800,000 in 2010.

We report employment in 2010 in the downstream industry segment by gender within each minority group for the eight broad occupational categories in six major regions and nationally. Estimates of total employment for two industries, Petroleum Refineries and Miscellaneous Petroleum and Coal Products, were drawn from IMPLAN data for 2010. Employment estimates for Fuel Dealers and Petroleum and Petroleum Product Merchant Wholesalers were based on BLS QCEW data, since the IMPLAN model includes these industries within more broadly defined industries.

4. Petrochemical Industry

- NAICS 325211, Plastic Material and Resin Manufacturing
    - Census Code 2170 in ACS
- NAICS 32531, Fertilizer Manufacturing
    - Census Code 2180 in ACS

[3] IHS, *Oil & Natural Gas Transportation & Storage Infrastructure: Status, Trends, & Economic Benefit*, report prepared for American Petroleum Institute, December 2013.
[4] PWC, *Economic Impacts of the Oil and Natural Gas Industry on the US Economy in 2011*, report prepared for American Petroleum Industry, July 2013.

- NAICS 32511, Petrochemical Manufacturing [Alkalies and Chlorine Manufacturing (325181) and Other Basic Chemical Manufacturing (32519)]
  - Census Code 2290 in ACS

Our analysis of occupational employment in the petrochemical industry is based on data drawn from a study of the unconventional oil and natural gas value chain conducted by IHS in 2013, which assessed the economic contributions associated with the capital and operational expenditures required to build out midstream and downstream energy and the energy-related chemicals industrial base to support the expansion of unconventional oil and gas.[5] We report employment in the petrochemical industry segment by gender within each minority group for eight broad occupational categories in six major regions and nationally. Employment estimates for 2010, which were not included in the IHS Manufacturing Renaissance report, are based on IMPLAN data.

5. Capital Investment in the Petrochemical Industry

- NAICS 23, Construction of Nonresidential Structures
  - Census Code 0770 in ACS
- NAICS 326122, Plastic Pipe and Fitting Manufacturing
  - Census Code 2370 in ACS
- NAICS 3273, Cement and Concrete Products
  - Census Code 2570 in ACS
- NAICS 3324, Metal Tank Manufacturing
  - Census Code 2870 in ACS
- NAICS 3329, Pipe, Valves and Fittings Manufacturing
  - Census Code 2980 in ACS
- NAICS 3333, Commercial Industry Machinery Manufacturing
  - Census Code 3090 in ACS
- NAICS 333611 Turbine and Turbine Generator Sets Manufacturing
  - Census Code 3180 in ACS
- NAICS 334513, Machinery Manufacturing
  - Census Code 3190 in ACS
- NAICS 3345, Instruments and Controls
  - Census Code 3380 in ACS
- NAICS 5413 Architectural, Engineering, and Related Services
  - Census Code 7290 in ACS

In the August 2013 *Manufacturing Renaissance* study, IHS estimated that by 2025, as much as $100 billion will have been invested in new chemical, plastics, and related derivative manufacturing facilities in the United States. While the unconventional

[5] IHS, *America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy, Volume 3: Manufacturing Renaissance*, August 2013

revolution will affect all parts of the petrochemical industry, the impact will be most profound in four segments: Ethylene (olefins), Propylene (olefins), Methanol, and Nitrogen Fertilizers (Ammonia).[6]

Much of this new investment will involve foreign production shifting back to the U.S. Ethylene producers, confident of an extended period of low natural gas prices, have already signaled their intentions to increase capacity, reversing the trend of closing plants in the United States during the first decade of this century.[7] The Canadian producer Methanex Corp. based in Vancouver, British Columbia, is moving two 1 million ton methanol units from Chile to Louisiana, and Orascom Construction Industries of Egypt is building a new nitrogen fertilizer plant in southeast Iowa — the first world scale natural gas-based fertilizer plant built in the United States in nearly 25 years.[8]

However, these projected investments in the petrochemical industry do not encompass the full potential of increases in domestic production associated with cheap natural gas supplies. Over the long term, given expectations that North America will remain a low-cost energy and feedstock source for the chemical industry, the region could return to more downstream manufacturing of durable and non-durable goods based on these low-cost chemicals and plastics. The result will be stronger growth in domestic consumption of basic chemicals and plastics as a result of the "on-shoring" of the manufacturing of certain products produced from polyethylene.[9]

6. Capital Investment in Oil & Gas Industry Transportation and Storage Infrastructure

In the December 2013 study for API cited above, IHS estimated future capital investment needs for oil and gas transportation and storage infrastructure in 20 asset classes, which can be grouped into the following five broad categories:

- Natural Gas
- NGL & LPG
- Crude Oil and Condensate
- Refineries and Refined Products
- Common Infrastructure

The capital investments projected in each of these five categories involve expenditures for the output of the following industries:

- NAICS 221, Utilities (power generation)
    - Census Code 0580 in ACS

[6] Ibid., p. 40.
[7] Ibid., p. 46.
[8] Ibid., pp. 50,53.
[9] Ibid., p. 39.

- NAICS 236pt, Oil & Gas Pipeline and Related Structures Construction
    - Census Code 0770 in ACS
- NAICS 331, Iron & Steel Mills (pipe manufacturing)
    - Census Code 2670 in ACS
- NAICS 332, Metal Products Manufacturing (valves & fittings, and compressor manufacturing)
    - Census Codes 2870 and 2980 in ACS
- NAICS 333, Machinery Manufacturing (mining and oil field machinery)
    - Census Code 3080 in ACS
- NAICS 541 Professional and Technical Services (architectural, engineering, and related services)
    - Census Code 7290 in ACS

The IHS infrastructure study includes projections of the total direct employment in each of these industries that will be stimulated by the expected capital expenditures. Using these projections as a starting point, we developed corresponding projections of the distribution of employment by gender and for the African American and Hispanic populations. We report employment by gender within each minority group for the eight broad occupational categories and for 20 occupations that account for the largest share of employment in these industries.

Occupational Categories

The industries to be analyzed here in the midstream and downstream segments of the oil and gas industry and in the petrochemical industry have a different occupational mix than the upstream oil & gas industry, which we analyzed in our 2012 report. Therefore, in each industry segment to be analyzed we identified a different set of detailed occupations that account for a large share of total employment. Since the total employment counts in some segments may not be large, we present data for a smaller number of detailed occupations than were identified in our 2012 report. However, for completeness, as in our 2012 report, all occupations have been grouped into eight aggregate categories, including separate categories for skilled, semi-skilled and unskilled production jobs. Summary tables that show data for all segments of the industry are presented at the level of these eight broad occupations.

As we developed our estimates of employment in all demographic groups using the ACS data, we maintained full detail by gender within each race/ethnicity group within each occupation and industry for each region. However, the small amounts of total oil & gas industry employment in some industries and regions (and, thus, the small sample sizes in the ACS data) limit the extent of detail we can report by gender within minority groups. Nonetheless, across all industry segments, we provide estimates of the overall male/female breakdown of employment at the level of eight major occupations and separately for each region.

Trends in Minority Employment Growth

The minority categories for which employment estimates are presented here are defined as they were in the report IHS prepared for API in 2012:

- The Hispanic population includes persons of Hispanic origin of all races and citizenry.
- The African American population includes self-identified persons not of Hispanic origin reporting African American or Black alone as a single response to the Census Bureau's question regarding race.

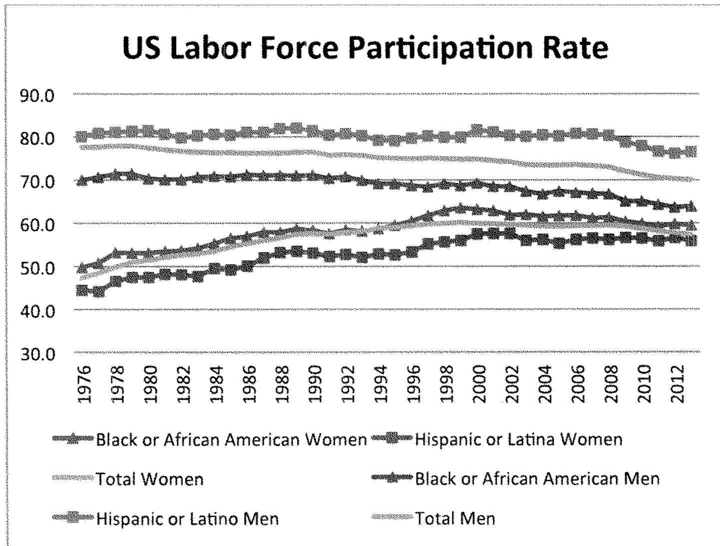
For each of the six segments of the oil and gas and related industries analyzed here, we compiled detailed current data on the incidence of minority employment by occupation using public-use microdata files from the American Community Survey. Our forecasts of the growth of employment of African Americans and Hispanics in all segments of the industry rely on the projections of the population, labor force, unemployment rates, and occupational employment trends for these two minority groups that we produced in our 2012 report for API.

Recent growth in the oil and gas and related industries has been significant in regions where American Indians and other Native populations constitute a larger portion of the population, such as Alaska (20 percent of the population), Oklahoma (13 percent of the population), and the Dakotas (less than 10 percent of the population). The data were not sufficient to develop comprehensive estimates and projections of the employment of American Indians and other Native populations in the oil and gas industry, but in certain regions the growth of the industry will create significant job opportunities for them.

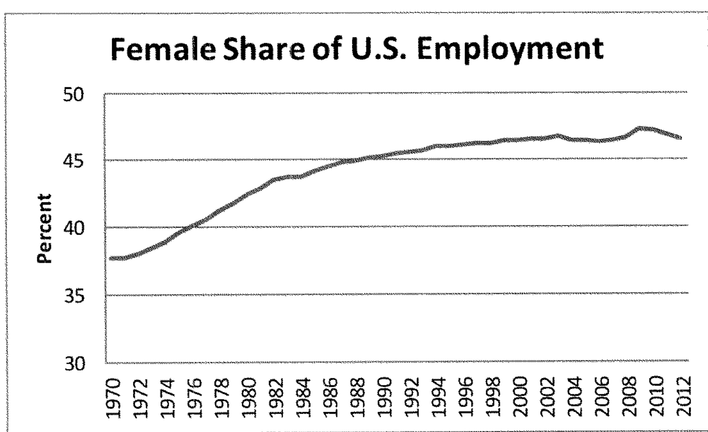
The Asian population is also not analyzed here, although they could have significant employment opportunities in the industry, especially in certain professional and technical occupations given their high incidence of college degrees and in certain regions such as the Monterey Shale.

Trends in Female Employment

The female labor participation rate rose steadily from the early 1970s through the mid-1990s, but for the next 15 years it was quite stable at a level near 60 percent. The 2008-2009 recession caused a decline to near 58 percent in 2011, but this was likely temporary. At the same time, the male labor participation rate has trended downward – leading to a long-term decline in the overall labor participation rate.



Given these opposing trends, the share of women in total U.S. employment rose steadily from 38 percent in 1970 to 46 percent in the mid-1990s and varied little in a range of 46.5-46.8 percent between 1999 and 2007. Male employment declined more sharply during the recession – boosting the female share of total employment to 47.3 percent in 2009. But that pattern has reversed as the recovery has progressed.



The dynamics of change in female labor participation across different demographic dimensions such as changes in education levels and working mothers with children has been documented extensively.[10] Of most interest for our purposes is identifying trends in the share of women within individual occupational groups. Changes in the Standard Occupational Classification – even at the broadest level – complicate the task of analyzing long-term changes. However, the relative stability of the overall female share of employment over the last 15 years suggests that an analysis focusing on this period should give good clues to possible future trends.

We compiled data on the female shares of employment at the level of 10 broad occupations over the period 2003-2013 using data from public-use microdata files of the March Supplement of the Current Population Survey. Economy-wide, no occupational category showed an increase of the female share of employment of more than 1.1 percentage points over this period. The "Management, Business and Financial Occupations" group showed the biggest gain. The female share of employment fell by 3 percentage points over this period in two occupational groups – "Office and Administrative Support Occupations" and "Production Occupations."

Table II.1

Change in the Female Share of Employment by Occupation Between 2003 and 2013

Occupational Group	Economy-wide	African American	Hispanic
Management, business, & financial occupations	+1%	0%	+4%
Transportation and material moving occupations	+1%	+2%	0%
Sales and related occupations	+1%	+2%	-1%
Professional and related occupations	0%	0%	+6%
Construction and extraction occupations	0%	-1%	0%
Farming, fishing, and forestry occupations	0%	+3%	-1%
Installation, maintenance, & repair occupations	-1%	-2%	-2%
Service occupations	-1%	-2%	+2%
Office and administrative support occupations	-3%	-5%	+1%
Production occupations	-3%	-3%	-3%

Among all African American workers, women also showed a drop in the latter two occupations. African American women gained share relative to African American men in "Transportation and Material Moving Occupations" and "Sales and Related Occupations."

[10] *BLS, Women in the Labor Force: A Data Book,* BLS Report 1040, February 2013.

Among Hispanic workers, women posted big gains in the shares of jobs in "Professional and Related Occupations" (up from 55% to 60%) and "Management, Business and Financial Occupations" (up from 44% to 48%).

To project trends in female employment, we extrapolated some of the trends observed in CPS data for the past decade, while maintaining stable shares where little movement was seen over this period.

Replacement Employment

In addition to projecting the growth of baseline employment in the oil and gas and petrochemical industries, we also project the number of job opportunities that arise when workers leave their occupations and need to be replaced. The Occupational Projections unit of the Bureau of Labor Statistics (BLS) estimates the number of job openings that will result from workers retiring from or permanently leaving an occupation. For each detailed occupation in the U.S. economy, BLS projects the share of employees who were at work in a recent base year that will have to be replaced over the following 10 years.

To estimate the number of jobs that will be created in the oil and gas and petrochemical industries due to replacement in 2010-2020, we applied BLS occupation-specific replacement rates to our baseline estimates of employment in the oil and gas and petrochemical industries by occupation in 2010. Job openings due to replacement demand will be even greater in the following decade, 2020-2030, because the wave of baby-boomers approaching retirement in those years (those age 45-55 in 2010) is about 22 percent larger than the first wave (those 55-65 in 2010). To approximate job opportunities due to replacement demand in the period 2020-2030, we adjusted the BLS replacement rates for 2010-2020 to reflect a correspondingly higher retirement rate. The report on employment of minorities in the oil and gas industry that IHS prepared for API in 2012 provides a more detailed description of our replacement employment forecast methodology.

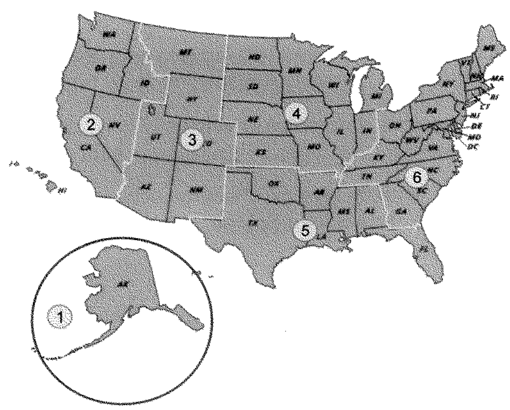
Definition of Regions

In our 2012 report for API we developed employment estimates by occupation and race/ethnicity for six regions of the country as well as at the national level. Here we present regional estimates of employment in 2010 on the same basis for three other segments of the industry – midstream, downstream and petrochemical. The states included in each region are listed below.

No regional detail was developed in producing the employment projections for any industry segment, because benchmark projections of total employment by region on a comparable basis were not available.

Figure 1.

Definition of Regions



States in Regions

Alaska	Alaska
West	California, Hawaii, Idaho, Nevada, Oregon, Washington
Rockies	Arizona, Colorado, Montana, New Mexico, Utah, Wyoming
Central	Iowa, Illinois, Indiana, Kansas, Missouri, Michigan, Minnesota, Nebraska, North Dakota, South Dakota, Wisconsin
Gulf	Alabama, Arkansas, Florida, Louisiana, Mississippi, Oklahoma, Texas
East	Connecticut, DC, Delaware, Georgia, Kentucky, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, Vermont, West Virginia

III. Minority and Female Employment in the Oil & Gas and Petrochemical Industries in 2010

Employment by Industry

The three segments of the U.S. oil and gas industry and the petrochemical industry together employed a total of 1.2 million people in 2010 (see Table III.1).

- The upstream segment, with employment of 721 thousand, accounted for 60% of the total, followed by the downstream segment with 23%.
- African American workers held 98 thousand jobs in these industries in 2010, accounting for 8.2% of total employment. Their share within the petrochemical industry was 11.2%.
- Hispanic workers held 188 thousand jobs across all four industry segments – 15.7% of the total. They accounted for a higher share of employment in the upstream segment than in the other segments.

Table III.1

African American and Hispanic Employment in the Oil & Gas and Petrochemical Industries by Segment: 2010

Total

	Total	Upstream	Midstream	Downstream	Petro-Chemicals
Total	1,198,590	720,911	42,079	279,162	156,438
African American	97,789	57,886	2,262	20,043	17,598
Hispanic	188,088	136,265	4,440	28,426	18,957

Minority Shares by Segment

	Total	Upstream	Midstream	Downstream	Petro-Chemicals
Total	100.0%	100.0%	100.0%	100.0%	100.0%
African American	8.2%	8.0%	5.4%	7.2%	11.2%
Hispanic	15.7%	18.9%	10.6%	10.2%	12.1%

Shares by Segment in Each Occupation

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	100.0%	60.1%	3.5%	23.3%	13.1%
African American	100.0%	59.2%	2.3%	20.5%	18.0%
Hispanic	100.0%	72.4%	2.4%	15.1%	10.1%

Employment by Gender

Women accounted for 19% of total employment in the combined oil and gas and petrochemical industries. Their share is higher in the downstream and petrochemical segments (25%) and lower in the upstream and midstream segments (15-16%). (See Table III.2.)

- The female share of employment in these industries is much lower for the Hispanic population – only 13%.
- The incidence of female employment for the African American population in the oil & gas industry generally mirrors the nation-wide pattern for the industry, at a share of 19%. In the midstream industry there is a higher female share.

Table III.2

Female Employment in the Oil & Gas and Petrochemical Industries by Segment: 2010

	Total	Upstream	Midstream	Downstream	Petro-Chemicals
Total	1,198,590	720,911	42,079	279,162	156,438
Female	225,687	110,350	6,840	69,140	39,357
Male	972,903	610,561	35,239	210,022	117,081
Percent Female	19%	15%	16%	25%	25%

	Total	Upstream	Midstream	Downstream	Petro-Chemicals
African American	97,789	57,886	2,262	20,043	17,598
Female	18,953	9,239	594	4,806	4,314
Male	78,836	48,647	1,668	15,237	13,284
Percent Female	19%	16%	26%	24%	25%

	Total	Upstream	Midstream	Downstream	Petro-Chemicals
Hispanic	188,088	136,265	4,440	28,426	18,957
Female	25,335	13,648	554	5,647	5,486
Male	162,753	122,617	3,886	22,779	13,471
Percent Female	13%	10%	12%	20%	29%

Note: In the detailed tables presented below, some employment cells are not reported because employment levels are small and result in very small sample sizes in the American Community Survey. These cases are identified by a "**" entry in the tables.

Employment by Occupation

The distribution of employment in eight major occupational categories in each of the four segments of the oil & gas and petrochemical industries is shown in Table III.3.

- Across all four industry segments, blue-collar jobs accounted for 57.2% of total employment. More than one-half of these blue-collar jobs were skilled blue-collar jobs.
- The upstream segment has the highest share of blue collar jobs (63% of the segment total) and the highest share of skilled blue-collar jobs (37.6% of all upstream jobs).
- The downstream and petrochemicals segments have higher shares of semi-skilled blue-collar jobs (such as production workers and truck drivers) – 25-30% of the total.

Similar distributions of employment in eight major occupational categories for the African American and Hispanic populations are shown in Tables III.4 and III.5.

- On average across all four segments of the oil & gas and petrochemical industries, the African American population has a slightly lower share of skilled blue-collar jobs and a higher share of semi-skilled blue-collar jobs.
- This difference is related to the African American population's high incidence of semi-skilled employment in the downstream and petrochemical segments.
- Nearly three-quarters of Hispanic workers employed in the oil & gas and petrochemical industries are in blue-collar occupations, with the largest share (35%) in skilled blue-collar jobs.

Table III.6 shows the wide variation in female shares of employment by occupation that underlies the overall female share of 19%.

- Female shares of employment are very low in the blue-collar occupation categories – the categories with the highest shares of total employment in the industry. (An exception is the high share of women in semi-skilled and unskilled blue-collar occupations in the petrochemical segment. Women occupy high shares of various production, assembly and inspector occupations in this segment.)
- Women have higher employment shares in the Office and Administrative Support category and in all management and professional occupational categories.

Data on employment by occupation in individual industries within the oil and gas industry at the level of eight broad occupations and in detailed occupational categories are provided in the appendices.

Table III.3
Employment in the Oil & Gas and Petrochemical Industries by Segment and Broad Occupation: 2010

Total

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	1,198,590	720,911	42,079	279,162	156,438
Management, Business and Financial	146,229	71,910	7,131	41,898	25,290
Professional and Related	164,441	113,155	5,021	23,246	23,019
Service	12,478	2,751	984	5,124	3,619
Sales and Related	53,780	11,308	436	36,844	5,192
Office & Administrative Support	135,130	67,233	5,125	46,739	16,033
Skilled Blue-collar	354,082	271,287	13,228	43,633	25,934
Semi-skilled Blue Collar	255,457	130,433	6,644	70,993	47,387
Unskilled Blue Collar	76,993	52,834	3,510	10,685	9,964

Shares by Occupation within Segment

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Management, Business and Financial	12.2%	10.0%	16.9%	15.0%	16.2%
Professional and Related	13.7%	15.7%	11.9%	8.3%	14.7%
Service	1.0%	0.4%	2.3%	1.8%	2.3%
Sales and Related	4.5%	1.6%	1.0%	13.2%	3.3%
Office & Administrative Support	11.3%	9.3%	12.2%	16.7%	10.2%
Skilled Blue-collar	29.5%	37.6%	31.4%	15.6%	16.6%
Semi-skilled Blue Collar	21.3%	18.1%	15.8%	25.4%	30.3%
Unskilled Blue Collar	6.4%	7.3%	8.3%	3.8%	6.4%

Shares by Segment in Each Occupation

	Total	Upstream	Midstream	Downstream	Petro-Chemicals
Total	100.0%	60.1%	3.5%	23.3%	13.1%
Management, Business and Financial	100.0%	49.2%	4.9%	28.7%	17.3%
Professional and Related	100.0%	68.8%	3.1%	14.1%	14.0%
Service	100.0%	22.0%	7.9%	41.1%	29.0%
Sales and Related	100.0%	21.0%	0.8%	68.5%	9.7%
Office & Administrative Support	100.0%	49.8%	3.8%	34.6%	11.9%
Skilled Blue-collar	100.0%	76.6%	3.7%	12.3%	7.3%
Semi-skilled Blue Collar	100.0%	51.1%	2.6%	27.8%	18.5%
Unskilled Blue Collar	100.0%	68.6%	4.6%	13.9%	12.9%

Table III.4
African American Employment in the Oil & Gas and Petrochemical Industries by Segment and Broad Occupation: 2010

Total

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	97,789	57,886	2,262	20,043	17,598
Management, Business and Financial	8,875	5,091	233	2,362	1,189
Professional and Related	11,690	8,010	267	1,503	1,910
Service	1,696	453	64	673	506
Sales and Related	2,357	952	**	1,267	135
Office & Administrative Support	12,169	7,562	615	2,435	1,557
Skilled Blue-collar	25,453	18,900	549	3,499	2,505
Semi-skilled Blue Collar	27,208	11,775	351	6,906	8,176
Unskilled Blue Collar	8,341	5,143	182	1,398	1,618

Shares by Occupation within Segment

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Management, Business and Financial	9.1%	8.8%	10.3%	11.8%	6.8%
Professional and Related	12.0%	13.8%	11.8%	7.5%	10.9%
Service	1.7%	0.8%	2.8%	3.4%	2.9%
Sales and Related	2.4%	1.6%	**	6.3%	0.8%
Office & Administrative Support	12.4%	13.1%	27.2%	12.2%	8.8%
Skilled Blue-collar	26.0%	32.7%	24.3%	17.5%	14.2%
Semi-skilled Blue Collar	27.8%	20.3%	15.5%	34.5%	46.5%
Unskilled Blue Collar	8.5%	8.9%	8.1%	7.0%	9.2%

Shares by Segment in Each Occupation

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	100.0%	59.2%	2.3%	20.5%	18.0%
Management, Business and Financial	100.0%	57.4%	2.6%	26.6%	13.4%
Professional and Related	100.0%	68.5%	2.3%	12.9%	16.3%
Service	100.0%	26.7%	3.8%	39.7%	29.8%
Sales and Related	100.0%	40.4%	**	53.8%	5.8%
Office & Administrative Support	100.0%	62.1%	5.1%	20.0%	12.8%
Skilled Blue-collar	100.0%	74.3%	2.2%	13.7%	9.8%
Semi-skilled Blue Collar	100.0%	43.3%	1.3%	25.4%	30.1%
Unskilled Blue Collar	100.0%	61.7%	2.2%	16.8%	19.4%

Table III.5

Hispanic Employment in the Oil & Gas and Petrochemical Industries by Segment and Broad Occupation: 2010

Total

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	188,088	136,265	4,440	28,426	18,957
Management, Business and Financial	12,753	7,932	410	2,974	1,437
Professional and Related	13,618	10,053	239	2,005	1,321
Service	2,097	665	123	916	393
Sales and Related	4,042	1,706	**	2,139	189
Office & Administrative Support	16,486	10,697	474	3,886	1,429
Skilled Blue-collar	64,908	54,993	1,278	5,852	2,785
Semi-skilled Blue Collar	49,174	30,680	897	8,191	9,406
Unskilled Blue Collar	25,010	19,539	1,011	2,463	1,997

Shares by Occupation within Segment

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Management, Business and Financial	6.8%	5.8%	9.2%	10.5%	7.6%
Professional and Related	7.2%	7.4%	5.4%	7.1%	7.0%
Service	1.1%	0.5%	2.8%	3.2%	2.1%
Sales and Related	2.1%	1.3%	**	7.5%	1.0%
Office & Administrative Support	8.8%	7.9%	10.7%	13.7%	7.5%
Skilled Blue-collar	34.5%	40.4%	28.8%	20.6%	14.7%
Semi-skilled Blue Collar	26.1%	22.5%	20.2%	28.8%	49.6%
Unskilled Blue Collar	13.3%	14.3%	22.8%	8.7%	10.5%

Shares by Segment in Each Occupation

	Total	Upstream	Midstream	Downstream	Petro-chemicals
Total	100.0%	72.4%	2.4%	15.1%	10.1%
Management, Business and Financial	100.0%	62.2%	3.2%	23.3%	11.3%
Professional and Related	100.0%	73.8%	1.8%	14.7%	9.7%
Service	100.0%	31.7%	5.9%	43.7%	18.7%
Sales and Related	100.0%	42.2%	**	52.9%	4.7%
Office & Administrative Support	100.0%	64.9%	2.9%	23.6%	8.7%
Skilled Blue-collar	100.0%	84.7%	2.0%	9.0%	4.3%
Semi-skilled Blue Collar	100.0%	62.4%	1.8%	16.7%	19.1%
Unskilled Blue Collar	100.0%	78.1%	4.0%	9.8%	8.0%

Table III.6
Female Employment in the Oil & Gas and Petrochemical Industries by Major Occupation and Industry Segment: 2010

Female Employment

	Total	Upstream	Midstream	Downstream	Petro-Chemicals
Total	225,687	110,350	6,840	69,140	39,357
Management, Business and Financial	41,181	18,883	1,789	13,474	7,035
Professional and Related	35,548	23,601	1,204	5,520	5,223
Service	2,741	801	97	1,027	816
Sales and Related	12,419	2,381	96	8,702	1,240
Office & Administrative Support	99,783	51,602	2,717	35,465	9,999
Skilled Blue-collar	8,999	5,476	410	1,520	1,593
Semi-skilled Blue Collar	19,605	5,187	379	2,665	11,374
Unskilled Blue Collar	5,411	2,419	148	767	2,077

Female Share in Each Occupation by Industry Segment

	Total	Upstream	Midstream	Downstream	Petro-Chemicals
Total	19%	15%	16%	25%	25%
Management, Business and Financial	28%	26%	25%	32%	28%
Professional and Related	22%	21%	24%	24%	23%
Service	22%	29%	10%	20%	23%
Sales and Related	23%	21%	22%	24%	24%
Office & Administrative Support	74%	77%	53%	76%	62%
Skilled Blue-collar	3%	2%	3%	3%	6%
Semi-skilled Blue Collar	8%	4%	6%	4%	24%
Unskilled Blue Collar	7%	5%	4%	7%	21%

Employment by Region

Summary data on employment by region are presented in Table III.7 through Table III.9. As noted above, some employment cells in these tables are not reported because employment levels are small and result in very small sample sizes in the American Community Survey. These cases are identified by a "**" entry in the tables. In particular, Alaska is identified as a separate region here, as in our 2012 report for API, and total employment across the four segments of the oil & gas and petrochemical industries in 2010 was only 12 thousand. Thus, many employment cells are too small to report in this region.

The national employment shares for minorities and females summarized above are affected by the fact that employment opportunities in the oil and gas industry are not uniformly distributed across regions or states. The mix of employment by race/ethnicity and gender is also affected by the educational attainment levels of the population in the regions with heavy concentrations of industry employment.

- The Gulf region accounts for over half of all oil & gas and petrochemical industry employment – including 62% in the upstream segment.
- The Gulf region also has the highest concentrations of minority employment in these industries. Approximately 64-65% of both African American and Hispanic workers employed in the industries work in the Gulf region.
- The shares of female employment in these industries (combining all four segments) vary little across regions, but are slightly above average in the Eastern and Central Regions – areas where the upstream segment represents a smaller share of the industry total.

Additional data on the distribution of employment in the oil & gas and petrochemical industries by occupation, race/ethnicity, gender and region are presented in separate appendices for each of the four industry segments.

Table III.7

Employment in the Oil & Gas and Petrochemical Industries by Region and Industry Segment: 2010

Total

	Total	Upstream	Midstream	Downstream	Petro-chemicals
US	1,198,590	720,911	42,079	279,162	156,438
Alaska	11,926	10,162	789	883	92
West	81,337	34,217	3,016	35,741	8,363
Rockies	103,600	84,861	2,997	12,995	2,747
Gulf	611,370	449,792	22,016	80,401	59,161
Central	138,609	55,898	5,331	45,388	31,992
Eastern	251,748	85,981	7,930	103,754	54,083

Regional Shares by Industry Segment

	Total	Upstream	Midstream	Downstream	Petro-chemicals
US	100.0%	100.0%	100.0%	100.0%	100.0%
Alaska	1.0%	1.4%	1.9%	0.3%	0.1%
West	6.8%	4.7%	7.2%	12.8%	5.3%
Rockies	8.6%	11.8%	7.1%	4.7%	1.8%
Gulf	51.0%	62.4%	52.3%	28.8%	37.8%
Central	11.6%	7.8%	12.7%	16.3%	20.5%
Eastern	21.0%	11.9%	18.8%	37.2%	34.6%

Shares by Industry Segment in Each Region

	Total	Upstream	Midstream	Downstream	Petro-chemicals
US	100.0%	60.1%	3.5%	23.3%	13.1%
Alaska	100.0%	85.2%	6.6%	7.4%	0.8%
West	100.0%	42.1%	3.7%	43.9%	10.3%
Rockies	100.0%	81.9%	2.9%	12.5%	2.7%
Gulf	100.0%	73.6%	3.6%	13.2%	9.7%
Central	100.0%	40.3%	3.8%	32.7%	23.1%
Eastern	100.0%	34.2%	3.1%	41.2%	21.5%

Table III.8

Employment of Minority Groups in the Combined Oil & Gas and Petrochemical Industries by Region: 2010

Total Employment

	Total	African American	Hispanic
US	1,198,590	97,789	188,088
Alaska	11,926	**	**
West	81,337	3,987	21,608
Rockies	103,600	1,761	21,949
Gulf	611,370	63,207	121,199
Central	138,609	6,254	8,755
Eastern	251,748	22,382	14,062

Regional Shares of Each Minority Group

	Total	African American	Hispanic
US	100.0%	100.0%	100.0%
Alaska	1.0%	**	**
West	6.8%	4.1%	11.5%
Rockies	8.6%	1.8%	11.7%
Gulf	51.0%	64.6%	64.4%
Central	11.6%	6.4%	4.7%
Eastern	21.0%	22.9%	7.5%

Minority Group Shares in Each Region

	Total	African American	Hispanic
US	100.0%	8.2%	15.7%
Alaska	100.0%	**	**
West	100.0%	4.9%	26.6%
Rockies	100.0%	1.7%	21.2%
Gulf	100.0%	10.3%	19.8%
Central	100.0%	4.5%	6.3%
Eastern	100.0%	8.9%	5.6%

Table III.9

Female Employment of Minority Groups in the Combined Oil & Gas and Petrochemical Industries by Region: 2010

Female Employment

	Total	African American	Hispanic
US	225,687	18,952	25,335
Alaska	1,737	**	**
West	16,519	858	3,301
Rockies	16,783	245	2,158
Gulf	105,245	11,683	15,319
Central	29,489	1,385	2,043
Eastern	55,914	4,752	2,463

Female Shares of Minority Employment in Each Region

	Total	African American	Hispanic
US	18.8%	19.4%	13.5%
Alaska	14.6%	**	**
West	20.3%	21.5%	15.3%
Rockies	16.2%	13.9%	9.8%
Gulf	17.2%	18.5%	12.6%
Central	21.3%	22.2%	23.3%
Eastern	22.2%	21.2%	17.5%

IV. Estimated Minority and Female Job Gains to 2030 in the Oil & Gas and Petrochemical Industries

As described in the Introduction, we consider four sources of future job opportunities in the oil & gas and related industries in this study:

- New jobs that are projected to be created under a baseline forecast of the growth of the oil & gas and petrochemical industries,
- Jobs that would be created under a scenario for more accelerated development of the upstream oil and gas industry,
- Jobs created by projected capital investment in the transportation and storage infrastructure of the oil & gas industry and in the petrochemical industry, and
- Job opportunities that will likely be created due to the need to replace workers who retire or otherwise leave the oil & gas and petrochemical industries.

Baseline employment growth is measured as the sum of projected growth in the upstream and midstream oil and gas industry and the petrochemical industry from 2010 in five-year increments through 2030. (We do not project employment growth in the downstream segment of the oil and gas industry.)

Growth from all sources over the period 2010-2030 is projected as follows:

- In our baseline forecast, employment in these industries in 2030 will be 202 thousand higher than in 2010.
- Under pro-development policies for the upstream oil and gas industry, an additional 323 thousand jobs would be added, bringing the total employment gain, 2010 to 2030, to 525 thousand jobs.
- Projected capital investments in the oil and gas industry infrastructure and in the petrochemical industry would stimulate another 160 thousand jobs in 2030.
- Combining the job creation from these three sources will result in a net increase of 685 thousand jobs in 2030 compared to our base-year of 2010.
- We estimate that the need to replace current workers who retire from the oil & gas and petrochemical industries over the 20-year period from 2010 to 2030 will create an additional 579 thousand job opportunities.
- Combining job opportunities due to replacement requirements with the net increase in employment from all sources, we project a total of 1.264 million job opportunities in these industries over these 20-years.

Table IV.1 summarizes our projections of the distribution of this total for minority and female job opportunities. The remainder of this section provides details on each component of the projections.

Table IV.1

Potential Job Opportunities in the Oil & Gas and Petrochemical Industries to 2030: Combining Baseline Growth and Replacement, Capital Expenditures, and Pro-Development Policy

Total

	African American	Hispanic	Total
Total	100,228	307,310	1,264,138
Management, Business and Financial	7,876	15,433	127,157
Professional and Related	10,006	16,792	164,946
Service	1,684	2,769	11,912
Sales and Related	3,325	6,350	48,043
Office & Administrative Support	12,633	22,062	110,293
Skilled Blue-collar	25,769	100,197	391,434
Semi-skilled Blue Collar	28,863	92,721	314,861
Unskilled Blue Collar	10,072	50,986	95,492

Female Employment

	African American	Hispanic	Total
Total	16,080	31,847	184,970
Management, Business and Financial	2,195	4,028	34,863
Professional and Related	1,945	3,453	33,965
Service	322	800	3,135
Sales and Related	261	334	9,782
Office & Administrative Support	7,166	13,589	73,362
Skilled Blue-collar	863	1,480	8,133
Semi-skilled Blue Collar	2,480	6,346	16,382
Unskilled Blue Collar	848	1,817	5,348

Female Share within Each Occupation

	African American	Hispanic	Total
Total	16%	10%	15%
Management, Business and Financial	28%	26%	27%
Professional and Related	19%	21%	21%
Service	19%	29%	26%
Sales and Related	8%	5%	20%
Office & Administrative Support	57%	62%	67%
Skilled Blue-collar	3%	1%	2%
Semi-skilled Blue Collar	9%	7%	5%
Unskilled Blue Collar	8%	4%	6%

Oil & Gas and Petrochemical Industry Operations

Table IV.2 provides a summary of projected baseline employment growth in the upstream and midstream oil and gas industry and the petrochemical industry, in total and for minority groups and women.

Table IV.2a

Baseline Employment in the Upstream and Midstream Oil & Gas and Petrochemical Industries

	2010	2020	2030	Change 2010-2030
Total	919,428	1,034,659	1,121,588	202,160
Upstream Oil & Gas Industry	720,911	796,662	864,974	144,063
Midstream Oil & Gas Industry	42,079	50,777	53,188	11,109
Petrochemical Industry	156,438	187,220	203,426	46,988

- Over the period 2010 to 2030, combined employment in these three segments is projected to increase by 202 thousand to reach 1.12 million.

Table IV.2b

Baseline African American Employment in the Upstream and Midstream Oil & Gas and Petrochemical Industries

	2010	2020	2030	Change 2010-2030
Total	77,746	93,038	101,908	24,162
Upstream Oil & Gas Industry	57,886	67,612	73,740	15,854
Midstream Oil & Gas Industry	2,262	2,868	3,046	784
Petrochemical Industry	17,598	22,558	25,122	7,524
Share of Industry Totals Shown in Table IV.2a				
Total	8%	9%	9%	
Upstream Oil & Gas Industry	8%	8%	9%	
Midstream Oil & Gas Industry	5%	6%	6%	
Petrochemical Industry	11%	12%	12%	

- African American employment is projected to increase by 24 thousand – from 78 thousand to 102 thousand.

Table IV.2c
Baseline Hispanic Employment in the Upstream and Midstream Oil & Gas and Petrochemical Industries

	2010	2020	2030	Change 2010-2030
Total	159,662	216,215	271,861	112,199
Upstream Oil & Gas Industry	136,265	180,609	224,965	88,700
Midstream Oil & Gas Industry	4,440	6,641	8,354	3,914
Petrochemical Industry	18,957	28,965	38,542	19,585
Share of Industry Totals Shown in Table IV.2a				
Total	17%	21%	24%	
Upstream Oil & Gas Industry	19%	23%	26%	
Midstream Oil & Gas Industry	11%	13%	16%	
Petrochemical Industry	12%	15%	19%	

- Hispanic employment is projected to increase by 112 thousand – from 160 thousand to 272 thousand.
- Combined minority employment in these industries will rise from one-quarter of the total in 2010 to one-third of the total in 2030.

Table IV.2d
Baseline Female Employment in the Upstream and Midstream Oil & Gas and Petrochemical Industries

	2010	2020	2030	Change 2010-2030
Total	156,547	167,862	179,442	22,895
Upstream Oil & Gas Industry	110,350	113,432	121,461	11,111
Midstream Oil & Gas Industry	6,840	8,133	8,472	1,632
Petrochemical Industry	39,357	46,297	49,509	10,152
Share of Industry Totals Shown in Table IV.2a				
Total	17%	16%	16%	
Upstream Oil & Gas Industry	15%	14%	14%	
Midstream Oil & Gas Industry	16%	16%	16%	
Petrochemical Industry	25%	25%	24%	

- Female employment is projected to increase by 23 thousand to 179 thousand.
- The overall share of female employment will decline slightly, in part because much of the employment growth in the industry will occur in the upstream segment, where the share of female employment is lowest due to the high shares of blue-collar production jobs.

As reported above, employment in the oil and gas and petrochemical industries is projected to grow by 202 thousand jobs between 2010 and 2030. Tables IV.3 and IV.4 provide data on the distribution of these additional 202 thousand jobs by industry, occupation, gender and minority group.

Among the eight broad occupations identified in this study, the greatest job growth will occur in skilled blue collar jobs – a net increase of 77 thousand jobs or 38 percent of the 202 thousand total. This growth of the demand for skilled blue-collar jobs is driven largely by the expansion of the upstream oil and natural gas industry, where we project 65 thousand new skilled blue collar jobs to be created (45 percent of the 144,000 net new jobs projected for the industry). An additional 53 thousand semi-skilled jobs will be added across the three industries.

Over 41 thousand jobs will be created in the 'Management, Business and Financial' and 'Professional and Related' occupational categories.

As noted above, because so much of the job growth will be concentrated in blue-collar occupations where female shares of employment have historically been low and are not projected to increase, the overall female share of projected job gains across the three industries is low – only 11 percent of the 202 thousand jobs that will be added. Female job gains will be greatest in the 'Management, Business and Financial' category, where women will account for one-third of the 16 thousand jobs to be added.

Women will also account for 33 percent of the jobs added in the 'Office and Administrative Support' group, but this is well below the current female share of employment in that category (74 percent as shown in Table III.6). Thus, the female share of employment in 'Office and Administrative Support' jobs will decline over the forecast period.

African Americans and Hispanics combined will account for 136 thousand (or two-thirds) of the 202 thousand net new jobs projected in the three industries between 2010 and 2030 (Table IV.4). The Hispanic population alone is projected to account for over half of the job gains.

Data on the distribution of employment by occupation, minority group and gender for the combined oil and gas and petrochemical industries at the beginning and end of the forecast period are shown in Tables IV.5 and IV.6.

Table IV.3

Jobs Projected to be Added in the Oil & Gas and Petrochemical Industries Between 2010 and 2030: Distribution by Industry, Occupation and Gender

Total

	Upstream	Midstream	Petro-chemical	Total
Total	144,063	11,109	46,988	202,160
Management, Business and Financial	7,408	1,924	6,853	16,185
Professional and Related	19,186	1,390	4,622	25,198
Service	590	262	1,256	2,108
Sales and Related	1,705	166	972	2,843
Office & Administrative Support	8,035	1,208	3,173	12,416
Skilled Blue-collar	65,043	3,629	8,103	76,775
Semi-skilled Blue Collar	32,472	2,028	18,444	52,944
Unskilled Blue Collar	9,624	502	3,565	13,691

Female Employment

	Upstream	Midstream	Petro-chemical	Total
Total	11,111	1,632	10,152	22,895
Management, Business and Financial	2,446	611	2,210	5,267
Professional and Related	4,121	346	1,046	5,513
Service	145	**	286	447
Sales and Related	143	32	207	382
Office & Administrative Support	2,282	479	1,294	4,055
Skilled Blue-collar	1,043	91	463	1,597
Semi-skilled Blue Collar	641	65	3,701	4,407
Unskilled Blue Collar	290	**	945	1,227

Female Share of Growth within Each Occupation

	Upstream	Midstream	Petro-chemical	Total
Total	8%	15%	22%	11%
Management, Business and Financial	33%	32%	32%	33%
Professional and Related	21%	25%	23%	22%
Service	25%	**	23%	21%
Sales and Related	8%	20%	21%	13%
Office & Administrative Support	28%	40%	41%	33%
Skilled Blue-collar	2%	3%	6%	2%
Semi-skilled Blue Collar	2%	3%	20%	8%
Unskilled Blue Collar	3%	**	27%	9%

Table IV.4

Jobs Projected to be Added in the Oil & Gas and Petrochemical Industries Between 2010 and 2030: Distribution by Minority Group, Occupation and Gender

Total

	African American	Hispanic	Total
Total	24,162	112,199	202,160
Management, Business and Financial	1,584	5,231	16,185
Professional and Related	2,070	6,064	25,198
Service	338	878	2,108
Sales and Related	275	1,100	2,843
Office & Administrative Support	2,730	7,772	12,416
Skilled Blue-collar	6,383	37,897	76,775
Semi-skilled Blue Collar	8,385	36,742	52,944
Unskilled Blue Collar	2,397	16,515	13,691

Female Employment

	African American	Hispanic	Total
Total	3,840	13,028	22,895
Management, Business and Financial	468	1,520	5,268
Professional and Related	438	1,248	5,513
Service	80	237	447
Sales and Related	28	76	382
Office & Administrative Support	1,334	4,708	4,055
Skilled Blue-collar	186	511	1,596
Semi-skilled Blue Collar	1,002	3,858	4,407
Unskilled Blue Collar	304	870	1,227

Female Share of Growth within Each Occupation

	African American	Hispanic	Total
Total	16%	12%	11%
Management, Business and Financial	30%	29%	33%
Professional and Related	21%	21%	22%
Service	24%	27%	21%
Sales and Related	10%	7%	13%
Office & Administrative Support	49%	61%	33%
Skilled Blue-collar	3%	1%	2%
Semi-skilled Blue Collar	12%	10%	8%
Unskilled Blue Collar	13%	5%	9%

Table IV.5

Baseline Employment in the Upstream and Midstream Oil & Gas and Petrochemical Industries: 2010

Total

	African American	Hispanic	Total
Total	77,746	159,662	919,428
Management, Business and Financial	6,512	9,779	104,331
Professional and Related	10,188	11,612	141,195
Service	1,023	1,181	7,354
Sales and Related	1,087	1,903	16,936
Office & Administrative Support	9,734	12,600	88,392
Skilled Blue-collar	21,956	59,057	310,450
Semi-skilled Blue Collar	20,303	40,983	184,462
Unskilled Blue Collar	6,943	22,547	66,308

Female Employment

	African American	Hispanic	Total
Total	14,147	19,688	156,547
Management, Business and Financial	1,816	2,481	27,708
Professional and Related	2,135	2,414	30,027
Service	268	326	1,715
Sales and Related	94	140	3,717
Office & Administrative Support	5,912	7,921	64,318
Skilled Blue-collar	965	1,046	7,479
Semi-skilled Blue Collar	2,403	4,341	16,939
Unskilled Blue Collar	554	1,019	4,644

Female Share within Each Occupation

	African American	Hispanic	Total
Total	18%	12%	17%
Management, Business and Financial	28%	25%	27%
Professional and Related	21%	21%	21%
Service	26%	28%	23%
Sales and Related	9%	7%	22%
Office & Administrative Support	61%	63%	73%
Skilled Blue-collar	4%	2%	2%
Semi-skilled Blue Collar	12%	11%	9%
Unskilled Blue Collar	8%	5%	7%

Table IV.6

Baseline Employment in the Upstream and Midstream Oil & Gas and Petrochemical Industries: 2030

Total

	African American	Hispanic	Total
Total	101,908	271,861	1,121,588
Management, Business and Financial	8,096	15,010	120,516
Professional and Related	12,258	17,676	166,393
Service	1,361	2,059	9,462
Sales and Related	1,362	3,003	19,779
Office & Administrative Support	12,464	20,372	100,808
Skilled Blue-collar	28,339	96,954	387,225
Semi-skilled Blue Collar	28,688	77,725	237,406
Unskilled Blue Collar	9,340	39,062	79,999

Female Employment

	African American	Hispanic	Total
Total	17,987	32,716	179,442
Management, Business and Financial	2,284	4,001	32,976
Professional and Related	2,573	3,662	35,540
Service	348	563	2,162
Sales and Related	122	216	4,099
Office & Administrative Support	7,246	12,629	68,373
Skilled Blue-collar	1,151	1,557	9,075
Semi-skilled Blue Collar	3,405	8,199	21,346
Unskilled Blue Collar	858	1,889	5,871

Female Share within Each Occupation

	African American	Hispanic	Total
Total	18%	12%	16%
Management, Business and Financial	28%	27%	27%
Professional and Related	21%	21%	21%
Service	26%	27%	23%
Sales and Related	9%	7%	21%
Office & Administrative Support	58%	62%	68%
Skilled Blue-collar	4%	2%	2%
Semi-skilled Blue Collar	12%	11%	9%
Unskilled Blue Collar	9%	5%	7%

Replacement Employment

In addition to projecting the growth of baseline employment in the oil & gas and petrochemical industries, we also projected the number of job opportunities that will arise when current workers retire or leave the industry over the forecast period and need to be replaced. Replacement employment is projected for all four segments of the oil and gas and petrochemical industries.

- Across all four industry segments, we project that there will be a need to replace 261 thousand workers over the period 2010-2020. Replacement requirements increase in the second decade of the forecast period as a larger cohort of current workers approaches retirement age.
- Cumulative replacement employment over the 20-year period, 2010-2030, is estimated to be 579 thousand. Thus, replacement requirements will generate nearly three times as many job opportunities in these industries as net employment growth over the 20-year forecast period.

Table IV.7

Replacement Employment in the Oil & Gas and Petrochemical Industries

	2010-2020	2020-2030	Total 2010-2030
Total	260,966	318,360	579,326
Upstream Oil & Gas Industry	151,235	184,496	335,731
Midstream Oil & Gas Industry	10,223	12,471	22,694
Downstream Oil & gas Industry	65,119	79,442	144,561
Petrochemical Industry	34,389	41,951	76,340

Table IV.8 provides estimates of the additional potential job gains by minority groups and women due to replacement requirements in the oil & gas and petrochemical industries. Note that baseline job gains for African American and Hispanic workers shown in the previous section effectively include some job gains associated with replacement requirements. Those data show total absolute job gains for the two minority groups over the forecast period, and part of that increase is due to minority workers replacing nonminority workers who retire. Therefore, estimates of potential additional jobs for African American and Hispanic workers due to replacement requirements in Table IV.8 include only the net amount of additional replacement gains for minority workers associated with replacing other minority workers who are projected to retire during the 20-year forecast period.

Table IV.8

Potential Job Gains for Minority Groups and Women from Replacement Requirements in the Oil & Gas and Petrochemical Industries: 2010-2030

Total

	African American	Hispanic	Total
Total	42,627	73,635	579,326
Management, Business and Financial	3,956	4,791	61,744
Professional and Related	5,311	5,358	84,906
Service	958	1,087	6,463
Sales and Related	2,626	3,712	34,802
Office & Administrative Support	5,786	6,324	54,971
Skilled Blue-collar	9,701	19,011	147,080
Semi-skilled Blue Collar	11,143	26,497	160,089
Unskilled Blue Collar	3,146	6,855	29,271

Female Employment

	African American	Hispanic	Total
Total	6,846	8,156	94,540
Management, Business and Financial	1,027	1,154	16,757
Professional and Related	981	1,128	17,813
Service	157	332	1,858
Sales and Related	179	169	7,552
Office & Administrative Support	3,444	3,986	40,380
Skilled Blue-collar	351	263	2,955
Semi-skilled Blue Collar	490	946	5,649
Unskilled Blue Collar	217	178	1,576

Female share within Each Occupation

	African American	Hispanic	Total
Total	16%	11%	16%
Management, Business and Financial	26%	24%	27%
Professional and Related	18%	21%	21%
Service	16%	31%	29%
Sales and Related	7%	5%	22%
Office & Administrative Support	60%	63%	73%
Skilled Blue-collar	4%	1%	2%
Semi-skilled Blue Collar	4%	4%	4%
Unskilled Blue Collar	7%	3%	5%

Baseline plus Replacement Employment

The overall job potential for minority and female workers in the oil and gas and petrochemical industries is best measured by combining baseline and replacement job possibilities.

- Combined job potential over the 20-year period is 781 thousand, including 480 thousand in the upstream oil and gas industry.

Table IV.9

Estimated Job Opportunities from Baseline Employment Change plus Replacement Requirements in the Oil & Gas and Petrochemical Industries

	2010-2020	2020-2030	Total 2010-2030
Total	376,197	405,289	781,486
Upstream Oil & Gas Industry	226,986	252,808	479,794
Midstream Oil & Gas Industry	18,921	14,882	33,803
Downstream Oil & Gas Industry*	65,119	79,442	144,561
Petrochemical Industry	65,171	58,157	123,328

*Replacement only

- We estimate that the 781,000 jobs created will include 67 thousand potential jobs for African American workers and 186 thousand for Hispanic workers.
- The combined total of 253 thousand minority jobs represents 32 percent of all projected job openings.
- The share of the total projected potential jobs that will be filled by women will be held down by the limited job gains projected for women in blue collar occupations where a substantial fraction of job growth in the oil & gas and petrochemical industries is expected.
- However, women will maintain or increase their shares of all jobs in the 'Management, Business and Financial' and service-related occupations.

Table IV.10

Estimated Job Opportunities from Baseline Employment Change plus Replacement Requirements in the Oil & Gas and Petrochemical Industries: 2010-2030

Total

	African American	Hispanic	Total
Total	66,789	185,834	781,486
Management, Business and Financial	5,540	10,022	77,929
Professional and Related	7,381	11,422	110,104
Service	1,296	1,965	8,571
Sales and Related	2,901	4,812	37,645
Office & Administrative Support	8,516	14,096	67,387
Skilled Blue-collar	16,085	56,908	223,855
Semi-skilled Blue Collar	19,528	63,239	213,033
Unskilled Blue Collar	5,542	23,370	42,962

Female Employment

	African American	Hispanic	Total
Total	10,686	21,184	117,435
Management, Business and Financial	1,495	2,674	22,025
Professional and Related	1,419	2,376	23,326
Service	237	569	2,305
Sales and Related	207	245	7,934
Office & Administrative Support	4,778	8,694	44,435
Skilled Blue-collar	537	774	4,551
Semi-skilled Blue Collar	1,492	4,804	10,056
Unskilled Blue Collar	521	1,048	2,803

Female Share within Each Occupation

	African American	Hispanic	Total
Total	16%	11%	15%
Management, Business and Financial	27%	27%	28%
Professional and Related	19%	21%	21%
Service	18%	29%	27%
Sales and Related	7%	5%	21%
Office & Administrative Support	56%	62%	66%
Skilled Blue-collar	3%	1%	2%
Semi-skilled Blue Collar	8%	8%	5%
Unskilled Blue Collar	9%	4%	7%

Employment Impacts of Capital Investment

As described in section II, in addition to projecting job growth within the oil & gas and petrochemical industries, we examine the employment impacts of capital expenditures to expand the capacity of these industries and to develop the transportation and storage infrastructure that supports them. We look separately at capital investment in the transportation and storage infrastructure for the oil and gas industry and at investments to expand the capacity of the petrochemical industry.

The employment estimates reported here are for employment stimulated in the industries directly impacted by the corresponding capital expenditures, which include the construction of pipelines and other facilities, manufacturing of the pipe, machinery and other metal products required, and supporting engineering services. (Only direct job impacts are considered here – not any indirect or induced employment impacts that will also result from the projected capital investments.)

For both the transportation infrastructure and the petrochemical industry, capital expenditures were projected annually from either 2013 or 2014 through 2030. The employment figures shown here are the numbers of jobs created by the amount of capital spending expected in selected years: 2015, 2020, 2025 and 2030.

For both the transportation infrastructure and the petrochemical industry the forces driving the need for accelerated investment are already well underway. As a result, the highest level of capital expenditures (and the greatest employment impact) occurs at the beginning of our forecast period and then declines over time.

- Capital investment in the oil & gas industry transportation and storage infrastructure in 2015 will create 311 thousand jobs in that year. Investment in the petrochemical industry will stimulate over 40 thousand additional jobs in 2015. The combined impact of these capital investment programs will be to create 351 thousand jobs in 2015.
- Over the next 15 years, the level of capital spending in both areas will gradually decline. Yet in 2030, these investment efforts together will still contribute an additional 160 thousand jobs.

Table IV.11

Employment Impacts of Investment in Oil and Gas Infrastructure and the Petrochemical Industry by Year

	2015	2020	2025	2030
Total	351,174	287,839	216,429	160,048
Oil & Gas Transportation Infrastructure	310,615	260,511	196,585	146,157
Petrochemical Industry	40,559	27,328	19,844	13,891

Tables IV.12 and IV.13 provide additional detail on the employment impact of these capital investment initiatives by occupation for minority groups and women in the peak year of activity – 2015.

These jobs are in industries that support investment activity and, thus, their occupational mix differs somewhat from core oil & gas industry jobs. Among the blue-collar jobs in construction and machinery and metal products manufacturing, the share of skilled blue-collar jobs is slightly lower than in the oil & gas industry, and the semi-skilled and unskilled shares higher. Nonetheless, the share of blue-collar jobs overall in these investment-related industries (61 percent of the total) is quite similar to core oil & gas industry jobs (57 percent). Thus, the female share of employment in these investment-related jobs is very near the share observed on average for the oil & gas and petrochemical industries.

Table IV.12

Employment Stimulated by Investment in Oil & Gas Transportation Infrastructure and the Petrochemical Industry: 2015

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	351,174	25,198	59,656	24%	56,335	16%
Mgmnt, Business and Fin'l	48,469	1,786	3,395	11%	11,783	24%
Professional and Related	42,963	1,496	2,861	10%	7,233	17%
Service	3,944	431	598	26%	882	22%
Sales and Related	8,774	192	703	10%	1,585	18%
Office & Administrative Support	31,846	2,452	3,377	18%	20,660	65%
Skilled Blue-collar	94,536	6,062	17,361	25%	2,651	3%
Semi-skilled Blue Collar	89,012	9,276	20,618	34%	9,498	11%
Unskilled Blue Collar	31,629	3,503	10,742	45%	2,044	6%

Table IV.13

Employment Stimulated by Investment in Oil & Gas Industry Infrastructure and the Petrochemical Industry: 2015

Total

	African American	Hispanic	Total
Total	25,198	59,656	351,174
Management, Business and Financial	1,786	3,395	48,469
Professional and Related	1,496	2,861	42,963
Service	431	598	3,944
Sales and Related	192	703	8,774
Office & Administrative Support	2,452	3,377	31,846
Skilled Blue-collar	6,062	17,361	94,536
Semi-skilled Blue Collar	9,276	20,618	89,012
Unskilled Blue Collar	3,503	10,742	31,629

Female Employment

	African American	Hispanic	Total
Total	4,680	6,190	56,335
Management, Business and Financial	647	914	11,783
Professional and Related	372	532	7,233
Service	124	151	882
Sales and Related	71	95	1,585
Office & Administrative Support	1,452	2,068	20,660
Skilled Blue-collar	188	430	2,651
Semi-skilled Blue Collar	1,579	1,617	9,498
Unskilled Blue Collar	247	383	2,044

Female Share within Each Occupation

	African American	Hispanic	Total
Total	19%	10%	16%
Management, Business and Financial	36%	27%	24%
Professional and Related	25%	19%	17%
Service	29%	25%	22%
Sales and Related	37%	14%	18%
Office & Administrative Support	59%	61%	65%
Skilled Blue-collar	3%	2%	3%
Semi-skilled Blue Collar	17%	8%	11%
Unskilled Blue Collar	7%	4%	6%

Pro-Development Policy for the Upstream Oil and Gas Industry

Our 2012 study of minority employment for API focused on the upstream oil & gas industry. That study included, in addition to baseline employment projections for African Americans and Hispanics, estimates of the additional job potential associated with pro-development policy for the upstream oil and gas industry. The relevant results from this pro-development policy analysis are reproduced here from IHS's 2012 report for API. In addition, we have developed estimates of employment by gender industry-wide and separately for African American and Hispanic workers.

Note also that the figures shown here do not include the small amount of indirect employment in two industries that was included in some tables of the 2012 IHS report.

Table IV.14
Additional Employment Impact of Pro-Development Policy in the Upstream Oil & Gas Industry

	2015	2020	2025	2030
Total	176,033	291,323	304,827	322,603
African American	11,590	19,731	21,155	21,644
Hispanic	35,955	64,210	73,903	88,572
Minority Share	27%	29%	31%	34%
Female	26,511	42,346	43,126	42,370
Female Share	15%	15%	14%	13%

In Table IV.15 the additional employment gains from pro-development policy are added to baseline employment projections for the upstream and midstream oil & gas and petrochemical industries. In the pro-development policy scenario, total employment in these industries increases by 525 thousand between 2010 and 2030, and we project 247 thousand of these additional jobs would be held by African Americans and Hispanics.

Table IV.15
Total Employment in the Upstream and Midstream Oil & Gas and Petrochemical Industries under Pro-Development Policy

	2010	2020	2030	Change 2010-2030
Total	919,428	1,325,982	1,444,191	524,763
African American	77,746	112,769	123,552	45,806
Hispanic	159,662	280,425	360,433	200,771
Minority Share	26%	30%	34%	
Female	156,547	210,208	221,812	65,265
Female Share	17%	16%	15%	

V. Summary

The tables on the following page summarize the components of employment growth in the oil & gas and related industries analyzed in this report.

- Our baseline projection shows employment in oil & gas and petrochemical industry operations increasing by 202 thousand over the period 2010-2030 (row 2).
- Under pro-development policies for the upstream oil and gas industry, an additional 323 thousand jobs would be added, bringing the total employment gain, 2010 to 2030, to 525 thousand jobs (rows 3 and 4).
- Projected capital investments in the oil and gas industry infrastructure and in the petrochemical industry would stimulate another 351 thousand jobs in 2015. As projects are completed, the job impacts of investment decline over time to 160 thousand jobs in 2030 (row 5).
- Combining the job creation from industry operations and capital investment will result in a net increase of 362 thousand jobs in 2030 compared to 2010 in our baseline forecast (row 6) and 685 thousand jobs in the pro-development policy scenario (row 7).
- We estimate that the need to replace current workers who retire from the oil & gas and petrochemical industries over the 20-year period from 2010 to 2030 will create an additional 579 thousand job opportunities (row 8).
- Combining job opportunities due to replacement requirements with the net increase in employment from all sources, we project a total of 942 thousand job opportunities in these industries over these 20 years under the baseline scenario and 1.3 million jobs under the pro-development scenario (rows 9 and 10).
- Of this total 1.3 million job opportunities, we project that there will be over 400 thousand job opportunities for minority workers – 100 thousand for African Americans and 307 thousand for Hispanics (rows 12 and 13).
- We project a net increase of 90 thousand in female employment in these industries between 2010 and 2030 (65 thousand in industry operations and 25 thousand due to capital investment in 2030), and replace requirements will create an additional 94 thousand job opportunities, for a total of 185 thousand (row 14).

Components of Employment Projections
(thousands)

		2010	2015	2020	2025	2030
1	Base line Employment in the Upstream and Midstream Oil & Gas and Petrochemical Industries	919	956	1,035	1,080	1,122
2	Increase Compared to 2010	--	36	115	160	202
3	Additional Employment Projected under Pro- Development Policy in the Upstream Oil & Gas Industry	--	176	291	305	323
4	Total Employment Gain Projected under Pro- Development Policy	--	212	407	465	525
5	Jobs Created in Selected Years by Capital Investment in Oil & Gas Industry Infrastructure and Petrochemical Industry	--	351	288	216	160
6	Baseline Employment Growth plus Jobs Created in selected Years by Capital Investment	--	387	403	277	362
7	Employment Growth under Pro-Development Policy plus Jobs Created in selected Years by Capital Investment	--	563	694	681	685

		2010-2020	2010-2030
8	Job Opportunities from Replacement Requirements in the Oil & gas and Petrochemical Industries	261	579
9	Baseline Growth and Jobs Created by Capital Investment in Selected Years plus Replacement Requirements	664	942
10	**Pro-Development Policy Growth and Jobs Created by Capital Investment in Selected Years plus Replacement Requirements**	**955**	**1,264**

	Employment Growth under Pro-Development Policy	Industry Operations	Capital Investment	Replacement Requirements	Total
11	Total	525	160	579	1,264
12	African American	46	12	43	100
13	Hispanic	201	33	74	307
14	Female	65	25	94	185

Appendix A. Upstream Oil & Gas Industry

National Employment in the Upstream Oil & Gas Industry: 2010

Total

	African American	Hispanic	Total
Total	57,886	136,265	720,911
Management, Business and Financial	5,091	7,932	71,910
Professional and Related	8,010	10,053	113,155
Service	453	665	2,751
Sales and Related	952	1,706	11,308
Office & Administrative Support	7,562	10,697	67,233
Skilled Blue-collar	18,900	54,993	271,287
Semi-skilled Blue Collar	11,775	30,680	130,433
Unskilled Blue Collar	5,143	19,539	52,834

Female Employment

	African American	Hispanic	Total
Total	9,239	13,648	110,350
Management, Business and Financial	1,316	1,855	18,883
Professional and Related	1,482	2,120	23,601
Service	77	204	801
Sales and Related	63	83	2,381
Office & Administrative Support	4,701	6,822	51,603
Skilled Blue-collar	745	856	5,476
Semi-skilled Blue Collar	540	1,192	5,187
Unskilled Blue Collar	316	516	2,419

Female Share within Each Occupation

	African American	Hispanic	Total
Total	16%	10%	15%
Management, Business and Financial	26%	23%	26%
Professional and Related	18%	21%	21%
Service	17%	31%	29%
Sales and Related	7%	5%	21%
Office & Administrative Support	62%	64%	77%
Skilled Blue-collar	4%	2%	2%
Semi-skilled Blue Collar	5%	4%	4%
Unskilled Blue Collar	6%	3%	5%

National Employment in the Top Detailed Occupations in the Upstream Oil & Gas Industry: 2010

		Employment by Industry			
	Total	NAICS 2111	NAICS 2131	NAICS 2389	NAICS 5413
Derrick, Rotary Drill and Service Unit Operators	89,437	12,262	77,104	69	**
Roustabouts, Oil & Gas	55,873	11,435	44,346	92	**
Construction Laborers	34,193	43	6,552	27,468	131
First-Line Supervisors/Mgr of Constr. & Extraction Workers	29,818	5,091	17,214	7,407	105
Operating Engineers & Other Construction Equip Operators	27,252	791	7,759	18,665	36
Truck Drivers, Heavy and Tractor-Trailer	25,460	1,240	15,711	8,481	28
Helpers and Other Extraction Workers	21,683	4,158	17,278	229	**
Pump Operators and Wellhead Pumpers	21,231	11,600	9,571	60	**
Petroleum Engineers	21,186	15,676	5,421	**	90
Secretaries	20,414	7,690	6,847	3,414	2,463
General and Operations Managers	18,929	5,800	9,442	2,356	1,330
Office Clerks, General	14,904	4,796	5,126	3,679	1,303
Bookkeeping, Accounting, and Auditing Clerks	13,194	4,465	5,473	2,496	760
Petroleum Pump System & Refinery Operators, and Gaugers	10,903	7,619	3,276	**	**
Accountants and Auditors	9,595	6,214	2,338	494	549
Geoscientists, Except Hydrologists and Geographers	9,504	7,548	1,657	**	299
Geological and Petroleum Technicians	8,988	4,406	4,483	**	98
Laborers and Freight, Stock, and Material Movers, Hand	8,289	567	5,614	1,822	286
Industrial Machinery Mechanics	8,058	2,363	5,601	59	36
Welders, Cutters, Soldiers, and Braziers	6,542	921	4,792	764	65
Cement Masons and Concrete Finishers	6,501	**	**	6,499	**
Maintenance and Repair Workers, General	6,264	2,103	3,199	854	109
Civil Engineers	6,137	520	385	66	5,166
Engineers, all other	5,861	4,678	373	23	787
Crane and Tower Operators	4,737	63	3,147	1,526	**
Excavating and Loading Machine and Dragline Operators	4,455	**	1,477	2,974	**
Mobile Heavy Equipment Mechanics, Except Engines	4,362	248	2,454	1,625	35

National Employment in the Top Detailed Occupations in the Upstream Oil & Gas Industry: 2010 (continued)

		Employment by Industry			
	Total	NAICS 2111	NAICS 2131	NAICS 2389	NAICS 5413
First-Line Supervisors/Mgr of Office and Admin Workers	4,114	1,358	1,760	599	397
Fence Erectors	4,090	**	**	4,090	**
Inspectors, Testers, Sorters, Samplers, and Weighers	4,019	343	3,019	**	643
Electricians	3,897	980	2,608	251	58
Construction Managers	3,833	295	886	2,281	370
Sales Representatives, Wholesale and Manufacturing	3,740	449	2,107	1,114	70
Paving, Surfacing, and Tamping Equipment Operators	3,653	**	77	3,575	**
Mechanical Engineers	3,369	354	951	24	2,040
Carpenters	3,121	**	424	2,676	21
Engineering Managers	3,095	904	642	**	1,535
Architects, Except Landscape and Naval	3,054	**	**	**	3,054
Architectural and Civil Drafters	2,897	**	**	38	2,859
Cost Estimators	2,836	35	347	2,259	195
Plumbers, Pipefitters, and Steamfitters	2,836	142	2,171	494	29
Electrical Engineers	2,090	177	540	**	1,357
Surveying and Mapping Technicians	1,681	224	77	**	1,370
Surveyors	1,660	154	116	50	1,341
Civil Engineering Technicians	1,476	**	45	**	1,420

** = less than 20

Female Employment in the Top Detailed Occupations in the Upstream Oil and Gas Industry: 2010

	Female Employment by Industry				
	Total	NAICS 2111	NAICS 2131	NAICS 2389	NAICS 5413
Derrick, Rotary Drill and Service Unit Operators	842	180	662	**	**
Roustabouts, Oil & Gas	549	168	380	**	**
Construction Laborers	1,403	**	518	881	**
First-Line Supervisors/Mgr of Constr. & Extraction Workers	761	250	279	224	**
Operating Engineers & Other Construction Equip Operators	516	64	73	377	**
Truck Drivers, Heavy and Tractor-Trailer	782	27	446	306	**
Helpers and Other Extraction Workers	441	115	317	**	**
Pump Operators and Wellhead Pumpers	477	339	137	**	**
Petroleum Engineers	2,762	2,145	608	**	**
Secretaries	19,763	7,504	6,622	3,284	2,353
General and Operations Managers	1,211	268	400	266	277
Office Clerks, General	11,648	3,641	4,050	2,984	973
Bookkeeping, Accounting, and Auditing Clerks	12,164	4,163	4,980	2,315	706
Petroleum Pump System & Refinery Operators, and Gaugers	171	79	93	**	**
Accountants and Auditors	6,204	3,970	1,512	339	384
Geoscientists, Except Hydrologists and Geographers	1,844	1,486	265	**	92
Geological and Petroleum Technicians	2,176	1,404	753	**	20
Laborers and Freight, Stock, and Material Movers, Hand	263	93	138	**	31
Industrial Machinery Mechanics	95	57	36	**	**
Welders, Cutters, Soldiers, and Braziers	79	**	61	14	**
Cement Masons and Concrete Finishers	70	**	**	70	**
Maintenance and Repair Workers, General	197	**	175	**	**
Civil Engineers	738	**	33	**	698
Engineers, all other	1,069	908	52	**	105
Crane and Tower Operators	26	**	**	19	**
Excavating and Loading Machine and Dragline Operators	28	**	**	20	**
Mobile Heavy Equipment Mechanics, Except Engines	56	**	37	**	**
First-Line Supervisors/Mgr of Office and Admin Workers	2,275	678	973	464	160

Female Employment in the Top Detailed Occupations in the Upstream Oil and Gas Industry: 2010 (continued)

	Female Employment by Industry				
	Total	**NAICS 2111**	**NAICS 2131**	**NAICS 2389**	**NAICS 5413**
Fence Erectors	67	**	**	67	**
Inspectors, Testers, Sorters, Samplers, and Weighers	255	59	103	**	91
Electricians	**	**	**	**	**
Construction Managers	259	29	**	182	48
Sales Representatives, Wholesale and Manufacturing	407	98	**	309	**
Paving, Surfacing, and Tamping Equipment Operators	103	**	**	103	**
Mechanical Engineers	237	**	90	**	146
Carpenters	41	**	**	38	**
Engineering Managers	304	143	**	**	148
Architects, Except Landscape and Naval	880	**	**	**	880
Architectural and Civil Drafters	634	**	**	**	628
Cost Estimators	251	**	**	205	47
Plumbers, Pipefitters, and Steamfitters	58	**	39	**	**
Electrical Engineers	121	**	**	**	109
Surveying and Mapping Technicians	100	**	**	**	84
Surveyors	212	48	22	**	133
Civil Engineering Technicians	218	**	**	**	211

** = less than 20

Employment in the Upstream Oil & Gas Industry by Region: 2010

	Total	African American	Hispanic	Minority Share	Female	Female Share
US	720,911	57,886	136,265	27%	110,350	15%
Alaska	10,162	179	504	7%	1,426	14%
West	34,217	1,085	10,278	33%	5,628	16%
Rockies	84,861	1,404	18,922	24%	12,553	15%
Gulf	449,791	44,219	95,479	31%	68,703	15%
Central	55,898	2,663	3,514	11%	8,424	15%
Eastern	85,981	8,336	7,568	18%	13,616	16%

Baseline Employment in the Upstream Oil & Gas Industry by Occupation: 2010-2030

	2010	2020	2030	Change 2010-2030
Total	720,911	796,662	864,974	144,063
Management, Business and Financial	71,910	75,908	79,318	7,408
Professional and Related	113,155	115,824	132,340	19,186
Service	2,751	2,714	3,341	590
Sales and Related	11,308	12,129	13,013	1,705
Office & Administrative Support	67,233	70,682	75,269	8,035
Skilled Blue-collar	271,287	314,812	336,330	65,043
Semi-skilled Blue Collar	130,433	159,183	162,905	32,472
Unskilled Blue Collar	52,834	45,410	62,458	9,624

Baseline Minority and Female Employment in the Upstream Oil & Gas Industry: 2010-2030

	2010	2020	2030	Change 2010-2030
Total	720,911	796,662	864,974	144,063
African American	57,886	67,612	73,740	15,854
percent of total	8.0%	8.5%	8.5%	
Hispanic	136,265	180,609	224,965	88,700
percent of total	18.9%	22.7%	26.0%	
Female	110,350	113,432	121,461	11,111
percent of total	15.3%	14.2%	14.0%	

Potential Job Gains from Replacement Requirements in the Upstream Oil & Gas Industry: 2010-2030

	African American	Hispanic	Total
Total	24,086	43,265	335,731
Management, Business and Financial	1,763	2,135	27,513
Professional and Related	3,731	3,764	59,645
Service	202	229	1,362
Sales and Related	445	629	5,898
Office & Administrative Support	2,432	2,658	23,104
Skilled Blue-collar	6,350	12,444	96,273
Semi-skilled Blue Collar	7,247	17,232	104,112
Unskilled Blue Collar	1,916	4,174	17,824

Appendix B. Midstream Oil & Gas Industry

National Employment in the Midstream Oil & Gas Industry: 2010

Total

	African American	Hispanic	Total
Total	2,262	4,440	42,079
Management, Business and Financial	233	410	7,131
Professional and Related	267	239	5,021
Service	64	123	984
Sales and Related	**	**	436
Office & Administrative Support	615	474	5,125
Skilled Blue-collar	549	1,278	13,227
Semi-skilled Blue Collar	351	897	6,643
Unskilled Blue Collar	182	1,011	3,510

Female Employment

	African American	Hispanic	Total
Total	594	554	6,840
Management, Business and Financial	51	188	1,789
Professional and Related	95	64	1,204
Service	**	**	97
Sales and Related	**	**	96
Office & Administrative Support	428	234	2,716
Skilled Blue-collar	**	**	410
Semi-skilled Blue Collar	**	59	379
Unskilled Blue Collar	**	**	148

Female Share within Each Occupation

	African American	Hispanic	Total
Total	26%	12%	16%
Management, Business and Financial	22%	46%	25%
Professional and Related	36%	27%	24%
Service	**	**	10%
Sales and Related	**	**	22%
Office & Administrative Support	70%	49%	53%
Skilled Blue-collar	**	**	3%
Semi-skilled Blue Collar	**	7%	6%
Unskilled Blue Collar	**	**	4%

Employment in the Top Detailed Occupations in the Midstream Oil & Gas Industry: 2010

	Total Employment	Female Employment	Female Share within Occupation
Pipelayers, plumbers, pipefitters, and steamfitters	3,148	164	5%
Laborers and freight, stock and material movers, hand	2,204	145	7%
Miscellaneous managers	2,056	299	15%
Inspectors, testers, sorters, samplers, and weighers	1,983	127	6%
Supervisors of transportation and material moving workers	1,917	38	2%
Welding, soldering, and brazing workers	1,255	41	3%
Driver/sales workers and truck drivers	1,229	75	6%
Pumping station operators	1,132	**	**
Other production workers	1,099	70	6%
Accountants and auditors	1,034	483	47%
Secretaries and administrative assistants	1,011	917	91%
Maintenance and repair workers, general	1,008	**	**
Civil engineers	911	219	24%
Miscellaneous plant and system operators	863	105	12%

** = less than 20

Employment in the Midstream Oil & Gas Industry by Region: 2010

	Total	African American	Hispanic	Minority Share	Female	Female Share
US	**42,079**	**2,262**	**4,440**	**16%**	**6,840**	**16%**
Alaska	789	**	**	**	175	22%
West	3,016	179	453	21%	528	17%
Rockies	2,997	58	521	19%	544	18%
Gulf	22,016	1,486	3,043	21%	3,772	17%
Central	5,331	194	178	7%	791	15%
Eastern	7,930	337	245	7%	1,032	13%

** = less than 20

Baseline Employment in the Midstream Oil & Gas Industry by Occupation: 2010-2030

	2010	2020	2030	Change 2010-2030
Total	42,079	50,777	53,188	11,109
Management, Business and Financial	7,131	8,626	9,055	1,924
Professional and Related	5,021	6,091	6,411	1,390
Service	984	1,189	1,246	262
Sales and Related	436	550	602	166
Office & Administrative Support	5,125	6,116	6,333	1,208
Skilled Blue-collar	13,227	16,029	16,857	3,629
Semi-skilled Blue Collar	6,643	8,148	8,672	2,028
Unskilled Blue Collar	3,510	4,028	4,012	502

Baseline Minority and Female Employment in the Midstream Oil & Gas Industry: 2010-2030

	2010	2020	2030	Change 2010-2030
Total	42,079	50,777	53,188	11,109
African American	2,262	2,868	3,046	784
percent of total	5.4%	5.6%	5.7%	
Hispanic	4,440	6,640	8,353	3,913
percent of total	10.6%	13.1%	15.7%	
Female	6,840	8,133	8,472	1,632
percent of total	16.3%	16.0%	15.9%	

Potential Job Gains from Replacement Requirements in the Midstream Oil & Gas Industry: 2010-2030

	African American	Hispanic	Total
Total	1,569	2,583	22,694
Management, Business and Financial	215	260	3,355
Professional and Related	195	196	3,113
Service	**	**	**
Sales and Related	26	36	340
Office & Administrative Support	187	204	1,774
Skilled Blue-collar	856	1,677	12,971
Semi-skilled Blue Collar	58	139	840
Unskilled Blue Collar	32	71	302

Appendix C. Downstream Oil & Gas Industry

National Employment in the Downstream Oil & Gas Industry: 2010

Total

	African American	Hispanic	Total
Total	20,043	28,426	279,162
Management, Business and Financial	2,362	2,974	41,898
Professional and Related	1,503	2,005	23,246
Service	673	916	5,124
Sales and Related	1,267	2,139	36,844
Office & Administrative Support	2,435	3,886	46,739
Skilled Blue-collar	3,499	5,852	43,633
Semi-skilled Blue Collar	6,906	8,192	70,992
Unskilled Blue Collar	1,398	2,463	10,685

Female Employment

	African American	Hispanic	Total
Total	4,806	5,647	69,140
Management, Business and Financial	1,254	1,096	13,474
Professional and Related	364	517	5,520
Service	194	199	1,027
Sales and Related	602	620	8,702
Office & Administrative Support	1,625	2,534	35,466
Skilled Blue-collar	168	122	1,520
Semi-skilled Blue Collar	380	356	2,665
Unskilled Blue Collar	218	204	767

Female Share within Each Occupation

	African American	Hispanic	Total
Total	24%	20%	25%
Management, Business and Financial	53%	37%	32%
Professional and Related	24%	26%	24%
Service	29%	22%	20%
Sales and Related	48%	29%	24%
Office & Administrative Support	67%	65%	76%
Skilled Blue-collar	5%	2%	3%
Semi-skilled Blue Collar	6%	4%	4%
Unskilled Blue Collar	16%	8%	7%

Employment in the Top Detailed Occupations in the Downstream Oil & Gas Industry: 2010

	Total Employment	Female Employment	Female Share
Drivers/Sales Workers and Truck Drivers	44,097	719	2%
Secretaries and Admin. Assistants	11,471	10,740	94%
Sales Representatives, Wholesale and Manufacturing	10,975	1,656	15%
Other Production Workers	9,784	943	10%
First-line Supervisors of Non-Retail Workers	9,773	1,762	18%
Accountants and Auditors	8,863	4,982	56%
Laborers and Freight, Stock and Material Movers, Hand	8,040	468	6%
First-line Supervisors of Retail Sales Workers	7,865	1,634	21%
First-line Supervisors of Production and Operating Workers	7,278	444	6%
Bookkeeping, Accounting, and Auditing Clerks	7,203	6,726	93%
Miscellaneous Mangers	7,085	1,297	18%
Customers Service Representatives	6,057	4,811	79%
Miscellaneous Plant and System Operators	5,330	251	5%
Retail Salespersons	4,834	1,366	28%
Maintenance and Repair Workers, General	4,744	**	**
Chemical Engineers	3,573	416	12%
General and Operations Managers	3,544	212	6%
Heating, Air-conditioning, and Refrigeration Mechanics and Installers	3,440	**	**
Inspectors, Testers, Sorters, Samplers, and Weighers	3,355	350	10%
First Line Supervisors of Office and Admin. Support Workers	3,096	2,058	66%
Managers, Chief Executive and Legislators	3,032	261	9%
Office Clerks, General	2,987	2,551	85%
Janitors and Building Cleaners	2,869	499	17%
Cashiers	2,798	2,013	72%
Industrial and Refractory Machinery Mechanics	2,730	51	2%
Pipelayers, Plumbers, Pipefitters, and Steamfitters	2,380	70	3%
Engineering Technician, Except Drafters	1,984	356	18%
Electricians	1,917	**	**
Welding, Soldering, and Brazing Workers	1,890	**	**
Geological and Petroleum Technicians, and Nuclear Technicians	1,877	477	25%

** = less than 20

Employment in the Downstream Oil & Gas Industry by Region: 2010

	Total	African American	Hispanic	Minority Share	Female	Female Share
US	**279,162**	**20,043**	**28,426**	**17%**	**69,140**	**25%**
Alaska	883	**	**	**	136	15%
West	35,741	2,495	7,920	29%	8,061	23%
Rockies	12,995	225	1,999	17%	3,057	24%
Gulf	80,401	8,918	13,413	28%	20,533	26%
Central	45,388	1,366	1,972	7%	10,895	24%
Eastern	103,754	7,038	3,111	10%	26,458	26%

Potential Job Gains from Replacement Requirements in the Downstream Oil & Gas Industry: 2010-2030

Total

	African American	Hispanic	Total
Total	11,222	18,086	144,561
Management, Business and Financial	1,234	1,494	19,254
Professional and Related	696	703	11,133
Service	443	503	2,989
Sales and Related	1,889	2,670	25,036
Office & Administrative Support	2,359	2,578	22,406
Skilled Blue-collar	1,576	3,088	23,894
Semi-skilled Blue Collar	2,312	5,498	33,218
Unskilled Blue Collar	713	1,553	6,631

Appendix D. Petrochemical Industry

National Employment in the Petrochemical Industry: 2010

Total

Petrochemical Industry	African American	Hispanic	Total
Total	17,598	18,957	156,438
Management, Business and Financial	1,189	1,437	25,290
Professional and Related	1,910	1,321	23,019
Service	506	393	3,619
Sales and Related	135	189	5,192
Office & Administrative Support	1,557	1,429	16,033
Skilled Blue-collar	2,505	2,785	25,934
Semi-skilled Blue Collar	8,176	9,407	47,386
Unskilled Blue Collar	1,618	1,997	9,964

Female Employment

Petrochemical Industry	African American	Hispanic	Total
Total	4,314	5,486	39,357
Management, Business and Financial	449	438	7,035
Professional and Related	558	230	5,223
Service	191	119	816
Sales and Related	31	57	1,240
Office & Administrative Support	782	865	9,999
Skilled Blue-collar	213	183	1,593
Semi-skilled Blue Collar	1,852	3,090	11,374
Unskilled Blue Collar	238	504	2,077

Female Share within Each Occupation

Petrochemical Industry	African American	Hispanic	Total
Total	25%	29%	25%
Management, Business and Financial	38%	31%	28%
Professional and Related	29%	17%	23%
Service	38%	30%	23%
Sales and Related	23%	30%	24%
Office & Administrative Support	50%	61%	62%
Skilled Blue-collar	8%	7%	6%
Semi-skilled Blue Collar	23%	33%	24%
Unskilled Blue Collar	15%	25%	21%

Employment in the Top Detailed Occupations in the Petrochemical Industry: 2010

	Total Employment	Female Employment	Female Share
Other production workers	18,894	4,848	26%
First-line supervisors of production and operating workers	8,935	1,002	11%
Miscellaneous managers	7,078	1,229	17%
Laborers and freight, stock and material movers, hand	6,463	971	15%
Chemical engineers	5,185	677	13%
Chemical technicians	5,105	1,320	26%
Sales representatives, wholesale and manufacturing	4,928	1,124	23%
Chemical processing machine setters, operators, and tenders	4,451	423	10%
Industrial and refractory machinery mechanics	4,038	90	2%
Inspectors, testers, sorters, samplers, and weighers	3,484	1,694	49%
Crushing, grinding, polishing, mixing and blending workers	3,226	220	7%
Miscellaneous assemblers and fabricators	3,167	1,552	49%
Secretaries and administrative assistants	3,136	3,014	96%
Industrial truck and tractor operators	2,864	226	8%
Driver/sales workers and truck drivers	2,693	43	2%
Industrial production managers	2,664	314	12%
Chemists and materials scientists	2,577	675	26%
Janitors and building cleaners	2,436	356	15%
Accountants and auditors	2,396	1,538	64%
Packaging and filling machine operators and tenders	2,387	1,140	48%

Employment in the Petrochemical Industry by Region: 2010

	Total	African American	Hispanic	Minority Share	Female	Female Share
US	**156,438**	**17,598**	**18,957**	**23%**	**39,357**	**25%**
Alaska	92	**	**	**	**	**
West	8,363	228	2,957	38%	2,302	28%
Rockies	2,747	74	507	21%	629	23%
Gulf	59,162	8,584	9,264	30%	12,238	21%
Central	31,992	2,030	3,091	16%	9,379	29%
Eastern	54,083	6,671	3,137	18%	14,809	27%

Baseline Employment in the Petrochemical Industry by Occupation: 2010-2030

	2010	2020	2030	Change 2010-2030
Total	156,438	187,220	203,426	46,988
Management, Business and Financial	25,290	29,683	32,143	6,853
Professional and Related	23,019	25,991	27,641	4,622
Service	3,619	4,383	4,875	1,256
Sales and Related	5,192	5,894	6,165	972
Office & Administrative Support	16,033	18,368	19,206	3,173
Skilled Blue-collar	25,934	31,168	34,038	8,103
Semi-skilled Blue Collar	47,386	59,332	65,829	18,444
Unskilled Blue Collar	9,964	12,401	13,529	3,565

Baseline Minority and Female Employment in the Petrochemical Industry: 2010-2030

	2010	2020	2030	Change 2010-2030
Total	156,438	187,220	203,426	46,988
African American	17,598	22,558	25,122	7,524
percent of total	11.2%	12.0%	12.3%	
Hispanic	18,957	28,965	38,542	19,585
percent of total	12.1%	15.5%	18.9%	
Female	39,357	46,298	49,509	10,152
percent of total	25.2%	24.7%	24.3%	

Potential Job Gains from Replacement Requirements in the Petrochemical Industry: 2010-2030

	African American	Hispanic	Total
Total	5,753	9,700	76,340
Management, Business and Financial	745	902	11,622
Professional and Related	689	695	11,016
Service	313	355	2,111
Sales and Related	266	376	3,528
Office & Administrative Support	809	884	7,686
Skilled Blue-collar	920	1,802	13,943
Semi-skilled Blue Collar	1,526	3,628	21,920
Unskilled Blue Collar	485	1,057	4,514

Appendix E. Capital Investment in Oil & Gas Industry Infrastructure

Employment Stimulated by Capital Investment in Oil & Gas Industry Transportation and Storage Infrastructure by Asset Class

	2015	2020	2025	2030
Total	310,615	260,511	196,585	146,157
Natural Gas	127,630	112,842	98,761	73,170
NGL & LPG	20,584	18,988	9,838	7,612
Crude Oil and Condensate	126,423	103,336	74,935	59,050
Refineries and Refined Product	15,129	7,689	5,216	1,914
Common Infrastructure	20,849	17,656	7,835	4,411

Employment Stimulated by Capital Investment in Oil & Gas Industry Transportation and Storage Infrastructure: 2015

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	310,615	22,171	52,402	24%	48,499	16%
Management, Business and Financial	42,940	1,581	3,002	11%	10,349	24%
Professional and Related	37,104	1,260	2,454	10%	6,188	17%
Service	3,510	373	513	25%	776	22%
Sales and Related	7,825	160	642	10%	1,365	17%
Office & Administrative Support	28,100	2,194	2,947	18%	18,098	64%
Skilled Blue-collar	84,401	5,375	15,390	25%	2,279	3%
Semi-skilled Blue Collar	78,980	8,129	18,072	33%	7,718	10%
Unskilled Blue Collar	27,756	3,098	9,381	45%	1,725	6%

Employment Stimulated by Capital Investment in Oil & Gas Industry Transportation and Storage Infrastructure: 2020

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	260,511	18,915	48,906	26%	40,762	16%
Management, Business and Financial	37,160	1,394	2,908	12%	8,969	24%
Professional and Related	30,001	1,019	2,181	11%	4,992	17%
Service	2,933	315	476	27%	645	22%
Sales and Related	7,604	157	699	11%	1,315	17%
Office & Administrative Support	24,080	1,935	2,846	20%	15,252	63%
Skilled Blue-collar	68,288	4,414	13,917	27%	1,816	3%
Semi-skilled Blue Collar	69,731	7,349	17,884	36%	6,563	9%
Unskilled Blue Collar	20,714	2,332	7,994	50%	1,210	6%

Employment Stimulated by Capital Investment in Oil & Gas Industry Transportation and Storage Infrastructure: 2025

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	196,585	14,441	37,886	27%	30,569	16%
Management, Business and Financial	28,483	1,081	2,367	12%	7,091	25%
Professional and Related	21,627	672	1,617	11%	3,512	16%
Service	2,178	221	336	26%	464	21%
Sales and Related	6,339	109	657	12%	1,007	16%
Office & Administrative Support	18,420	1,578	2,352	21%	11,059	60%
Skilled Blue-collar	50,654	3,176	10,590	27%	1,393	3%
Semi-skilled Blue Collar	54,510	5,880	14,213	37%	5,063	9%
Unskilled Blue Collar	14,374	1,722	5,753	52%	979	7%

Employment Stimulated by Capital Investment in Oil & Gas Industry Transportation and Storage Infrastructure: 2030

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	146,157	10,715	29,530	28%	22,603	15%
Management, Business and Financial	21,533	821	1,923	13%	5,374	25%
Professional and Related	15,930	464	1,239	11%	2,526	16%
Service	1,606	157	249	25%	336	21%
Sales and Related	5,142	80	589	13%	778	15%
Office & Administrative Support	14,005	1,241	1,943	23%	8,134	58%
Skilled Blue-collar	36,687	2,243	8,048	28%	1,024	3%
Semi-skilled Blue Collar	41,665	4,529	11,453	38%	3,758	9%
Unskilled Blue Collar	9,588	1,179	4,084	55%	673	7%

Employment in the Top Detailed Occupations for Capital Investment in Oil & Gas Industry Infrastructure: 2015

	Total	African American	Hispanic	Minority Share	Female	Female Share
Construction Laborers	18,599	1,739	6,757	46%	601	3%
Welding, Soldering, and Brazing Workers	18,320	1,212	2,722	21%	489	3%
Carpenters	11,975	650	3,507	35%	177	1%
Miscellaneous Assemblers and Fabricators	11,254	1,261	1,505	25%	2,533	23%
Miscellaneous Managers	9,947	312	693	10%	1,721	17%
First-line Supervisors of Production and Operating Workers	9,302	535	1,060	17%	636	7%
First-line Supervisors of Construction Trade and Extraction Workers	7,861	343	1,189	19%	236	3%
Machinists	7,649	497	926	19%	197	3%
Electricians	7,542	471	1,140	21%	145	2%
Mechanical Engineers	7,246	149	288	6%	465	6%
Miscellaneous Metal Workers and Plastic Workers	6,938	815	1,629	35%	803	12%
Secretaries and Administrative Assistants	6,542	236	622	13%	6,275	96%
Construction Managers	6,041	199	540	12%	484	8%
Laborers and Freight, Stock, and Material Movers	5,942	692	685	23%	696	12%
Sales Representatives, Wholesale and Manufacturing	5,243	63	442	10%	846	16%
Inspectors, Testers, Sorters, Samplers, and Weighers	5,214	543	503	20%	985	19%
Painters, Construction and Maintenance	5,099	360	2,200	50%	303	6%

Appendix F. Capital Investment in the Petrochemical Industry

Employment Stimulated by Investment in the Petrochemical Industry: 2015

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	40,559	3,028	7,254	25%	7,837	19%
Management, Business and Financial	5,529	205	393	11%	1,434	26%
Professional and Related	5,859	235	407	11%	1,045	18%
Service	434	58	85	33%	106	24%
Sales and Related	949	32	61	10%	221	23%
Office & Administrative Support	3,746	258	431	18%	2,562	68%
Skilled Blue-collar	10,136	687	1,971	26%	371	4%
Semi-skilled Blue Collar	10,033	1,147	2,546	37%	1,780	18%
Unskilled Blue Collar	3,874	405	1,362	46%	318	8%

Employment Stimulated by Investment in the Petrochemical Industry: 2020

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	27,328	2,081	5,479	28%	5,319	19%
Management, Business and Financial	3,735	141	298	12%	987	26%
Professional and Related	3,927	159	301	12%	728	19%
Service	297	40	64	35%	75	25%
Sales and Related	632	22	45	11%	159	25%
Office & Administrative Support	2,482	175	322	20%	1,779	72%
Skilled Blue-collar	6,841	469	1,478	28%	258	4%
Semi-skilled Blue Collar	6,823	799	1,949	40%	1,244	18%
Unskilled Blue Collar	2,590	277	1,022	50%	89	3%

Employment Stimulated by Investment in the Petrochemical Industry: 2025

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	19,844	1,533	4,395	30%	3,724	19%
Management, Business and Financial	2,719	104	239	13%	722	27%
Professional and Related	2,846	115	237	12%	516	18%
Service	219	30	52	37%	53	24%
Sales and Related	452	16	36	11%	105	23%
Office & Administrative Support	1,771	128	256	22%	1,178	66%
Skilled Blue-collar	4,986	344	1,179	31%	178	4%
Semi-skilled Blue Collar	4,976	594	1,576	44%	817	16%
Unskilled Blue Collar	1,875	204	820	55%	155	8%

Employment Stimulated by Investment in the Petrochemical Industry: 2030

	Total	African American	Hispanic	Minority Share	Female	Female Share
Total	13,891	1,078	3,376	32%	2,563	18%
Management, Business and Financial	1,908	73	184	14%	507	27%
Professional and Related	1,986	80	178	13%	361	18%
Service	155	21	40	39%	37	24%
Sales and Related	311	11	27	12%	72	23%
Office & Administrative Support	1,218	89	195	23%	800	66%
Skilled Blue-collar	3,501	241	899	33%	124	4%
Semi-skilled Blue Collar	3,504	421	1,224	47%	555	16%
Unskilled Blue Collar	1,307	143	628	59%	106	8%

Appendix G. Selected Occupation Descriptions

General and Operations Managers	Plan, direct, or coordinate the operations of public or private sector organizations. Duties and responsibilities include formulating policies, managing daily operations, and planning the use of materials and human resources, but are too diverse and general in nature to be classified in any one functional area of management or administration, such as personnel, purchasing, or administrative services.
Construction Managers	Plan, direct, or coordinate, usually through subordinate supervisory personnel, activities concerned with the construction and maintenance of structures, facilities, and systems. Participate in the conceptual development of a construction project and oversee its organization, scheduling, budgeting, and implementation. Includes managers in specialized construction fields, such as carpentry or plumbing.
Engineering Managers	Plan, direct, or coordinate activities in such fields as architecture and engineering or research and development in these fields.
Cost Estimators	Prepare cost estimates for product manufacturing, construction projects, or services to aid management in bidding on or determining price of product or service. May specialize according to particular service performed or type of product manufactured.
Accountants and Auditors	Examine, analyze, and interpret accounting records to prepare financial statements, give advice, or audit and evaluate statements prepared by others. Install or advise on systems of recording costs or other financial and budgetary data.
Architects, Except Landscape and Naval	Plan and design structures, such as private residences, office buildings, theaters, factories, and other structural property.
Surveyors	Make exact measurements and determine property boundaries. Provide data relevant to the shape, contour, gravitation, location, elevation, or dimension of land or land features on or near the earth's surface for engineering, mapmaking, mining, land evaluation, construction, and other purposes.
Civil Engineers	Perform engineering duties in planning, designing, and overseeing construction and maintenance of building structures, and facilities, such as roads, railroads, airports, bridges, harbors, channels, dams, irrigation projects, pipelines, power plants, and water and sewage systems.
Electrical Engineers	Research, design, develop, test, or supervise the manufacturing and installation of electrical equipment, components, or systems for commercial, industrial, military, or scientific use.
Mechanical Engineers	Perform engineering duties in planning and designing tools, engines, machines, and other mechanically functioning equipment. Oversee installation, operation, maintenance, and repair of equipment such as centralized heat, gas, water, and steam systems.
Petroleum Engineers	Devise methods to improve oil and gas extraction and production and determine the need for new or modified tool designs. Oversee drilling and offer technical advice.
Engineers, all other	Miscellaneous engineers not listed separately in the occupational classification.
Architectural and Civil Drafters	Prepare detailed drawings of architectural and structural features of buildings or drawings and topographical relief maps used in civil engineering projects, such as highways, bridges, and public works. Use knowledge of building materials,

	engineering practices, and mathematics to complete drawings.
Civil Engineering Technicians	Apply theory and principles of civil engineering in planning, designing, and overseeing construction and maintenance of structures and facilities under the direction of engineering staff or physical scientists.
Surveying and Mapping Technicians	Perform surveying and mapping duties, usually under the direction of an engineer, surveyor, cartographer, or photogrammetrist to obtain data used for construction, mapmaking, boundary location, mining, or other purposes. May calculate mapmaking information and create maps from source data, such as surveying notes, aerial photography, satellite data, or other maps to show topographical features, political boundaries, and other features. May verify accuracy and completeness of maps.
Geoscientists, Except Hydrologists and Geographers	Study the composition, structure, and other physical aspects of the Earth. May use geological, physics, and mathematics knowledge in exploration for oil, gas, minerals, or underground water; or in waste disposal, land reclamation, or other environmental problems. May study the Earth's internal composition, atmospheres, oceans, and its magnetic, electrical, and gravitational forces. Includes mineralogists, crystallographers, paleontologists, stratigraphers, geodesists, and seismologists.
Geological and Petroleum Technicians	Assist scientists or engineers in the use of electronic, sonic, or nuclear measuring instruments in both laboratory and production activities to obtain data indicating potential resources such as metallic ore, minerals, gas, coal, or petroleum. Analyze mud and drill cuttings. Chart pressure, temperature, and other characteristics of wells or bore holes. Investigate and collect information leading to the possible discovery of new metallic ore, minerals, gas, coal, or petroleum deposits.
Sales Representatives, Wholesale and Manufacturing	Sell goods for wholesalers or manufacturers where technical or scientific knowledge is required in such areas as biology, engineering, chemistry, and electronics, normally obtained from at least 2 years of post-secondary education.
First-Line Supervisors/ Managers of Office and Administrative Workers	Directly supervise and coordinate the activities of clerical and administrative support workers.
Bookkeeping, Accounting, and Auditing Clerks	Compute, classify, and record numerical data to keep financial records complete. Perform any combination of routine calculating, posting, and verifying duties to obtain primary financial data for use in maintaining accounting records. May also check the accuracy of figures, calculations, and postings pertaining to business transactions recorded by other workers.
Secretaries	Provide high-level administrative support by conducting research, preparing statistical reports, handling information requests, and performing clerical functions such as preparing correspondence, receiving visitors, arranging conference calls, and scheduling meetings. May also train and supervise lower-level clerical staff. Perform routine clerical and administrative functions such as drafting correspondence, scheduling appointments, organizing and maintaining paper and electronic files, or providing information to callers.
Office Clerks, General	Perform duties too varied and diverse to be classified in any specific office clerical occupation, requiring knowledge of office systems and procedures. Clerical duties may be assigned in accordance with the office procedures of individual establishments and may include a combination of answering telephones, bookkeeping, word processing, stenography, office machine operation, and filing.

Skilled Blue Collar	
First-Line Supervisors/ Managers of Construction Trades and Extraction Workers	Directly supervise and coordinate activities of construction or extraction workers.
Carpenters	Construct, erect, install, or repair structures and fixtures made of wood, such as concrete forms; building frameworks, including partitions, joists, studding, and rafters; and wood stairways, window and door frames, and hardwood floors. Includes brattice builders who build doors or brattices in underground passageways.
Cement Masons and Concrete Finishers	Smooth and finish surfaces of poured concrete, such as floors, walks, sidewalks, roads, or curbs using a variety of hand and power tools. Align forms for sidewalks, curbs, or gutters; patch voids; and use saws to cut expansion joints.
Paving, Surfacing, and Tamping Equipment Operators	Operate equipment used for applying concrete, asphalt, or other materials to road beds, or equipment used for tamping gravel, dirt, or other materials. Includes concrete and asphalt paving machine operators, form tampers, tamping machine operators, and stone spreader operators.
Operating Engineers and Other Construction Equipment Operators	Operate one or several types of power construction equipment, such as motor graders, bulldozers, scrapers, compressors, pumps, derricks, shovels, tractors, or front-end loaders to excavate, move, and grade earth, erect structures, or pour concrete or other hard surface pavement. May repair and maintain equipment in addition to other duties.
Electricians	Install, maintain, and repair electrical wiring, equipment, and fixtures. Ensure that work is in accordance with relevant codes. May install or service street lights, intercom systems, or electrical control systems.
Plumbers, Pipefitters, and Steamfitters	Assemble, install, alter, and repair pipelines or pipe systems that carry water, steam, air, or other liquids or gases. May install heating and cooling equipment and mechanical control systems. Includes sprinkler fitters.
Derrick, Rotary Drill, and Service Unit Operators, Oil and Gas	Rig derrick equipment and operate pumps to circulate mud through drill hole. Set up or operate a variety of drills to remove underground oil and gas, or remove core samples for testing during oil and gas exploration. Operate equipment to increase oil flow from producing wells or to remove stuck pipe, casing, tools, or other obstructions from drilling wells.
Mobile Heavy Equipment Mechanics, Except Engines	Diagnose, adjust, repair, or overhaul mobile mechanical, hydraulic, and pneumatic equipment, such as cranes, bulldozers, graders, and conveyors, used in construction, logging, and surface mining.
Industrial Machinery Mechanics	Repair, install, adjust, or maintain industrial production and processing machinery or refinery and pipeline distribution systems.
Maintenance and Repair Workers, General	Perform work involving the skills of two or more maintenance or craft occupations to keep machines, mechanical equipment, or the structure of an establishment in repair. Duties may involve pipe fitting; boiler making; insulating; welding; machining; carpentry; repairing electrical or mechanical equipment; installing, aligning, and balancing new equipment; and repairing buildings, floors, or stairs.
Petroleum Pump System Operators, Refinery Operators, and Gaugers	Operate or control petroleum refining or processing units. May specialize in controlling manifold and pumping systems, gauging or testing oil in storage tanks, or regulating the flow of oil into pipelines.

Crane and Tower Operators	Operate mechanical boom and cable or tower and cable equipment to lift and move materials, machines, or products in many directions.
Pump Operators and Wellhead Pumpers	Tend, control, or operate power-driven, stationary, or portable pumps and manifold systems to transfer gases, oil and other liquids to and from various vessels and processes. Operate power pumps and auxiliary equipment to produce flow of oil or gas from wells in oil field.
Semi-skilled Blue Collar	
Roustabouts, Oil and Gas	Assemble or repair oil field equipment using hand and power tools. Perform other tasks as needed.
Helpers and all other Extraction Workers	Help extraction craft workers, such as earth drillers, blasters and explosives workers, derrick operators, and mining machine operators, by performing duties requiring less skill. Duties include supplying equipment or cleaning work area. All oil and natural gas extraction workers not listed separately.
Welders, Cutters, Solderers, and Brazers	Use hand-welding, flame-cutting, hand soldering, or brazing equipment to weld or join metal components or to fill holes, indentations, or seams of fabricated metal products.
Inspectors, Testers, Sorters, Samplers, and Weighers	Inspect, test, sort, sample, or weigh nonagricultural raw materials or processed, machined, fabricated, or assembled parts or products for defects, wear, and deviations from specifications. May use precision measuring instruments and complex test equipment.
Truck Drivers, Heavy and Tractor-Trailer	Drive a tractor-trailer combination or a truck with a capacity of at least 26,000 pounds Gross Vehicle Weight (GVW). May be required to unload truck. Requires commercial drivers' license.
Excavating and Loading Machine and Dragline Operators	Operate or tend machinery equipped with scoops, shovels, or buckets, to excavate and load loose materials.
Unskilled Blue Collar	
Construction Laborers	Perform tasks involving physical labor at construction sites. May operate hand and power tools of all types: air hammers, earth tampers, cement mixers, small mechanical hoists, surveying and measuring equipment, and a variety of other equipment and instruments. May clean and prepare sites, dig trenches, set braces to support the sides of excavations, erect scaffolding, and clean up rubble, debris and other waste materials.
Fence Erectors	Erect and repair fences and fence gates, using hand and power tools.
Freight, Stock, and Material Movers, Hand	Manually move freight, stock, or other materials or perform other general labor. Includes all manual laborers not elsewhere classified.

Source: Bureau of Labor Statistics, Occupational Employment Statistics

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WOMEN AND MINORITIES
IN THE OIL AND NATURAL GAS INDUSTRY

A vast opportunity exists for the oil and natural gas industry to attract, retain, and develop life long careers for women and minorities. Nearly 1.3 million job opportunities are projected in the oil & gas and petrochemical industries through 2030. Women and minority workers represent a critically vital and available talent pool to help meet the demands of the projected growth and expansion.[1]

Minority Workers

Almost 408,000 job opportunities—32% of the total—are projected to be filled by African American and Hispanic workers, raising the share of minorities from one-quarter of the total jobs in 2010 to one-third in 2030. These opportunities will be available across all areas of the industry and all regions of the country.

The high concentration of Hispanic workers in the Gulf and Mountain areas, the top two areas in projected oil and gas job opportunities, make Hispanics particularly well situated to take advantage of the industry's job growth.

African American and Hispanic workers are projected to have particularly high shares of employment in blue collar occupations, where most of the total job growth is expected.

Blue collar positions include jobs such as carpenters, electricians, pipefitters, welders, and truck drivers, which typically require a high school diploma and some post-secondary education.

Women Workers

Female employment in the oil & gas and petrochemical industries is projected to account for 185,000 of the total job opportunities through 2030.

Women are projected to be employed across all job categories, with significant presence expected in professional and managerial jobs. The number of job opportunities for women projected in these areas—jobs such as engineers, accountants, general managers, and geoscientist—**reaches nearly 70,000** by 2030. These are jobs that typically require a four-year degree.

Though opportunities for women in oil and gas are available all across the country, most women are not familiar with the job opportunities and career development available in the industry.

Highlighting women already working in oil and gas helps other women see the possible paths for them.

Learn more at **www.api.org**

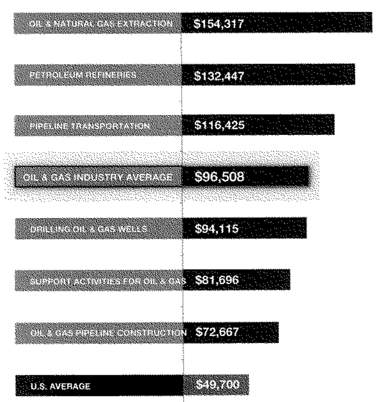
1 The job estimates presented here are projections based on current and projected trends in educational attainment, labor force participation rates, unemployment rates, and other factors. As interest and training are directed to women and minorities groups, these projections should not be considered ceilings.

WOMEN AND MINORITIES
IN THE OIL AND NATURAL GAS INDUSTRY




Benefits

Jobs in the oil and natural gas industry offer good benefits, high pay, and the opportunity to make a difference. Based on average annual wage data from the *Bureau of Lobar Statistics (BLS)*, the average pay in the oil and gas industry is **nearly $50,000 higher** than the U.S. average.



Education

Workforce training is critical to the projected industry growth that will keep the nation at a competitive advantage and provide the energy the nation depends on. A key element in achieving a growing level of women and minorities to fill the oil and gas industry jobs is to increase the number of such individuals who obtain the education and training needed for the available positions.

While women are now earning the majority of all bachelor's and associate degrees and certificates, **they have very low representation in those awarded in STEM fields, particularly in the engineering and science fields that are critical for the oil and gas industry.** In building trades and construction disciplines, women earned only 6.2% of the degrees/certificates awarded, despite earning 60.3% of the total.

African Americans and Hispanics are also under-represented in degrees applicable to the oil and gas industry, relative to their overall percentage of degree attainment. Employment levels for women and minority groups in the oil and natural gas industry could be improved through improvements in educational attainment. This would require sustained efforts focusing on STEM related disciplines starting in primary education and continuing throughout a student's education.

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U.S. Crude Oil and Natural Gas Production in Federal and Non-Federal Areas

Marc Humphries
Specialist in Energy Policy

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CRS REPORT
Prepared for Members and
Committees of Congress

Summary

A number of proposals designed to increase domestic energy supply, enhance security, and/or amend the requirements of environmental statutes that apply to energy development were before the 113th Congress and are likely to be reintroduced in the 114th Congress. A key question in this discussion is how much oil and gas is produced in the United States each year and how much of that comes from federal versus non-federal areas. Oil production has fluctuated on federal lands over the past five fiscal years but has increased dramatically on non-federal lands. Non-federal crude oil production has been rapidly increasing in the past few years, partly due to favorable geology and the ease of leasing, rising by 3.0 million barrels per day (mbd) between FY2010 and FY2014, causing the federal share of total U.S. crude oil production to fall from 36.4% to 21.4%.

Crude oil production on federal lands, particularly offshore, however, is likely to continue to make a significant contribution to the U.S energy supply picture and could remain consistently higher than previous decades, but still fall as a percent of total U.S. production, if production on non-federal lands continues to rise at a faster rate.

The shale gas boom has resulted in rising supplies of natural gas. Overall, annual U.S. natural gas production rose by about 4.7 trillion cubic feet (tcf) (or 21%) since FY2010, while production on federal lands (onshore and offshore) fell by about 1.6 tcf, (or 31%) over the same time period. Natural gas production on non-federal lands grew by 37% over the same time period. The big shale gas plays have been primarily on non-federal lands and have attracted a significant portion of investment for natural gas development.

There is however, continued interest among some in Congress to open more federal lands for oil and gas development (e.g., the Arctic National Wildlife Refuge (ANWR) and areas offshore) and increase the speed of the permitting process. But having more lands accessible may not translate into higher levels of production on federal lands, as industry seeks out the most promising prospects and higher returns on more accessible non-federal lands.

Another major issue that Congress may address is streamlining the processing of applications for permits to drill (APDs). Some Members contend that this would be one way to help boost energy production on federal lands. After a lease has been obtained, either competitively or noncompetitively, an application for a permit to drill must be approved for each oil and gas well. It took an average of 307 days for all parties to process (approve or deny) an APD in FY2011, but that has declined to an average of 227 days in FY2014 (up from 194 days in FY2013). The Bureau of Land Management (BLM) stated in its annual budget justifications (FY2012 and FY2016), that overall processing times per APD rose to such high levels in FY2011 and other years because of the complexity of the process, but they expect shorter timeframes in the future.

The Energy Policy Act of 2005 (EPACT '05) included a provision to initiate and fund (funding authorized through FY2015) a pilot program at seven Bureau of Land Management (BLM) field offices in an effort to streamline the permitting process for oil and gas leases on federal lands. There were legislative proposals in the 113th Congress that would have established the streamlining pilot program as a permanent program. This topic may be revisited in the 114th Congress.

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Introduction[1]

In 2014, the price of oil averaged $92 per barrel (average composite price), down from $98 per barrel in 2013. Prices dropped dramatically in December 2014, and by January 2015 crude oil prices were under $50 per barrel. The Energy Information Administration (EIA) projects crude oil prices to average in the lower to upper $50 per barrel range through 2015. This lower price, if sustained, may impact long term oil development and lower production volumes.

A number of proposals designed to increase domestic energy supply, enhance security, and/or amend the requirements of environmental statutes that apply to energy development were before the 113th Congress and are likely to be reintroduced in the 114th Congress. A key question in this discussion is how much oil and gas is produced in the United States each year and how much of that comes from federal versus non-federal areas. Oil production has fluctuated on federal lands over the past five fiscal years but has increased dramatically on non-federal lands. Non-federal crude oil production has been rapidly increasing in the past few years, partly due to favorable geology and the ease of leasing, rising by 3.0 million barrels per day (mbd) between FY2010 and FY2014, causing the federal share of total U.S. crude oil production to fall from 36.4% to 21.4%.

Natural gas prices, on the other hand, have remained low for the past several years, allowing gas to become much more competitive with coal for power generation. The shale gas boom has resulted in rising supplies of natural gas. Overall, annual U.S. natural gas production rose by about 4.7 trillion cubic feet (tcf) (or 21%) since FY2010, while production on federal lands (onshore and offshore) fell by about 1.6 tcf (or 31%) over the same time period. Natural gas production on non-federal lands grew by 37% over the same time period (see **Table 2**). The big shale gas plays have been primarily on non-federal lands and have attracted a significant portion of investment for natural gas development.

This report examines U.S. oil and natural gas production data for federal and non-federal areas with an emphasis on the past five fiscal years of production.[2]

U.S. Crude Oil Production: Federal and Non-Federal Areas (Fiscal Year)

Historically, according to Department of the Interior (DOI) data, crude oil production on federal lands was consistently under 20% of total U.S. production until the late 1990s. Annual production then surged on federal lands (primarily offshore), rising to over 30% in the early 2000s and reaching a high point of about 36% in FY2010.[3] As a result of recent production increases on

[1] For a broader analysis of offshore oil and gas leasing and resources, see CRS Report R40645, *U.S. Offshore Oil and Gas Resources: Prospects and Processes*, by Marc Humphries and Robert Pirog.

[2] For more information on U.S. oil development, see CRS Report R43148, *An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions*, by Michael Ratner and Mary Tiemann, and CRS Report R43429, *Federal Lands and Natural Resources: Overview and Selected Issues for the 114th Congress*, coordinated by Katie Hoover.

[3] The early data (1980 and 1990s) were taken from annual Mineral Revenue reports. The data used at that time were accounting data which are considered by the Office of Natural Resources Revenue as not very reliable. The more useful production volume data provided by ONRR now are based on fiscal year sales data.

non-federal lands, the question is raised whether non-federal lands might regain a more dominant position of roughly 80%-85% of total U.S. crude oil production. The fact remains, however, that there are an estimated 5.3 billion barrels of proved oil reserves located on federal acreage onshore and another 4.3 billion barrels of proved reserves offshore (nearly all in the Gulf of Mexico). Taken together, U.S. federal oil reserves equal about 26% of all U.S. crude oil reserves, which are estimated at 36.5 billion barrels, according to the EIA.[4] Proved oil reserves are amounts accessible under current policy, prices, and technology. Higher prices often translate into higher reserve estimates.

Crude oil production on federal lands, particularly offshore, is likely to continue to make a significant contribution to the U.S energy supply picture and could remain consistently higher than previous decades, but it could still fall as a percent of total U.S. production, if production on non-federal lands continues to rise at a faster rate.

There is, however, continued interest among some in Congress to open more federal lands for oil and gas development (e.g., the Arctic National Wildlife Refuge (ANWR) and areas offshore) and increase the speed of the permitting process. But having more lands accessible may not translate into higher levels of production on federal lands, as industry seeks out the most promising prospects and higher returns on more accessible non-federal lands.

Table 1. U.S. Crude Oil Production: Federal and Non-Federal Areas FY2010-FY2014

(Barrels per day)

Fiscal Year	U.S. Total	Non-Federal	Total Federal (% of U.S. Total)	Federal Offshore	Federal Onshore
2014	8,324,000	6,545,000	1,779,000 (21.4)	1,372,400	406,200
2013	7,261,200	5,583,300	1,677,900 (23)	1,303,300	374,600
2012	6,249,000	4,603,500	1,645,500 (26.3)	1,302,800	342,700
2011	5,550,200	3,775,700	1,774,400 (32)	1,454,300	320,100
2010	5,446,500	3,466,300	1,980,200 (36.4)	1,685,200	295,000

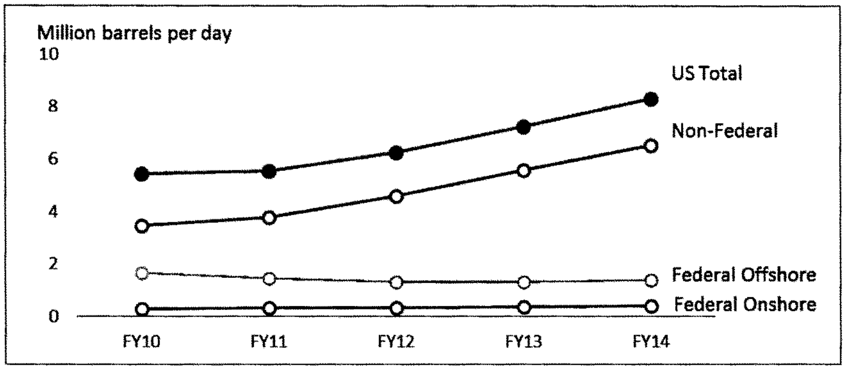
Source: Federal data obtained from the Office of Natural Resources Revenue (ONRR) Statistics, as of January 5, 2015, http://www.onrr.gov (using sales year data), March 2015.

Notes: U.S. Fiscal Year Total data derived from EIA monthly production data contained in its publication *Petroleum and Other Liquids, U.S. Field Production of U.S. Crude Oil*, March 30, 2015, http://www.eia.gov. Data includes lease condensate, defined by EIA as a liquid hydrocarbon recovered from lease separators or field facilities at associated and non-associated natural gas wells.

[4] EIA, U.S. Crude Oil and Natural Gas Proved Reserves, 2013, December 2014, http://www.eia.gov.

Figure 1. U.S. Crude Oil Production: Federal and Non-Federal Areas, FY2010-2014

Million barrels per day (Mb/d)



Source: Federal data obtained from ONRR Statistics, http://www.onrr.gov (using sales year data). Non-federal from EIA. Figure created by CRS.

U.S. Natural Gas Production: Federal and Non-Federal Areas (Fiscal Year)

Natural gas production in the United States overall has dramatically increased each year since 2010, while production on federal lands has declined each year over the same period. Much of the decline can be attributed to offshore production falling by about 50%. Onshore production declines were less dramatic. Federal natural gas production fluctuated from around 30% of total U.S. production for much of the 1980s through the early 2000s (34% of U.S. total in 2003), after which there began a steady decline through 2014.[5] This picture of natural gas production is much different than that of federal crude oil in that federal natural gas had accounted for a much larger portion of total U.S. natural gas over that past few decades.

Any increase in production of natural gas on federal lands is likely to be easily outpaced by increases on non-federal lands, particularly because shale plays are primarily situated on non-federal lands and are where most of the growth in production is projected to occur.

U.S. dry gas proved reserves are estimated at about 354 tcf by the EIA,[6] of which the federal share is about 24% (69 tcf onshore, 16 tcf offshore). Nearly all of the offshore proved reserves are located in the Central and Western Gulf of Mexico.

[5] U.S. natural gas production on federal lands fell from about 7 trillion cubic feet in FY2003 to about 3.5 trillion cubic feet in FY2014.

[6] EIA, *U.S. Crude Oil and Natural Gas Proved Reserves, 2013*, December 2014, http://www.eia.gov. Dry gas is marketed production less extraction losses.

Table 2. U.S. Natural Gas Production: Federal and Non-Federal Areas FY2010-FY2014

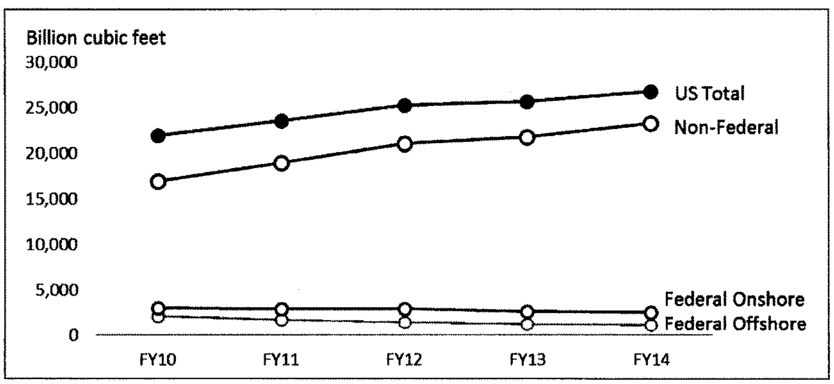
(billion cubic feet)

Fiscal Year	U.S. Total	Non-Federal	Total Federal (% of U.S. Total)	Federal Offshore	Federal Onshore
2014	26,679	23,158	3,521 (13)	1,060	2,461
2013	25,551	21,733	3,818 (15)	1,189	2,629
2012	25,190	20,944	4,246 (16.9)	1,365	2,881
2011	23,510	18,934	4,576 (19.5)	1,682	2,894
2010	21,924	16,850	5,074 (23)	2,070	3,004

Source: Federal data obtained from ONRR Statistics, http://www.onrr.gov (using sales year data as of January 5, 2015), March 2015.

Notes: U.S. Fiscal Year Total data derived from EIA monthly production data in its publication "Natural Gas, U.S. Natural Gas Marketed Production," March 30, 2015, http://www.eia.gov.

Figure 2. U.S. Natural Gas Production: Federal and Non-Federal Areas FY2010-FY2014



Source: Federal data obtained from ONRR Statistics, http://www.onrr.gov (using sales year data). Figure created by CRS.

EIA Projections

While in the short-term, EIA estimates show oil production continuing to decline in federal offshore areas, EIA's longer-term estimates show a slight increase in federal offshore oil production overall, from its nearly 1.4 mbd in FY2014 to 1.6-2.0 mbd in 2040.[7] Overall, the EIA

[7] EIA, *Annual Energy Outlook 2014*, December 2013. The release of the *Annual Energy Outlook, 2015* is due later in (continued...)

projects in the short term, oil production reaching 9.5 mbd in 2016,[8] but long-term estimates show U.S. oil production falling to about 7.5 mbd by 2040 (essentially equal to 2013 production levels) and at 9.0 mbd in 2025.[9] According to these estimates, offshore production in 2040 could range from 21% to 27% of total U.S. crude oil production. (See **Table 3**.)

Offshore natural gas production is projected to reverse a years-long decline in 2015, with annual production rising as high as 2.9 tcf in 2040. Even though these projections are in calendar years, 2.9 tcf of natural gas is nearly triple the current offshore production (provided in fiscal years in the earlier sections of this report) but would only account for about a 7.7% share of total U.S. production in 2040. (See **Table 4**.)

Table 3. EIA Oil Production Projections

(million barrels per day)

Year	U.S. Offshore	U.S. Total
2025	1.6-2.0	9.0
2040	1.6-2.0	$\geq$ 7.5

Source: EIA, Early Release Overview, 2014, Annual Energy Outlook, December 2013.

Table 4. EIA Natural Gas Production Projections

(trillion cubic feet per year)

Year	U.S. Offshore	U.S. Total
2025	1.7-2.9	31.93
2040	1.7-2.9	37.61

Source: EIA, Early Release Overview, 2014 Annual Energy Outlook, December 2013.

Oil and Natural Gas Lease Data for Federal Lands

Based on the federal government's inter-agency's Phase III report, there are 113 million acres of onshore federal lands open and accessible for oil and gas development and about 166 million acres off-limits or inaccessible.[10] The Bureau of Land Management (BLM) is seeking to lease in

(...continued)

April 2015.

[8] EIA, *Short Term Energy Outlook*, http://www.eia.gov/forecasts/steo, March 10, 2015.

[9] Ibid.

[10] U.S. Depts. of the Interior, Agriculture, and Energy, *Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development (Phase III)*, May 2008, available on the BLM website at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/EPCA_III.html.

The availability of public lands for oil and gas leasing can be divided into three categories: lands open under standard lease terms, open to leasing with restrictions, and closed to leasing. Areas are closed to leasing pursuant to land withdrawals or other mechanisms. Much of this withdrawn land consists of wilderness areas, national parks and monuments, and other unique and environmentally sensitive areas that are unlikely to ever be reopened to oil and gas leasing. Some lands are closed to leasing pending land use planning or NEPA compliance, while other areas are closed because of federal land management decisions on endangered species habitat or historical sites. Some of those (continued...)

areas where it anticipates fewer legal challenges. The BLM also says it is addressing public concerns prior to a lease sale at a higher rate than in the past. In 2014, 49% of onshore federal leases and 37% of onshore federal acreage were not in production. Offshore, most of the 1.7 billion acres of federal water are no longer under leasing and development moratoria. The current five-year leasing program has lease sales scheduled in Western and Central Gulf of Mexico (GOM) and parts of Alaska.[11] In the offshore areas, 85% of the acreage that is leased is not in production, but may have an approved exploration or development plan.

According to the BLM and the Bureau of Ocean Energy Management (BOEM), there are approximately 67 million acres of oil and gas leases in federal areas (onshore and offshore). About 34.6 million acres are located onshore and an additional 32 million acres are offshore. Approximately 12.7 million federal acres onshore and about 4.8 million federal acres offshore are producing commercial volumes. (See **Table 5**.)

Table 5. Oil and Gas Lease Data for Federal Lands, 2014

	Onshore	Offshore
Acreage under lease	34.6 million acres	32 million acres
Leased acres producing	12.7 million acres	4.8 million acres
Leased acres not in production or exploration	21.9 million acres	27.3 million acres
Number of Leases	46,193	5,938
Producing Leases (or with approved DOCD)[a]	23,657	970
Percentage of producing leases	51	16

Source: Offshore data: DOI/BOEM, Combined Leasing Status Report, March 2015 (www.boem.gov). Onshore data: DOI/BLM, Oil and Gas Statistics (www.blm.gov/wo/st/en)

a. A DOCD is a Development Operations Coordination Document that must be submitted for approval to BOEM before development activities begin.

Producing Acres

The number of federal producing acres may or may not be a function of how many acres are leased, and the number of acres leased may or may not correlate to production levels, but it is beyond the scope of this report to examine that issue thoroughly. In recent years, some members of Congress have proposed a $4/acre lease fee for non-producing leases. This proposal grew out of the efforts to open more public land and water (offshore) for oil and gas drilling and development when gasoline prices spiked in 2006-2008. Some in Congress noted that there were many leases they believed were not being developed in a timely manner, while at the same time, others in Congress were advocating greater access to areas off-limits (such as ANWR and areas under leasing moratoria offshore). Higher rents for offshore leases were imposed by the Secretary of the Interior in 2009 to discourage holding unused leases and to move more leases into

(...continued)

restricted areas may be opened by future administrative decisions.

[11] Nearly all of the Eastern GOM is under a leasing moratorium until 2022 under the Gulf of Mexico Energy Security Act, and the North Aleutian Basin of Alaska was withdrawn from leasing under an executive order by the Obama Administration. Separately, President Obama withdrew selected parts of the Chukchi and Beaufort Seas of Alaska indefinitely in January 2015.

production, if possible. The escalation in annual rents is significant over time, as they rise from \$7/acre to \$28/acre (in year-8 forward) in water depths less than 200 meters, and increase from \$11/acre to \$44/acre (in year-8 forward) in water depths between 200 and 400 meters. However, there was no similar escalation for onshore leases, as they remain \$1.50/acre for years 1-5, then rise to \$2/acre thereafter.[12] Legislative options to increase the rents and royalties on federal oil and gas leases have been debated in Congress. A non-producing fee or an escalation of rents may not increase production but may increase the ratio of producing leases to active leases. Thus, there might be fewer "idle" leases and acreage not in production or exploration. The BLM can re-lease acreage that has been relinquished or passed over at a future lease sale.

Applications for Permits to Drill (APDs)

Another major issue that Congress may address is streamlining the processing of applications for permits to drill (APDs). Some Members contend that this would be one way to help boost energy production on federal lands. After a lease has been obtained, either competitively or noncompetitively, an application for a permit to drill must be approved for each oil and gas well. As noted in the Mineral Leasing Act, Section 226 (g), "no permit to drill on an oil and gas lease issued under this chapter may be granted without the analysis and approval by the Secretary concerned of a plan of operations covering proposed surface-disturbing activities within the lease area." The application form (APD form 3160-3) must include, among other things, a drilling plan, a surface use plan, and evidence of bond/surety coverage. The surface use plan should contain information on drillpad location, pad construction, the method for containment and waste disposal, and plans for surface reclamation.[13]

Prior to the Energy Policy Act of 2005 (P.L. 109-58, EPACT '05), a major concern that prompted the streamlining of permits debate was the lengthy timetable to process an APD. The BLM attributed the longer timelines to the rewriting of outdated Resource Management Plans (RMPs). There were several RMPs revised over the past decade. Leading up to the provisions in EPACT '05 that attempted to streamline the permitting process, the BLM announced, in April 2003, new strategies to expedite the APD process. The new strategies included processing and conducting environmental analyses on multiple permit applications with similar characteristics, implementing geographic area development planning for an oil or gas field or an area within a field, establishing a standard operating practice agreement that identifies surface and drilling practices by oil and gas operators, allowing for a block survey of cultural resources, promoting consistent procedures, and revising relevant BLM manuals.[14] EPACT '05 Section 366 (Deadline for Consideration of Application for Permits) provided a new timeline for BLM to process APDs.[15]

[12] DOI, *Oil and Gas Lease Utilization, Onshore and Offshore, Updated Report to the President,* May 2012, p.18.

[13] U.S. Department of the Interior, Bureau of Land Management (BLM), *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development,* The Gold Book, Fourth Edition-Revised 2007, p. 8.

[14] DOI/BLM Instruction Memorandum No. 2003-152, Application for Permit to Drill Process Improvement#1-Comprehensive Strategies, April 14, 2003.

[15] Within 10 days of receiving the application from the operator, BLM shall notify the operator as to whether the application is complete and also schedule a site visit. If the application is not complete, the operator then has 45 days to submit additional information to BLM to complete the application or the application is returned to the operator. Within 30 days of receiving a completed application the BLM will approve or defer the application. If deferred, the operator has up to two years to take specified actions to complete the application or face the possibility of being denied a permit.

While the current Administration processed more APDs than it received from 2009-2013, it received far fewer applications over that period than had been received annually from 2006-2008. Even though the number of pending applications has fallen steadily from 2008-2013, the ratio of APDs pending to APDs processed was higher than during the period 2006-2008. In addition, there are 6,000 approved APDs that are not in the exploration or production stages (approved but not drilled).[16] The BLM expected to process over 5,000 APDs in each of the fiscal years 2015 and 2016.

Table 6. Onshore Oil and Gas Drilling Permits (FY2006-FY2014)

Fiscal Year	New APDs Received	Total APDs Processed	APDs Pending at Year-End
2014	5,316	4,924	4,121
2013	4,757	4,892	3,546
2012	5,240	5,861	3,683
2011	4,728	5,200	4,108
2010	4,251	5,237	4,603
2009	5,257	5,306	5,589
2008	7,884	7,846	5,638
2007	8,370	8,964	5,600
2006	10,492	8,854	6,194

Source: DOI/ BLM, *FY2016 Budget Justification* for years FY2011-FY2016. For earlier years, see DOI, *Oil and Gas Utilization, Onshore and Offshore*, May 2012.

It took an average of 307 days for all parties to process (approve or deny) an APD in FY2011, but that has declined to an average of 227 days in FY2014 (up from 194 days in FY2013).[17] In FY2006, it took the BLM an average of 127 days to process an APD, while in FY2014 it took BLM 133 days (up from 95 days in FY2013). In FY2006, the industry took an average of 91 days to complete an APD, but in 2014, the industry took 133 days (up from 99 days in FY2013). The BLM stated in its annual budget justifications for FY2012 and FY2016 that overall processing times per APD rose to such high levels in FY2011 and other years because of the complexity of the process, but they expect shorter timeframes in the future.

Some critics of this lengthy timeframe highlight the relatively speedy process for permit processing on private lands. However, crude oil and gas development on federal lands takes place in a wholly different regulatory framework than that of development on private lands.[18] State

[16] U.S Department of the Interior, *Oil and Gas Lease Utilization, Onshore and Offshore, Updated Report to the President*, May 2012, p. 14.

[17] Bureau of Land Management, "Average Application for Permit to Drill (APD) Approval Timeframes: FY2005-FY2014," http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/statistics/apd_chart.html.

[18] Under the Federal Land Policy and Management Act (FLPMA), Resource Management Plans or Land Use Plans (43 U.S.C. 1712) are required for tracts or areas of public lands prior to development. The Bureau of Land Management (BLM) must consider environmental impacts during land-use planning when RMPs are developed and implemented. RMPs can cover large areas, often hundreds of thousands of acres across multiple counties. Through the land-use planning process, the BLM determines which lands with oil and gas potential will be made available for leasing.

agencies permit drilling activity on private lands within their states, with some approving permits within 10 business days of submission. This faster approval rate does not necessarily diminish the additional work required by the state to address other state requirements. But often, some surface management issues are negotiated between the producer and the individual land/mineral owner. A private versus federal permitting regime does not lend itself to an "apples-to-apples" comparison.

Streamline Pilot

EPACT '05 also included a provision to initiate and fund (funding authorized through FY2015) a pilot program at seven BLM field offices in an effort to streamline the permitting process for oil and gas leases on federal lands. Initial results from the pilot project were published according to the timetable required by EPACT '05 (within three years after enactment). The conclusion was that the pilot made a difference in improving the processing times for APDs at the pilot offices overall and increased the number of environmental inspections. The BLM noted that the National Environmental Policy Act (NEPA) processing time for APDs and rights of way (ROW) applications fell from 81 to 61 days or roughly 25% due to "colocation" of agency staff. BLM reported that the number of environmental inspections went up by 78% from FY2006 to FY2007.[19] The BLM reported mixed results at the specific field offices. While some of the offices processed more permits in 2007 than they did in 2005, all the pilot sites reported more completed environmental inspections.[20] There were legislative proposals in the 113th Congress that would have established the streamlining pilot program as a permanent program. This topic may be revisited in the 114th Congress.

Concerns over Non-Producing Leases

A number of concerns may arise in the oil and gas leasing process that could delay or prevent oil and gas development from taking place, or might account for the relatively large number of leases held in non-producing status. It should be noted that many leases expire without exploration or production ever occurring.

Below is a list of often-cited issues which, individually or in combination, are cited by various stakeholders to explain why more leases are not producing.

- Rig or equipment availability, particularly offshore;
- Oil and natural gas prices;
- High capital costs and available capital;
- Skilled labor shortages;
- Leases in the development cycle (e.g., conducting environmental reviews, permitting, or exploring) but not producing;
- Legal challenges that might delay or prevent development;
- No commercial discovery on a lease tract;

[19] Bureau of Land Management, BLM Year Two Report, Section 365 of EPACT 2005 Pilot Project to Improve Federal Permit Coordination, February 2008.

[20] Ibid.

- Holding leases (because of the lack of capital or as "speculators") to sell or "farm out" at a later date;
- Ability to secure extensions on non-producing leases;
- Securing and being able to hold large number of lease tracts, often contiguous, to maximize return on their investment; and
- The potential for inadequate coordination between the Department of the Interior's lease management and regulatory agencies (Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement) and other federal agencies to ensure protection of federal areas encompassing coastal and marine sanctuaries.

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Executive Summary
Economic Impacts of Oil & Gas Development on Federal lands in the West
April 2012

WESTERN ENERGY ALLIANCE
Formerly IPAMS

SWCA Environmental Consultants prepared for Western Energy Alliance an analysis of the economic impacts of all outstanding oil and natural gas projects proposed on federal lands in the West. After a thorough review of projects undergoing environmental analysis in accordance with the National Environmental Policy Act (NEPA) as of January 1, 2012, SWCA determined that 44,329 wells were proposed in twenty NEPA documents currently under development as of January 1, 2012. Since the vast majority, 44,289, were proposed in Utah and Wyoming, SWCA performed full analysis just for those two states.

Key Findings

- The total annual impact of the twenty proposed projects is 3,164 wells drilled, **120,905 jobs, $8 billion in wages, $27.5 billion in economic activity, and $139 million in government revenue.** The total economic impact of the projects over their anticipated lifespan (usually between ten and fifteen years) is **$383.5 billion.**

- In the oil and natural gas NEPA process, companies are responsible for proposing projects, and the Bureau of Land Management (BLM) or the Forest Service (USFS) is responsible for completing the NEPA analysis. Development cannot proceed on federal lands until the government completes the NEPA analysis. Companies regularly pay for contractor support, yet the government is responsible for managing the contractors and approving the documents.

- The projects proposed in Wyoming could create 58,480 jobs, $14.8 billion in economic impact, and $82.5 million in government revenue annually, based on 1,720 wells drilled per year.

- The projects proposed in Utah could create 62,425 jobs, $12.7 billion in economic impact, and $56.7 million in government revenue annually, based on 1,445 wells drilled per year.

- The majority of the wells, 30,789, are proposed in NEPA documents that have been underway for over two years. Many of these were begun over five years ago, delaying projects for years past the usual processing times.

- Outstanding projects delayed over three years represent 22,835 proposed wells, or about 1,631 wells per year. Federal government delays to these projects are preventing the creation of **64,805 jobs, $4.3 billion in wages, and $14.9 billion** in economic impact every year.

By 2020, the West could produce as much oil and natural gas on a daily basis as the U.S. imports from Russia, Iraq, Kuwait, Saudi Arabia, Venezuela, Algeria, Nigeria, and Colombia combined, while creating new jobs, expanding investment, and providing much needed government revenue. Bureaucratic delays, however, could significantly undermine these projections of growth, investment and expansion.

Economic Impacts of Oil and Gas Development on Public Lands in the West

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April 2012

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INTRODUCTION

This report follows a progressive analysis for the estimated impacts of oil and gas development and production for the states of Wyoming and Utah. A methodology is presented, followed by baseline analysis of both states. Economic analysis of both development and production of proposed oil and gas projects in Utah and Wyoming comprise the impact study of this report. All projects analyzed in this analysis were in some phase of the National Environmental Policy Act (NEPA) process as of January 1, 2012. We estimate the yearly and aggregate estimated economic values of development and production with regards to these delayed projects (i.e., the opportunity costs of the NEPA process). There are two phases of analysis for this project, the first involved gathering data regarding projects undergoing NEPA review in Wyoming, Utah, Colorado, New Mexico, and Montana, and the second is estimating the economic impacts for oil and gas development and their relationship with the NEPA process.

RESEARCH AND METHODOLOGY

PHASE 1: PROJECTS CURRENTLY UNDERGOING THE NEPA PROCESS

Data for Phase 1 were gathered via internet databases and personal correspondences with Bureau of Land Management (BLM) State and Field Office NEPA specialists. This included internet sites such as the Environmental Notification Bulletin Board (ENBB) and other state-based NEPA planning information centers. Being that there is not a central information center for current Environmental Assessments (EAs) and Environmental Impact Statements (EISs), the states were researched one-by-one. Each state also uses different tracking mechanisms for NEPA, sometimes broken down by field office and other times presented at a state level. To maximize the validity of our findings, the projects were cross-referenced with NEPA representatives for each of the respective states. Only EAs and EISs that assess the impacts of oil and gas development on public land (BLM and U.S. Forest Service [USFS]) are contained within our results, with the caveat of a minimum restriction of at least 25 proposed total wells for each project. NEPA projects between 2006 and 2011 were considered in our analysis.

PHASE 2: ECONOMIC ANALYSIS

The data gathered in Phase 1 is analyzed in the Phase 2 analysis of this report. Data collected during Phase 1 revealed that only Wyoming, Utah, and Colorado had ongoing projects that meet the above criteria. In Colorado, only one project (Bull Mountain Unit EA) met the criteria for inclusion in the analysis; therefore, it was determined that economic modeling would only be performed for Wyoming and Utah. Baseline conditions for oil and gas development in Wyoming and Utah were established, and then an input-output model (IMPLAN) was used to estimate the impacts of proposed projects in these states.

IMPLAN

IMPLAN economic modeling was used for this analysis. IMPLAN is an input-output model that is used to yield estimates of the indirect (backward) and induced (forward) linkages in the economy. Indirect effects include changes in business demands where purchases are made for inputs. Induced effects are the increase in demand for goods and services as household's income increases due to the associated economic activity of oil and gas wells. Jobs are reported in Annual Job Equivalents, or (AJE)s. One AJE is equal to 12 months of employment, and includes part- and full-time empoyment (i.e. ,1 AJE could be one worker who works all year, or two workers who work 6 months each, etc.).

The total impact is the sum of the indirect, direct, and induced effects. More information is available at: http://implan.com/V4/Index.php.

Baseline Data

Various sources were used to establish baseline indicators for the states of Wyoming and Utah. These included the Energy Information Administration (EIA), Utah Department of Oil, Gas, and Minerals (DOGM), the Office of Natural Resource Revenue (ONRR), and IMPLAN data. IMPLAN also provides descriptive baseline information in addition to the impact analysis.

Oil and Gas Well Development and Production

To determine marginal effects for oil and gas development in Utah and Wyoming, IMPLAN economic modeling was used. For this analysis the average median national cost of constructing a typical oil and gas well was used. This information is available from the Energy Information Administration (EIA 2012c). The same cost was used for both states so that the marginal effects of each state could be contrasted without bias. The costs are assumed to be constant across the development of the projects, and that wells are developed evenly across the planned time horizon.

To obtain estimates for economic activity associated with oil and gas production, IMPLAN software was also used. Employment per well was calculated using the most up-to-date data (2009). Total employment for NAICS 2111 (oil and gas extraction) for Wyoming and Utah was 3,543 and 1,241 respectively (U.S. Census Bureau 2012a). In 2009, the total number of producing oil and gas wells for Wyoming was 34,543 and for Utah was 8,920 (EIA 2012a, b), yielding 9.74 workers per well for Wyoming and 7.18 for Utah. The following sectors from the North American Industry Classification System (NAICS) were used in IMPLAN for this analysis:

- NAICS 21311(Drilling Oil and Gas Wells) - This U.S. industry comprises establishments primarily engaged in drilling oil and gas wells for others on a contract or fee basis. This industry includes contractors that specialize in spudding in, drilling in, redrilling, and directional drilling (U.S. Census Bureau 2012).
- NAICS 21211(Oil and Gas Extraction) - Industries in the Oil and Gas Extraction subsector operate and/or develop oil and gas field properties. Such activities may include exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operating separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property. This subsector includes the production of crude petroleum, the mining and extraction of oil from oil shale and oil sands, and the production of natural gas, sulfur recovery from natural gas, and recovery of hydrocarbon liquids. Establishments in this subsector include those that operate oil and gas wells on their own account or for others on a contract or fee basis. Establishments primarily engaged in providing support services, on a fee or contract basis, required for the drilling or operation of oil and gas wells (except geophysical surveying and mapping, mine site preparation, and construction of oil/gas pipelines) are classified in Subsector 213, Support Activities for Mining (U.S. Census Bureau 2012a).

WYOMING BASELINE ANALYSIS

The section presents a baseline analysis of oil and gas activity and economic contribution for the state of Wyoming. Figure 1 illustrates historic oil and gas production for Wyoming. Since 2000 natural gas production has doubled, while oil production has remained at a near constant level, just less than one million barrels per year.

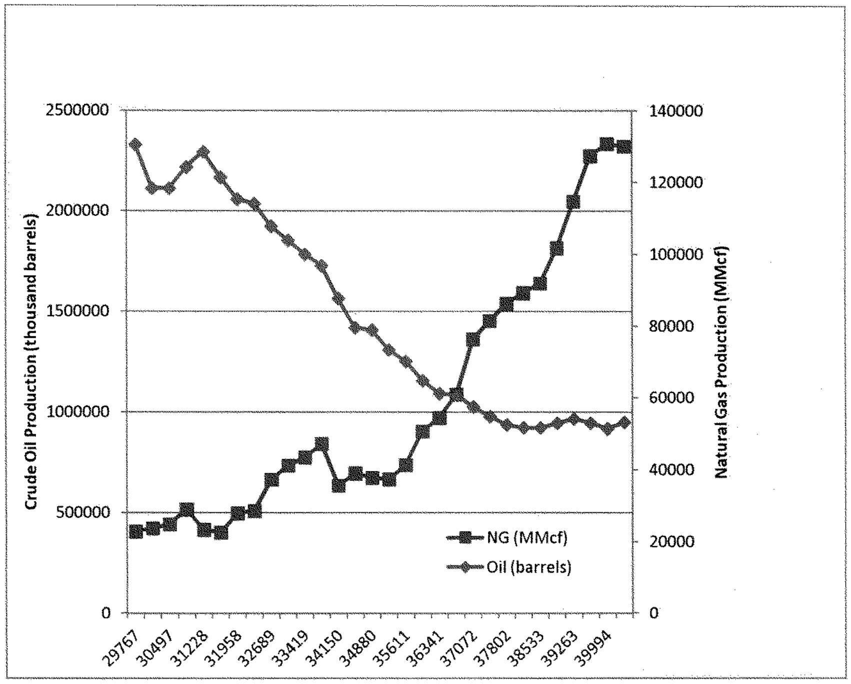

Figure 1. Historical Oil and Natural Gas Production in Wyoming. (Source: EIA 2012a)

Table 1 provides an economic summary for oil and gas activities in Wyoming in 2010 according to IMPLAN data. This includes the extraction of oil and gas, support activities for oil and gas, and drilling of wells. In 2010 these sectors generated over 22,000 AJEs and over $9 billion in total economic contribution.

Table 1. 2010 Oil and Gas Economic Summary for Wyoming.

Industry Code	Description	Employ-ment (AJEs)	Output*	Employee Compensation*	Proprietor Income*	Other Property Type Income*	Indirect Business Taxes*	Total Economic Contribution*
20	Extraction of oil and natural gas	9,956.50	$2,509,661	$483,882	$521,046	$542,430	$285,100	$4,342,120
29	Support activities for oil and gas operations	9,683.30	$1,907,591	$648,745	$97,826	$4,550	$32,079	$2,690,793
28	Drilling oil and gas wells	2,671.60	$1,122,572	$217,921	$31,529	$592,214	$16,755	$1,980,994
Wyoming Oil and Gas Industry Totals		22,311.40	$5,539,825	$1,350,549	$650,402	$1,139,195	$333,935	$9,013,907

* in thousand dollars (000's)
Source: IMPLAN 2010

Figures 2 and 3 break down the economic components shown in Table 1 into percentages of total activities related to oil and natural gas. Employment and economic output related to production are the largest components of natural gas activity in Wyoming.

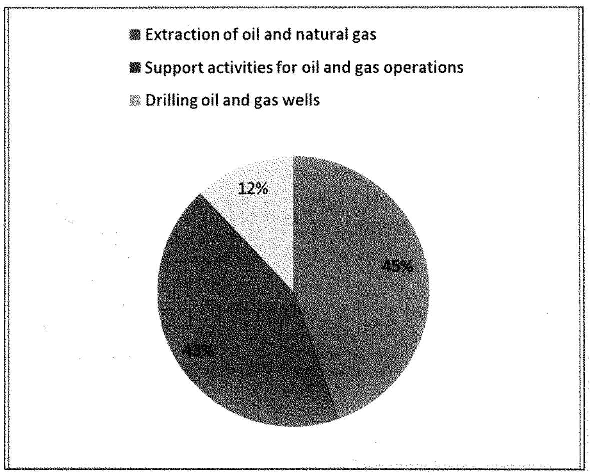

Figure 2. Employment form Oil and Natural Gas Activities in Wyoming. (Source: IMPLAN 2010)

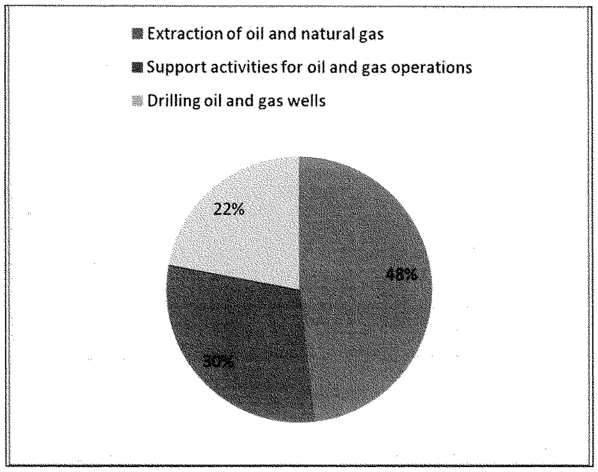

Figure 3. Economic Components of Oil and Natural Gas Activities in Wyoming. (Source: IMPLAN 2010)

Table 2 shows state and federal tax revenue for Wyoming in 2010. These numbers are based off of the 2009 production year. In 2010 there were 34,957 producing oil and gas wells (EIA 2012b), with each well providing approximately $47,991 in Ad Valorum tax, Severance Tax, and Federal Mineral Royalties.

Table 2. 2010 Tax Revenue for Oil and Gas Production Wyoming (34,957 producing wells).

	Total Tax $	Tax $ per well
Ad Valorum Tax	$784,912,412	$22,454
Severance Tax	$460,013,007	$13,159
Federal Mineral Royalties	$432,704,926	$12,378
Total	$1,677,630,345	$47,991

Sources: Wyoming Department of Revenue, ONRR 2012b, EIA 2012b

Table 3 represents the major projects (more than 25 wells proposed) undergoing the NEPA process in Wyoming. This table is current through January 1, 2012. There are currently a total of nine EA's and EIS's that are proposed in Wyoming representing over 24,000 proposed wells to be drilled over the full duration of these projects.

Table 3. Current Oil and Gas Projects Undergoing the NEPA Process in Wyoming.

Land Management Agency	EIS/EA	Project Initiation	Wells Proposed	Wells/Year
BLM - Kemmerer Field Office	Moxa Arch Infill Drilling Project EIS	10/5/05	1,861	186
BLM - Lander Field Office	Beaver Creek Coal Bed NG Development Project EIS	7/29/08	228	23-46
	Moneta Divide EIS	Pending	4,250	295
BLM - Pinedale Field Office	LaBarge Platform Infill OG EIS	8/3/09	838	60
	Normally Pressure Lance Natural Gas Development Project EIS	4/12/11	3,500	350
BLM - Rawlins Field Office	Continental Divide-Creston Natural Gas Project EIS	3/5/06	8,950	600
	Table Rock Oil and Gas EA	5/11	88	6
Rock Springs	Hiawatha Regional Energy Development Project EIS	9/6/06	4,208	140-210
USFS - Big Piney Ranger District	Plains Exploration Eagles Prospect and Noble Basin Oil and Gas Master Development Plan	1/11/06	136	12
	Total Proposed Wells		24,059	1,720

UTAH BASELINE ANALYSIS

The section presents a baseline analysis of oil and gas activity and economic contribution for the state of Utah. Figure 4 summarizes historical oil and gas production over the last 30 years. Both oil and natural gas production in Utah has been on a generalized downward trend since 2005.

Table 4 provides an economic summary for oil and gas activities in Utah in 2010 according to IMPLAN data. This includes the extraction of oil and gas, support activities for oil and gas, and drilling of oil and gas wells. In 2010 these sectors generated over 8,000 AJEs and over $3 billion in total economic contribution.

Figures 5 and 6 break down the economic components exhibited in Table 3 into percentages of total activities related to oil and natural gas. Like Wyoming, employment and economic output related to production are the largest components of natural gas activity in Utah.

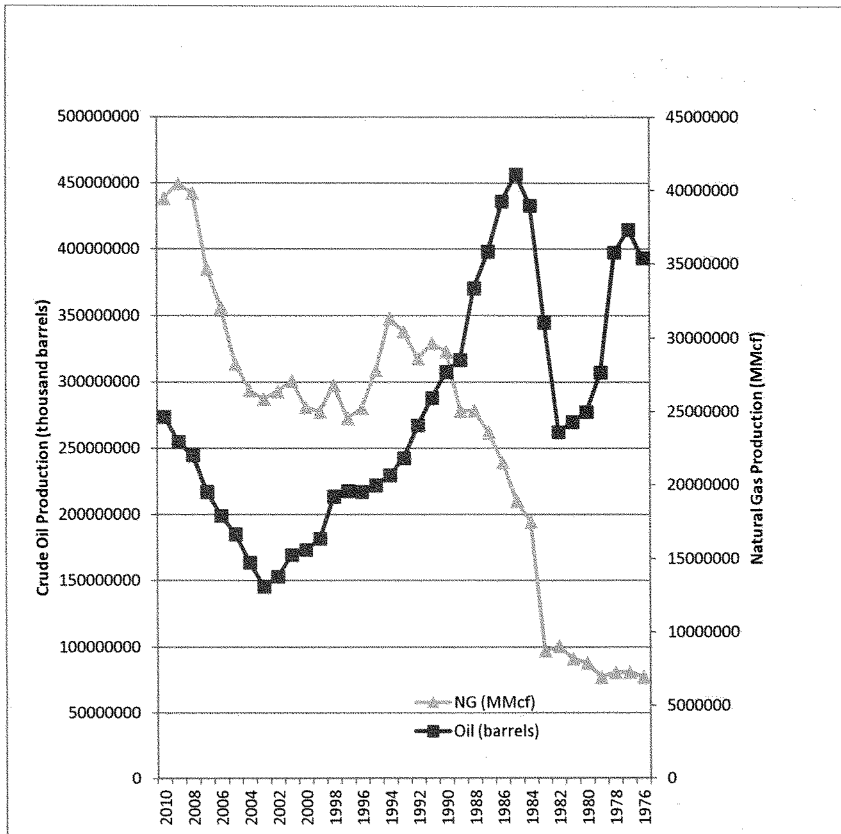

Figure 4. Historical Oil and Natural Gas Production in Utah. (Source: Utah DOGM 2012)

Table 4. 2010 Oil and Gas Summary for Utah

Industry Code	Industry	Employment (AJEs)	Output*	Employee Compensation*	Proprietor Income*	Other Property Type Income*	Indirect Business Taxes*	Total Economic Contribution*
20	Extraction of oil and natural gas	4,092.40	$918,700	$157,982	$210	$198,221	$104,185	$1,589,499
29	Support activities for oil and gas operations	3,410.70	$651,478	$200	$44,601	$1,473	$10,389	$908,833
28	Drilling oil and gas wells	769.8	$284,472	$52	$11,181	$149,946	$4,242	$502,006
Oil and Gas Industry Totals		8,272.90	$1,854,650	$411,036	$266,193	$349,641	$118,817	$3,000,340

Source: IMPLAN 2010
* in thousand dollars (000's)

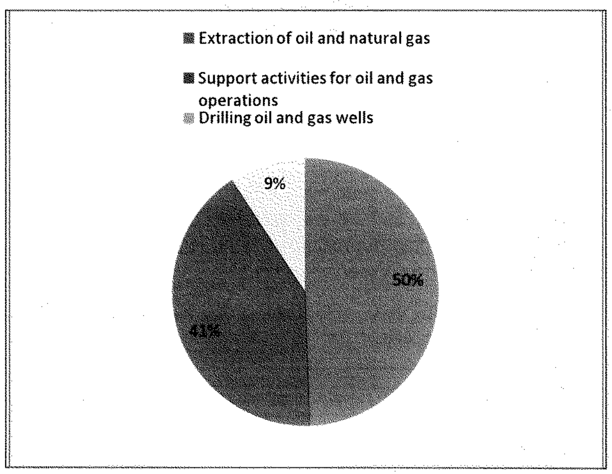

Figure 5. Components of Employment Related to Natural Gas and Oil Activities in Utah.

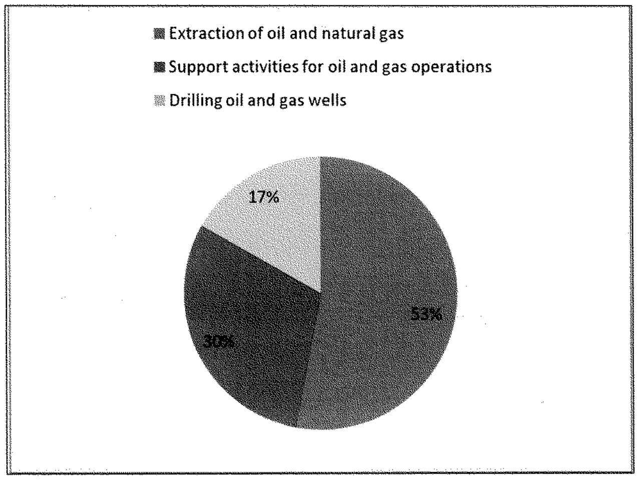

Figure 6. Total Economic Contribution from Natural Gas and Oil Activities in Utah.

Table 5 shows state and federal tax revenue for Utah in 2010. These numbers are based off of the 2009 production year. In 2010 there were 9,221 producing oil and gas wells (EIA 2012a), with each well providing approximately $39,326 in Ad Valorum tax, Severance Tax, Federal Mineral Royalties, and Conservation Fees.

Table 5. 2010 Tax Revenue for Oil and Gas Production Utah (9,221 producing wells).

	Total Tax $	Tax $ per well
Oil and Gas Severance Tax	$56,200,970	$6,095
Ad Valorem Tax	$42,581,114	$4,618
Conservation Fees	$4,191,039	$455
Federal Royalties	$259,372,275	$28,128
Total	$362,345,398	$39,296

Sources: Utah Tax Commission 2010, ONRR 2012a, EIA 2012a

Table 6 represents the major projects (more than 25 wells) undergoing the NEPA process in Utah. This table is current through January 1, 2012. There are currently a total of eleven EA's and EIS's that are proposed in Utah representing over 20,000 proposed wells to be drilled over the project's lifetimes.

Table 6. Current Oil and Gas Projects Undergoing the NEPA Process in Utah.

Land Management Agency	EIS/EA	Project Initiation	Wells Proposed	Wells/Year
BLM - Vernal Field Office	Gasco Energy Uintah Basin NG Development Project EIS	2/10/06	1,538	100
	Anadarko Greater Natural Buttes EIS	10/5/07	3,496	358
	Greater Chapita Wells NG Infill EIS	9/9/09	7,028	469
	Monument Butte Area OG Development Project EIS	8/25/10	5,750	250
	XTO's Little Canyon Field EA	10/17/06	510	73
	XTO's Kings Canyon Plan of Development	2008	90	Unknown
	XTO's Hill Creek Unit EA	4/30/09	137	14-24
	XTO's River Bend Unit Infill Development EA	7/17/07	368	37-93
	Big Pack Natural Gas EA	9/26/06	664	66
	Southam Canyon Gas Field EA	9/24/08	249	25
USFS - Duchesne Ranger District	South Unit Oil and Gas Development EIS	8/2907	400	20
	Total Proposed Wells		20,230	1,445

Sources: (BLM 2012a-c, 2012e, 2011a, 2010, 2009a, 2008a, 2006a; USFS 2011)

ECONOMIC IMPACT ANALYSIS

DEVELOPMENT OF OIL AND GAS WELLS IN WYOMING

Table 7 shows the economic impacts of a typical well developed in Wyoming. IMPLAN was used to estimate indirect and induced effects. Development and completion of one typical oil and gas well is estimated to produce over $5 million in economic activity and provide over 17 AJEs, with an average labor income of $73,944 per AJE.

Table 8 summarizes the top ten sectors impacted through the development of a typical oil and gas well in Wyoming. These include direct, indirect, and induced effects. These sectors are economically tied to the drilling activities of oil and gas well development.

Tables 9 and 10 show the annual and total economic impacts of the proposed projects that are undergoing the NEPA process in Wyoming. The development impacts are illustrated in the number of wells that are proposed to be developed on an annual basis and at a total project level. The total project economic activity represents the estimated economic impact of each project at the aggregate level over the trajectory of the project's lifetime.

Table 7. Impacts from Development and Completion of a Typical Oil and Gas Well Wyoming (2010).

Estimated Activity	Conventional Well
Total Cost (direct effect)	$4,387,260
Indirect effect	$272,404
Induced Effect	$538,869
Total Economic Activity	$5,198,533
Employment (AJE)	
Direct Annual AJE	10.4
Indirect and Induced AJE	7
Total AJE	17.4
Total Labor Income	$1,286,630
Average Labor Income per AJE	$73,944

Sources: (IMLPLAN 2010, EIA 2012c)

Table 8. Top Ten Sectors Impacted Per Well Developed.

Sector #	Description	Total Employment	Total Labor Income	Total Value Added	Total Output
28	Drilling oil and gas wells	10.4	$974,909	$3,354,901	$4,387,260
413	Food services and drinking places	0.7	$12,109	$18,343	$35,216
360	Real estate establishments	0.5	$4,805	$34,974	$39,325
394	Offices of physicians, dentists, and other health practitioners	0.3	$25,132	$25,948	$39,152
369	Architectural, engineering, and related services	0.3	$16,867	$17,149	$29,829
356	Securities, commodity contracts, investments, and related activities	0.3	$835	$883	$34,672
319	Wholesale trade businesses	0.3	$19,546	$34,822	$44,722
335	Transport by truck	0.2	$15,713	$18,929	$32,593
329	Retail Stores - General merchandise	0.2	$5,790	$9,020	$11,780
367	Legal services	0.2	$10,875	$16,560	$19,964

Source: (IMPLAN 2010)

Table 9. Annual Estimated Economic Activity from Gas and Oil Well Development and Completion for Wyoming by Project.

Proposed Project	Total Wells Proposed	Annual Wells Proposed for Development	Total Cost (Direct Effect)	Indirect Effect	Induced Effect	Total Annual Economic Activity	Total Project Economic Activity
Moxa Arch Infill Drilling Project EIS	1,861	186	$816,030,360	$50,667,144	$100,229,634	$966,927,138	$9,674,469,913
Beaver Creek Coal Bed NG Development Project EIS	228	36	$157,941,360	$9,806,544	$19,399,284	$187,147,188	$1,185,265,524
Moneta Divide EIS	4,250	295	$1,294,241,700	$80,359,180	$158,966,355	$1,533,567,235	$22,093,765,250
LaBarge Platform Infill OG EIS	838	60	$263,235,600	$16,344,240	$32,332,140	$311,911,980	$4,356,370,654
Normally Pressure Lance Natural Gas Development Project EIS	3,500	350	$1,535,541,000	$95,341,400	$188,604,150	$1,819,486,550	$18,194,865,500
Continental Divide-Creston Natural Gas Project EIS	8,950	600	$2,632,356,000	$163,442,400	$323,321,400	$3,119,119,800	$46,526,870,350
Table Rock Oil and Gas EA	88	6	$26,323,560	$1,634,424	$3,233,214	$31,191,198	$457,470,904
Hiawatha Regional Energy Development Project EIS	4,208	175	$767,770,500	$47,670,700	$94,302,075	$909,743,275	$21,875,426,864
Plains Exploration Eagles Prospect and Noble Basin Oil and Gas Master Development Plan	136	12	$52,647,120	$3,268,848	$6,466,428	$62,382,396	$707,000,488
Totals	24,059	1,720	$7,546,087,200	$468,534,880	$926,854,680	$8,941,476,760	$125,071,505,447

Source: IMPLAN 2010

Table 10. Annual Employment from Oil and Gas Well Development and Completion for Wyoming by Project.

Proposed Project	Direct Annual AJE	Indirect and Induced AJE	Total AJE	Total Labor Income
Moxa Arch Infill Drilling Project EIS	1,934.4	1,302.0	3,236	$239,313,180
Beaver Creek Coal Bed NG Development Project EIS	374.4	252.0	626	$46,318,680
Moneta Divide EIS	3,068.0	2,065.0	5,133	$379,555,850
LaBarge Platform Infill OG EIS	624.0	420.0	1,044	$77,197,800
Normally Pressure Lance Natural Gas Development Project EIS	3,640.0	2,450.0	6,090	$450,320,500
Continental Divide-Creston Natural Gas Project EIS	6,240.0	4,200.0	10,440	$771,978,000
Table Rock Oil and Gas EA	62.4	42.0	104	$7,719,780
Hiawatha Regional Energy Development Project EIS	1,820.0	1,225.0	3,045	$225,160,250
Plains Exploration Eagles Prospect and Noble Basin Oil and Gas Master Development Plan	124.8	84.0	209	$15,439,560
Totals	17,888.0	12,040.0	29,928	$2,213,003,600

Source: IMPLAN 2010

Table 11 and Figure 7 summarize the opportunity costs associated with the delay of oil and gas development in Wyoming annually; and at 5-year impacts and 10-year impacts. A 10-year time period is used because development would occur over at least a 10-year period for all of the proposed projects (with exception to the Beaver Creek EIS which will take place over 9 years, proposing 36 wells per year).

Table 11. Total Economic Impacts of Delays of Oil and Gas Development Wyoming.

	Project Delay		
Impact	1-year	5-year	10-year
Labor Income	$2,213,003,600	$11,065,018,000	$22,130,036,000
Total AJE	29,928	149,640	299,280
Economic Output	$8,941,476,760	$44,707,383,800	$89,414,767,600

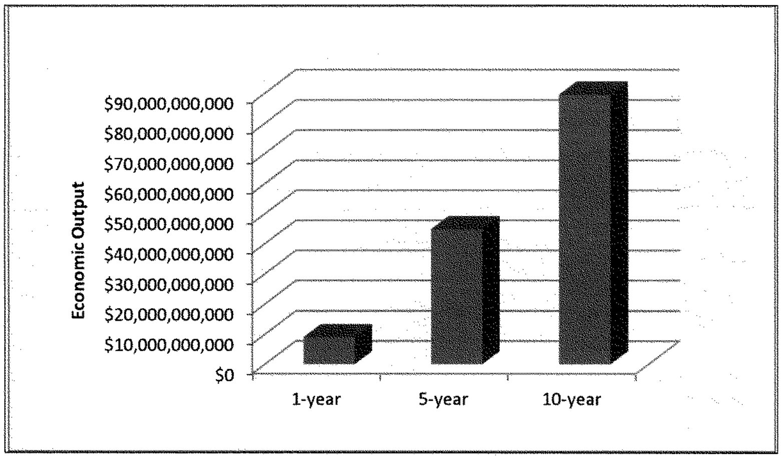

Figure 7. Economic Impacts of Delays of Oil and Gas Development in Wyoming.

ESTIMATED ECONOMIC IMPACTS OF OIL AND GAS PRODUCTION IN WYOMING

Table 11 shows the economic impacts of a typical oil or gas well producing in Wyoming. IMPLAN was used to estimate indirect and induced effects. One typical oil and gas well is estimated to produce over $3.3 million in economic activity annually and provide over 16 AJEs per producing year, with an average labor income of $75,224 per AJE.

Table 11. Economic Impacts of Production from a Typical Oil and Gas Well Wyoming (2010).

Estimated Activity	Conventional Well
Direct effect	$2,455,087
Indirect effect	$394,370
Induced effect	$540,128
Total Economic Activity	$3,389,585
Employment (AJE)	
Direct Annual AJE	9.7
Indirect and Induced AJE	6.9
Total AJE	16.6
Total Labor Income	$1,248,712
Average Labor Income per AJE	$75,224

Sources: IMPLAN 2010, Census Bureau 2012b

Table 12 summarizes the top ten sectors impacted through the production effects of a typical oil and gas well in Wyoming. These include direct, indirect, and induced effects. These sectors are economically tied to the production activities of oil and gas wells.

Table 12. Top Ten Sectors Impacted Per Well in Operation in Wyoming.

Sector #	Description	Total Employment	Total Labor Income	Total Value Added	Total Output
20	Extraction of oil and natural gas	9.7	$983,575	$1,793,521	$2,456,334
413	Food services and drinking places	0.7	$11,839	$17,933	$34,429
39	Maintenance and repair construction of nonresidential structures	0.5	$28,273	$34,792	$65,287
360	Real estate establishments	0.4	$4,165	$30,315	$34,086
29	Support activities for oil and gas operations	0.3	$24,705	$25,917	$63,125
394	Offices of physicians, dentists, and other health practitioners	0.3	$24,816	$25,621	$38,659
329	Retail Stores - General merchandise	0.2	$6,060	$9,441	$12,329
356	Securities, commodity contracts, investments, and related activities	0.2	$652	$689	$27,075
324	Retail Stores - Food and beverage	0.2	$5,639	$8,134	$11,093
398	Nursing and residential care facilities	0.2	$6,296	$7,242	$10,410

Source: IMPLAN 2010

Tables 13 and 14 show the annual and total economic impacts for the proposed projects undergoing the NEPA process in Wyoming. The number of wells that are proposed to be producing on an annual basis and total project economic activity are presented. Annual and the lifetime production effects are shown for each project.

Table 13. Annual Estimated Economic Activity from Gas and Oil Well Production for Wyoming by Project.

Proposed Project	Total Wells Proposed	Annual Wells Proposed for Production	Direct Effects	Indirect Effects	Induced Effects	Total Annual Economic Activity	Total Project Economic Activity
Moxa Arch Infill Drilling Project EIS	1,861	186	$456,646,229	$73,352,870	$100,463,765	$630,462,864	$6,308,018,222
Beaver Creek Coal Bed NG Development Project EIS	228	36	$88,383,141	$14,197,330	$19,444,600	$122,025,070	$772,825,446
Moneta Divide EIS	4,250	295	$724,250,739	$116,339,229	$159,337,693	$999,927,660	$14,405,737,476
LaBarge Platform Infill OG EIS	838	60	$147,305,235	$23,662,216	$32,407,666	$203,375,117	$2,840,472,472
Normally Pressure Lance Natural Gas Development Project EIS	3,500	350	$859,280,538	$138,029,594	$189,044,720	$1,186,354,851	$11,863,548,510
Continental Divide-Creston Natural Gas Project EIS	8,950	600	$1,473,052,350	$236,622,160	$324,076,663	$2,033,751,173	$30,336,788,332
Table Rock Oil and Gas EA	88	6	$14,730,524	$2,366,222	$3,240,767	$20,337,512	$298,283,505
Hiawatha Regional Energy Development Project EIS	4,208	175	$429,640,269	$69,014,797	$94,522,360	$593,177,425	$14,263,374,894
Plains Exploration Eagles Prospect and Noble Basin Oil and Gas Master Development Plan	136	12	$29,461,047	$4,732,443	$6,481,533	$40,675,023	$460,983,599
Totals	**24,059**	**1,720**	**$4,222,750,070**	**$678,316,860**	**$929,019,767**	**$5,830,086,696**	**$81,550,032,456**

Source: IMPLAN 2010

Table 14. Annual Estimated Employment from Oil and Gas Production for Wyoming by Project.

Proposed Project	Direct Annual AJE	Indirect and Induced AJE	Total AJE	Total Labor Income
Moxa Arch Infill Drilling Project EIS	1,804.2	1,283.4	3,088	$232,260,456
Beaver Creek Coal Bed NG Development Project EIS	349.2	248.4	598	$44,953,637
Moneta Divide EIS	2,861.5	2,035.5	4,897	$368,370,078
LaBarge Platform Infill OG EIS	582.0	414.0	996	$74,922,728
Normally Pressure Lance Natural Gas Development Project EIS	3,395.0	2,415.0	5,810	$437,049,245
Continental Divide-Creston Natural Gas Project EIS	5,820.0	4,140.0	9,960	$749,227,277
Table Rock Oil and Gas EA	58.2	41.4	100	$7,492,273
Hiawatha Regional Energy Development Project EIS	1,697.5	1,207.5	2,905	$218,524,622
Plains Exploration Eagles Prospect and Noble Basin Oil and Gas Master Development Plan	116.4	82.8	199	$14,984,546
Totals	16,684.0	11,868.0	28,552	$2,147,784,861

Source: IMPLAN 2010

Table 15 and Figure 8 summarize the opportunity costs associated with the delay of oil and gas production in Wyoming annually; and at 5-year and 10-year impacts. A 10-year time period is used because development would occur over at least a 10-year period for all of the proposed projects (with exception to the Beaver Creek EIS which will take place over 9 years, proposing 36 wells per year).

Table 16 and Figure 9 summarize estimated tax and royalty revenue that is lost in the state of Wyoming while these projects are being delayed.

Table 15. Economic Impacts of Delays of Oil and Gas Production in Wyoming

	Project Delay		
Impact	1-year	5-year	10-year
Labor Income	$2,147,784,861	$10,738,924,303	$21,477,848,605
Total AJE	28,552	142,760	285,520
Economic Output	$5,830,086,696	$29,150,433,481	$58,300,866,962

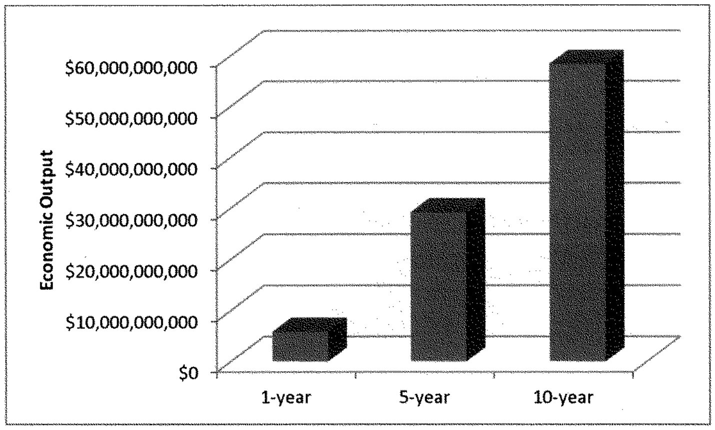

Figure 8. Economic Impacts of Delays of Oil and Gas Production in Wyoming.

Table 16. Tax Revenue and Royalty Impacts of Delays of Oil and Gas Production in Wyoming.

	Project Delay		
Impact	1-year	5-year	10-year
Ad Valorum Tax	$38,620,286	$193,101,431.56	$386,202,863.13
Severance Tax	$22,634,161	$113,170,805.85	$226,341,611.71
Federal Mineral Royalties	$21,290,513	$106,452,566.40	$212,905,132.80
Total Royalty and Tax Revenue	$82,544,961	$412,724,804	$825,449,608

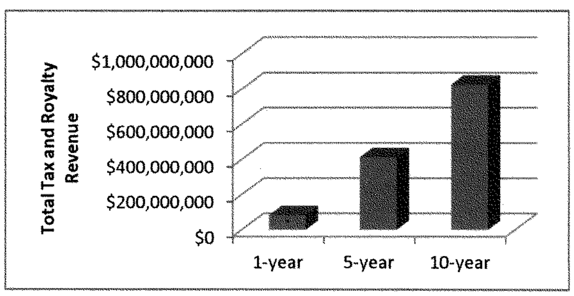

Figure 9. Tax Revenue and Royalty Impacts of Delays of Oil and Gas Production in Wyoming.

DEVELOPMENT OF OIL AND GAS WELLS IN UTAH

Table 17 shows the economic impacts of a typical well developed in Utah. IMPLAN was used to estimate indirect and induced effects. Development and completion of one typical oil and gas well is estimated to produce over $6 million in economic activity (spending in the economy) and provide over 27 AJEs, with an average labor income of $57,418 per AJE.

Table 17. Impacts from Development and Completion of a Typical Oil and Gas Well Utah (2010).

Estimated Activity	Conventional Well
Total Cost (direct effect)	$4,387,260
Indirect effect	$595,717
Induced Effect	$1,153,425
Total Economic Activity	**$6,136,402**
Employment (AJE)	
Direct Annual AJE	11.9
Indirect and Induced AJE	15.2
Total AJE	**27.1**
Total Labor Income	**$1,556,032**
Average Labor Income per AJE	**$57,418**

Sources: IMPLAN 2010, EIA 2012c

Table 18 summarizes the top ten sectors impacted through the development of a typical oil and gas well in Utah. These include direct, indirect, and induced effects. These sectors are economically tied to the drilling activities of oil and gas well development.

Table 18. Top Ten Sectors Impacted Per Well Developed in Utah.

Sector #	Description	Total Employment	Total Labor Income	Total Value Added	Total Output
28	Drilling oil and gas wells	11.9	$976,937	$3,354,900	$4,387,260
413	Food services and drinking places	1.2	$20,950	$31,984	$60,848
360	Real estate establishments	1.1	$11,026	$80,801	$90,853
394	Offices of physicians, dentists, and other health practitioners	0.6	$37,548	$38,773	$63,082
319	Wholesale trade businesses	0.6	$38,519	$68,293	$87,708
356	Securities, commodity contracts, investments, and related activities	0.6	$6,755	$7,116	$77,828
369	Architectural, engineering, and related services	0.6	$34,037	$34,595	$59,653
355	Nondepository credit intermediation and related activities	0.5	$26,036	$30,536	$57,845

Table 18. Top Ten Sectors Impacted Per Well Developed in Utah (Continued).

Sector #	Description	Total Employment	Total Labor Income	Total Value Added	Total Output
367	Legal services	0.4	$28,812	$44,159	$53,236
381	Management of companies and enterprises	0.4	$29,535	$33,886	$58,669

Source: IMPLAN 2010

Tables 19 and 20 show the annual and total project economic impacts for the proposed projects undergoing the NEPA process in Utah. The number of wells that are proposed to be developed on an annual basis and total project economic activity are presented. The total project economic activity represents the estimated economic impact of each project at the aggregate level over the course of the project's lifetime.

Table 19. Annual Estimated Economic Activity from Gas and Oil Well Development and Completion for Utah by Project.

Proposed Project	Total Wells Proposed	Annual Wells Proposed for Development	Total Cost (Direct Effect)	Indirect Effect	Induced Effect	Total Annual Economic Activity	Total Project Economic Activity
Gasco Energy Uintah Basin NG Development Project EIS	1,538	100	$438,726,000	$59,571,743	$115,342,502	$613,640,244	$9,437,786,960
Anadarko Greater Natural Buttes EIS	3,496	358	$1,570,639,080	$213,266,839	$412,926,156	$2,196,832,075	$21,452,862,946
Greater Chapita Wells NG Infill EIS	7,028	469	$2,057,624,940	$279,391,474	$540,956,333	$2,877,972,747	$43,126,636,381
Monument Butte Area OG Development Project EIS	5,750	250	$1,096,815,000	$148,929,357	$288,356,254	$1,534,100,611	$35,284,314,056
XTO's Little Canyon Field EA	510	73	$320,269,980	$43,487,372	$84,200,026	$447,957,378	$3,129,565,247
XTO's Hill Creek Unit EA	137	19	$83,357,940	$11,318,631	$21,915,075	$116,591,646	$840,687,135
XTO's River Bend Unit Infill Development EA	368	65	$285,171,900	$38,721,633	$74,972,626	$398,866,159	$2,258,196,100

Table 19. Annual Estimated Economic Activity from Gas and Oil Well Development and Completion for Utah by Project (Continued).

Proposed Project	Total Wells Proposed	Annual Wells Proposed for Development	Total Cost (Direct Effect)	Indirect Effect	Induced Effect	Total Annual Economic Activity	Total Project Economic Activity
Big Pack Natural Gas EA	664	66	$289,559,160	$39,317,350	$76,126,051	$405,002,561	$4,074,571,223
Southam Canyon Gas Field EA	269	25	$109,681,500	$14,892,936	$28,835,625	$153,410,061	$1,650,692,258
South Unit Oil and Gas Development EIS	400	20	$87,745,200	$11,914,349	$23,068,500	$122,728,049	$2,454,560,978
Totals	20,160	1,445	$6,339,590,700	$860,811,684	$1,666,699,148	$8,867,101,532	$123,709,873,283

Source: IMPLAN 2010

Table 20. Annual Estimated Employment from Oil and Gas Well Development and Completion for Utah by Project.

Proposed Projects	Direct Annual AJE	Indirect and Induced AJE	Total AJE	Total Labor Income
Gasco Energy Uintah Basin NG Development Project EIS	1,190.0	1,520.0	2,710	$155,603,200
Anadarko Greater Natural Buttes EIS	4,260.2	5,441.6	9,702	$557,059,456
Greater Chapita Wells NG Infill EIS	5,581.1	7,128.8	12,710	$729,779,008
Monument Butte Area OG Development Project EIS	2,975.0	3,800.0	6,775	$389,008,000
XTO's Little Canyon Field EA	868.7	1,109.6	1,978	$113,590,336
XTO's Hill Creek Unit EA	226.1	288.8	515	$29,564,608
XTO's River Bend Unit Infill Development EA	773.5	988.0	1,762	$101,142,080
Big Pack Natural Gas EA	785.4	1,003.2	1,789	$102,698,112
Southam Canyon Gas Field EA	297.5	380.0	678	$38,900,800
South Unit Oil and Gas Development EIS	238.0	304.0	542	$31,120,640
Totals	17,195.5	21,964.0	39,160	$2,248,466,240

Source: IMPLAN 2010

Table 21 and Figure 10 summarize the opportunity costs associated with the delay of oil and gas development in Utah annually; and with 5-year impacts and 10-year impacts. A 10-year time period is used because development would occur over at least a 10-year period for all of the proposed projects (with exception to the XTO's Little Canyon Field EA which will take place over approximately 7 years, proposing 73 wells per year).

Table 21. Economic Impacts of Delays of Oil and Gas Development in Utah.

	Project Delay		
Impact	1-year	5-year	10-year
Labor Income	$2,248,466,240	$11,242,331,200	$22,484,662,400
Total AJE	39,160	195,798	391,595
Economic Output	$8,867,101,532	$44,335,507,662	$88,671,015,324

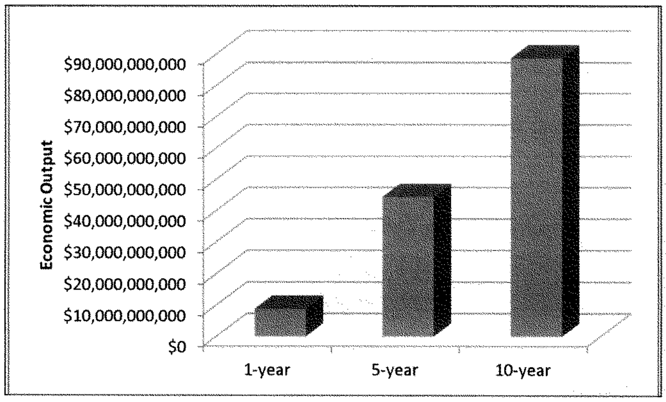

Figure 10. Economic Impacts of Delays of Oil and Gas Development in Utah.

ESTIMATED ECONOMIC IMPACTS OF OIL AND GAS PRODUCTION IN UTAH

Table 22 shows the economic impacts of a typical oil or gas well producing in Utah. IMPLAN was used to estimate indirect and induced effects. One typical oil and gas well is estimated to produce over $2.6 million in economic activity annually and provide over 16 AJEs per year in production, with an average labor income of $60,586 per AJE.

Table 22. Economic Impacts of Production from a Typical Oil and Gas Well in Utah (2010).

Estimated Activity	Conventional Well
Direct effect	$1,611,814
Indirect effect	$301,714
Induced effect	$721,956
Total Economic Activity	**$2,635,484**
Employment (AJE)	
Direct Annual AJE	7.2
Indirect and Induced AJE	8.9
Total AJE	**16.1**
Total Labor Income	**$975,441**
Average Labor Income per AJE	**$60,586**

Source: IMPLAN 2010, U.S. Census Bureau 2012a

Table 23 summarizes the top ten sectors impacted through the production effects of a typical oil and gas well in Utah. These include direct, indirect, and induced effects. These sectors are economically tied to the production activities of oil and gas wells.

Table 23. Top Ten Sectors Impacted Per Well in Operation in Utah.

Sector #	Description	Total Employment	Total Labor Income	Total Value Added	Total Output
20	Extraction of oil and natural gas	7.2	$646,475	$1,177,154	$1,612,182
413	Food services and drinking places	0.7	$12,590	$19,221	$36,567
360	Real estate establishments	0.6	$6,019	$44,109	$49,597
39	Maintenance and repair construction of nonresidential structures	0.6	$27,221	$34,569	$68,067
394	Offices of physicians, dentists, and other health practitioners	0.4	$23,209	$23,966	$38,991
356	Securities, commodity contracts, investments, and related activities	0.3	$3,365	$3,545	$38,770
355	Nondepository credit intermediation and related activities	0.3	$13,778	$16,160	$30,612
319	Wholesale trade businesses	0.2	$14,967	$26,537	$34,081
397	Private hospitals	0.2	$12,743	$13,915	$26,674
324	Retail Stores - Food and beverage	0.2	$6,238	$9,011	$12,290

Source: IMPLAN 2010

Tables 24 and 25 show the annual and aggregate economic impacts for the proposed projects undergoing the NEPA process in Utah. The number of wells that are proposed to be producing on an annual basis and total project economic activity are presented. Annual and the lifetime production effects are shown for each project.

Table 24. Annual Estimated Economic Activity from Gas and Oil Well Production for Utah by Project

Proposed Project	Total Wells Proposed	Annual Wells Proposed for Production	Direct Effects	Indirect effects	Induced Effects	Total Annual Economic Activity	Total Project Economic Activity
Gasco Energy Uintah Basin NG Development Project EIS	1,538	100	$161,181,400	$30,171,400	$72,195,600	$263,548,400	$4,053,374,392
Anadarko Greater Natural Buttes EIS	3,496	358	$577,029,412	$108,013,612	$258,460,248	$943,503,272	$9,213,652,064
Greater Chapita Wells NG Infill EIS	7,028	469	$755,940,766	$141,503,866	$338,597,364	$1,236,041,996	$18,522,181,552
Monument Butte Area OG Development Project EIS	5,750	250	$402,953,500	$75,428,500	$180,489,000	$658,871,000	$15,154,033,000
XTO's Little Canyon Field EA	510	73	$117,662,422	$22,025,122	$52,702,788	$192,390,332	$1,344,096,840
XTO's Hill Creek Unit EA	137	19	$30,624,466	$5,732,566	$13,717,164	$50,074,196	$361,061,308
XTO's River Bend Unit Infill Development EA	368	65	$104,767,910	$19,611,410	$46,927,140	$171,306,460	$969,858,112
Big Pack Natural Gas EA	664	66	$106,379,724	$19,913,124	$47,649,096	$173,941,944	$1,749,961,376
Southam Canyon Gas Field EA	269	25	$40,295,350	$7,542,850	$18,048,900	$65,887,100	$708,945,196
South Unit Oil and Gas Development EIS	400	20	$32,236,280	$6,034,280	$14,439,120	$52,709,680	$1,054,193,600
Totals	20,160	1,445	$2,329,071,230	$435,976,730	$1,043,226,420	$3,808,274,380	$53,131,357,440

Source: IMPLAN 2010

Table 25. Annual Estimated Employment from Oil and Gas Production for Utah by Project

Proposed Project	Direct Annual AJE	Indirect and Induced AJE	Total AJE	Total Labor Income
Gasco Energy Uintah Basin NG Development Project EIS	720.0	890.0	1,610	$97,544,100
Anadarko Greater Natural Buttes EIS	2,577.6	3,186.2	5,764	$349,207,878
Greater Chapita Wells NG Infill EIS	3,376.8	4,174.1	7,551	$457,481,829
Monument Butte Area OG Development Project EIS	1,800.0	2,225.0	4,025	$243,860,250
XTO's Little Canyon Field EA	525.6	649.7	1,175	$71,207,193
XTO's Hill Creek Unit EA	136.8	169.1	306	$18,533,379
XTO's River Bend Unit Infill Development EA	468.0	578.5	1,047	$63,403,665
Big Pack Natural Gas EA	475.2	587.4	1,063	$64,379,106
Southam Canyon Gas Field EA	180.0	222.5	403	$24,386,025
South Unit Oil and Gas Development EIS	144.0	178.0	322	$19,508,820
Totals	10,404.0	12,860.5	23,264.5	$1,409,512,245

Source: IMPLAN 2010

Table 26 and Figure 11 summarize the opportunity costs associated with the delay of oil and gas production in Utah annually; and with 5-year and 10-year impacts. A 10-year time period is used because development would occur over at least a 10-year period for all of the proposed projects (with exception to the XTO's Little Canyon Field EA which will take place over approximately 7 years, proposing 73 wells per year).

Table 26. Economic Impacts of Delays of Oil and Gas Production in Utah

	Project Delay		
Impact	1-year	5-year	10-year
Labor Income	$1,409,512,245	$7,047,561,225	$14,095,122,450
Total AJE	23,265	116,323	232,645
Economic Output	$3,808,274,380	$19,041,371,900	$38,082,743,800

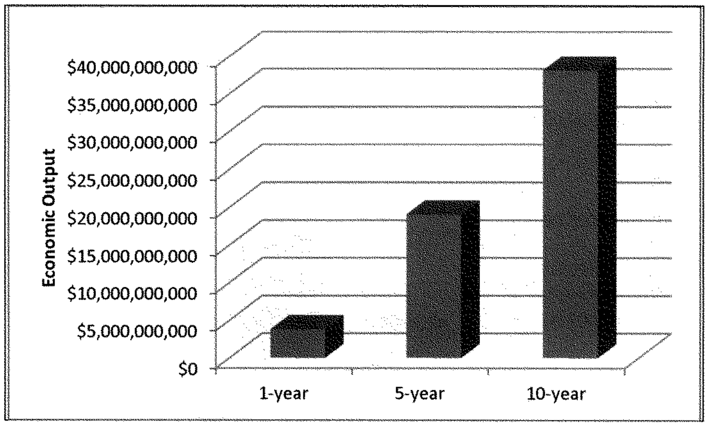

Figure 11. Economic Impacts of Delays of Oil and Gas Production in Utah

Table 27 and Figure 12 summarize estimated tax and royalty revenue in Utah that is lost while these projects are being delayed.

Table 27. Tax Revenue and Royalty Impacts of Delays of Oil and Gas Production in Utah

	Project Delay		
Impact	1-year	5-year	10-year
Ad Valorum Tax	$8,807,114	$44,035,572	$88,071,144
Severance Tax	$6,672,781	$33,363,903	$66,727,806
Conservation Fees	$656,767	$3,283,837	$6,567,673
Federal Mineral Royalties	$40,645,585	$203,227,924	$406,455,848
Total Royalty and Tax Revenue	$56,782,247	$283,911,235	$567,822,471

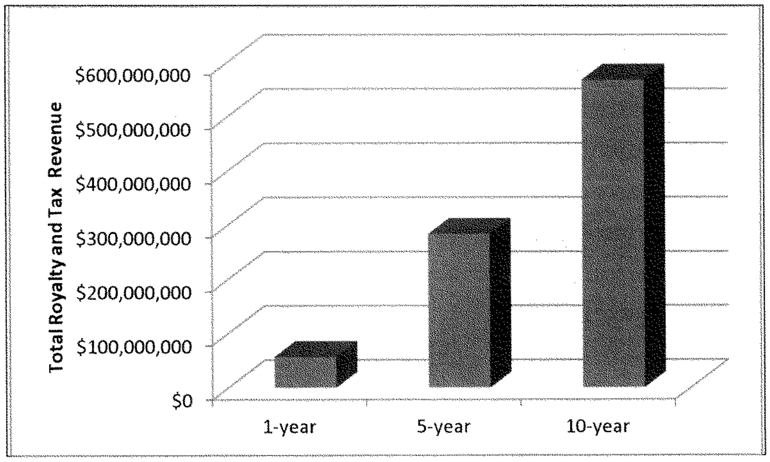

Figure 12. Tax Revenue and Royalty Impacts of Delays of Oil and Gas Production in Utah

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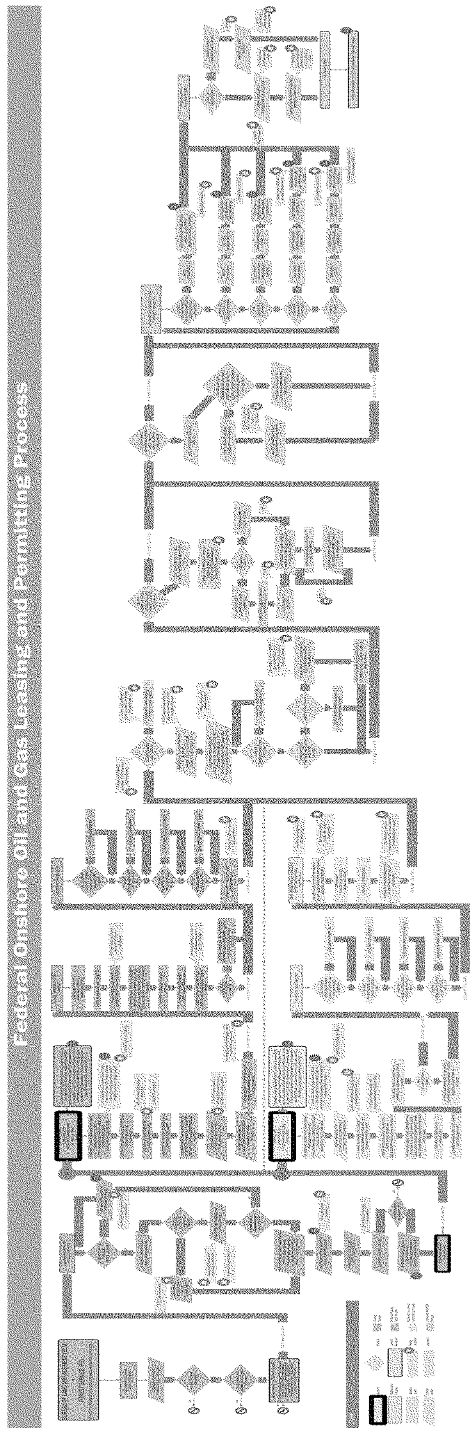
Federal Onshore Oil and Gas Leasing and Permitting Process

U.S. Senate Committee on Energy and Natural Resources
May 19, 2015 Hearing: Energy Supply Legislation
Questions for the Record Submitted to Mr. Brent Sheets

Questions from Senator Murkowski

Question 1: What can be done to attract commercial investment in geothermal sites around Alaska and the rest of the country, similar to what you've seen in Nome?

The key to attracting commercial investment to low-temperature geothermal sites is to reduce financial uncertainty associated with both resource exploration and initial development. Geothermal is unlike other renewable resources such as solar and wind – once a viable resource has been identified and developed, it provides much higher value as a renewable resource because it is non-variable in nature. On the other hand, it is far more difficult and expensive to assess in early stage of evaluation and development, and hence financially riskier.

The DOE Geothermal Technologies Program (GTP) has been very proactive in developing programs to mitigate these risks at the local and regional level. In our experience, the DOE-GTP has best embodied a successful private sector – public partnership model for developing projects that have a meaningful impact on society. Two specific programs that have been highly effective in fostering exploration projects like those at Chena Hot Springs and Pilgrim Hot Springs in Alaska are:

- Geothermal Exploration and Resource Definition (GRED) - industry cost-shared drilling program will support the evaluation of identified geothermal resources
- Play Fairway Analysis funding to support regional exploration efforts leading to targeted prospect level drilling

Funding for R&D to explore for and identify subsurface signals that will ascertain geothermal resource "hot spots" will lead to better drilling targets, and thus allow for more efficient use of (GRED) drilling funds. For example, the Pilgrim Hot Springs was originally funded through DOE as a demonstration site of a low-cost remote sensing exploration technique developed by the University of Alaska Fairbanks Geophysical Institute.

Finally, and perhaps most critically, reinstatement of the federal tax credit for geothermal development would incentivize private sector development of economically marginal resources, many of which are located in the Western US including Alaska. The 20-year firm PPA to develop Pilgrim Hot Springs was dependent on these tax credits, which have now expired.

U.S. Senate Committee on Energy and Natural Resources
May 19, 2015 Hearing: Energy Supply Legislation
Questions for the Record Submitted to Mr. Brent Sheets

Question 2: In general, many consider traditional geothermal to be a mature technology, but do you think that there are still R&D needs for low temperature geothermal, and is low temperature geothermal still an untapped resource in Alaska and other parts of the country?

In short – yes, absolutely. When the Chena Hot Springs site was developed less than a decade ago, the general consensus was that the temperatures available at this site were too low for commercial power generation. Alaska has long been a progenitor of geothermal technologies – the first ORC system in the world was tested at Manley Hot Springs in the late 1970's. Areas for additional advancement/research include:

- Mineral extraction from geothermal brines.
- Advanced direct use research including promising work on industrial waste heat (including rejected heat from diesel generators). Of particular interest to Alaska would be smaller systems 50kW or less.
- Additional work that needs to be conducted on improving the efficiency of energy conversion for lower temperature resources and optimizing CHP geothermal applications.
- Large-scale (*e.g.*, campus or installation-wide) fully integrated direct use applications have the potential to offset thermal loads currently being supplied by the combustion of fossil fuels.

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Question 3: Alaska demonstrated three in river turbines over the summer. What kind of broader use or recognition has this technology seen since then?

Two of the companies that demonstrated turbines last summer are returning to conduct additional tests of turbines after successful generation of power during 2015 (Oceana and ORPC). ORPC has negotiated an agreement with the power company serving Igiugig to have their hydrokinetic turbine remain in the Kvichak River as the first commercial hydrokinetic turbine operation in Alaska. Oceana is working with ACEP to improve their device for an Alaskan market.

In addition, Gus Simiao, an economist working for Brown University (developer of a hydrokinetic technology funded by DOE) has done an extensive assessment of the economic potential of deploying hydrokinetic turbines to provide power to remote communities along major Alaskan rivers. One of his interesting conclusions is that deploying hydrokinetic turbines in Alaskan rivers is potentially economic as the power that is produced would be as much during the short Alaskan summer as a turbine located most tidal zones. This occurs because tidal turbine power production varies with tidal stage whereas river power is relatively continuous throughout the summer.

Finally, there continues to be interest in investigation the use of wave energy in Yakutat and there is quite a lot of interest in utilizing the debris diversion technology developed by the Alaska Hydrokinetic Energy Research Center (a component of the Alaska Center for Energy and Power at the University of Alaska Fairbanks) to protect surface deployed turbines from floating debris that is common in all major rivers that flow through wooded landscapes.

Testimony Submitted to

United State Senate

Committee on Energy and Natural Resources

by

Advanced Energy Management Alliance

Chairman Murkowski, Ranking Member Cantwell, and members of the Committee, thank you for the opportunity to submit written testimony for the record regarding numerous bills related to energy efficiency, infrastructure, and supply that together can create a vision for and guide our nation's overarching energy policy in the coming years. The Advanced Energy Management Alliance ("AEMA")[1] applauds this effort and looks forward to serving as a resource as a final bipartisan bill is crafted.

AEMA is an association of demand response providers of commercial, industrial, and residential services; consumers that use demand response and advanced energy management tools to reduce the cost of energy; and organizations that provide services and choices to these consumers and providers. Our members are united in an effort to overcome barriers to nationwide use of demand response and other energy management technologies for a more efficient, reliable, and resilient grid.

While our electric grid is considered an engineering marvel, new technologies, applications and business models are changing the way it operates and the manner in which consumers interact with the system. Given the increasing demand for electricity, public policy must allow for innovative applications and technologies to become part of the grid infrastructure

[1] Advanced Energy Management Alliance website: http://aem-alliance.org

in ways that do not compromise the system, but instead provide additional resources. Many of the legislative proposals move toward that goal.

AEMA supports many of the bills introduced by Members on both sides of the aisle. In particular, we support bills that call for grid modernization, such as S. 1207, for transformative grid innovation; S. 1232, the Smart Grid Act of 2015; and S. 1243, the Grid Modernization Act of 2015. Demand response and advanced energy management will be key elements in a smarter grid that can enhance consumer choice while preventing increased customer expense. Allowing for utilities to invest in technologies and applications that provide more flexible solutions will be important to assuring that their business models can evolve and remain robust. We also support including demand response as part of the menu of distributed energy resources states should consider, as in S. 1213, Free Market Energy Act and S. 1201, Clean Distributed Energy Integration Act.

AEMA believes that, with increasingly smarter grid communication and control technologies, the distribution side of the grid can increasingly provide resources that balance the supply side in real time. AEMA agrees with the goals of S. 1044, Access to Consumer Energy Information (E-Access) Act, that would allow for access to energy data by consumers and authorized third parties, spurring innovation in advanced energy products and enabling more informed choices on energy use. We are generally supportive of programs that incentivize energy efficiency—as in S. 523 for school retrofits, S. 600 for non-profit retrofits, S. 720 for strengthened federal energy efficiency, S. 1346 for innovation to reduce energy cost in high heating cost regions—assuming that demand response and advanced energy management are able to participate in those programs. AEMA also supports efforts to increase system resilience as in S. 888 to encourage regional resilience partnerships and S. 1227 to encourage microgrid development in remote communities. S. 1258, Local Energy Supply and Resiliency Act of 2015, would provide technical assistance and grants to entities considering deployment of demand response and other advanced energy management programs. All of these bills represent varying ways in which innovation can participate to improve and modernize our grid—through local incentives, state regulatory guidance, and bulk power market policies.

AEMA would draw attention to S. 1222, the Continuity of Electric Capacity Resources Act which defines "electric capacity resource" as "an electric generating resource, as measured by the maximum load-carrying ability of the resource, exclusive of station use and planned, unplanned, or other outage or derating." Based on the current capacity market and operational evidence in organized and regional transmission systems, "electric capacity resource" should have a far broader definition to include any flexible resource (like demand response and other advanced energy management tools such as energy efficiency, distributed generation and storage) that can commit to providing capacity when called upon.

A stark example of such a response was during the 2014 Polar Vortex when demand response was able to supply critical resources to PJM that stabilized the grid at a time when many generators were unavailable. These events demonstrated that rather than investing in additional generation, enabling flexible resources—in this case, demand response—could ensure continued reliability and cost-effectiveness.

In a report titled "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events"[2], PJM Interconnection asserted that, while the electric grid was stressed during the Polar Vortex, demand response played an important role in maintaining the reliability of the system. During the Polar Vortex, PJM called on demand response three times – the morning and evening of January 7 and the morning of January 8 throughout the Regional

[2] Report dated May 8, 2014: http://www.pjm.com/documents/reports.aspx, report can be downloaded here.

Transmission Organization ("RTO"). The report states that, "demand response, although not required to participate during the winter this year, responded each time it was called upon." In fact, the report confirmed that demand response "exceeded PJM's expectations in real time." AEMA believes that this experience demonstrates the value of demand response as a fast-acting, responsive resource that can help independent system operators and electric utilities maintain grid reliability.

Limiting capacity markets to traditional generation resources would essentially remove the ability of flexible resources like demand response to be called upon to respond. In addition, customers would be limited in their ability to save; demand response and energy efficiency have lowered consumer energy costs in PJM by $16 billion, based on the State of the Market 2014.[3] In the 2017/2018 auction, demand response is estimated to be the majority of the customer savings from efficiency and demand response combined--close to $9.3 billion.[4]

In summary, AEMA is in agreement that the Committee should continue to develop bipartisan legislation that moves our electric grid into the future, spurring continued innovation to reduce cost, increase reliability and resilience, and allow for consumer engagement and choice. Including demand response and advanced energy management solutions as part of that smarter grid will provide the appropriate tools for local, state and regional entities to take full advantage of technologies and applications and make that 21st century grid a reality.

We look forward to addressing any questions the Committee has about AEMA, demand response, and advanced energy solutions more generally. Thank you for the opportunity to submit this testimony.

[3] PJM Market Monitor, State of the Market 2014, http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2014/2014q2-som-pjm.pdf
[4] *Analysis of the 2017/2018 RPM Base Residual Auction*, Marketing Analytics, October 6, 2014, page 6: http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf

Respectfully submitted by,

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THE POWER OF Alaska

ALASKA INDEPENDENT POWER PRODUCERS ASSOCIATION

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May 18, 2015

The Honorable Lisa Murkowkski
Alaska Senator, U.S Senate
709 Hart Senate Building
Washington, D.C. 20510

RE: Alaska Independent Power Producer Association Strong Support for S. 1236 Hydropower Improvement Act.

Dear Sen. Murkowski,

Thank you for your leadership and vision to create a bright energy future for America. Our organization that is comprised of Alaska's Independent Power Producers strongly support your Hydropower Improvement Act.

S 1236 reduces the risk for investing in America's hydropower by reducing the risk of investment and providing certainty for credible developers by providing the Federal Energy Regulatory Commission guidance and discretion commensurate with America's need to develop renewable energy to provide our nation energy security and a cleaner environment.

Further, hydropower is the oldest form of renewable energy known to humankind. Ancient cultures harnessed hydropower to grind grain and provide mechanical advantage. Therefore, it is ironic that our Congress has not allowed America's hydropower resources to be federally classified and defined as "renewable". We commend your leadership for moving our nation to the common sense and common-man understanding that hydropower is renewable and that our federal government should take this same common sense approach.

Please let us know how we can assist you in ensuring that the S 1236 is timely passed by Congress and enacted into law.

Regards,

Duff Mitchell
Executive Director

Written Testimony
Hydropower Modernization Act, S.1236
Committee on Energy and Natural Resources Hearing, May 19, 2015

Submitted June 3rd, 2015
Kevin Colburn, National Stewardship Director, American Whitewater

Chair Murkowski, Ranking Member Cantwell, and members of the committee:

American Whitewater appreciates having the opportunity to provide written testimony in relation to the May 19th Committee Hearing regarding Hydropower Modernization and to share our perspective on and experience with the Federal Energy Regulatory Commission's (FERC) hydropower relicensing process.

American Whitewater is a national 501(c)(3) non-profit organization with a mission "to conserve and restore America's whitewater resources and to enhance opportunities to enjoy them safely." With over 5,700 members and 100 affiliate clubs, we represent the conservation interests of tens of thousands of whitewater enthusiasts across the country. Since the early 1990's, we have actively participated in the FERC hydropower licensing and relicensing process and restored flows to rivers across the country impacted by private and municipal hydropower dams. Through the Federal Power Act, our efforts have brought life back to rivers that had been severely impacted by hydropower for decades. In our work, we strive to balance society's need for power with what flowing rivers can also do for fish, wildlife and our communities. As the rivers have come back, so have local economies that depend on outdoor recreation, including paddlesports, fishing, and other river-dependent recreation.

I. American Whitewater Opposes S.1236

We strongly oppose S.1236. If enacted, this bill would have significant negative impacts on outdoor recreation and its associated local economic benefits, and will remove opportunities for meaningful local public involvement in hydropower licensing.

A. The bill federalizes all authority over hydropower development in the country, centralizing it in Washington DC at the Federal Energy Regulatory Commission, an agency that has limited capacity to adequately address local interests and values, including recreation, fish and wildlife.

S.1236 vests FERC with new authority and additional controls over management decisions affecting rivers. This approach will not fulfill one of the intended goals of the proposed legislation, which is to reduce costs and improve efficiency. Instead, it will have the opposite effect by increasing costs and controversy, resulting in mounting delays and adverse impacts to local communities.

We agree with FERC Office of Energy Projects Director Ann Miles, who recently provided testimony on similar legislation before the House Energy and Commerce Committee, that the attitude and approach of the hydropower license applicant has a significant role in determining whether the licensing process is short or long, simple or complex.[1] In our experience, project review and license issuance can happen very quickly and efficiently when the license applicant engages stakeholders early and often, builds relationships in the local community, and establishes an environment where stakeholders are engaged in the regulatory proceeding. We have participated in dozens of settlement agreements where this has been the case, and the end result has been hydropower licenses that, in many cases, enhance electricity production, improve fishery resources, and create new opportunities for river-based recreation.

Local citizens and resource experts are intimately familiar with the river and are better suited to craft creative solutions that meet local needs. FERC staff only have the ability to participate in one or two site visits, and typically have minimal experience and familiarity with local resources and values. Shifting the power away from local citizens and resource experts to a DC-based federal regulator, as S. 1236 outlines, will not only hinder FERC's ability to process hydropower licenses in a timely fashion, but also result in outcomes that are detrimental to local communities.

B. The bill removes State authority and local control over State water quality standards that protect water quality for recreation, aquatic resources and local communities.

Section 401 of the Clean Water Act has given the 50 states and numerous Tribes the authority to include conditions in FERC licenses so that hydropower dams will comply with State Water Quality Standards. American Whitewater opposes S.1236 because it effectively nullifies this important provision. Section 401 water quality certification authority is a critical component that protects the interests of states by giving them an effective role in making decisions regarding the potential water quality and quantity impacts of hydropower projects. These impacts can harm water-based recreation, important local fishery resources, aesthetics, and other local benefits. In dozens of projects we have worked on, the state water quality certification has been used to protect the interests of local communities in recreation and aesthetics, and to protect and enhance fishery resources.

C. The bill eliminates the ability of federal agencies that oversee national forests, wildlife refuges, Indian reservations, and federal locks and dams

[1] Ann Miles, Testimony before the House Energy and Commerce Committee Hearing on Discussion Drafts Addressing Hydropower Regulatory Modernization and FERC Process Coordination under the Natural Gas Act, May 13, 2015, page 6. Available at: http://docs.house.gov/meetings/IF/IF03/20150513/103443/HHRG-114-IF03-Wstate-MilesA-20150513.pdf (last visited May 28, 2015).

to ensure that hydropower development will not undermine the purposes for which Congress created the reservation.

The Federal Power Act grants federal agencies authority under Section 4(e) to protect the public interest in hydropower licensing using their experience and expertise with complex topics that impact local communities. When federal agencies use this authority, the public often sees improvements in hydropower facilities and operations, including putting water back in dewatered rivers, restoring commercially valuable fisheries and providing opportunities for river-based recreation. As FERC Office of Energy Projects Director Ann Miles noted in her testimony before the House Energy and Commerce Committee,[2] FERC is required to consider complex issues such as whether a project will flood local communities or visitors have adequate public access to a reservoir or impacted river. She noted:

> "Congress determined that these matters sometimes are more than a local concern, and thus should be resolved by an entity that is required to consider the overall public interest. Therefore, I am concerned that proposed FPA section 4(j) could subordinate the general public interest to a more narrow range of considerations. In addition, as I understand this section, it would require the Commission staff to identify all state and local laws and regulations related to project shorelines and other lands. This will be time consuming and challenging across the fifty states."

American Whitewater holds similar concerns. In our experience, where Congress authorized certain federal agencies to oversee and protect the purpose of federal reservations, those agencies are best suited to understand and protect those interests.

D. The bill allows FERC to rely on outdated information to inform the decision making process.

The bill encourages FERC to use "existing studies and data" to inform decisions that relate to the impacts of hydropower development and operations on fish and wildlife, water quality, recreation and other issues relevant to the public interest. We note that existing information may be outdated or not relevant to the specific river in question, thereby utilizing scientific methods and principles that are not supported within the scientific community. Additionally, initial studies of a project can come from hydropower developers with a bias towards power generation. It is critically important to the public interest that hydropower license provisions are based on modern, impartial, place-based and science-based studies and reports that assess the impact of a hydropower project on the river.

[2] *Id* at page 13.

E. The bill limits public review of a hydropower project while extending the length of time a hydropower developer can hold onto a potential site for development.

New dams have the greatest impacts on local communities and river resources, taking away private lands through condemnation for the dam, access roads, and transmission; flooding and dewatering public trust rivers; and destroying critical habitat for fish and wildlife habitat. If anything, these impacts require more time to assess and not less. The current limits on how long a hydropower developer can hold a site saves tax dollars and community resources that would be exhaustive and wasted if a developer were permitted to hold a site for up to 16 years. Provisions in this legislation that would extend the length of time a hydropower developer could hold a potential site are not in the public interest.

F. The bill discourages investments in new renewable energy.

If passed, the bill would change the way hydropower is counted towards renewable energy. It would shift the emphasis away from instances where hydropower developers have increased efficiency or added new capacity at existing dams, and towards all hydropower. In many states, this would maintain the status quo for energy production and provide a disincentive for companies to invest in new wind, solar and other renewable energy sources. In the end, this would do little to support the goal of reducing emissions from carbon-producing energy sources or diversifying our portfolio of renewable energy resources.

This provision is not necessary, including for states with ample hydropower production. In California, the state's current RPS goal is 33% by 2030, and includes minimal amounts of existing hydropower. The state is already well on their way towards meeting this goal, and as a result, the state legislature is considering whether to increase their goal to 50% by 2030. They will be able to do so without changing how hydropower is treated within the renewable portfolio standard.

G. The bill requires resource agencies to report to Congress annually, creating an administrative burden.

The bill requires state and federal agencies to justify to Congress, on an annual basis, their reasoning and methodology for protecting the public interest from the impacts of hydropower development and operations. This includes decisions and activities to protect fish, wildlife, habitat, water quality, recreation, tribal trust obligations and public lands. Congress has already authorized these agencies to protect these aspects of the public interest. This mandate is unfunded, creating an administrative burden for these agencies.

II. The Importance of 4(e) Authority for State and Federal Agencies to Protect the Public Interest

The authorities granted to federal agencies by section 4(e) of the Federal Power Act have helped assure that hydropower operations balance our society's need for power with the values that flowing rivers also provide for fish, wildlife and our communities. Below, we provide examples from our work as a key stakeholder in the Federal Energy Regulatory Commission's hydropower relicensing process.

A. <u>Cheoah River, North Carolina, Tapoco Hydroelectric Project (P-2169)</u>

In Western North Carolina, the Cheoah River was dammed and diverted through a massive nine-mile long pipe in 1928. Because the project was built in the days before the Federal Power Act allowed state and federal resource agencies to protect water quality, fish, and recreation, the river went completely dry, except for water from a few small side streams. The Cheoah River flows through Graham County, and by the time the FERC relicensing process began in the late 1990's, it was the third poorest in North Carolina.

American Whitewater saw an opportunity to bring life back to the Cheoah River, and became a stakeholder in the relicensing process. We advocated for and secured a test release of water into the dewatered riverbed so that paddlers could explore and assess the river. We found that the Cheoah River was fantastic, utterly unique and one of the best whitewater rivers in the region. As the studies and negotiations played out, we collaborated with federal and state agencies that ultimately used their 4(e) authority to return a limited amount of water to the river.

Since the new 40-year license was issued in 2005, the Cheoah River has become a classic whitewater run. Thanks to the new license and because of 4(e) conditions implemented by resource agencies, the Cheoah has enough flow to support paddling about 18 days each year. Those days have fostered a new commercial rafting economy in Graham County and draw several hundred kayakers and canoeists. These flows have also begun to restore natural processes to the Cheoah River. The fish – and fishing – are getting better, the river is cleaner, and it is functioning once again like a healthy river. It is clear that returning water back to the river has stimulated the local economy. At the same time, the hydropower facility continues to profitably generate electricity with a majority of the river's flow, effectively balancing the power and non-power values of the river.

None of this would have happened without the very federal and state authorities granted under section 4(e) that the bill before you seeks to eliminate. The utility and FERC would not have come to this solution on their own, and without the federal agencies exercising their authority to protect the public interest, American

Whitewater would have had limited power to effectively advocate for the public interest during relicensing negotiations.

B. Deerfield River, Massachusetts, Deerfield River Hydroelectric Project (P-2323)

The Deerfield River in western Massachusetts was one of the earliest and most successful examples of a hydropower relicensing process that brought together hydropower companies, federal and state land and river resource protection agencies, conservation groups, anglers, boaters, outfitters, and the local community. When New England Power sought to relicense a series of hydropower projects stretching from the headwaters of the Deerfield River in southern Vermont to its convergence with the Connecticut River in Massachusetts, a coalition of community stakeholders and resource agencies worked with the power company and FERC to study ways in which power generation needs could be met while also protecting non-power river values for future generations. The result was an historic settlement agreement that protected lands within the project boundary and restored flows to the river. These flows have sustained aquatic habitat, provided scheduled whitewater opportunities (which spawned a robust outdoor recreation industry), and created a cold water trout fishery that provides one of the best angling opportunities in the region. State and federal resource agencies with license conditioning authority included the terms of this settlement in the 401 water quality certification and other prescriptions, which ultimately became part of the 1997 FERC license. The Settlement Agreement achieved the following results:

- Assured whitewater releases in two sections of the river for paddlers: 106 days each year in the Class III Fife Brook Section, and 32 days of releases in the Class IV Monroe Bridge Section.
- Provided free public access to the river and to project related lands.
- Installed fish passage facilities at various locations on the river.
- Implemented a wildlife enhancement program on project related lands.
- Provided new base flows for river reaches and reservoir levels upstream.
- Created a $100,000 resource protection and enhancement fund for future conservation efforts.
- Granted conservation easements on 18,000 acres of land to protect it from development.
- Continued ample profitable power generation.

Today, the Town of Charlemont has an active outdoor industry that supports the local economy, and is a very different place than it was prior to this settlement agreement. Businesses provide rafting and kayak instruction and fishing guide services, and the local community benefits from at least 50,000 tourists annually. None of these benefits could ever have been achieved by FERC alone, as would be the case under the proposed legislation. This success happened because there was a dynamic partnership among diverse parties sharing common interests, and a regulatory process where state and federal resource agencies represented local interests.

III. Federal Resource Agencies Improve the Effectiveness and Efficiency of License Implementation

Proponents of S.1236 have raised concerns about the length of time it takes for a project to either receive a new license or be relicensed. We agree that this is an important consideration, and also believe that it is equally important that license conditions be implemented in a timely and cost-effective manner after the license is issued. In our experience, hydropower license conditions are implemented much more efficiently and effectively when federal land managing agencies (USFS and BLM) use their resource area expertise and authority under the Federal Power Act. This is due to several factors, including:

- Agencies have skills and experience in meeting the recreation needs of the public, where recreation is a second or third order priority for FERC and utility companies;
- Agencies have on-the-ground knowledge of how best to meet the needs of the recreating public;
- Agencies are accustomed to working with limited budgets to deliver projects, where regulated utilities can pass cost overruns along to ratepayers.

Here, we provide an example where federal land managers were responsible for implementing recreation-based license conditions and contrast that with a situation where the utility was responsible. These projects are representative of our experiences with license implementation throughout the country.

Pit 3, 4, 5 Hydroelectric Project (P- 233) Pit River, California
4(e) Conditioning Agency: US Forest Service

American Whitewater actively participated in the relicensing proceedings for PG&E's Pit 3, 4, 5 hydropower project, which began in 2000. Working with other interested stakeholders, including the U.S. Forest Service, licensing participants reached a basic agreement in 2004 for improved instream flows, ramping rates, spring snowmelt flows and flows for whitewater recreation. Just two years later, the State Water Resources Control Board ("SWRCB") issued the 401 water quality certification for the project, and the final FERC license was issued on July 2, 2007.

Despite the fact that PG&E knew the agreed-upon parameters for the improved flows in the new license in 2004, it was not until the SWRCB released the 401 in 2006 that PG&E revealed that its release facilities were not capable of providing the required flows. PG&E requested and received a three-year grace period to allow them to upgrade their release infrastructure. This delay, which came from the licensee rather than an agency with authority to protect the public interest under Section 4(e), pushed back all of the license measures related to flow, including flows for whitewater recreation.

In contrast, a federal agency with 4(e) authority (U.S. Forest Service) led efforts to plan for and implement improvements to recreation facilities, as required by the new license. These improvements included:

- 14 River Access sites
- 3 Campgrounds
- 2 Boat Launches
- 3 Overlook Areas, 2 Other Access Sites
- 1 Reservoir Access
- 1 Ferry Crossing
- 1 Trail
- 1 Rest Area

All of these recreational facilities 1) were completed within the estimated project timeline of 5 years, 2) were constructed within the original cost estimate of $3.4 million, and 3) are utilized heavily by the public today, demonstrating that they are meeting an important recreation need within the project area.

Additionally, similar to the Cheoah and Deerfield Rivers mentioned above, the new license conditions and improved operations on the Pit 3, 4, 5 project demonstrate the importance of the public interest and Section 4(e) authority granted by the Federal Power Act. Since the new flow conditions have been implemented, the Pit River has been revitalized as a recreational resource. Whitewater boaters enjoy four to eight days of whitewater recreation each year, and anglers have seen a great improvement in the quality of the fishery. Historically, fishing on the Pit River was very good, however catch rates and fish size were in decline prior to the new license. Since the new flows were implemented, the Pit River has become one of the best trout fisheries in California. Surveys from 2014 showed that skilled guides can catch up to 12 fish per hour, and many of these fish are over 15 inches in length. Given the time it takes to retrieve and release a trout, catch rates this high equate to catching a fish on virtually every cast.

Pit 1 Hydroelectric Project (P- 2687), Pit River, California
No 4(e) Conditioning Agency

PG&E also operates the Pit 1 hydroelectric project just upstream of the Pit 3, 4, 5 project. American Whitewater also participated in the relicensing proceedings for this project, and FERC issued a new license in 2003. While the SWRCB issued a 401 water quality certification that applied to minimum instream flows and water quality issues, no land managing agencies participated in the proceedings and

American Whitewater was the only participant with an interest in restoring whitewater recreation flows and improving access.

The final license for the Pit 1 project contained several provisions to build and improve recreation facilities on the river, and PG&E was responsible for their implementation. On this project, implementing the recreation license conditions was incredibly inefficient and ineffective, both financially and in the outcome. For example, the cost to plan for and construct one river access facility with a vault toilet and 12 adjoining parking places was $1.2 million. A similar facility on Pit 3, 4, 5, where the Forest Service was managing the project, was constructed for only $42,300. Additionally, the access site at Pit 1 sees little recreational use. The location was selected by PG&E primarily because of its ease of construction and was not the preferred location recommended by American Whitewater. We believe that a significant reason for the different outcome is the fact that there was no land managing agency with 4(e) authority on the Pit 1 project.

Conclusion

American Whitewater appreciates having the opportunity to provide testimony regarding S.1236. While hydropower provides many benefits, it also comes with significant impacts. In our experience, FERC does a good job of efficiently processing license applications and working with other state and federal agencies that have specific areas of expertise and authority under existing laws and regulations. This legislation would upset that important balance and cooperative approach to hydropower licensing that effectively ensures that the interests of local communities and their interest in recreation, aesthetics, and fish and wildlife are represented. American Whitewater strongly opposes S.1236, along with any effort to diminish the ability of local citizens and public resource agencies to ensure that hydropower licenses include provisions that protect the public river resources that are important to them.

Statement for the Record
Bureau of Land Management
Department of the Interior

Senate Committee on Energy and Natural Resources

S. 562, Geothermal Exploration Opportunities Act
S. 822, Geothermal Production Expansion Act
S. 1057, Geothermal Energy Opportunities Act
S. 1226, American Helium Production Act
S. 1236, Hydropower Improvement Act
S. 1271, Fuel Loss Abatement and Royalty Enhancement Act

May 19, 2015

Introduction

The following is the Bureau of Land Management's (BLM) Statement for the Record on six bills pertaining to energy supply from our nation's onshore public lands: S. 562, the Geothermal Exploration Opportunities Act; S. 822, the Geothermal Production Expansion Act; S. 1057, the Geothermal Energy Opportunities Act; S. 1226, the American Helium Production Act; S. 1236, the Hydropower Improvement Act; and S. 1271, the Fuel Loss Abatement and Royalty Enhancement Act.

This is the second hearing the Committee has convened, with very short notice, in the last two weeks that will address a large number of significant bills. As a consequence, and given the breadth of subject matter contained in the text of the bills, the Administration has not had adequate time to conduct an in-depth analysis and receive input from the many agencies impacted, and the Department has not had sufficient time to develop the detailed, thorough testimony that is appropriate for a hearing on these matters. The following statement represents an initial review and analysis given the time constraints; however the Administration may identify additional concerns with the legislation.

Background

The BLM is responsible for protecting the resources and managing the uses of our nation's onshore public lands, which are located primarily in 12 western states, including Alaska. The BLM administers more land – over 245 million surface acres – than any other Federal agency. The BLM also manages approximately 700 million acres of onshore Federal mineral estate throughout the nation, including subsurface estate overlain by properties managed by other Federal agencies such as the Department of Defense and the U.S. Forest Service (USFS). That's more than 10 percent of the Nation's surface and nearly a third of its minerals.

The BLM manages this vast portfolio on behalf of the American people under the dual framework of multiple use and sustained yield. This means the BLM administers public lands for a broad range of uses, including renewable and conventional energy development, livestock grazing, timber production, hunting, fishing, recreation, and conservation. We manage lands with some of the most significant energy development in the world and some of North America's most wild and sacred landscapes. This unique role often puts the BLM in the middle of some of the most challenging natural resource issues facing our country, from species conservation to advancements in energy extraction. Across the country, we do this work proudly and with a special emphasis on transparency and public processes that incorporate the input and needs of the American people and of the communities in which we live and work.

As part of our mission and in accordance with the President's all-of-the-above energy strategy, the BLM is pursuing science-based, environmentally responsible development of both renewable and conventional energy resources on the nation's public lands. The BLM's activities provide critical infrastructure and energy for our nation which reduces our reliance on oil imports, by boosting our domestic energy production, while also protecting our public land and water resources, and providing important recreational opportunities that benefit local economies.

The BLM's contribution to the national energy portfolio provides a critical benefit to the U.S. economy. The Department collects billions of dollars annually for the Federal Treasury through mineral lease sale bonus bids, rents, and royalties for mineral extraction and other activities, and shares these revenues each year with states, tribes, counties, and other entities. In many states, energy production and other activities are a critical component of the local economy. For example, in fiscal year 2014, onshore Federal oil and gas royalties exceeded $3 billion, approximately half of which were paid directly to the states in which the development occurred. In the same period, tribal oil and gas royalties exceeded $1 billion with all of those revenues paid to the tribes and/or individual Indian owners of the land on which the development occurred.

Federal lands continue to boost domestic energy production in a variety of areas. The BLM works diligently to fulfill its role in securing America's energy future, coordinating closely with partners across the country to ensure that development of conventional and renewable resources occurs in the right places and that those projects are managed safely and responsibly. Secretary Jewell's 2014 mitigation strategy supports this goal by outlining key principles and actions to more effectively offset impacts of large energy development projects on public lands through the use of landscape-level planning. Advancing both development and conservation, the strategy provides greater certainty for project developers with regards to permitting and better outcomes for conservation through more effective and efficient project planning.

Conventional Energy – Secretary Jewell has made it clear that as we expand and diversify our nation's energy portfolio, the development of conventional energy resources from BLM-managed lands will continue to play a critical role in meeting our energy needs and fueling our economy. Facilitating the safe and efficient development of these resources is one of the BLM's many responsibilities and part of the Administration's broad energy strategy, outlined in the President's *Blueprint for a Secure Energy Future*. Environmentally responsible development of these resources will improve economic conditions by increasing supplies for consumers and reduce our nation's reliance on oil, while also protecting our federal lands and the environment. As part of this effort, the Department is working with various agencies in support of Executive Order 13604 to improve the performance of Federal permitting and review of infrastructure projects by increasing transparency and predictability of infrastructure permitting and reviews.

In recent years, the BLM has overseen a significant increase in oil production, while also supporting continued natural gas production. Oil production from the Federal and Indian lands for which the BLM has permitting and oversight responsibility rose twelve percent in 2014 from the previous year and is now up 81 percent since 2008 – 113 million barrels per year in 2008 to 205 million barrels per year today. By comparison, nationwide oil production over the same period increased 73 percent. The BLM is proud to be a leader in this area and of its efforts to make public lands available for oil and gas development in excess of industry demand.

Oil & Gas Pipelines – Oil and gas production is outpacing pipeline capacity and creating bottlenecks in some areas, putting a strain on existing infrastructure. The BLM is doing its part to expand the nation's pipeline infrastructure and increase the capacity available for the transport of energy resources when and where they are needed. As authorized by Section 28 of the Mineral Leasing Act (MLA), the BLM issues right-of-way (ROW) grants for oil and natural gas gathering, distribution, and transmission pipelines and related facilities. The BLM may grant MLA ROWs on any public lands, or on lands which are administered by two or more Federal agencies, except land in the National Park System and land held in trust for Indian tribes. A designated corridor is a preferred location for the placement of ROWs and the BLM actively encourages use of designated ROW corridors to streamline the authorization process. This work minimizes the proliferation of separate ROWs and promotes sharing of ROWs to the greatest extent possible, while simultaneously considering engineering and technological compatibility, national security, and land use planning. Use of existing corridors and sharing of existing ROWs for pipelines protects the quality of natural resources and prevents unnecessary environmental damage to lands and resources.

Since 2009, the BLM has participated in the approval of nine major pipeline expansion projects totaling nearly 2,000 miles of new oil and gas pipeline with nearly 1,050 of those miles crossing Federal lands. In the next 18 months, the BLM is expected to complete review and disposition of four more major pipeline projects totaling approximately 1,000 additional miles with approximately 450 of those miles across Federal lands. Work on these major oil and gas pipeline projects is in addition to the thousands of miles of smaller pipeline projects that are approved every year to transport oil and gas from production sites to the larger gathering and transportation facilities.

Renewable Energy – In the past six years, the BLM has worked to facilitate a clean energy revolution on public lands, approving scores of utility-scale renewable energy generation and transmission projects. This includes 32 utility-scale solar facilities, 11 wind farms, and 12 geothermal plants, with associated transmission corridors and infrastructure to connect with established power grids. If fully built, these projects will provide more than 14,000 megawatts of power, or enough electricity to power about 4.8 million homes, and provide over 20,000 construction and operations jobs. The BLM continues to actively facilitate and support solar, wind, and geothermal energy development on BLM lands.

In 2014, the BLM proposed a rule for competitive leasing in order to promote additional renewable energy development at appropriate sites in areas that have been determined optimal for wind and solar energy production. Offering lands through a competitive leasing process will allow the BLM to plan smarter by targeting future development toward low-conflict lands close to existing or planned transmission capability. Increased production of renewable energy will create jobs, provide clean energy, and enhance U.S. energy security by adding to the domestic energy supply. The President has established an aggressive goal to increase permitting of new renewable electricity generation capacity on public lands to 20,000 megawatts by 2020.

Transmission Infrastructure – The BLM performs a key role in efforts to strengthen the nation's electric transmission grid. The BLM currently carries the largest portfolio of transmission projects among the nine Federal agencies involved in the interagency Rapid Response Team for Transmission (RRTT). It serves as the lead agency for four of the original seven major RRTT transmission projects. Since January 2009, the BLM has approved 90 major transmission projects (100 kV and larger), totaling over 2,300 miles, 1,600 miles of which cross through BLM lands in 10 western states. From 2012 to 2013 alone, the BLM approved permits which will enable construction of nearly 1,000 miles of transmission lines across Federal lands in seven states. Of 21 currently pending major transmission projects in various stages of environmental review, the BLM is the lead Federal agency for 18. The pending projects total approximately 3,811 miles, with approximately 1,311 miles crossing BLM-managed land. The BLM has undertaken efforts to ensure that the Bureau is poised to successfully fill its role as a leader among Federal agencies in the build-out and upgrade of the nation's electrical grid.

Helium – The BLM has processes in place to analyze and approve applications for helium production on Federal lands – both in combination with natural gas production processes and for drilling proposals focused exclusively on helium production. Helium commonly exists as a minor component of most natural gas plays. When natural gas is produced, it is typically transported by pipeline to a processing plant where it is separated into marketable components, which could include helium if it is a viable option. Because the helium on Federal lands is reserved to the United States, natural gas lessees can enter into additional contracts with the BLM to provide for the processing and sale of the helium. This type of arrangement occurs near Kemmerer, Wyoming, where helium produced from Federal lands partially supplies an ExxonMobil helium refinery.

Similar contracts can also be used to enable the recovery of helium as a primary gas in combination with Applications for Permit to Drill (APDs). This method is feasible where the gas composition in a reservoir consists of a low Btu gas with relatively high helium concentrations. For example, the BLM approved an APD in 2013 for a 1,100-foot exploratory well in the Harley Dome gas field in eastern Utah and an associated right-of-way to transport the produced gas via a surface pipeline to a new gas processing plant. Here, the proponent has constructed a four-inch, 7,183-foot pipeline to a small plant where the helium is removed from the gas stream and compressed for truck transport. The well is located five miles west of the Utah-Colorado border on Federal lands in northern Grand County and the helium extraction plant is located 1.4 miles from the well on private property.

During fiscal year 2014, the Department of the Interior collected almost $15 million in revenues from the sale of helium produced from Federal mineral estate. While the long-term potential for such production remains unclear, the BLM has noticed a recent increase in expressions of interest for helium production on Federal lands. The BLM looks forward to working with interested parties on helium production contracts that will help meet the helium needs of the country.

S. 562, the Geothermal Exploration Opportunities Act

S. 562 amends the Geothermal Steam Act of 1970 and identifies a number of categorically excluded activities under the National Environmental Policy Act (NEPA), including both geothermal exploration and geothermal resource testing activities. In addition, the bill provides for the use of the Department's extraordinary circumstances provisions – in circumstances when NEPA review would still be warranted. S. 562 would only apply to those geothermal exploration or test activities on leased lands where the leaseholder has the right to the testing of leased geothermal resources. The bill also includes notice and review timeframes for the categorically excluded activities.

Under the bill, the leaseholder would be required to provide notice to the BLM 30 days before the date of the proposed drilling activity, and the BLM would be required to review the proposed activity not later than 10 days after receipt of the notice. The leaseholder also would be provided with an opportunity to remedy any deficiencies in the notice to still qualify for the categorical exclusion under the bill.

Analysis

NEPA review is an important component of responsible development, and the Department opposes the routine use of categorical exclusions for geothermal exploration and geothermal resource testing activities as proposed in the S. 562. Although the bill follows the extraordinary circumstances provisions of NEPA, it still contemplates overly prescriptive levels of disturbance or types of activities that would qualify for a categorical exclusion. Furthermore, requiring the review to be completed in 10 days is tantamount to waiving compliance with NEPA.

Geothermal drilling plans are typically comprised of a comprehensive scope of activities – including temperature gradient wells, geothermal resource test wells, observation wells, and production and injection wells – and it is the BLM's responsibility under NEPA to complete an appropriate analysis of these activities before they are undertaken. Precluding this analysis would undermine the reasoned consideration of the environmental effects of such projects and impede the opportunity to consider alternatives with less adverse impacts on communities and the environment. Failure to complete NEPA review would reduce transparency in agency decision making and would impact our ability to identify relevant and useful information for consideration by the public and by the BLM as a decision-maker. As drafted, these provisions would preclude appropriate environmental review, negate opportunity for appropriate public engagement or input, and be little more than a rubber stamp. The BLM strongly opposes provisions limiting appropriate environmental reviews by impeding or waiving the NEPA process.

Furthermore, the BLM is concerned that the notice and review timeframe provisions of the bill would be a challenge for those projects that involve a wide variety of exploration and drilling activities in different locations and results in a waiver of appropriate review when circumstances make it clear that further consideration is necessary before making a decision. For example, the review of certain large projects may require more than 10 days to determine whether the project is an eligible activity for a categorical exclusion under the bill.

S. 822, Geothermal Production Expansion Act

S. 822 amends the Geothermal Steam Act to authorize non-competitive leasing of up to 640 acres of Federal geothermal resources when a valid geothermal discovery is made on adjoining lands and the geothermal resources extend into unleased Federal land. The bill requires that regulations be issued within 270 days after enactment to implement the provisions of the bill establishing the procedures to determine the fair market value of leases and the minimum price for that evaluation. Under the bill, minimum value must be at least $50 per acre or four times the median amount paid per acre for all land leased under the Geothermal Steam Act during the preceding year, whichever is greater. The bill also requires that proposed fair market value determinations be published and open for public comment for 30 days; that proposed determinations be appealable; and that annual rental rates be the same as the rate for competitive leases.

Analysis

The BLM supports the bill's objective to enhance geothermal exploration and development by ensuring that geothermal discoveries can be responsibly developed. The BLM also generally supports maintaining competitive leasing processes for the development of Federal energy resources, but recognizes that there are situations in which non-competitive leasing may be appropriate, such as to increase investor confidence that geothermal discoveries could ultimately be fully developed.

Additionally, the BLM supports a requirement that regulations be promulgated to establish procedures for determining the fair market value of leases on adjoining lands. The BLM would consider a number of factors in identifying a price that is fair for a given lease, including information on known existing resources and the value of other leases within the local market. The BLM supports measures that help ensure a fair return to U.S. taxpayers for the use of public lands, and would like to work with the sponsor on this provision.

Finally, however, the BLM has concerns with the timeframes included in the bill. Specifically, the promulgation of regulations issued by the Secretary typically requires more than 270 days. The 180 days provided in the bill for determining the fair market value of a lease also may not be adequate to conduct such an evaluation.

S. 1057, Geothermal Energy Opportunities Act

S. 1057 sets a goal for the Secretary of the Interior to approve at least 15,000 megawatts (MWs) of new geothermal energy capacity on the public lands within 10 years after enactment. The bill also directs the BLM, in consultation with other Federal agencies, to identify high-priority areas for geothermal development on public lands and to take actions to facilitate that development. To that end, S. 1057 amends the Geothermal Steam Act to allow for the noncompetitive leasing of adjoining areas for development and coproduction of geothermal energy from a producing oil and gas well. Lands subject to the latter provision would be oil and gas leases issued pursuant to the Mineral Leasing Act or the Mineral Leasing Act for Acquired Lands.

Furthermore, the bill directs the USGS and DOE to identify sites capable of producing a total of 50,000 MWs of geothermal power. It provides authority to the Department of Energy (DOE) for a federally funded program of cost-shared drilling for geothermal resource exploration. Data from exploration activities carried out under the cost-share program would be provided to both the DOE and the DOI (presumably the USGS) for geothermal resource assessments. The program would be funded by a special U.S. Treasury account into which the Federal share of revenues from geothermal leases would be deposited. Although the bill requires no direct distribution of revenues to the BLM or the Forest Service, it would provide DOE with authority to transfer funds to cooperating Federal agencies to meet the goals of the bill.

Finally, S. 1057 amends Title VI of the Energy Independence and Security Act of 2007 to provide additional focus on the Geothermal Technologies Program and the Building Technologies Program of the DOE. The bill provides additional authority to the DOE to make grants promoting the development of geothermal heat pumps and the direct use of geothermal energy. It also requires DOI and DOE to submit a report to Congress within three years of enactment and once every five years thereafter describing the progress towards achieving the goals of the bill.

Analysis

While the Department supports the aggressive goal for additional geothermal projects on the public lands set by this bill, it feels strongly that consideration must be given to having the appropriate market incentives in place in order to achieve this goal. The BLM presently manages 593 geothermal leases, with 73 leases in producing status, and a total capacity of 1,500 MWs of geothermal energy on public lands. The goal of 15,000 MWs of new capacity by 2025 would require a ten-fold increase in the approval of geothermal projects from Federal geothermal leases, or approximately 1,500 MWs of additional capacity per year. This goal is highly dependent on a variety of factors, including state renewable energy standards and market conditions that are outside of the BLM's control. A limited number of proposed geothermal development projects on Federal lands are pending at this time and it is unclear what future projects may be proposed.

The Department also supports the sponsor's interest in identifying areas for potential geothermal development, but notes that a process is currently in place for industry to nominate areas of interest for geothermal leasing on Federal lands. The BLM and the FS completed a "Programmatic Environmental Impact Statement for Geothermal Leasing in the Western United States" in October 2008 and issued a Record of Decision and land use plan Amendments in December 2008 to facilitate geothermal leasing and development. As part of that process, the BLM amended 114 land use plans to help facilitate geothermal leasing and development. In total, approximately 111 million acres of BLM-managed public land are open to geothermal leasing and about 79 million acres of FS lands are open to leasing. The BLM depends on industry to nominate lands for leasing and to identify those priority areas of development interest.

In addition, the Department supports amendment of the Geothermal Steam Act to provide for the non-competitive leasing of geothermal resources, although implementation of these provisions of the bill would require the promulgation of regulations in order to address the approval and permitting process, and production royalties. Finally, the Department defers to DOE on how the geothermal and building technology research contemplated under the bill fits within its existing renewable energy funding priorities. It should be noted, however, that the federal portion of revenues from geothermal energy leases on public lands is currently deposited in the Treasury. We have concerns about the redirection of Federal receipts traditionally deposited in the Treasury toward this new special-purpose account.

S. 1226, American Helium Production Act

S. 1226 amends the Mineral Leasing Act (MLA) and the Mineral Leasing Act for Acquired Lands (MLAAL) to include helium as a leasable mineral under the two Acts. In establishing a leasing program for helium exploration, development, and production, the bill requires collection of a $5,000 permit processing fee. Under the bill, half of the revenues generated by fee payments would be used by the field offices in which helium leases are located to cover the costs of processing protests, leases, and permits. S. 1226 also repeals the current reservation of helium on Federal lands to the United States, and directs the Secretary of the Interior to prepare a Programmatic Environmental Impact Statement (PEIS) on helium exploration and development.

Analysis

The BLM supports the goal of the bill to encourage private development of helium resources on Federal lands, as well as repeal of the helium reservation. We would like to work with the Committee, however, to include helium as a leasable mineral under the MLA and MLAAL without creating a new separate leasing program. The BLM believes that the separate leasing program authorized by the bill could create conflicts in cases of overlapping leases which would be counterproductive to the goals of S. 1226. Instead, a simple repeal of the helium reservation would allow future fluid mineral lessees to acquire the right to produce helium under their leases. These lessees could then either process the helium themselves or enter into private agreements with helium refiners to separate the helium from the rest of the gas they produce. Further, BLM opposes requiring a specific Helium PEIS. Occurrences of helium in marketable quantities within natural gas on Federal lands are relatively well known and not wide spread; consequently, the BLM should continue to have the ability to use either programmatic or case-by-case NEPA reviews to make the most efficient use of its planning processes based on the facts at hand. In most cases, experience has taught that specific NEPA analysis for the development of the helium resource can be completed on a case-by-case basis in a more cost effective manner.

S. 1236, Hydropower Improvement Act,

The Department is the second largest producer of hydroelectric power in the United States, and we are actively engaged in looking for opportunities to encourage development of additional hydropower capacity at our facilities. The Department, along with our federal partners, has made significant strides in encouraging the development of reliable, affordable and environmentally sustainable hydropower at our existing federal facilities, and with FERC at non-Reclamation facilities. Through the advancement of hydropower, we are helping to meet the Administration's goal of generating 80 percent of our energy from clean energy sources by 2035. Recent progress in advancing hydropower development includes the renewal of the 2010 Memorandum of Understanding for Hydropower on March 24, the ongoing assessment of non-powered dams, and the implementation of legislation to encourage the development of small hydropower on existing facilities and other water conduits.

S. 1236 would undermine the Department's ability to: (1) facilitate sustainable hydropower, (2) protect and manage our Nation's public lands and water resources, (3) operate and manage Federal water and power facilities, and (4) fulfill the Federal trust responsibility to American Indians. The Department believes that clean energy development and environmental compliance can co-exist and that one should not exclude the other. S. 1236 could hinder our ongoing efforts, and the Department offers the following views in opposition to S. 1236.

Section 5 threatens to undermine the Federal trust responsibility to American Indians, the Federal policy to promote Indian self-determination and economic self-sufficiency, and would significantly impact the Department's ability to manage and protect fish and wildlife resources, tribal lands, cultural and historic resources, and other lands and interests in lands managed by the United States. Section 5 of the bill would amend section 4(e) of the Federal Power Act to subordinate the Department's authority to establish conditions necessary for the adequate protection and utilization of reserved lands to the findings of the Federal Energy Regulatory Commission (FERC). This would authorize FERC to determine the appropriateness of conditions based on whether FERC determines a "clear and direct nexus" exists between the conditions and the presence or operations of a license. This provision would impact agencies' ability to fulfill mandates under other laws, and would effectively transfer some authority over the use of Indian reservations to FERC for purposes of implementing the Federal Power Act. This conditioning authority was reserved for land management agencies dating back to the enactment of the Federal Power Act. This provision would undermine these agencies ability to "continue to play the major role in determining what conditions would be included in the license in order to protect the resources under their respective jurisdictions".[1]

Section 9 would subordinate the Department's role in overseeing the use of, design, construction and operation of fishway facilities to FERC, by authorizing FERC to determine appropriate measures to mitigate effects on fish populations subject their determination of a "direct nexus to the presence or operations of the project being licensed". Information for fish and wildlife and fish passage constraints are important to address from an environmental and natural resource standpoint, and should remain with the Department and Department of Commerce.

Section 10 would eliminate land management agencies' ability to review and accept proposed alternative conditions for FERC licenses and allow FERC to determine whether a proposed alternative condition "adequately protects the reservation from adverse effects of the project". The Department remains best suited to determine the needs for protecting resources under their management, and this provision would undermine the Department's ability to manage public lands and infrastructure.

Section 34 would require FERC to use existing studies and data in licensing proceedings; however, it is unclear whether FERC would need to justify their decision that a study is not necessary or whether there would an appeals process. Resource agencies need appropriate information to complete their analyses in a timely fashion.

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[1] *Escondido Mut. Water v. La Jolla Band of Indians*, 466 U.S. 765 (1984).

Section 35 amends the Federal Power Act to designate FERC as the lead agency responsible for coordinating all required Federal authorizations related to the licensing or relicensing of a hydropower project. This would include authorizations granted by other Federal agencies. The Department believes that the lead agency should be determined based upon the substantive statute at issue. For example, the legislation is unclear on its approach for licensing of hydropower on Federal facilities versus non-Federal facilities, which could impact how hydropower is sited on Reclamation facilities. It is also unclear on what impact this legislation may have on Reclamation's Lease of Power Privilege The Department looks forward to working with the Committee to ensure that approval of rights of way or use authorizations on public lands are carried out with sufficient Departmental analysis under NEPA or input on the terms and conditions needed to protect important resource values and public health and safety. The bill also provides that if a Federal agency does not issue a required Federal authorization related to the licensing process within a 3-year deadline, a FERC license alone is deemed sufficient to satisfy the required federal authorization. This could result in incomplete applications from a developer; the need to conduct public outreach, tribal consultation, cultural resource surveys, or other analyses needed to balance power generation with mitigation and protection of the natural and cultural resources of the public lands. We would like to work with the Committee to provide additional clarity on these issues.

In conclusion, the Department appreciates this Committee's interest in encouraging the development of hydropower, and we look forward to working with you to increase the use of reliable, affordable and environmentally sustainable hydropower.

S. 1271, Fuel Loss Abatement & Royalty Enhancement Act

S. 1271 requires the Secretary of the Interior to issue regulations within 180 days to: (1) prevent or minimize the venting and flaring of gas in oil and gas production operations on Federal land onshore and offshore; and (2) promote the capture and beneficial use or reinjection of gas back into these operations. The bill requires such regulations to require operators to pay royalties on vented or flared gas from a federal lease, and it provides that the regulations would not apply to existing leases if that would constitute a breach of contract by the United States. S. 1271 also requires the U.S. Comptroller General to assess the venting and flaring of gas in oil and gas operations on Federal land, and to submit a report to Congress that includes an estimate of the volume of gas that is vented or flared in such operations on annual basis.

Analysis

The BLM supports the goals of the bill – to reduce the amount of gas that is vented or flared from oil and gas development on public lands, promote the conservation of produced oil and gas, and ensure a fair market return to the U.S. taxpayers. The BLM is currently updating decades-old standards to reduce wasteful venting, flaring, and leaks of natural gas from oil and gas wells on public lands. These standards, to be proposed later this year, will address both new and existing oil and gas wells on public lands. The BLM is concerned that the bill's 180-day deadline for rulemaking provides insufficient time to issue a final rule.

Conclusion

Thank you for inviting our testimony on S. 562, S. 822, S. 1057, S. 1226, S. 1236, and 1271. The Department of the Interior is committed to supporting the responsible supply of energy for our nation.

GENERAL COUNSEL OF THE DEPARTMENT OF DEFENSE
1600 DEFENSE PENTAGON
WASHINGTON, D.C. 20301-1600

JUL 09 2008

GENERAL COUNSEL

The Honorable James M. Inhofe
Ranking Member
Committee on Environment & Public Works
U.S. Senate
Washington, DC 20510

Dear Senator Inhofe:

The Department of Defense (DoD) supports S. 2827, a bill "to repeal a requirement with respect to the procurement and acquisition of alternative fuels." The bill would repeal section 526 of the Energy Independence and Security Act of 2007. Section 526 has the potential to generate significant problems for DoD in its procurement of fuels for the national defense. It creates uncertainty about what fuels DoD can procure and will discourage the development of new sources, particularly reliable domestic sources, of energy supplies for the Armed Forces. The following is representative of the Department's concerns.

The Department believes section 526 is overly broad both in design and application. The law's terms are not defined and some may argue that it covers a very broad range of fuels commonly purchased by DoD. As written, section 526 could apply to alternative and synthetic fuels, including E85 (fuel that is 85% ethanol) and B20 (diesel fuel that contains 20% biofuels), that the Department is encouraged or required to use under other statutes.

Section 526 applies to "an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources." The provision opens the Department up to court or administrative challenges to every fuel purchase it makes, with the inherent potential for an adverse decision that would cover fuels the military already relies on as well as potential reliable sources of fuel that could be developed in the future. Such a decision could cause significant harm to the readiness of the Armed Forces because these fuels may be widely used and particularly important in certain geographic areas.

Section 526 applies worldwide, not just to purchases within the United States. There are no means to accurately and authoritatively determine the lifecycle greenhouse gas emissions from non-domestically produced fuels because we do not track all of the fuel inputs in other countries and many producing countries lack the infrastructure or institutional control necessary to reliably track these inputs. For example, our military aircraft used over 6 million gallons of Canadian jet fuel in 2007 while exercising with the Canadian Armed Forces, conducting joint operations along the Distant Early Warning Line, and refueling at Canadian commercial airports. Canadian fuels include a mix of fuels including those produced from tar sands crude at various percentages. If these fuels were subject to section 526, and fuel suppliers were unable to authoritatively certify the lifecycle greenhouse gas emissions associated with the fuel, our military aircraft may be required to stop refueling in Canada, potentially affecting our national security.

Section 526 requires an analysis that may never be possible. The source of a fuel informs the greenhouse gas emissions footprint. Fuels, including conventional petroleum, are produced from numerous sources and often mixed together. Current standards for determining emissions of fuels from various origins are determined on averages. However, section 526 could be interpreted to require an analysis of individual fuel purchases for lifecycle greenhouse gas emissions, even though determining the emissions footprint for any individual batch of fuel may be impossible. For example, conventional fuel derived from oil produced in Venezuela or Nigeria is more likely to have a larger footprint than domestic oil because of the energy used transporting the oil to the United States. Foreign and domestic oil may be mixed together at a refinery. Once foreign and domestic oils are mixed together, the oils cannot be differentiated from one another. Therefore, the footprint of the resulting fuel cannot be determined accurately or authoritatively.

Finally, even a narrow interpretation of section 526 in an effort to reduce the uncertainty and the scope of section 526 still could limit the Department's flexibility in making emergency fuel purchases, overseas fuel purchases, and purchases at commercial stations and airports. Currently, there is no method for determining whether fuel purchased at these locations meets the requirements of section 526.

The Office of Management and Budget advises that, from the standpoint of the Administration's program, there is no objection to the presentation of this report for the consideration of the committee.

Sincerely,

Paul A. Koffsky

for Daniel J. Dell'Orto
Acting

cc: The Honorable Barbara Boxer
Chairman
Committee on Environment
& Public Works

The Honorable Pete V. Domenici
Ranking Member
Energy & Natural Resources
Committee

The Honorable Jeff Bingaman
Chairman
Energy & Natural Resources
Committee

DNV·GL

Statement for the Record

Submitted by DNV GL

for the

Senate Energy and Natural Resources

Committee Hearing on

Energy Supply

19 May 2015

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DNV GL is pleased to submit a Statement for the Record of the Senate Energy and Natural Resources Committee Hearing on Energy Supply that was held on 19 May 2015.

Shale development is becoming an important source of energy supply in the U.S.

However, shale operations, as well as other oil and gas production activities, currently flare natural gas. The capture of flared gas presents an opportunity to reduce the environmental impact as well as an economic opportunity. The gas captured can be used to create new value chains, drive innovation and development of new technologies, capture economic value and expand commercialization within the gas value chain that can benefit not only the industry but also people's quality of life.

Today, regulators are addressing flaring by mandating reductions of flaring and/or cutbacks in production without due consideration to available alternatives.

We recommend that the legislative language mandates and directs operators to evaluate alternatives to flaring in terms of technology available, alternative uses, development of markets, business models, socio/economic impacts and, finally, demonstrate and quantify reduction in flaring. This will need to be evidence based to show that scenarios have been considered, ideally with external expertise, and over time this will provide regulators with the visibility of the different technologies, commercial scenarios and market impacts and so will provide an excellent foundation for high impact insights for regulators.

DNV GL also respectufully recommends that legislation requires operators to submit a gas capture plan, a clear component of which will include a review of technologies and solutions which could provide a roadmap to conversion of gas captured into energy for own use (for example power generation) or for market distribution, other commercial uses and utilisation. The plan should demonstrate a conceptual review of suitable solutions and market scenarios which include the following:

- Technology options
- Volumes of gas capture possible for each technology evaluated
- Estimated annual volumes of improvements in flaring reductions
- Technical comparisons and limitations
    - Infrastructure requirement
    - Logistical comparisons
    - Technology maturity
    - Processing requirements

- Market scenarios (for example routes to market, distance to market)
- Economic scenarios (estimates of cost/benefit)
- Social impact statement
- Methods used for the evaluations in the plan, including, and possibly mandating, independent third party assessments and reviews.
- Roadmap for implementation in line with requirements for reductions and penalty avoidance along with other existing reduction methods

Lastly, the legislation should provide for verification of reductions in flaring and promote innovation and technology by requiring the operator to conduct independent third party audits to review and verity the levels of flared gas capture and utilization and report these annually.

Background: Technology solutions are largely dependent on the flow rate, gas compositions and distance to market. DNV GL has carried out conceptual studies based on real locations and real field conditions both onshore and offshore. The cases cover different small-scale flow rates and gas compositions in four countries; Russia, USA, Algeria and Vietnam. DNV GL acted as an independent party and reviewed all the existing and innovative technologies as alternatives to flaring to reduce the amount of flared gas.

The alternatives to flaring fall under four broad categories:

1. Using more cost-effective ways of transporting natural gas where there is no existing pipeline
2. Converting gas into products with a higher economic value through chemical processes
3. Novel Concepts. Bringing the market closer to the source of gas flaring
4. Other Solutions

Within each of these broad categories, there are a number technically feasible options, as well as some novel, and promising, technologies.

DNV GL is pleased to attach our brochure: Alternatives to Flaring, which provides the Committee with a summary of our research and recommendations for alternatives to flaring. In addition, DNV GL has developed a tool which may greatly assist operators to identify and choose a suitable option to flaring. This tool:

- Supports high level decision making:
  - It is technology and market relevant

- It screens technologies that are relevant for particular flowrates / applications
- It gives an initial assessment of the most suitable technology options available for capturing associated gas
- It uses a NPV graphical output to compare technology options
- It also demonstrates the potential cost penalty for flaring per year and cost of loss of production as well as the equivalent amount of energy / volume lost through flaring

- The tool can be populated with any metrics necessary to create NPV scenarios – with a small number of inputs in the first tier:
  - Gas flowrate
  - Distances to transport products to market
  - Location
  - Sensitivities (for CAPEX, OPEX, revenue and gas price to allow changes in economics to be explored)
  - Several other variables are built into the tool to assess sensitivities, these include (but are not limited to): CAPEX, OPEX, Revenues, Gas price, Royalties

- The tool also has an additional tier for gas quality considerations should more detailed information be available and includes cost modules should additional gas clean-up be necessary prior to the main technology. The quality issues being H_2S, Hg, high CO_2 and high N_2 concentrations.

- It can also give a detailed calculation model for a specific country or basin economics. Any detailed calculations would be carried out on a case by case basis.

Attachment: Alternatives to Flaring

DNV·GL

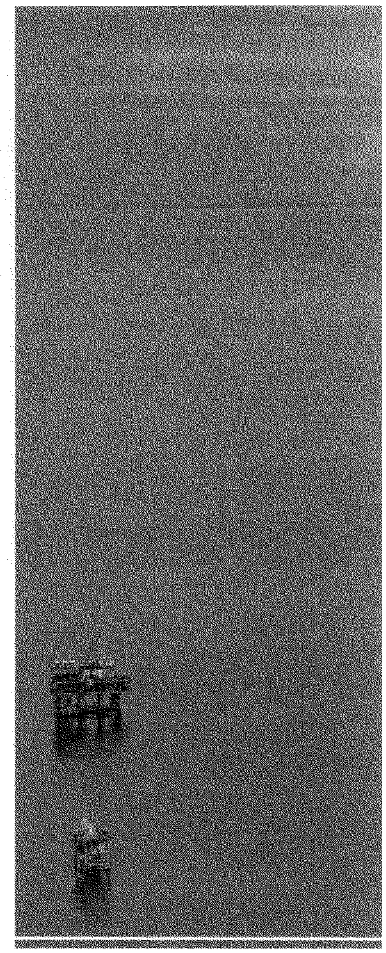
OIL AND GAS

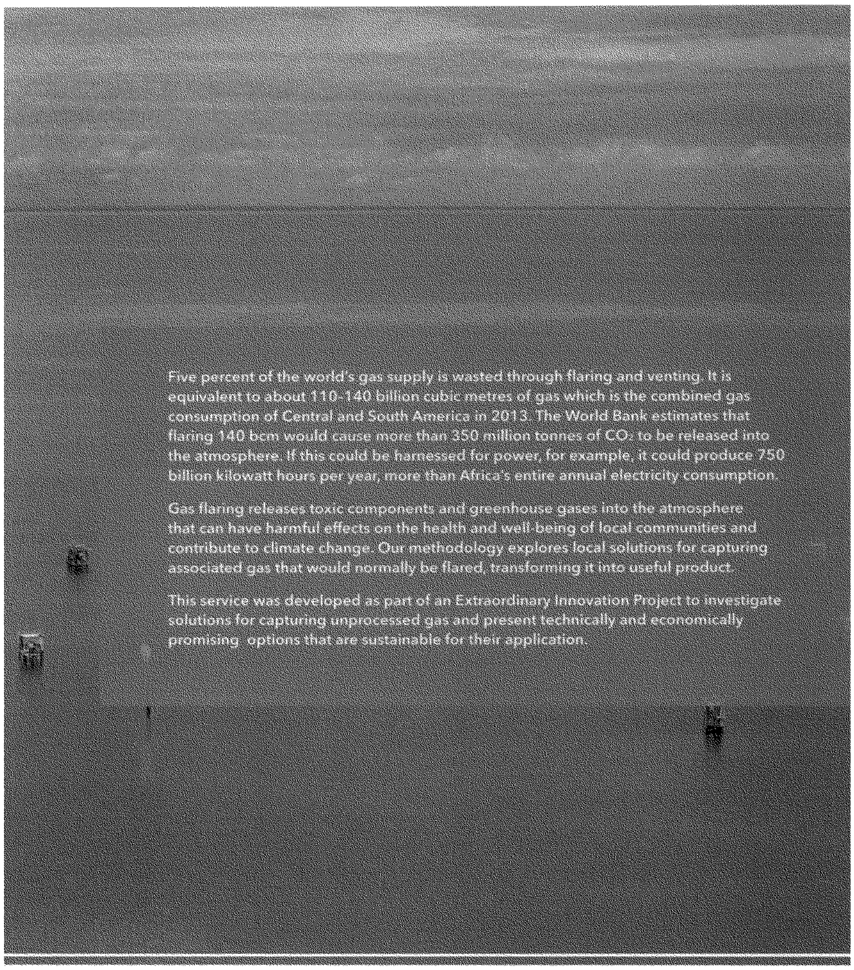
NATURAL GAS CAPTURE

Clean and economic

SAFER, SMARTER, GREENER

CONTENTS





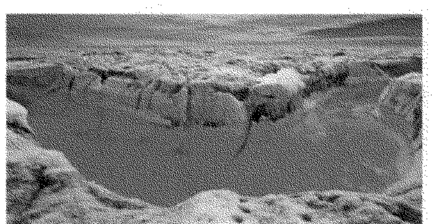
Five percent of the world's gas supply is wasted through flaring and venting. It is equivalent to about 110-140 billion cubic metres of gas which is the combined gas consumption of Central and South America in 2013. The World Bank estimates that flaring 140 bcm would cause more than 350 million tonnes of CO_2 to be released into the atmosphere. If this could be harnessed for power, for example, it could produce 750 billion kilowatt hours per year, more than Africa's entire annual electricity consumption.

Gas flaring releases toxic components and greenhouse gases into the atmosphere that can have harmful effects on the health and well-being of local communities and contribute to climate change. Our methodology explores local solutions for capturing associated gas that would normally be flared, transforming it into useful product.

This service was developed as part of an Extraordinary Innovation Project to investigate solutions for capturing unprocessed gas and present technically and economically promising options that are sustainable for their application.

THE IMPACTS OF FLARING

It is well known that flared gas is a significant contributor to global warming. However, some other important issues that are not so well known exist.



Complete combustion does not occur during flaring and this leads to the production of black carbon particles. These particles strongly absorb sunlight and emit heat to the surroundings which warms the air and can affect regional cloud formation and precipitation patterns. When deposited on snow and ice, melting is accelerated. Gas flaring produces an estimated 66% of the black carbon emissions in the Arctic.

Flaring can be fatal for some species of birds and airborne insects that are attracted to the heat and flames. Migrating birds can be killed by the heat and flames from flaring. For example in 2013, 7,500 songbirds were killed at Canaport gas plant in Saint John, Canada.

Valuable natural resources are wasted by flaring. According to the World Bank, 20% of the world's population do not have access to electricity and 40% rely on solid fuels for cooking. This results in over four million premature deaths due to indoor air pollution every year. The natural gas could have been used to generate electricity and also for cooking.

CHALLENGES TO REDUCE FLARED GAS

Most of the flaring occurs at either ageing and/or remote installations. The associated gas at these installations is usually small in volume and requires moderate gas processing. Retrofits and transportation of recovered gas to processing facilities also involve significant capital cost. Without a global cost penalty for emitted carbon, there are few business incentives to capture the flared gas. Financial barriers can significantly impede the efforts to reduce emissions and this is particularly true for countries with developing economies.

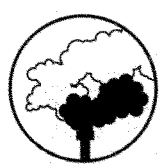
ALTERNATIVES TO FLARING

Capture of flared gas presents an opportunity to reduce the environmental impact as well as providing an economic opportunity. The gas captured can be used to create new value chains that can benefit not only the industry but also people's quality of life.

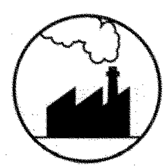
DNV GL can help to identify technology solutions to capture associated gas that is currently being flared in oil production fields and assess how these resources can be converted, transported and utilised.

Technology solutions are largely dependent on the flow rate, gas compositions and distance to market. DNV GL has carried out conceptual studies based on real locations and real field conditions both onshore and offshore. The cases cover different small-scale flow rates and gas compositions in four countries; Russia, USA, Algeria and Vietnam. DNV GL acted as an independent party and reviewed all the existing and innovative technologies as alternatives to flaring to reduce the amount of flared gas, taking into account various aspects during the studies as shown on the right. The details and results can be found on pages 08-11.

SOURCE OF FLARED GAS



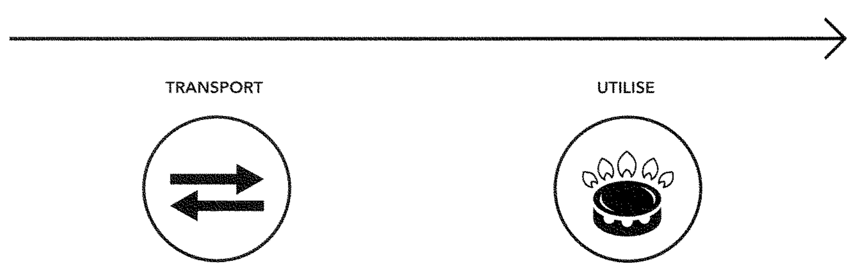
CAPTURE AND PROCESS



CREATING VALUE FROM FLARED GAS

By capturing the associated gas that would otherwise be flared, we can create new value chains that are sustainable. These bring benefits such as:

- Reduced carbon footprint
- Revenue generation
- Improvements to people's quality of life



ALTERNATIVES TO FLARING

Novelty of the Technology Solutions: Many of the technology solutions are mature at large scale but few technologies have been used commercially at small-scale. Therefore most of the technology solutions shown are novel except for Gas to Wire.

Using more cost-effective ways of transporting natural gas where there is no existing pipeline

Adsorbed Natural Gas (ANG) is natural gas stored in a porous adsorbent material.

Compressed Natural Gas (CNG) is a pressurised form of natural gas at around 250 bar.

Liquefied Natural Gas (LNG) is a liquid form of natural gas at cryogenic state of around -160 °C at atmospheric pressure.

Natural Gas Hydrates (NGHs) are crystalline solids composed of water and natural gas in physical combination where individual gas molecules exist within 'cages' of water molecules.

Novel solutions such as **reusable pipes** can be used to transport the associated gas to other users. This will result in cost savings as these pipes are cheaper and can be re-used many times.

Converting gas into products with a higher economic value through chemical processes

Compact **Gas to Liquids** processes are being developed for small-scale applications that generate valuable products such as synthetic crude oil, petrol (gasoline), diesel and jet fuels.

Ammonia is used in the paper and pharmaceuticals industries whereas urea is used for fertilisers.

Methanol and Methanol Mixes (Methanol/Ethanol/Formalin) are used for a variety of purposes including automotive fuels as well as for industrial uses.

Dimethyl Ether is used for a wide range of fuel applications including domestic cooking.

Hydrogen is often used as an industrial chemical as well as for automotive fuel.

Ethylene and **propylene** are used for plastics production.

Novel Concepts
Bringing the market closer to the source of gas flaring

The power generated can either be used on site immediately or stored in **battery** form for future use such as back-up supply.

Moreover, the power generated can be used for **air separation** which is an energy intensive process.

The associated gas can also be used as fuel gas to heat up the wastewater to **evaporate the water** for ease of waste disposal.

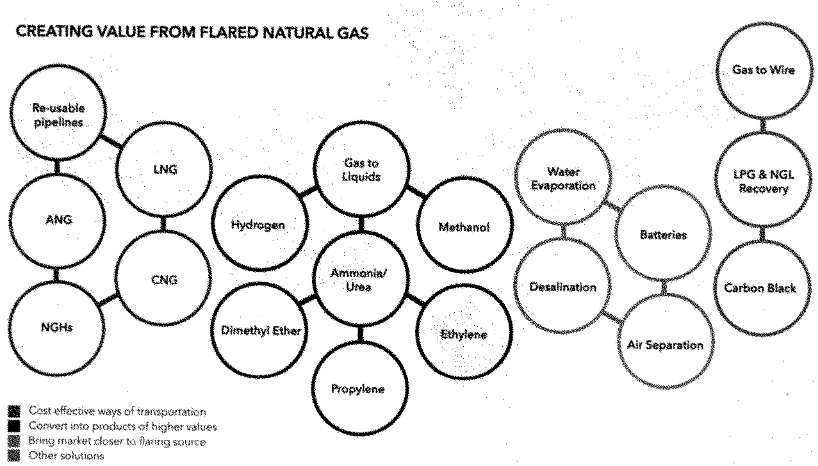
Similarly, the same concept can be used for **desalination** to provide clean water for nearby communities.

Other Solutions

The gas can also be used for power generation, i.e. **Gas to Wire**.

Associated gas usually has lower methane content and higher heavy hydrocarbons, therefore **Liquefied Petroleum Gas (LPG)** and **Natural Gas Liquids (NGLs)** can be recovered during the gas processing treatment.

Carbon Black can be produced by incomplete combustion or thermal decomposition of hydrocarbons. It is mainly used in the rubber industry for tyre production as well as for plastics and paints.


CREATING VALUE FROM FLARED NATURAL GAS
Re-usable pipelines
LNG
ANG
CNG
NGHs
Hydrogen
Gas to Liquids
Methanol
Ammonia/ Urea
Dimethyl Ether
Ethylene
Propylene
Water Evaporation
Batteries
Desalination
Air Separation
Gas to Wire
LPG & NGL Recovery
Carbon Black
Cost effective ways of transportation
Convert into products of higher values
Bring market closer to flaring source
Other solutions

CASE STUDIES

NORTH DAKOTA

Location Onshore
Solutions Mobile and permanent
Flowrate 0.3 MMscfd (from a single well pad)
10 MMscfd (from multiple well pads)

Most technically and economically promising solutions
From single well pad
CNG, Methanol Mixes, Gas to Wire, LPG/NGLs
From multiple well pads
LNG, Methanol Mixes, Gas to Wire, LPG/NGLs

RUSSIA

Location Onshore
Solutions Permanent
Flowrate 30 MMscfd

ALGERIA

Location Onshore
Solutions Permanent
Flowrate 20 MMscfd

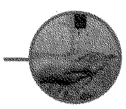
Most technically and economically promising solutions
LNG, Gas to Liquids, Methanol, Methanol Mixes, Dimethyl Ether, Ammonia, Propylene, Gas to Wire

VIETNAM

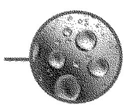
Location Offshore
Solutions Floating/Mobile
Flowrate 25 MMscfd

Most technically and economically promising solutions
CNG, Gas to Wire, Gas to Liquids and Methanol Mixes are promising for the future

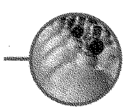
NOVEL CONCEPTS



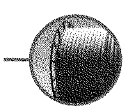
Desalination
The associated gas can be used as fuel gas for desalination of the produced water stream which will produce a clean water source. This is extremely useful for remote areas where clean water is often an expensive and scarce commodity.



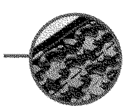
Produced water evaporation
The associated gas can be used as fuel gas for evaporation of the produced water stream to reduce water removal transportation costs.



Air separation
The associated gas can also be used as fuel gas to separate air into nitrogen and oxygen. Nitrogen can be used for industrial uses or for well stimulation. Oxygen can be used for domestic/ industrial processes.



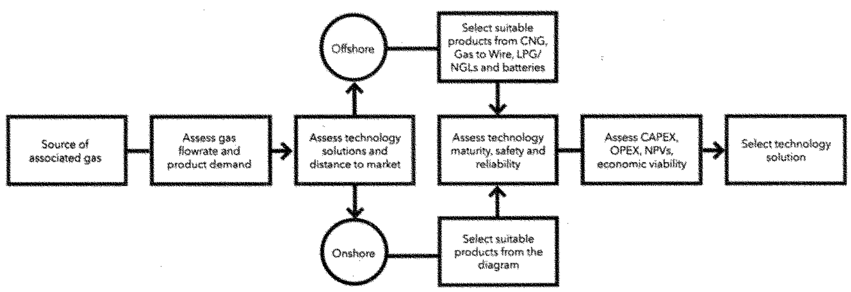
Re-usable pipes
The associated gas can be transported to other users via pipelines that could be re-used eliminating the use of road or rail transport. These pipes can be taken up after the well is depleted and re-laid elsewhere.



Batteries
The associated gas can be used to generate electricity to store in batteries.

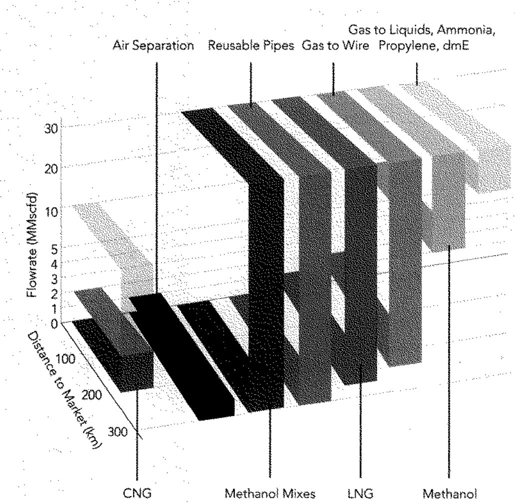
OUR METHODOLOGY

It is a complex process to determine suitable technology solutions as alternatives to flaring. The flowchart shows DNV GL's methodology. This methodology uses the gas flowrate and the distances to market for various products to select the most appropriate technology solutions for a particular case.



Technology Selection Methodology Flowchart

PROMISING TECHNOLOGY OPTIONS



Onshore technology options chart based on uncontaminated flared gas flowrates and the distance to product markets. Each geographical setting provides different technical, regulatory and economic challenges and, therefore, the boundaries of each study should be framed prior to starting any study. The above graph reflects a generic set of solutions based on the cases studies assessed in our work to date.

THE WAY FORWARD

DNV GL has performed thorough conceptual studies based on real locations and real field conditions in four countries.

We have found that there are solutions and new concepts that can contribute to safer and sustainable future. We have identified novel techniques for addressing this topic that could present new revenues.

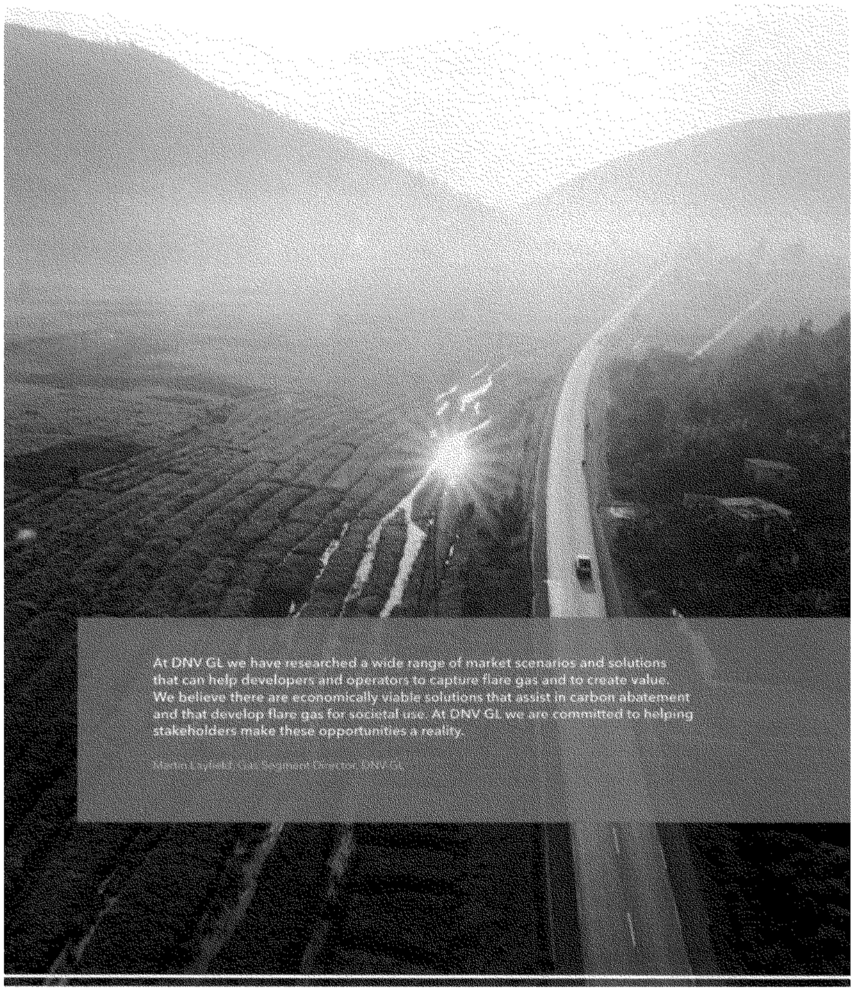
The technology solutions and means of transportation that we have explored can also be applied to:

- Monetisation of small-scale stranded gas fields
- Monetisation of associated gas from extended well tests
- Resolve demands at remote areas where there is no infrastructure
- Capturing vented gas

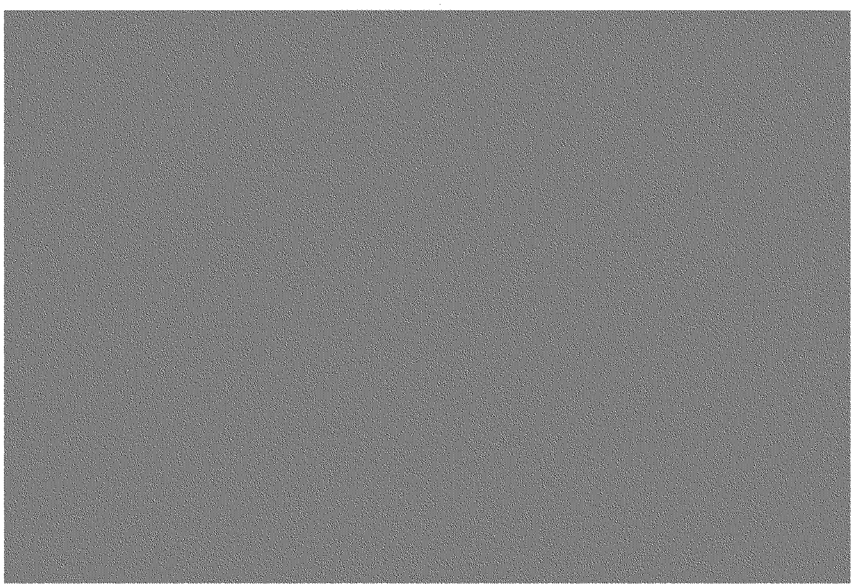
Services
DNV GL can provide a wide range of services for stakeholders to better utilise the associated gas, such as:

- Conceptual studies
- Techno-economic studies
- Technology qualification
- Verification of conceptual designs
- Development of innovative solutions
- Provide technical advice to policy makers and regulators

CONTACT
For more information on how to capture flared gas, please contact Martin Layfield: Martin.Layfield@dnvgl.com


At DNV GL we have researched a wide range of market scenarios and solutions that can help developers and operators to capture flare gas and to create value. We believe there are economically viable solutions that assist in carbon abatement and that develop flare gas for societal use. At DNV GL we are committed to helping stakeholders make these opportunities a reality.
Martin Layfield, Gas Segment Director, DNV GL

SAFER, SMARTER, GREENER



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ABOUT DNV GL
Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries.

Combining leading technical and operational expertise, risk methodology and in-depth industry knowledge, we empower our customers' decisions and actions with trust and confidence. We continuously invest in research and collaborative innovation to provide customers and society with operational and technological foresight. With our origins stretching back to 1864, our reach today is global. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping customers make the world safer, smarter and greener.

**STATEMENT OF THE EDISON ELECTRIC INSTITUTE
SUBMITTED TO THE
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
ON ENERGY SUPPLY LEGISLATION FOR ITS MAY 19 HEARING**

Introduction

The Edison Electric Institute (EEI) appreciates the opportunity to submit this statement for the record on several of the bills considered by the Committee during its May 19 hearing on energy supply legislation. We also commend the Committee for considering a wide range of public policy issues that are important to the electric utility industry during its hearings.

EEI is the association of U.S. investor-owned electric utilities, international affiliates, and industry associates worldwide. Our members provide electricity for 220 million Americans, directly and indirectly employ more than one million American workers, and operate in all 50 states and the District of Columbia. With more than $90 billion in annual capital expenditures, the electric power industry is responsible for providing reliable, affordable, and increasingly clean electricity that powers the economy and enhances the lives of all Americans.

The electricity sector is the most capital-intensive industry in the country, as well as a key critical infrastructure industry. The electricity we provide is essential to the well-being of every American, as well as to economic growth and job creation. Because of this, energy supply issues are critical to our member companies.

S. 1199—A bill to authorize Federal agencies to provide alternative fuel to Federal employees on a reimbursable basis, and for other purposes (Murray)

EEI supports S.1199, introduced by Senator Murray, a bill to authorize federal agencies to provide alternative fueling infrastructure to federal employees.

Workplace charging is a critical part of the infrastructure that will speed deployment of plug-in electric vehicles (PEVs). The federal government should lead by example in developing alternative fuel vehicles, but due to uncertainty in authority, many agencies do not offer charging stations. Congress already addressed this situation for areas under the control of the Senate (P.L. 112-167) and the House (P.L. 112-170), but has not extended this authority to federal agencies. The Murray bill would make clear that federal agencies have the authority to install charging stations while also comporting with federal policy that prohibits using appropriated dollars for personal expenses; under the Murray bill, employees would pay for the fuel consumed.

Today, 93 percent of the energy consumed in transportation comes from petroleum, while less than one percent of electricity nationwide is generated from fuel oil. The transportation sector is the second largest consumer of energy in the United States, and PEVs powered by electricity made from domestic energy sources provide customers with an economical alternative to "filling up" gasoline-dependent vehicles. While the generation of electricity is not responsible for this country's dependence on oil, electrification of the transportation sector can be part of the solution.

S. 1222—Continuity of Electric Capacity Resources Act (Murkowski)

Turning to S. 1222, Chairman Murkowski's bill to address issues in electric capacity markets, we appreciate that she shares our goal of reforming these markets so they work for the benefit of electricity consumers. In the organized wholesale markets, EEI has focused on making sure that capacity market rules appropriately value the resources needed to maintain reliability and that the energy price signals accurately reflect the cost of building, maintaining, and operating the electric system. This enables the owners of generation resources to make appropriate investment decisions.

Whether they operate in competitive wholesale markets that are in vertically integrated environments, that are bilateral markets or that are in markets operated by regional transmission organizations (RTOs) or independent system operators (ISOs), EEI's members remain committed to developing and safely delivering the reliable, affordable and increasingly clean electricity necessary to meet their customers' needs. To help reach this goal, policies that support and encourage the development of the resources and services necessary for a reliable energy system must be in place.

A reliable electric supply system requires having adequate electric generation capacity to meet customer needs on demand and a robust electric transmission system in place to ensure energy delivery and reliability. The electric system must also have reliability support, generation fuel availability, and adequate upstream fuel transportation and storage infrastructure to supply primary input fuels to electric generation resources.

The emergence of new technologies, new environmental policies, the evolving fuel mix, and other factors are changing market fundamentals and require policy makers to re-examine and review the regulations, policies and programs currently in place. This includes recognizing the services provided by all generation resources in maintaining resource adequacy and that fuel firmness, diversity, and baseload capacity are essential in ensuring a reliable, resilient, and affordable power supply. It also includes properly recognizing and valuing the electric utility services that are considered "ancillary," but are necessary to system reliability, such as spinning and supplemental reserves, regulation, reactive power, voltage support, black start capabilities, and load-following services.

The long-term investments needed to meet public policy objectives, maintain resource adequacy, and maintain system reliability are promoted by sound, consistent regulatory and market policies. These policies should also preserve the ability of market participants to enter into and rely upon bilateral contracts.

Competitive wholesale electricity markets operated by RTOs and ISOs present unique challenges as the markets must provide both the short and long-term market price signals necessary to promote investment in generation and to recover capital costs. EEI believes the following principles should be considered when developing and implementing policies in these markets:

- Wholesale markets should provide accurate price signals to promote efficient operations as well as mechanisms to ensure long-term resource adequacy (where authorized) and reliability.

- Out-of-market solutions and payments should be minimized as they interfere with the competitive price signals needed for efficient dispatch and to inform long-term investment decisions.

- Competitive market rules should not favor any one corporate structure, business or regulatory model, technology or fuel source over another.

- The administrators of competitive markets should be independent from undue influence by market participants, and fully committed to market integrity, and the constant pursuit of market rules that support efficient operations, investment and entry and exit. Such rules should be consistent with competitive market forces.

In reviewing S. 1222, we offer the following observations on the capacity market provisions:

- The bill requires RTOs and ISOs to file tariff amendments that achieve a number of objectives – one of which is a diverse generation portfolio. While EEI supports the goal of having a diverse and flexible resource mix, this language appears to require RTOs and ISOs to engage in a form of integrated resource planning, which has not been the traditional role of organizations set up to coordinate and direct transmission system operations and administer wholesale markets under rules approved by the Federal Energy Regulatory Commission (FERC). However, electricity markets are changing, and there is no longer the excess generation that was present when the organized markets were created. In order to maintain this diversity, regional market rules may need to be reformed to incent efficient investment decisions and to compensate resources for the attributes that they provide to the grid.

- The bill requires transmission organizations to include in their reports to FERC an evaluation of the financial health, viability, and projected remaining years of service of available electric capacity resources. We do not believe the transmission organizations have this information. Given that many of them are located in regions with competitive retail markets, some of this information is proprietary, confidential, and business-sensitive. And, with respect to the projected remaining years of service of available capacity resources, this information is simply unknown. For example, as electric utilities begin to plan for implementation of a final rule under the Environmental Protect Agency (EPA) proposed Clean Power Plan (CPP), they will need to make decisions affecting their generating facilities based on state implementation plans that are not even required to be filed until 13 months after the EPA guidelines are final.

- The bill requires transmission organizations to identify over short- and long-term periods announced and projected generation retirements. Again, most transmission organizations are not aware of retirements until they are announced, making long-term projections very difficult.

- It is unclear what is meant by enhanced self-supply provisions. The transmission organizations that have capacity markets already have self-supply provisions, which in many cases, due to the potential impact on the market, are the result of extensive negotiation between the stakeholders in the region. If this provision is included, it is unclear why it would be limited to cooperatives and state utilities.

Turning to the provision of S. 1222 amending Section 202(c) of the Federal Power Act, we are concerned about whether the bill language is broad enough to provide assurance that any action or omission taken to comply with a DOE emergency order will not be considered a violation of environmental laws and regulations for any purpose. It is important that this language is sufficiently broad to protect generators against potential threats of enforcement actions, fines, penalties, orders, and citizen suits, not just legal liability, during a power supply emergency.

S. 1236—Hydropower Improvement Act of 2015 (Murkowski)

EEI strongly supports S. 1236, introduced by Chairman Murkowski, to improve and rationalize the process for licensing hydropower projects. In particular, we support placing lead agency authority for all federal authorizations related to a hydropower project with FERC, including the responsibility to develop a consolidated record of decision, the authority to set deadlines, and to evaluate and consider alternative conditions under section 4(e) and the fishway prescriptions under section 18.

We appreciate that the bill clarifies that conditions proposed by the Secretaries under these sections should have a direct nexus to the project and its impacts. We applaud the improvements to the trial-type hearing process, especially the bill's provision that moves these hearings under FERC's jurisdiction. We find considerable value in the thoughtful revisions proposed by the bill. We believe they can lead to a more efficient, cost-effective, timely, and rational process for licensing and relicensing hydropower projects, which the bill recognizes as an important and significant renewable resource.

S. 1264—Renewable Electricity Standard Act (Udall)

EEI strongly opposes S. 1264, introduced by Senator Udall, which would amend the Public Utility Regulatory Policies Act (PURPA) to establish a mandatory federal renewable electricity standard (RES). S. 1264 would impose a mandate requiring electricity suppliers—other than government-owned utilities or electric cooperatives—to generate an increasing percentage of their electricity from certain renewable energy resources. The mandate would be 7.5 percent this year, increasing to 30 percent by 2030.

Congress has been debating electricity portfolio standard mandates for more than a decade. At the same time, electricity markets have changed rapidly. It is time for the congressional energy policy debate to catch up with today's realities in electricity markets. A federal renewable electricity standard (RES) requirement is a stale, supposed solution in search of a problem. It would create winners and losers among states, electricity generators, and electricity suppliers, while imposing new burdens on electric operations and reliability.

A federal RES mandate also is out-of-date in light of EPA's proposed CPP guidelines, which are expected to be finalized later this summer. As mentioned earlier, states will have thirteen months after the rule is finalized to file implementation plans. One of the building blocks in the CPP is the deployment of more renewable energy resources; this is going to be a significant driver of additional new renewable energy resources. Layering a federal RES mandate that doesn't necessarily match EPA's proposed state targets on top of the CPP further threatens the fuel diversity and flexibility needed to help ensure stability and reliability in electricity supply, and it could further complicate some states' efforts to devise and implement their CPP compliance plans.

Twenty-nine states and the District of Columbia already have renewable electricity portfolio standards. Another eight states have renewable portfolio goals. States have taken the lead in establishing portfolio levels and eligible renewable resources tailored to their individual state circumstances. A federal RES mandate would shoehorn states into a one-size-fits-all approach that would conflict with many existing state programs.

In addition, renewable energy resources already enjoy significant subsidies:

- 24 states offer either personal tax credits or corporate tax credits or both for renewables;
- 28 states and Puerto Rico offer sales tax incentives for renewables;
- 16 states and the District of Columbia offer rebates for renewables;
- 15 states, the District of Columbia and Puerto Rico have public benefits funds estimated to total $7.7 billion by 2017 that benefit renewable energy;
- 38 states, the District of Columbia and Puerto Rico offer property tax incentives for renewables;
- 41 states offer loan programs for renewables; and
- 22 states offer grant programs for renewables.

Interestingly, S. 1264 does not apply the federal mandate evenly and fairly to all retail electricity suppliers. Instead, the RES mandate applies only to shareholder-owned electricity suppliers, but not to government-owned utilities or electric cooperatives. If supporters of a federal RES want to boost renewable energy throughout the country, as they claim, then the bill's mandate should apply to all retail electricity suppliers, not just selectively to some. The selective approach in S. 1264 would unfairly increase electricity prices for consumers of shareholder-owned retail electricity suppliers.

Like all energy resources, renewable energy resources have their benefits and their challenges. Most renewable energy resources are variable in nature – the wind doesn't always blow, and the sun doesn't always shine – so they cannot be dispatched when they are most needed to meet electricity demand. Until large-scale energy storage is widely deployed, most renewable energy resources cannot be counted on for round-the-clock, baseload generation. And, renewable energy resources do not provide the same grid stability services that baseload generation resources do to maintain reliable electric service.

Some proponents of RES proposals have argued that all energy resources face challenges, such as droughts or cold weather. This is true, but there is a huge difference between promoting fuel diversity and mandating specific fuel choices. That is why fuel diversity has always been an important objective for utilities and why utilities plan for contingencies that will impact their generation fleet.

The availability of renewable resources also varies greatly among regions. While renewable energy costs have fallen, in regions that are not blessed with abundant renewable resources a national renewables mandate would drive up electricity prices, with the heaviest burden falling on low-income consumers who can least afford it. Utilities in many states would have to comply by making alternative compliance payments to the federal government, with no guarantees that additional renewable generation actually will be developed.

A federal RES mandate could supersede or preempt existing state RES plans – each of which has been tailored to fit available resources and electricity markets in that state – resulting in additional costs and uncertainty to ongoing renewable programs. Virtually every state RES program includes energy resources that are not recognized under S. 1264 as a renewable energy resource. For example, many state RES programs provide credit for existing hydropower, and this is an important renewable energy resource for many electricity suppliers in meeting their state programs. S. 1264 does not provide federal credits for existing hydro – only incremental hydro. In addition, while S. 1264 includes language requiring DOE to "facilitate coordination" with state programs and "incorporate common elements of existing [state] renewable energy programs," that is a far cry from providing federal credits for all of a utility's state-eligible renewables.

Our industry has had many bad experiences with congressionally-imposed fuel mandates that have raised electricity prices for our consumers. For example, the Fuel Use Act of 1978 prohibited the use of natural gas to produce electricity because natural gas resources were expected to become scarce; that prohibition was finally repealed in 1987. PURPA, which also was enacted in 1978, mandated that utilities purchase certain types of power from certain energy producers at government-determined prices. Electricity consumers continue to pay above-market prices for electricity because of the PURPA mandatory purchase obligation. We do not need a repeat with another federal fuel mandate on electric companies.

Significant changes are underway across the electric power sector. Our industry continues to transform how electricity is generated and delivered. Our fuel mix is changing and becoming cleaner, but our fuel sources remain diverse and homegrown—natural gas, coal, nuclear, and renewable energy, including water, wind, and sun. It is critical that utilities continue to have the entire fuel portfolio available to ensure that electricity remains affordable and reliable for consumers.

During the debate over the Keystone XL pipeline bill earlier this year, the Senate rejected a similar RES proposal from Senator Udall by a 45-53 vote. We urge the Senate again to reject efforts to impose even more mandates and fuel restrictions on electric companies.

S. 1282, S. 1283 and S. 1285 (Manchin)

S. 1282, S. 1283 and S. 1285 are intended to promote the development, deployment and commercial viability of advanced clean coal technologies, a goal that EEI supports.

As the electric generation fleet continues to undergo dramatic changes, EEI's member companies remain committed to their core mission: to provide a reliable, affordable, and environmentally sustainable supply of electricity to their customers. A balanced and diverse mix of fuel sources – including coal – will continue to be a critical part of the industry's strategy for fulfilling this important mission.

S. 1304—A bill to require the Secretary of Energy to establish a pilot competitive grant program for the development of a skilled energy workforce, and for other purposes (Cantwell)

EEI strongly supports S.1304, introduced by Ranking Member Cantwell. S.1304 is a holistic and comprehensive approach to energy workforce development that takes into account opportunities for career coaching and support for state consortia that will enhance efforts to encourage a diverse group of students to pursue careers in the energy sector.

Over the next decade, more than half of today's skilled utility workforce is expected to turn over, and more than one-third of the workforce may need to be replaced over the next five years. Thankfully, work is already underway to address this change. In 2006, electric and natural gas utilities and their trade associations – EEI, American Gas Association, Nuclear Energy Institute, and National Rural Electric Cooperative Association – formed the nonprofit Center for Energy Workforce Development (CEWD). CEWD brings together energy utilities, organized labor, the public workforce system, educators, and other stakeholders to improve the pipeline of workers by identifying career pathways and creating workforce development solutions to fill this gap

Working with those stakeholders, CEWD has created State Energy Workforce Consortia covering more than 35 states. These consortia can focus on the particular needs of a state or region. Together, CEWD and the State Energy Workforce Consortia have cut the time it takes to get applicants trained and into jobs as well as saved time and money by sharing curricula and best practices. EEI appreciates that Senator Cantwell's bill gives priority consideration to programs that work with state or regional consortia. These consortia focus on calibrating the programs offered with the workforce needs.

One area where more assistance is needed and where more focus is merited is in the area of wrap-around services and career coaching. For the funding spent on curriculum development and partnerships to be effective, students must be able to get to and stay in the classroom. Wrap-around services, such as defraying the cost of transportation or childcare, can mean the difference between success and failure. Providing career coaching to understand both the education and workforce worlds has proven to increase the percentage of students who complete training programs. EEI similarly appreciates that Senator Cantwell's bill gives priority to programs that provide career coaching and wrap-around services.

Conclusion

EEI appreciates this opportunity to submit this statement for the record, and commends the Committee for taking a fresh look at the public policy issues facing a changing electric power industry. We look forward to working with the Committee as it moves forward with energy legislation.

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June 1, 2015

The Honorable Lisa Murkowski
Chairman, Senate Committee on Energy and Natural Resources
United States Senate
304 Dirksen Senate Office Building
Washington, DC 20510

Dear Chairman Murkowski,

Thank you for your leadership in developing bipartisan energy legislation. In particular, we thank you for introducing S. 1222, requiring the Federal Energy Regulatory Commission ("FERC" or "the Commission") to direct transmission organizations that operate electric capacity markets to file reports and tariff amendments to the Commission.

Our industry is in a period of significant changes and transition. Policies must adapt with this transition in order to ensure reliability over the near and long term. Organized markets are not sending the necessary signals to incent essential reliability services.

Up until recently, capacity was synonymous with reliability as virtually all capacity procured in the capacity markets came from generation that had essential reliability attributes. Today, however, organized markets are becoming increasingly reliant on generation that is less reliable and less dependable. A diverse energy mix is good, but not all generation shares the same reliability attributes. As such, capacity no longer equals reliability. Policies must adjust to this reality.

Capacity markets must properly value and incent reliability services like voltage support and frequency regulation, and ensure short and long term reliability.

Over the last few years we have seen the premature loss of a significant number of generation units that provided essential reliability services to the grid. And many more similar units in organized markets are under stress and are at risk of premature retirement. If policies do not adjust to the reality of today, we will have an unacceptable erosion of reliability in organized markets.

Your legislation recognizes the importance of reliability attributes and seeks to ensure that capacity markets deliver the reliability that our customers expect and what the markets were originally designed to deliver. Thank you for making reliability a priority and for introducing S. 1222.

Sincerely,

Statement of the Geothermal Energy Association

Submitted to the

Senate Energy and Natural Resources Committee

May 19, 2015

Chairman Murkowski, Ranking Member Cantwell, and Members of the Committee, thank you for the opportunity to submit this statement to the Committee as it considers legislation to spur greater energy production.

The Geothermal Energy Association represents over 120 companies involved in the production and use of geothermal energy in the United States and around the world. Today, utility scale geothermal power facilities are producing clean baseload electricity in seven states and nearly 30 different countries. U.S geothermal power plants provide roughly 3,500 MW of baseload electrical capacity.[i]

Geothermal Energy

The potential for geothermal energy production in the U.S. is significant, but still largely untapped. According to the US Geologic Survey, there are 3,675 MW to 16,457 MW in identified geothermal systems; 7,917 MW to 73, 286 MW in undiscovered systems; and well over 100,000 MW in potential EGS, or Enhanced Geothermal Systems.[ii]

There are many good reasons to support expanding geothermal power production.[iii]

- **Flexibility.** Geothermal power is the only renewable resources that can provide both baseload and ancillary services such as load following, ramping, and spinning reserve.
- **Reliability.** Geothermal electricity production does not depend on the climate or weather and is reliably available.
- **Job Creation.** Geothermal power helps create and maintain high-paying jobs in both the clean energy and the oil and gas sectors. The average 50 MW facility will create permanent employment for about 100 people. Geothermal power facilities employ both clean energy & drilling engineers, including blue collar welders, plumbers, electricians and technicians as well as white collar lawyers, executives, and management. Build more geothermal across the U.S. and we will create employment for both the oil and gas sector and the renewable sector, while producing clean power! This means we can repurpose our unemployed drillers and oil exploration companies (due to cheap oil prices) in the effort to explore and develop our nation's untapped geothermal resources.
- **A Small Footprint.** Geothermal power has a much smaller development footprint compared to other energy sources, particularly when weighed against other renewables.

Unlike solar, wind, and biomass sources, which are predicated upon gathering diffuse ambient energy over large tracts of land, geothermal power exploits a concentrated, subterranean resource. This plant design equates to less surface area needed to produce comparable levels of power. If we build geothermal we have less tradeoff between developing public lands and protecting their beauty and undisturbed habitats for future generation. In many countries, geothermal plants are actually designed to camouflage into scenery and landscapes.

- **State and Local Tax Base.** The average geothermal facility will pay $6-11 million dollars of property taxes over the 30 year life of its power sales contract. Expanding the U.S. geothermal fleet to 15 GW, a goal of S. 1057, would generate between $5 and $8.25 billion dollars in property taxes for state and local government.
- **Rents and Royalties.** Additionally, geothermal energy facilities paid about $26 million in Rents and Royalties to state, federal and local governments nationwide in 2014 of which quarter (about $19.5 million) is returned to benefit state and local county governments. Expanding the geothermal fleet to 15 GW would generate close to $111 million annually in rents and royalties.

The US Geothermal Energy Market

Today, the US geothermal power market is in the doldrums, even as the world market is booming. As leaders in geothermal technology and expertise, US firms are very active in the world market, and are we estimate involved in 75% of the countries developing geothermal power.[iv] Yet the domestic market is seeing limited growth in new geothermal projects.

Why the disparity? To understand the issues involved, some brief background on geothermal power is needed.

Geothermal projects require expensive high risk exploration. As noted in the USGS estimate cited earlier, most of the geothermal resources in the US are either "undiscovered" or require advanced technology that is still under development, EGS. The high initial risk is compounded by the long-lead times required for project development, much of which is driven by governmental requirements.[v]

In global markets, the World Bank and other lenders have worked to reduce exploration risk. Through both direct funding and insurance mechanisms, global lenders have helped reduce risk and shorten the exploration lead time. This has spurred development by reducing the time and discount rate for financing exploration, with dramatic results. In the past few years, we have seen the number of countries pursuing geothermal development nearly triple, with over 80 countries now pursuing projects at some stage of development.

In addition to the upfront risk, geothermal projects in the U.S. face lead times that can be as long as ten years! Recent analysis by NREL indicates that "with no permit issues, a project could be developed (from start of exploration to power online) in 3 to 3.5 years."[vi] But, geothermal projects are subject to repeated, duplicative NEPA and related permitting requirements. A geothermal energy facility on Federal lands is typically subject to NEPA processes when the land is leased, and again when exploratory wells are drilled to assess the geothermal resource, and still again when the geothermal facility is constructed. "Geothermal development project can go through as many as six NEPA analyses," the NREL analysts have concluded.[vii]

While geothermal projects have been helped by federal renewable energy incentives, such as the Production Tax Credit (PTC) and the Investment Tax Credit (ITC), the relatively long lead times of geothermal development makes the comparatively short-term nature of federal incentives a mismatch. For example, the PTC was extended at the end of last year with two weeks remaining. Perhaps some developers of other technologies can utilize a two-week window to qualify for a tax credit, but geothermal projects cannot meaningfully benefit from such short-term incentives.

Legislation before the Committee

Legislation before the Committee today would address some of the most important barriers to geothermal development in the U.S. Three bills are of note, S. 562, S.822, and S. 1057. Since the provisions of S. 822 are also included in S.1057 we will address the later legislation in our statement for brevity.

S562. GEA supports the provisions of S. 562 and urges the Committee to include them in any energy legislation reported. This legislation would provide geothermal exploration the same treatment afforded oil and gas exploration under the 2005 Energy Policy Act – a limited categorical exclusion -- with the additional restriction for lands or resources viewed as involving extraordinary circumstance.

This legislation would help reduce the process time for geothermal development at one of its most critical moments – exploration. Given the multiple NEPA processes required for geothermal development, and the inclusion of a restriction for lands involving extraordinary circumstances, we believe this process improvement can be made without risk to the environment.

S1057. GEA also supports the provisions of S1057, and urges the Committee to include them in any energy legislation it reports. This legislation includes a number of important provisions which together would facilitate a collaborative industry-government effort to expand geothermal energy production in the U.S.

1) The bill establishes National Geothermal Goals. This recommendation is consistent with the recommendation of leading industry, government and scientific exploration experts made as a result of a workshop convened by the Great Basin Center for Geothermal Energy (GBCGE), in collaboration with the DOE Geothermal Technology Program office (DOE-GTP) and the Geothermal Energy Association. The first overall

recommendation of the experts convened was: "The Department of Energy (DOE) should set a goal of identifying within the next ten years sites capable of producing 50,000 - 100,000MW of geothermal power (5-10% of total US power generation), utilizing the full range of technologies, through a sustained national exploration effort, significantly supported by long-term federally funded programs."[viii]

2) The bill directs the Bureau of Land Management, along with other federal agencies, to identify Priority Areas for Geothermal Development. The Secretary of Interior signed a Record of Decision in October 2012 to create and promote priority areas for solar energy development on public lands.[ix] Given the importance of geothermal for Western energy development, and the greater financial return from geothermal development, we believe this provision is important.
3) The bill allows federal oil and gas lease holders to obtain a non-competitive geothermal lease to facilitate coproduction of geothermal from their wells when practicable. The Department of Energy estimates that "25 billion barrels of hot water is produced annually from oil and gas wells within the United States." Unfortunately, the geothermal leasing laws when they were revised in 2005 did not anticipate this issue, and there are permitting obstacles that prevent oil and gas facilities using this resource to produce electricity. S. 1057 corrects the problem and could facilitate significant new geothermal electricity production.[x]
4) The bill authorizes cost shared exploration of geothermal energy resources. The DOE and USGS have both utilized industry-governmental partnerships to facilitate exploration and, in particular, help expand knowledge of the undiscovered geothermal resource base. Authorizing a new partnership will help reduce risks, develop new technology, and provide data critical to the achievement of the national goals set by the legislation.
5) The bill re-authorizes the use of geothermal lease revenues to support the expansion of our knowledge of the resource base. EPACT 2005 utilized geothermal revenues to re-start the geothermal leasing program, which had been dormant for more than a decade. This legislation seeks to use these revenues to support the exploration of the resource base needed to characterize the still undiscovered potential of geothermal energy.
6) Finally, the bill incorporates the provisions of S.822, which seek to facilitate new discoveries, by allowing the limited leasing of adjacent lands where a new discovery has been made. These provisions will encourage production by avoiding the delays that would otherwise be required, and includes provisions to ensure that fair market value is received.

Conclusion

The Geothermal Energy Association respectfully urges the committee to support the important legislative measures introduced by members from both sides of the aisle to help spur development of the substantial untapped geothermal energy resources here in the U.S. In particular, we urge support for S. 1057, the Geothermal Energy Opportunities Act, introduced by

Senator Wyden; and S. 562, the Geothermal Exploration Opportunities Act of 2015, introduced by Senator Heller.

The clean baseload geothermal energy produced as a result of these important measures will help the nation achieve a more diverse and reliable electricity supply, even as it reduces emissions, helps state and local economies, and creates jobs in both the oil and gas, and the renewable sectors.

Thank you for your time and attention. I would of course be happy to provide additional information or answer any questions from members of the panel.

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[i] Geothermal Energy Association, *2015 Annual U.S. & Global Geothermal Power Production Report*, February 2015, available at: http://geo-energy.org/reports/2015/2015%20Annual%20US%20%20Global%20Geothermal%20Power%20Production%20Report%20Draft%20final.pdf

[ii] USGS, *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*, 2008, available at: http://pubs.usgs.gov/fs/2008/3082/

[iii] Geothermal Energy Association Issue Brief: *Additional Economic Values of Geothermal Power*, February 2015, available at: http://geo-energy.org/events/Geothermal%20Energy%20Association%20Issue%20Brief_Economic%20Values%202015_Final.pdf

[iv] Geothermal Energy Association, *The International Geothermal Market At a Glance*, May 2015, *http://geo-energy.org/reports/Int'lMarketataGlanceMay2015Final5_14_15.pdf*

[v] For more discussion of geothermal risks and efforts to address them, see:
Best Practices for Geothermal Power Risk Reduction Workshop Follow-Up Manual, 2014, available at: http://geo-energy.org/reports/Geothermal%20Best%20Practices%20Publication%20Final%20CL188154847.pdf

[vi] Katharine R. Young, National Renewable Energy Laboratory, *Policy and Regulatory Concerns Impacting the Geothermal Industry*, State of the Geothermal Industry Briefing, February 24, 2015.

[vii] *Ibid.*

[viii] Great Basin Center for Geothermal Energy, *Report on Workshop on Exploration and Assessment of Geothermal Resources*, September 21-22, 2010, Reno, NV, available at: http://geo-energy.org/pdf/Wkshop_Report_Final.pdf

[ix] http://www.blm.gov/wo/st/en/info/newsroom/2012/october/NR_10_12_2012.html

[x] If DOE's identified potential for co-production of 3000MW is even partially achieved, this provision would generate significant new royalty revenues through royalties.

Statement for the Record -- Senator Dean Heller
Senate Committee on Energy and Natural Resources
Legislative Hearing on the Geothermal Exploration Opportunities Act of 2015 (S.562)
May 19, 2015

Chairman Murkowski and Ranking Member Cantwell, thank you for holding today's hearing. It is great to be part of this robust conversation on our nation's long-term energy strategy. Energy is one of the most far-reaching commodities touching the lives of just about every single American today. Whether we're discussing the economy, jobs, or national security, energy finds itself at the forefront of many important issues facing our nation. That's why it is imperative we address the need for comprehensive energy legislation.

I appreciate that my bill, the Geothermal Exploration Opportunities Act, was included in the long list of proposals being considered today and look forward to working with you on advancing it and many of the other common-sense ideas my colleagues are offering.

Energy is one of Nevada's greatest assets, and I believe that continuing to develop renewable and alternative sources of energy is not only important to my state, it is important for our nation's economic future. Today, more than 23 percent of Nevada's total electricity generation, 2,300 megawatts of capacity, comes from renewables. That far exceeds the national average.

Geothermal energy production in particular has been a real boon in the state, providing low cost base load electricity. Since 2005, the United States has built over 38 geothermal power projects, including more than fifteen in Nevada alone.

Although we have had a lot of successes across the West, including Nevada, we have the potential to do more. The U.S. Geological Survey (USGS) estimates nearly 90 percent of the geothermal energy potential in the nation is on federal lands. Our nation's public lands must play a critical role in our nation's effort to improve energy independence, but uncertainty in the permitting process impedes or delays our ability to harness their renewable energy potential.

Many companies tell me that the process to develop on federal lands is simply too difficult, causing them to abandon any efforts to develop projects in those areas. In a state like Nevada, which is over 85% federal land, that sentiment is a death sentence. Our state lives and dies by resources development on our federal lands, such as mining, energy production, and ranching.

From my conversations, one of the largest impediments to capitalizing on this abundant resource is the bureaucratic red tape on geothermal exploration test projects. For those of you unfamiliar with geothermal development, drilling accounts for over half the costs, and exploration of deep resources entails significant risks. For example, a typical well in Nevada can support 4.5 megawatts (MW) of electricity, but costs about $10 million to drill, with a 20% failure rate.

Under current regulations, companies must go through a lengthy environmental review process just to test if a resource is viable, despite causing minimal surface disturbance. The process to obtain a lease for exploration can be difficult, time consuming, and cost prohibitive. In fact, the

National Renewable Energy Laboratory (NREL) estimates that approval for simple exploration activities takes between 18 to 24 months.

That simply does not make sense, and that is why Senator Risch and I introduced the Geothermal Exploration Opportunity Act – the GEO Act – which will streamline the review process for simple exploration activities.

In short, it creates a new limited categorical exclusion for exploration activities, based off a policy created under the bipartisan Energy Policy Act of 2005 so that companies can test on public lands in Nevada, Idaho, Alaska, and other western states to see if a resource is viable before going through a multi-year environmental review process.

I want to be clear my legislation does not affect any of the analysis that would need to be conducted if a developer decided to move forward with a power station, simply the exploratory testing.

This bill is another piece to the puzzle that will allow our federal lands to play a major role in our country's all-of-the-above energy future. I have seen first-hand in Nevada, where we have made tapping our geothermal resources a priority, the impact these projects can have in communities. I hope we can increase production in my state and make similar gains across the west.

Thank you again for considering my bill. I stand ready to help your efforts to implement comprehensive legislation which will modernize our nation's long-term all-of-the-above energy strategy.

###

*** Alabama Rivers Alliance * Alaska Hydro Project * Alpine Lakes Protection Society * Altamaha Riverkeeper * American Rivers * American Whitewater * Appalachian Mountain Club *California Hydropower Reform Coalition * California Outdoors * California Sportfishing Protection Alliance * Cascadia Wildlands * Center for Environmental Law & Policy * Center for Sierra Nevada Conservation * Central Sierra Environmental Resource Center * Clean Oceans Competition * Columbia River Bioregional Education Project * Connecticut River Watershed Council * Conservation Law Foundation * Conservation Northwest * Defenders of Wildlife * Downeast Salmon Federation * Earthjustice * Environment America * Farmington River Watershed Association * Foothill Conservancy * Friends of Living Oregon Waters * Friends of Merrimeeting Bay * Friends of the Earth * Friends of the Eel River * Friends of the Kinni * Friends of the River * Friends of the White Salmon * Georgia River Network * Golden West Women Flyfishers * Greater Edwards Aquifer Alliance * Hells Canyon Preservation Council * Hydropower Reform Coalition * Idaho Rivers United * Kalmiopsis Audubon Society * Kentucky Waterways Alliance * Kettle Range Conservation Group * Klamath-Siskiyou Wildlands Center * Los Padres ForestWatch * Lower Columbia Canoe Club * Lower Mississippi River Foundation * Maine Rivers * Maryland Conservation Council *Michigan Hydro Relicensing Coalition * Mono Lake Committee*Natural Resources Defense Council * Naugatuck River Revival Group * New England FLOW * North Cascades Conservation Council * North Coast Rivers Alliance * Northwest Environmental Advocates * O.A.R.S * Olympic Forest Coalition * Oregon Forest Coalition * Oregon Kayak and Canoe Club * Oregon Wild * Pacific Rivers Council * Planning and Conservation Council * Protect American River Canyons * River Alliance of Wisconsin * River Management Society * Rogue Riverkeeper * Save Our Wild Salmon * Sierra Club * Sierra Nevada Alliance * Smith River Alliance * Snake River Waterkeeper * South Yuba River Citizens League * Southern Environmental Law Center * Spearfish Canyon Society * Spokane Riverkeeper * Steamboaters * The Lands Council * The Mountaineers * The Rivers Institute * Tualatin Riverkeepers * Tuolumne River Trust * Umpqua Audubon Society *Vermont Natural Resources Council * Washington Wild * WaterWatch of Oregon * WESPAC Foundation * Wild Fish Conservancy * Wild Steelhead Coalition * Wild Washington Rivers ***

May 28, 2015

The Honorable Lisa Murkowski and Committee
Chairman, U.S. Senate Committee on Energy and Natural Resources
304 Dirksen Senate Building
Washington, DC 20510

The Honorable Fred Upton and Committee
Chairman, U.S. House Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

Dear Senators and Representatives:

On behalf of our millions of members across the country, we are writing you in strong opposition to the draft hydropower legislation being considered by the House Energy and Commerce Committee, as well as S. 1236 being considered by the Senate Energy and Natural Resources Committee.

If enacted, these bills would upend the carefully crafted balance between competing interests on public waterways that has been in place since President Wilson signed the Federal Power Act in 1920. If they were to become law, they would open new loopholes that would allow hydroelectric operators to avoid complying with the Endangered Species Act, the Clean Water Act, and any and all federal land management statutes crucial to protecting our nation's valuable natural resources.

Further, these bills are an unprecedented federalization of State authority over water. The bills strip the States and many Native American tribes of their historic right to manage and control water resources and to protect water quality, giving it to the unelected and virtually unaccountable Federal Energy Regulatory Commission (FERC) headquartered in Washington, DC.

By exempting power companies from environmental laws, the Committee draft would shift the responsibility for complying with these laws onto farmers, ranchers, industrial facilities, municipal water and sewer providers, and small businesses.

The House Energy and Commerce Committee draft and S. 1236 strip public land management agencies of their authority to manage water on public lands. These bills give the final authority on how public lands will be managed to FERC, an agency that has a mandate to permit energy projects, not manage federal property.

By removing the final authority to protect fisheries from the National Marine Fisheries Service, the agency tasked with managing fisheries, these bills give FERC the final say on how the impacts of hydropower dams on recreational fisheries and commercial fisheries can best be managed.

The House Committee draft also gives unprecedented, sweeping authority to FERC to reopen any and all licenses that have already been issued, even if they are the result of a settlement agreement signed by multiple parties. Under the House Committee draft, a hydropower operator can petition FERC to reopen the license and retroactively reject provisions that the States or natural resource agencies felt were necessary to protect the public interest. In addition, both bills discourage FERC from using modern science and site-specific studies to analyze dams' impacts on natural resources

Incredibly, S.1236 waives FERC's ex parte rules for communications between Commission staff and power companies applying for a new license. The bill thus allows secret, off–the-record meetings between FERC staff and energy corporations with no prior public notice or transcript.

Hydropower licenses are issued for up to 50 years. Hydropower facilities that are coming up for relicensing now were first constructed before the Clean Water Act, the Endangered Species Act, and virtually all other environmental laws. It is during relicensing proceedings that the public gets the opportunity to ensure that dam owners make the necessary changes to get their facilities up to modern standards. The opportunity to mitigate for the damage to the environment, while still providing reliable electricity, only arises once in a generation or two. If we don't get a license right, we are forced to live with that mistake for more than four decades.

The balance that has existed for almost a century protects the public's right to enjoy their rivers for recreation, drinking water, agriculture, and their natural beauty. This balance can and should be compatible with responsible electricity production. The House Committee draft and S. 1236 upend that balance by instead transferring all authority to FERC, which has neither the inclination nor the expertise necessary to protect the environment or the interests of the States.

Congress should reject these bills and with them the narrow interests of the large energy corporations that seek to maximize their profits and minimize their responsibilities to the public.

Sincerely,

Alabama Rivers Alliance
Alaska Hydro Project
Alpine Lakes Protection Society
Altamaha Riverkeeper
American Rivers
American Whitewater
Appalachian Mountain Club
California Hydropower Reform Coalition
California Outdoors
California Sportfishing Protection Alliance
Cascadia Wildlands
Center for Environmental Law & Policy
Center for Sierra Nevada Conservation
Central Sierra Environmental Resource Center
Clean Oceans Competition
Columbia River Bioregional Education Project
Connecticut River Watershed Council
Conservation Law Foundation
Conservation Northwest
Defenders of Wildlife
Downeast Salmon Federation
Earthjustice
Environment America
Farmington River Watershed Association
Foothill Conservancy
Friends of Living Oregon Waters
Friends of Merrimeeting Bay
Friends of the Earth
Friends of the Eel River
Friends of the Kinni
Friends of the River
Friends of the White Salmon
Georgia River Network
Golden West Women Flyfishers
Greater Edwards Aquifer Alliance
Hells Canyon Preservation Council
Hydropower Reform Coalition
Idaho Rivers United
Kalmiopsis Audubon Society
Kentucky Waterways Alliance
Kettle Range Conservation Group
Klamath-Siskiyou Wildlands Center
Los Padres ForestWatch
Lower Columbia Canoe Club
Lower Mississippi River Foundation
Maine Rivers
Maryland Conservation Council
Michigan Hydro Relicensing Coalition
Mono Lake Committee
Natural Resources Defense Council
Naugatuck River Revival Group, Inc
New England FLOW
North Cascades Conservation Council
North Coast Rivers Alliance
Northwest Environmental Advocates
O.A.R.S.
Olympic Forest Coalition
Oregon Forest Coalition
Oregon Kayak and Canoe Club
Oregon Wild
Pacific Rivers Council
Planning and Conservation Council
Protect American River Canyons
River Alliance of Wisconsin
River Management Society
Rogue Riverkeeper
Save Our Wild Salmon
Sierra Club
Sierra Nevada Alliance
Smith River Alliance
Snake River Waterkeeper

South Yuba River Citizens League
Southern Environmental Law Center
Spearfish Canyon Society
Spokane Riverkeeper
Steamboaters
The Lands Council
The Mountaineers
The Rivers Institute
Tualatin Riverkeepers
Tuolumne River Trust
Umpqua Audubon Society
Vermont Natural Resources Council
Washington Wild
WaterWatch of Oregon
WESPAC Foundation
Wild Fish Conservancy
Wild Steelhead Coalition
Wild Washington Rivers

Industrial Energy Consumers of America
The Voice of the Industrial Energy Consumers

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May 22, 2015

The Honorable Lisa Murkowski
Chairman
Senate Committee on Energy and Natural Resources
709 Hart Senate Office Building
Washington, DC 20510

Re: IECA Supports S. 1215, the "Methane Hydrate Research and Development Amendments Act of 2015"

Dear Chairman Murkowski:

On behalf of the Industrial Energy Consumers of America (IECA), we support passage of S. 1215, the "Methane Hydrate Research and Development Amendments Act of 2015." It is important to U.S. supply long-term that we develop methane hydrate resources as a commercially viable source of energy.

IECA companies are energy-intensive trade-exposed (EITE) industries, which means that relatively small changes to the price of energy can have significant negative impacts to our competitiveness. EITE industries consume 75 percent of the entire manufacturing sector's use of natural gas (29% of U.S. demand), and 82 percent of all energy from the manufacturing sector.

The U.S. has 85 trillion cubic feet (Tcf) of known methane hydrate reserves onshore Alaska, and 13,000 Tcf offshore in the Gulf of Mexico and Atlantic Ocean. This is a significant potential supply of natural gas and we need to find ways to tap this vast energy resource.

We thank you for your leadership on this important legislation and look forward to working with you.

Sincerely,

Paul N. Cicio
President

cc: Senate Committee on Energy and Natural Resources

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 2,900 facilities nationwide, and with more than 1.4 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemical, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, brewing, independent oil refining, and cement.

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May 22, 2015

The Honorable Lisa Murkowski
Chairman
Senate Committee on Energy and Natural Resources
709 Hart Senate Office Building
Washington, DC 20510

Re: IECA Supports S. 1226, the "American Helium Production Act of 2015"

Dear Chairman Murkowski:

On behalf of the Industrial Energy Consumers of America (IECA), we support passage of S. 1226, the "American Helium Production Act of 2015."

We are supportive of establishing a leasing program for helium exploration, development, and production, and identifying areas that are open to helium production. Helium is a natural element that is generally extracted from natural gas and used in industrial processes.

As the Federal Helium Reserve enters its final years of operation, the U.S. risks having a substantial share of its current helium supply go offline, without any guarantee of replacement from new private development. We support a standardized leasing process for helium development on federal lands. Currently, ownership of helium on federal lands is reserved to the government and leaseholders must request the rights to develop helium on a case-by-case basis.

We thank you for your leadership on this important legislation and look forward to working with you.

Sincerely,

Paul N. Cicio
President

cc: Senate Committee on Energy and Natural Resources

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 2,900 facilities nationwide, and with more than 1.4 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemical, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, brewing, independent oil refining, and cement.

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May 22, 2015

The Honorable Lisa Murkowski
Chairman
Senate Committee on Energy and Natural Resources
709 Hart Senate Office Building
Washington, DC 20510

Re: IECA Supports S. 1236, the "Hydropower Improvement Act of 2015"

Dear Chairman Murkowski:

On behalf of the Industrial Energy Consumers of America (IECA), we support passage of S. 1236, the "Hydropower Improvement Act of 2015." We are supportive of an all-of-the-above energy approach, which includes hydropower and believe that hydropower should be defined as a renewable energy resource.

IECA companies are energy-intensive trade-exposed (EITE) industries, which means that relatively small changes to the price of energy can have significant negative impacts to our competitiveness. EITE industries consume 73 percent of the entire manufacturing sector's use of electricity (26% of U.S.), 75 percent of the natural gas (29% of U.S.), and 82 percent of all energy from the manufacturing sector.

We also support streamlining the hydropower licensing procedures to reduce regulatory backlog. More than 250 projects, representing about 16,000 MW of capacity, are estimated to require relicensing by 2025. On average it takes eight to ten years to relicense an existing project. S. 1236 will help to reduce the time to relicense.

We thank you for your leadership on this important legislation and look forward to working with you.

Sincerely,

Paul N. Cicio
President

cc: Senate Committee on Energy and Natural Resources

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 2,900 facilities nationwide, and with more than 1.4 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemical, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, brewing, independent oil refining, and cement.

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LONNIE R. STEPHENSON
International President

SAM J. CHILIA
International
Secretary-Treasurer

June 25, 2015

The Honorable Lisa Murkowski
Chair
Energy and Natural Resources Committee
United State Senate
304 Senate Dirksen Building
Washington, DC 20510

The Honorable Maria Cantwell
Ranking Member
Energy and Natural Resources Committee
United States Senate
304 Senate Dirksen Building
Washington, DC 20510

Dear Chair Murkowski and Ranking Member Cantwell:

On behalf of the approximately 750,000 active members and retirees of the International Brotherhood of Electrical Workers (IBEW), I write in support of the *Hydropower Improvement Act of 2015* (S. 1236), legislation to reform the relicensing and regulation of hydroelectric generation.

As the United States moves toward a lower-carbon future, it has become clear that hydropower – the original renewable energy resource – has become burdened with excessive, time-consuming, and costly regulation. Nowhere is this truer than in the relicensing process where procedures for renewal have become difficult and duplicative. Lacking in transparency and efficiency, the process to relicense an existing hydropower facility can, in some cases, take more than a decade.

To help address the issue of relicensing existing carbon-free hydro generation facilities, the *Hydropower Improvement Act of 2015* makes a number of licensing process coordination improvements aimed at addressing permitting backlogs. If adopted by Congress and signed by the President, S. 1236 would improve administrative efficiency and transparency, reduce duplicative oversight, and promote efficient and timely decision-making in the relicensing process.

Hydro generation continues to be a very viable renewable energy resource, which is an essential component of an "all of the above" energy policy. Moreover, being a carbon-free source of electricity, it is incumbent on the federal government to support the efficient and timely relicensing of existing hydropower facilities. I appreciate your attention to this issue and support of the *Hydropower Improvement Act of 2015*.

Sincerely yours,

Lonnie Stephenson

Lonnie Stephenson
International President

Form 200

LRS:mlm

MDE
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Larry Hogan
Governor

Boyd Rutherford
Lieutenant Governor

Ben Grumbles
Secretary

June 2, 2015

The Honorable Lisa Murkowski, Chairman
Energy and Natural Resources Committee
United States Senate
304 Dirksen Senate Building
Washington, DC 20515

The Honorable Maria Cantwell, Ranking Member
Energy and Natural Resources Committee
United States Senate
304 Dirksen Senate Building
Washington, DC 20515

Re: Senate Energy & Natural Resources Committee Hearing *May 19, 2015 on Energy Supply Legislation;* S.1236 – Hydropower Improvement Act

Dear Chairman Murkowski and Ranking Member Cantwell:

The State of Maryland ("Maryland") provides the following comment on S. 1236 – Hydropower Improvement Act. Although Maryland generally welcomes reforms that streamline the FERC licensing process, Maryland strenuously opposes the provision in S. 1236 that would strip states of their authority under Section 401 of the Clean Water Act to develop license conditions to protect water quality. Decades of federal court decisions interpreting Section 401 have established the states' authority to require conditions in FERC licenses necessary to protect water quality. These decisions recognize and affirm the basic principle of federalism embodied in the Clean Water Act that states have the primary role and responsibility to ensure state water quality standards are met.

Maryland's interest in protecting water quality is as important and relevant today as ever, particularly now as FERC considers the relicensing of the Conowingo hydroelectric dam on the Susquehanna River in Maryland. The Susquehanna River provides approximately 50% of the fresh water to the Chesapeake Bay and is an important driver of the Bay's water quality. A joint study funded by Maryland and the Army Corps of Engineers concluded that the Dam's loss of capacity to trap sediment and nutrients adversely affects the health of the Bay. The precise nature of the Dam's adverse impacts on the health of the Bay and the circumstances under which they occur are currently the subject of additional study. What is clear, however, is that any new FERC license for the Dam will have to contain appropriate conditions to address sediment and nutrient transport and ensure that

The Honorable Lisa Murkowski
The Honorable Maria Cantwell
Page 2

Maryland's water quality standards are maintained. Without appropriate conditions Maryland may not be able to meet its commitment to achieve EPA's Total Maximum Daily Loads ("TMDL") for the Bay.

In removing or impairing the states' primary role and responsibility under Section 401 to fashion conditions in FERC licenses, S. 1236 relegate the states – the entities with the greatest interest and expertise in protecting state water quality – to bystander or second-class status. Maryland strenuously objects to this provision and urges that it be stricken from the bill.

Also, as a member of the Association of Fish and Wildlife Agencies (AFWA), the Maryland Department of Natural Resources supports the attached comments from Larry Voyles, President of the AFWA. These comments are regarding the U.S. House of Representatives Committee on Energy and Commerce Discussion Drafts Addressing Hydropower Regulatory Modernization and FERC Process Coordination under the Natural Gas Act. While these comments do not speak directly to S. 1236, they are relevant to the Senate bill and important for the Energy and Natural Resources Committee to consider in its deliberations.

Respectfully,

Ben Grumbles
Secretary
Maryland Department of the Environment

Mark Belton
Secretary
Maryland Department of Natural Resources

Enclosure

cc: The Honorable Brian E. Frosh, Attorney General, Maryland

ASSOCIATION of FISH & WILDLIFE AGENCIES

The voice of fish and wildlife agencies

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May 28, 2015

The Honorable Ed Whitfield, Chairman
Energy and Power Subcommittee
Subcommittee on Energy and Power
United States House of Representatives
Washington, DC 20515

The Honorable Bobby L. Rush, Ranking Member
Energy and Power Subcommittee
Subcommittee on Energy and Power
United States House of Representatives
Washington, DC 20515

Dear Chairman Whitfield and Ranking Member Rush:

The Association of Fish and Wildlife Agencies (Association) is writing to provide comment for the record of your May 13, 2015 hearing on Discussion Drafts Addressing Hydropower Regulatory Modernization and FERC Process Coordination under the Natural Gas Act. Our comments are limited to the discussion of the Hydropower Drafts (Drafts) and do not include comment on Gas Pipeline permitting or related processes.

The Association represents the state fish and wildlife agencies' interests in fish and wildlife management before Congress, the federal agencies and the Administration. The Association's mission is to protect state authority and support provincial and territorial authority for fish and wildlife conservation; promote sound resource management; and strengthen federal, state, territorial and private cooperation in conserving fish, wildlife and their habitats in the public interest based on scientific principles. All 50 state fish and wildlife agencies are members of the Association.

While hydropower projects make significant contributions to meeting our nation's energy needs, the Association has serious concerns about the Drafts, and we strongly oppose provisions therein that reduce, restrict, undermine or otherwise usurp state fish and wildlife agencies' mandated responsibilities for conserving the fish and wildlife resources within their borders to the benefit of all citizens. Proponents of the Drafts claim that the intent is to improve the Federal Energy Regulatory Commission (Commission) hydropower licensing process. The Association stands ready to work with the Committee and Congress on meaningful process reforms that resolve relicensing concerns while protecting state fish and wildlife agencies' management authority for their public trust resources. We urge the Committee to reconsider its approach and to work with stakeholders to find a better path forward.

While our concerns with the bill are many, attached are a few based on our interpretation and its subsequent effects on our state fish and wildlife agency members.

The Association supports common-sense reforms that will improve administrative processes without sacrificing state's authority and the fish and wildlife resources they manage as public trust resources. Rather than minimizing the ability of state resource managers to fulfill their mandated responsibilities, we suggest that the existing process could be improved through more effective agency coordination and communication, additional process support to first-time applicants, and through enhancements to the power purchase and power interconnect processes.

We anticipate continued activity and interest from this committee and its members related to hydropower regulatory improvements or reforms. As this discussion moves forward, we encourage the committee to seek broader input on the underlying goals of this proposal – i.e., what reforms, if any, are needed - and to work with state agencies, industry and members of the affected public to design more balanced solutions to any problems identified. The Association is ready to work with representatives from industry, resource agencies, the regulatory Commission and members of this committee to identify process improvements that do not sacrifice state agency authorities and the protection, mitigation and enhancement of our nations' rivers, streams, fish and wildlife.

Thank you for the opportunity to provide comments on the draft hydropower bill, and the Association looks forward to working with you on hydropower reform.

Sincerely,

Larry D Voyles

Larry D. Voyles
President

U.S. House of Representatives Committee on Energy and Commerce
Subcommittee on Energy and Power

Hearing on
Discussion Drafts Addressing Hydropower Regulatory Modernization and FERC Process Coordination under the Natural Gas Act

May 28, 2015

Statement for the Record of the Association of Fish and Wildlife Agencies

The Association appreciates the opportunity to provide a statement for the record and represents the state fish and wildlife agencies' interests in fish and wildlife management before Congress, the federal agencies and the Administration. The Association's mission is to protect state authority and support provincial and territorial authority for fish and wildlife conservation; promote sound resource management; and strengthen federal, state, territorial and private cooperation in conserving fish, wildlife and their habitats in the public interest based on scientific principles. All 50 state fish and wildlife agencies are members of the Association.

The Association has serious concerns about the Drafts, and we strongly oppose provisions therein that reduce, restrict, undermine or otherwise usurp state fish and wildlife agencies' mandated responsibilities for conserving the fish and wildlife resources within their borders to the benefit of all citizens. Here are a few of our concerns based on our interpretation of the Drafts and its subsequent effects on our state fish and wildlife agency members.

- While hydropower projects make significant contributions to meeting our nation's energy needs, they create many unique environmental impacts. Hydropower projects do not in all cases enhance environmental conditions. In some instances hydropower projects cause significant negative environmental consequences upstream and downstream, affecting multiple industries and economies, and at times can work at cross-purposes with states' efforts to restore threatened, endangered or other native fish species that would otherwise reduce regulatory threats and burdens on surrounding communities, industries and other stakeholders. While undoubtedly the licensing process could be improved, this is not best accomplished by reducing the authority of state and federal resources agencies in the licensing process and restricting their ability to manage public trust resources.
- We are concerned that the Drafts strip state agencies' authority to develop license conditions specific to their intimate understanding of local resources issues. Transferring resources management from state and federal agencies to the Commission removes the incentive for collaboration between applicants and the agencies charged with protecting natural resources, while solely meeting the objectives of the applicant and potentially at the expense of state managed species. Centralized control does not benefit the local communities that are directly impacted by the projects. We strongly encourage close cooperation with state fish and wildlife agencies who often have the best available science

and data on local fish and wildlife resource issues to collaboratively find solutions that help reduce, minimize and mitigate the impacts of hydropower projects.

- We are deeply concerned that the Drafts grant the Commission the exclusive authority on final determinations for all license terms and conditions. This provision effectively restricts the states from protecting their public trust resources, which we strongly oppose. First, the language indicates the Commission has authority over all certifications and requirements included in a license. This would include state-issued 401 water quality certifications (WQC). The states often use the 401 WQC to ensure that not only will water quality be protected, but also fish habitat, fish passage, shoreline management, and water-based recreation. Second, by allowing the Commission to select which provisions of the state 401 WQC will apply, this seems to set up a conflict with Clean Water Act authorities and usurp the states' authority to manage its natural resources. The 401 Water Quality Certification is very important to the states as its conditions must be included in the license, which we continue to support, and because none of the other conditions noted by a state agency must be included. This is a critical tool for helping states manage water quality that supports healthy fish, fish habitats, jobs and rural economies.
- The Drafts require the Commission to weigh the cost of new studies against their value in supporting decision-making. In application, the Commission likely will rely on existing information. Study requests for new information will likely be few and far between as the Commission must determine in advance that it is necessary and worth the cost, which they are not likely to know without collecting the appropriate current data. Consequently, the Commission will be making licensing decisions based on outdated information without taking into consideration changing environmental and habitat conditions, state investments in fish and wildlife restoration, or priorities of state and local communities. Moreover, because the provisions allow for use of data "regardless of source," there will continue to be inappropriate utilization of studies from one part of the country applied to another with completely different circumstances. Furthermore, it is critical for the scientific information and technical data used to make licensing decisions be credible in terms of both content and source so that decisions made by the Commission do not lead to unnecessary conflict between resource agencies, the Commission and the applicants. It is not unusual to need a broad range of information to determine the effects of a project on public trust resources, and existing information may not be suitable for conducting an appropriate environmental analysis. Ill-informed licensing decisions will likely create more challenges, potentially avoidable with good data, to states' management of fish and wildlife resources. Finally, this provision would prevent state and federal agencies from obtaining the information necessary to support licensing recommendations, and terms and conditions, undermining the states' recommendations for licensing. Many states routinely work with applicants to develop study plans so that there is sufficient data for the applicant to submit a complete application which saves everyone time and money.
- The Drafts appear to limit the Commission's authority with respect to shoreline and other project lands by requiring a nexus to a "site-specific license requirement". It is not clear how a site-specific license requirement is defined or determined. This could limit the size of the project area and thereby limit general requirements to protect habitat surrounding a project, which is of concern to us. This could curtail habitat protection and recreational use of public lands with high recreational value and of local economic significance. Additionally, the provision presumes that state and local laws will not change during the license term,

which may not be accurate, and a review of state and local laws should be required in the case that these laws change during the license term.

- We are concerned about the loss of transparency through the allowance of informal, ex parte meetings between Commission staff and applicants which is contrary to the preamble of the draft bill to "promote transparency." Notice of meetings involving substantive policy or technical issues must be provided to stakeholders prior to meetings to promote participation which serves to protect all parties to a licensing proceeding.
- The elimination of cost recovery to the states is of grave concern. The Drafts remove the responsibilities of the Developers to compensate states for the direct loss of public resources, which essentially becomes an additional problem and financial burden for the states. Cost recovery by the states must continue. Developers should be responsible for reimbursing the public for the loss of public trust natural resources. This cost should not be borne by the states and local communities.
- Reviewing hydropower projects over the past 50, let alone 70 years, shows that our understanding of impacts and issues affecting a project change considerably over time. There is no reason to expect that this increase in knowledge or change in actual physical conditions will not occur in the future. Extending the license term to 70 years provides little to no consideration for the adaptive management needs of state fish and wildlife agencies and restricts the options of future generations on decisions affecting public trust resources. Licensing periods of 70 years does not allow for adaptive adjustments for cumulative, ongoing or new unanticipated impacts, and essentially turns any license into a permanent license without the necessary ability to address issues important to the citizens of each state.
- Nonpowered dams have significant impacts on streams and rivers, sometimes more so than conduits. Greater care must be taken in exempting nonpowered dam projects when compared to conduits. The Drafts discourage and may preclude any improvement from baseline conditions at an existing nonpowered dam. Coupled with other provisions, it appears to remove the ability of state agencies to require operational changes that would improve baseline environmental conditions such as water quality, and would substantially impair federal, state and local efforts to restore and enhance fish and wildlife species. Unfortunately, the Drafts also limit the application of the National Environmental Policy Act by allowing only an Environmental Assessment and precluding an Environmental Impact Statement even if the environmental impacts would be significant and warrant a higher degree of examination. The criteria for a nonpowered dam exemption could exempt projects that pose a significant environmental impact. The 40 megawatt limitation is not a sufficient criterion to prevent potential significant environmental impacts. These provisions could result in unintended and adverse consequences to the states' ability to manage its public trust resources.
- We are deeply concerned about the definition of a "qualifying nonpowered dam," which provides an opportunity for previously licensed dams to avoid addressing prior or existing conditions of their license. The definition requires only that a dam be constructed prior to the effective date of the act. We are concerned this would allow previously licensed, but now defunct dams, to be exempt from licensing and begin operations without the same level of review and conditions that would have been required if their previous license was renewed. Further, it could allow currently licensed powered dams to avoid meeting existing license conditions by allowing them to surrender their current license and then renew

power production under the exemption, at the expense of state public trust resources. Currently or previously licensed projects should not be eligible for the nonpowered dam exemption. We are concerned that the Drafts deregulate development of certain classes of hydropower at existing non-powered dams, essentially removing these projects from federal and state oversight through the hydropower licensing process.

- In some states, projects <5 MW built at existing non-powered dams are the vast majority of dams, which would not need a federal license under the Drafts. It appears this would ensure that <5 MW dams will have no federal oversight, creating burdens on the states that may not have mechanisms in place to manage this new workload. It is unclear whether this really means that there will be a state issued license, if the state possess such authority, or if the projects would be excluded from all regulation, which we find disconcerting. The Drafts would unfairly transfer the onus to state agencies to take responsibility for dam safety, enforcing compliance with environmental conditions, and decommissioning.
- We remain deeply concerned that the Drafts diminish state and federal agency authority in the Commission's licensing processes. The proposed language would eliminate the Federal Power Act's mandate to ensure a balancing between power and non-power interests by transferring key protection determinations away from state and federal resource managers and centralizing that power at the Commission. Although the Commission has a skilled staff, the agency does not have the expertise necessary to adequately evaluate all of the local conditions and considerations necessary to conserve fish and wildlife resources under state management authority. Furthermore, we are perplexed by provisions that seem to create conflict between the Commission and other federal agencies, specifically those agencies that are charged with conserving and protecting the lands and resources that are currently within the jurisdiction of the Departments of the Interior and Commerce, such as fish and wildlife, endangered species, and public lands. These agencies carry out fish, wildlife and habitat conservation that is important to state fish and wildlife agencies and the hunters, anglers and other outdoor enthusiasts who depend upon these lands for both recreation and economic well-being.
- The Drafts weaken state and federal authority to ensure safe, timely and effective fish passage around dams and hydropower projects, and when considering exempt licenses at existing non-powered dams, current environmental conditions would be the baseline when assessing potential impacts. We are concerned that the Drafts would strip mandatory authority for the state and federal agencies allowed under 30(c) and grant the Commission the authority to determine which conditions are necessary to prevent loss of or damage to, or to mitigate adverse effects to, fish and wildlife resources directly caused by the project compared to the current environmental baseline. This is problematic because the Commission currently has the authority to reject fish and wildlife agency recommendations it solicits under section 10(j) of the FPA for licenses and has a proven track record of rejecting meaningful 10(j) recommendations not supported with a mandatory filing under section 18 or 4(e). Because exemptions are issued in perpetuity, the Commission's new authority to veto protection for fish and wildlife could never be rectified, whereas corrections can now be attempted every 30-50 years for licenses. The Drafts only require the Commission to consider the current, often degraded, environmental baseline and offers no opportunity to rectify issues with long standing environmental degradation.
- The Association supports the streamlining of a Commission generated timeline to help ensure predictability in the licensing process. However, the proposed language creates

overly restrictive time limits, imposing potentially arbitrary deadlines that do not account for the agency specific processes or information gathering needs of state and federal agencies. Rather than a lack of clear timeframes, delays are often connected to agency budget constraints or other administrative hurdles. Improved agency communication and coordination early and often would benefit the process.

- The Drafts mandate an overly restrictive scope of project review, prohibiting the Commission or the resource agencies from requiring contribution from a project to ongoing project impacts. This would place the burden back on federal agencies to manage any expense or upkeep of underlying facilities, regardless of any profit to the power operator. This amounts to private profit from public resources - allowing private companies to profit from existing infrastructure with no requirement that those developers contribute to the upkeep or enhancement of the underlying facility or its impacts, and handing the profit to the developer while leaving the burden on the public resource and taxpayer.
- The significant changes in Section 6 usurp the state's authority to complete its own environmental review. This federal preemption strips the people of a state to their right to a clean and healthful environment, as guaranteed in some state constitutions.
- While we understand the importance of timeliness for the industry and the Commission, the provisions provide draconian repercussions for the failure of federal and state agencies to strictly adhere to the Commission established schedule. Budgetary and staffing issues may make it impossible for federal or state agencies to strictly comply with the Commission schedule, particularly if communication and coordination among agencies are lacking. Further, the availability of newly discovered information must be considered, which requires adjustment of schedules. Many states assisting the hydropower industry with licensing processes work to ensure all necessary information and issues are addressed before submission to the Commission.
- We are concerned that the Drafts result in legal appeals being heard on hydropower projects in jurisdictions outside the state in which the project is located. Because review of state agency actions is included in judicial review, such review should occur in the Federal District Court of the respective state.
- The Drafts minimize or eliminate a developer's responsibility to comply with state and federal resource protection laws (like the Endangered Species Act and Clean Water Act), which will place a greater burden on the states, surrounding businesses and local communities. The current language:
    - Imposes fisheries and wildlife management costs on commercial fishermen, farmers, taxpayers and local communities by exempting hydropower dam owners from reasonable measures to protect fish and wildlife; and
    - Shifts the costs and burdens of meeting state water quality standards away from the hydropower industry and onto municipal water treatment facilities, factories, farmers and taxpayers.
- Many states have multiple dams on every major stream. As a result most of the state species of greatest conservation need, at-risk and federally threatened and endangered aquatic species are found above the highest dams in these chains-of-dams, which is likely where new hydropower developments will be proposed. Any further dam construction will destroy some, if not most, of the remaining aquatic habitat and push more species to federal listing under the Endangered Species Act, if not extirpation in some cases. The provision exempts developers from the requirements of the Clean Water Act and the

Endangered Species Act but by adding more species to the list of federally threatened or endangered species, these potential new developments will increase the burden for future developers anywhere within the range of newly listed species and may thwart development of any kind into the future. State fish and wildlife agencies strive to maintain management authority of all the species under their jurisdiction, rather than list them under the federal Endangered Species Act, and we are disconcerted by processes that undermine their historical and financial contributions toward maintaining their authority.

- Projects proposed at existing dams can and will affect upstream and downstream aquatic habitats, depending on the type of generating equipment used and changes to the operation of the dam and water releases. The states would prefer that new hydropower development be installed at existing dams, which could have fewer impacts to species and habitats than building new dams.
- We should note that projects proposed under the Drafts could create unacceptable terrestrial as well as aquatic environmental costs and losses, and depending on the scale of development could be catastrophic to many terrestrial species. Unfortunately, it is the rural communities where these new development projects occur and whose economic livelihoods often depend on healthy fish, wildlife and habitats who will be the most adversely effected.
- Some states expect all of the new development under the Drafts will occur upstream of existing projects, changing flow characteristics downstream and requiring model adjustments, if not reprogramming. Flow changes to existing hydropower sites will very likely negatively affect states' ability to manage coldwater sport fisheries, reducing the sportfishing potential for anglers and jeopardizing the $115 billion economic impact produced by anglers across the country.

May 19th, 2015

National Enhanced Oil Recovery Initiative

The Honorable Lisa Murkowski
The Honorable Maria Cantwell
Energy and Natural Resources Committee
304 Senate Dirksen Building
Washington, DC 20510

Dear Chairman Murkowski and Ranking Member Cantwell:

On May 19th 2015, the Senate Energy and Natural Resources Committee will host a hearing on energy supply legislation. On behalf of the National Enhanced Oil Recovery Initiative (NEORI), we are submitting a statement of support for **S. 1282**. Introduced by Sen. Joe Manchin and cosponsored by Sens. Heidi Heitkamp and Sheldon Whitehouse, this bill will "amend the Energy Policy Act of 2005 to require the Secretary of Energy to consider the objective of improving the conversion, use, and storage of carbon dioxide produced from fossil fuels in carrying out research and development programs under that Act."

Launched in 2011, NEORI brings together leaders from industry, labor organizations, environmental groups, and state representatives, who recognize the potential of **enhanced oil recovery with carbon dioxide (CO_2-EOR)** captured from power plants and industrial facilities to meet domestic energy, economic, and environmental challenges. NEORI supports policies that lower the economic barriers to utilizing CO_2 in EOR. As such, NEORI recognizes the important role of the Department of Energy (DOE) in enabling the development and deployment of current and next generation carbon capture technologies that can be applied to a broad range of CO_2 sources.

NEORI stands ready to work on a bipartisan basis with all interested Members of Congress to move quickly on opportunities to advance CO_2-EOR. If you have any questions or require additional information, please have your staff contact Patrick Falwell of the Center for Climate and Energy Solutions (703-516-0611, falwellp@c2es.org) or Brad Crabtree of the Great Plains Institute (701-647-2041, bcrabtree@gpisd.net).

Signed,

Brad Crabtree
Vice President for Fossil Energy
Great Plains Institute

Patrick Falwell
Solutions Fellow
Center for Climate and Energy Solutions

June 24th, 2015

National Enhanced Oil Recovery Initiative

The Honorable Lisa Murkowski
The Honorable Maria Cantwell
Energy and Natural Resources Committee
304 Senate Dirksen Building
Washington, DC 20510

Dear Chairman Murkowski and Ranking Member Cantwell:

On behalf of the National Enhanced Oil Recovery Initiative (NEORI), we are submitting a statement of support for **S. 1285**. Introduced by Senator Heidi Heitkamp and co-sponsored by Senator Joe Manchin, this bill would authorize the U.S. Department of Energy (DOE) to enter into binding contracts that would stabilize the price of electricity and carbon dioxide (CO_2) generated and sold by carbon capture utilization and storage (CCUS) projects.

Launched in 2011, NEORI brings together leaders from industry, labor organizations, environmental groups, and state representatives, who recognize the potential of **enhanced oil recovery with carbon dioxide (CO_2-EOR)** captured from power plants and industrial facilities to meet domestic energy, economic, and environmental challenges.

NEORI supports policies that lower the economic barriers to utilizing CO_2 in EOR. As such, NEORI believes price stabilization contracts would address a key barrier faced by CO_2 capture projects in receiving private sector finance. The sales price of captured CO_2 is usually tied to the price of oil, and persistent volatility in the global oil market creates a considerable economic risk for CO_2 capture projects. This uncertainty, combined with the emerging nature of capture technologies, means that CO_2 capture faces relatively high capital costs. By guaranteeing that CO_2 sales revenues will not fall below a certain level, CO_2 capture projects can attract financing on more favorable terms. Furthermore, NEORI wants to ensure that the authorization of price stabilization contracts limits potential fiscal impacts and that federal revenue generated by new CO_2-EOR production covers the cost of the contracts over time.

NEORI stands ready to work on a bipartisan basis with all interested Members of Congress to move quickly on opportunities to advance CO_2-EOR. If you have any questions or require additional information, please have your staff contact Patrick Falwell of the Center for Climate and Energy Solutions (703-516-0611, falwellp@c2es.org) or Brad Crabtree of the Great Plains Institute (701-647-2041, bcrabtree@gpisd.net).

Sincerely,

Brad Crabtree
Vice President for Fossil Energy
Great Plains Institute

Patrick Falwell
Sr. Solutions Fellow, Project Manager
Center for Climate and Energy Solutions

National Enhanced Oil Recovery Initiative

Initiative Participants

- Tom Altmeyer, Vice President, Government Affairs, Arch Coal, Inc.
- Roger Ballentine, Representative, NRG Energy
- Jason Begger, Government Affairs Manager, Cloud Peak Energy, Inc.
- Dipka Bhambhani, Representative, Breitling Energy
- Mark Calmes, Vice President-Environmental, Archer Daniels Midland Co.
- Myra Crownover, Vice Chair, House Energy Resources Committee, Texas
- Pete DePasquale, Manager, Government Relations, Praxair, Inc.
- Paul Doucette, Global Leader, Public Policy and External Funding, GE Oil & Gas
- John Duffy, Vice President, Utility Workers Union of America
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- Daniel Enderton, Director, External Affairs, C12 Energy
- Hal Fitch, Director, Michigan Geological Survey
- Richard Garrett, Energy and Legislative Advocate, Wyoming Outdoor Council
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- N. Hunter Johnston, Counsel, Leucadia Energy
- Krish Krishnamurthy, Head of Clean Energy Technology- North America, Linde LLC.
- Greg Kunkel, Vice President, Environmental Affairs, Tenaska Energy
- Rick Lancaster, Vice President, Generation, Great River Energy
- Dale Magnusson, Business Development and Intellectual Property Manager, LI-COR Biosciences
- Brad Markell, Executive Director, Industrial Union Council, AFL-CIO
- Dave Martin, Cabinet Secretary, New Mexico Energy, Minerals & Natural Resources Department
- Talina Mathews, Division Director, Kentucky Dept. for Energy Development and Independence
- Laura Miller, Director of Projects, Summit Power Group, LLC and former Mayor of Dallas
- Mark A. Northam, Director, University of Wyoming, Enhanced Oil Recovery Institute
- Ellen O'Connell, Market Manager, Tonnage Gases, Equipment and Energy, Air Products, Inc.
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- John Sherwell, Administrator, Maryland Department of Natural Resources
- John Steelman, Climate Program Manager, Natural Resources Defense Council
- Samuel Thernstrom, Executive Director, Energy Innovation Reform Project
- Kurt Waltzer, Carbon Storage Development Coordinator, Clean Air Task Force
- Thomas Weber, President, Jupiter Oxygen Corporation

Initiative Observers

- Kevin Macumber, Enhanced Oil Recovery Manager, Tellus Operating Group, LLC
- Robert Mannes, President, Core Energy, LLC
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- Scott Wehner, Senior Vice President, EOR Operations, Chaparral Energy LLC

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Statement for the Record

On behalf of

The National Hydropower Association

Before the

U.S. Senate Energy and Natural Resources Committee

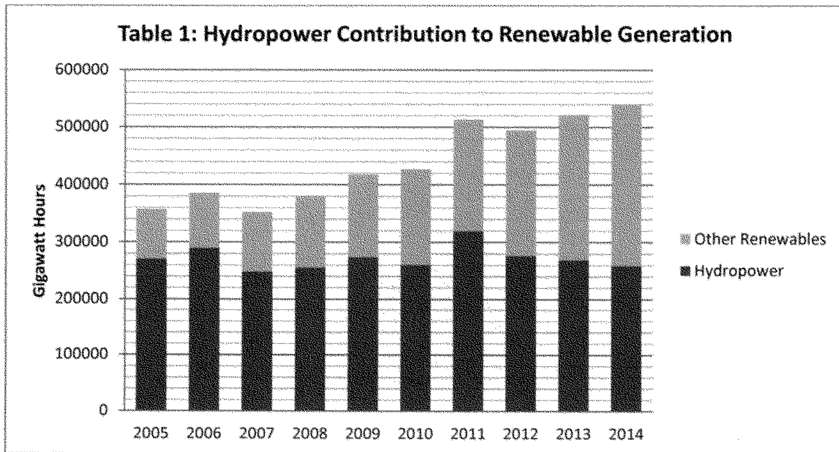
Regarding

Full Committee Hearing on Energy Supply Legislation on May 19, 2015

The National Hydropower Association[1] appreciates this opportunity to provide a statement for the record on the Committee's May 19 hearing on energy supply legislation. Included in the list of bills for consideration were several pieces of hydropower legislation. These include: S. 1058, the Marine and Hydrokinetic Renewable Energy Act, sponsored by Sen. Wyden (D-OR); S.1236, Hydropower Improvement Act, sponsored by Sen. Murkowski (R-AK); and S. 1270; the Reliable Investment in Vital Energy Reauthorization Act, sponsored by Sen. Gardner (R-CO).

Introduction

Hydropower plays a central and indispensable role in reaching the nation's clean energy goals and objectives for the U.S. electric power sector. Like wind, solar, and other renewables, hydropower is a source of clean, emissions-free energy. Distinct from these other renewables, however, hydropower provides flexible base load power to follow load, as well as peaking power when energy demand on the grid reaches its highest levels. Hydropower also is a reliable and proven energy source. According to the U.S. Energy Information Administration, over the past 10 years hydropower generation has met or exceeded the generation of all other renewables *combined* - in some years constituting 75 percent or more of all annual renewable energy generation. Table 1 depicts hydropower's substantial contribution to renewable energy generation over the last 10 years.



[1] NHA is the national non-profit association dedicated exclusively to advancing the interests of the hydropower industry, including conventional, pumped storage, conduit power and new marine and hydrokinetic technologies. NHA's membership consists of more than 210 organizations, including consumer-owned utilities, investor-owned utilities, independent power producers, project developers, equipment manufacturers, environmental and engineering consultants, and other service providers.

What is often overlooked, however, is hydropower's potential to grow in an environmentally responsible way. Building upon the existing U.S. asset base, there are growth opportunities to increase capacity and generation at existing hydro facilities, add new generation units to existing non-powered dams, and build new pumped storage as well as low impact small hydropower projects (additional details below).

The unique, flexible qualities of hydropower help integrate additional intermittent renewable resources to the electric grid. Hydropower facilities can quickly go from zero power to maximum output, making them exceptionally good at meeting rapidly changing demands for electricity throughout the day. This flexibility, along with energy storage benefits provided by both conventional and hydropower pumped storage projects, are critical to integrating greater amounts of intermittent renewable sources like wind and solar—thereby significantly increasing clean emission-free generation while preserving grid reliability.

These same attributes allow both fossil and nuclear units to run at peak efficiencies. This avoids unnecessary and undesired cycling of baseload nuclear generation units, as well as reducing carbon emissions from fossil units that would otherwise be called to run in less efficient modes of operation.

Thus, hydropower serves as the backbone for the effective functioning of the electric grid and the reliability and stability services it provides will be in even greater demand into the future. Particularly in conjunction with the emergence of wind, solar, and other renewables, hydropower plays an essential role in bringing these intermittent resources to the grid, expanding the utilization of this clean, emissions-free generation.

To illustrate, states that utilize more hydropower have the cleanest air and the lowest carbon intensity rates in the nation. For example, Washington state ranks number 10 in the nation in the amount of electricity generated. Because the majority of that generation comes from hydropower, the state ranks 50th in carbon intensity with only 132 lbs of carbon dioxide produced per MWh. In 2012, nationwide, the use of hydropower avoided over 190 million metric tons of CO_2. This is the equivalent of avoiding the GHG emissions from approximately 40 million cars.

Absent policies that protect existing hydropower resources and promote new hydropower development, NHA believes that our clean energy goals cannot be achieved.

Growth Potential of Hydropower

Today, hydropower accounts for approximately 7 percent of the nation's total electricity generation and half of all renewable electricity generation. Hydropower capacity in the United States is just over 100,000 MW, which includes 22,000 MW of pumped storage - by far the largest utility-scale energy storage resource deployed both in the U.S. and globally.

While many may assume that hydropower is mainly a Pacific Northwest energy resource, in fact, hydropower is utilized and available across the country, powering homes and businesses in every state. There are over 2200 federal and non-federal hydropower projects in service in the U.S. These projects are providing low-cost emissions-free power to consumers in every one of the 50 states.

While hydropower's existing contribution to the nation's energy system is significant, there also exists tremendous opportunity to increase capacity. One such growth area is on existing dams and conduits. The vast majority of U.S. dams were constructed for purposes other than hydropower generation - such as water supply, flood control, irrigation, and navigation. These dams include structures and impoundments that provide opportunities to install hydropower generation.

NHA estimates that only about 3 percent of the nation's approximately 80,000 existing dams are equipped with generation facilities. This presents an opportunity to maximize the public benefits of these non-powered dams and related infrastructure through retrofits to produce electricity. A 2012 study by the U.S. Department of Energy concluded that an additional **12 GW** of capacity were available for development at existing non-powered dams. According to this study, the top ten sites alone have the potential to provide approximately **3 GW**, with the top 100 sites able to provide up to **8 GW**. Most of the sites with greatest potential are located at federal dams administered by the U.S. Army Corps of Engineers. Hydropower can be added to many existing dams with no incremental environmental impacts. Arguably, this makes such new generation the cleanest of all new capacity options.

Another important area of hydropower growth is adding capacity or improving efficiency at existing hydropower facilities. These improvements are often the most cost-effective and least impactful of any energy project, generally involving addition of powerhouses to the existing project or even just upgrading current equipment to state-of-the-art new technology. A 2009 analysis by Navigant Consulting, commissioned by NHA, found that there was approximately **9 GW** of additional capacity available to develop. In fact, data from FERC on the production tax credit demonstrates this potential. From 2006-2014, 139 projects have been certified to receive the PTC demonstrating a 9.35 percent increase in generation on average.

In addition to maximizing the contribution of existing infrastructure, further opportunities exist for the deployment of new projects such as pumped storage (both open and closed loop), marine and hydrokinetic (MHK), as well as low-impact new stream reach development. For pumped storage alone, FERC reports there are currently almost **28 GW** of proposed projects currently under consideration.

Existing Hydropower Resources

In addition to significant growth potential, existing hydropower resources and the benefits they provide are at risk and should be preserved. The Federal Energy Regulatory Commission expects to receive over 400 applications to relicense more than 16,000 MW of hydroelectric capacity over the next 15 years. Most of these are small projects under 10 MW that may be at risk to closure based on the considerable costs associated with the current relicensing process alone.

Legislation

The three bills included as part of the May 19 hearing each play an important part, in differing areas, to preserve the existing hydropower system and to support the licensing of additional new capacity of conventional hydropower and new marine energy projects.

S.1236 - Hydropower Improvement Act

NHA believes the development of more hydropower should be a key component America's clean energy portfolio. Currently, hydropower is not, due in part to the fractured, protracted, expensive, and lengthy licensing process that was designed for another era and that puts it at a distinct disadvantage vis a vis other generation options – fossil or otherwise.

From 2005 to 2013 there was only a 1.48 GW increase in installed hydropower capacity in the United States. Capacity additions to existing hydropower projects accounted for 86 percent of the increase. In contrast, there was an increase of 42 GW of installed summer capacity for generators burning natural gas in that same time period. While there have been improvements in the licensing and administration of hydropower, additional work is needed to make the process more efficient, so a significant portion of that undeveloped capacity can be constructed and also ensure that existing capacity is preserved. The time, cost and risks associated with licensing hydropower projects are not commensurate with the impacts, particularly when compared with other forms of generation.

NHA also believes hydro licensing modernization is a benefit to all stakeholders in the process. License applicants, for existing or new projects, often reach agreements with parties in a license proceeding and are prepared to implement significant mitigation packages associated with their projects. Unfortunately, the implementation of these measures is postponed when decision-making is deferred and approvals are delayed. This situation benefits neither the project nor natural resources.

The time and cost of licensing hydropower projects is in part driven by the regulations requiring extensive information on the proposed project, existing environment, and potential impacts. Protecting the environment and natural resources is important, and is a commitment the hydropower industry takes very seriously, but the amount of information that is requested can be excessive and not directly related to the project or its potential impacts. For existing projects undergoing relicensing, extensive information requests are sometimes used as a negotiating tactic, which can increase costs and prolong negotiations. For proposed new development, where the license applicant does not have the benefit of the proposed project's income stream, study requests can be an effective means of increasing project costs to a point where the project is no longer cost-competitive. The fact is that the licensing process can be shortened without sacrificing environmental and other priorities.

In addition to over-expansive study requests, other aspects of the licensing process add undue costs to hydropower projects and, ultimately, to ratepayers. Under the Federal Power Act (FPA), for example, the FERC has the statutory obligation to craft license conditions in a manner that gives "equal consideration" to the spectrum of public interests present in our nation's waterways, such as power development, environmental protection, navigation, recreation, and water supply. However, FERC's obligation is frustrated when other agencies exercise their broad powers, under the FPA and other statutes, to impose conditions in the license that FERC cannot balance or modify in the public interest, and which create inconsistencies and conflicts, which themselves can cause further delays and increase licensing costs.

The proposals contained in S. 1236 would help make hydropower more attractive to developers and investors – while ensuring environmental values are considered and preserving the ability to protect natural resources.

While there are many important proposals contained in the legislation, NHA will highlight one in particular – placing FERC as the lead agency for all authorizations required under federal law for the licensing and development of hydropower resources. This is an improvement that both hydropower project owners and project developers have long supported. Authorizing FERC to establish and enforce an overall schedule will help keep the process on track and avoid delays that have been the status quo for decades. Requiring other agencies with review requirements to cooperate with FERC will create efficiencies, promote economy, reduce redundancies, and again reduce delays. This should not be mischaracterized as a weakening of other agencies' authorities under their organic statutes which are preserved by the legislation. Instead, the goal is to allow all relevant agencies to exercise their authorities, but to do so in a more optimized and disciplined timeframe.

S.1236 also makes significant policy recommendations for improvements to the implementation of the EPAct of 2005 trial-type hearing and alternative conditions provisions, changes to the preliminary permit system and the commencement of construction deadline, as well as substantially broadening the consideration of hydropower as a renewable resource under federal procurement and other policies. These proposals would address the length, expense and uncertainty of hydropower licensing, all of which significantly disadvantage its development, particularly when competing against other energy options with much more expedited development timelines.

The federal licensing and approval of hydropower projects should be guided by the following general principles and objectives:

1. A fair, efficient process where FERC takes the input of all the relevant agencies and appropriate stakeholders, but is the ultimate decision-maker.

2. A scheduled process that is comparable to that of other generation technologies with regard to cost and duration so that hydropower is not disadvantaged.

3. A process that meets the legal requirements of environmental protection, but takes into account the benefit and costs when evaluating options for enhancement, protection and mitigation measures.

NHA believes these principles can be achieved through incremental changes to the FPA, consistent with what is proposed in S.1236 – changes that promote efficiencies in environmental reviews, eliminate redundancies, increase coordination, add accountability and transparency, and prioritize progress over process – without compromising natural resource protection.

As one hydropower project developer recently testified, "[i]n the hydropower sector, securing development, construction and project financing is extremely challenging. The length of the licensing process makes the investment financially too risky. Time is money. These licenses and permits contribute to development costs being 25-30% of the overall project cost." NHA believes proposals like those contained in S.1236 should help alleviate these concerns.

<u>S. 1058 - Marine and Hydrokinetic Renewable Energy Act</u>

S.1058 is similar to previous legislation that NHA also supported (S.630, the Marine and Hydrokinetic Renewable Energy Promotion Act of 2011 and S.1419, the Marine and Hydrokinetic Renewable Energy Act of 2013).

Marine and hydrokinetic technologies represent a huge untapped opportunity to create reliable, clean energy from predictable and forecastable ocean currents, waves, tidal flows and in-stream sources. While these technologies are currently in various stages of research, development and deployment, thousands of megawatts of potential are available from projects from New England to the West Coast and Alaska.

By any measure, the U.S. has significant marine energy resources. The Department of Energy has estimated that the technically extractable resource potential is almost 900 TWh/yr for wave energy and 400 TWh/yr for tidal and ocean current. This represents up to 25 percent of projected U.S. electricity generation needs by 2050. With more than 50 percent of our population living within 50 miles of coastlines, there is significant potential to provide power from marine energy systems to these coastal communities.

The Marine and Hydrokinetic Renewable Energy Act particularly addresses the needs of these industries by creating programs to develop the technologies, test devices, gain environmental and other data, and deploy. The establishment of MHK test facilities to demonstrate technologies in actual operating environments here in the United States is another critical feature of the legislation.

The international marine energy industry has seen the benefit of such facilities, particularly in Europe. The United Kingdom established the European Marine Energy Center in Scotland almost a decade ago. That center has directly assisted the advancement of the European MHK industry by providing independent assessment of devices' energy conversion capabilities, structural performance and survivability; research and engineering support; testing validation; and other services.

The United States must lead in the development and deployment of marine and hydrokinetic technologies, not lag behind. Not only will this increase the amount of our clean energy generation, but it will create new markets, both domestically and internationally, for U.S. companies and American products and technologies -- markets that will stimulate domestic job growth and new economic opportunities. As such, NHA supports the legislation.

S. 1270 - Reliable Investment in Vital Energy Reauthorization Act

As authorized by EPAct 2005, the Section 242 hydroelectric production incentive provides payments over a 10-year period for renewable hydroelectric power generated at these facilities. The program provides awards to qualified hydroelectric facilities - existing powered or non-powered dams and conduits that added a new turbine or other hydroelectric generating device. These qualified facilities may receive up to 1.8 cents per kilowatt hour, indexed for inflation, with maximum payments of $750,000 per year for hydroelectric energy generated by the facility.

For the first 8 years following the inception of the program, Congress provided no appropriations to the Department of Energy for the program. That changed for Fiscal Year 2014, when Congress appropriated $3.6 million to the program, with an additional $3.9 million in appropriations approved for Fiscal Year 2015.

While the program is now receiving consistent appropriations support, this year the 10-year eligibility window for projects to qualify will now close and the Department of Energy will not be allowed to accept new program applications. As a result, an incentive that can work for all sectors of the hydropower industry – investor owned utilities, public power, independent power producers and small developers – will effectively be lost.

S.1270 provides for a 10-year extension of the Section 242 hydropower production incentive along with the corresponding Section 243 hydroelectric efficiency improvement incentive, which provides an incentive payment of ten percent of the capital costs to increase the efficiency of existing hydropower facilities. Developers, particularly small project developers, have recognized the Sec. 242 program as one of the most useful incentives to support project deployment. As such, the industry is calling on Congress to reauthorize the program, which would allow the DOE to continue to accept and fund new projects after the 2015 deadline. As such, NHA supports the legislation to extend these programs.

Conclusion

Hydropower is America's leading affordable, reliable, and renewable domestic energy resource, and its significant growth potential offers an indispensable tool to help meet our nation's clean energy goals. NHA looks forward to working further with the Committee and other stakeholders on these bills, as we also continue to advance additional policies to stimulate development of the country's untapped hydropower resources.

Sincerely,

Linda Church Ciocci

Linda Church Ciocci
Executive Director

OUTDOOR ALLIANCE

June 1, 2015

Senator Lisa Murkowski
Chair, Senate Committee on Energy and Natural Resources
709 Hart Senate Building
Washington, DC 20510

Senator Maria Cantwell
Ranking Member, Senate Committee on Energy and Natural Resources
511 Hart Senate Office Building
Washington, DC 20510

Re: S. 1236 Hydropower Improvement Act

Dear Chairman Murkowski and Ranking Member Cantwell:

We are writing to share our perspectives on the S. 1236, the Hydropower Improvement Act. If enacted, this bill would have significant negative impacts on outdoor recreation and its associated local economic benefits, and would remove opportunities for meaningful local public involvement in hydropower licensing.

Outdoor Alliance, a coalition of seven member-based organizations, including Access Fund, American Canoe Association, American Whitewater, International Mountain Bicycling Association, Winter Wildlands Alliance, the Mountaineers, and the American Alpine Club, represents the interests of the millions of Americans who hike, paddle, climb, mountain bike, and backcountry ski on our nation's public lands, waters, and snowscapes. Collectively, Outdoor Alliance has members in all fifty states and a network of local clubs and advocacy groups across the nation.

Our members directly participate in licensing processes for hydropower projects in partnership with federal land managers, including in particular the Forest Service and Bureau of Land Management. The authorities granted to federal agencies by section 4(e) of the Federal Power Act have helped ensure that hydropower operations balance our society's need for power with the benefits of flowing rivers, including important economic benefits generated through the outdoor recreation economy, and outdoor recreation is one benefit of hydropower under certain circumstances. On the section of their website promoting the benefits of hydropower, the National Hydropower Association states that "Swimming, boating, fishing, camping, skiing and hiking are just some of the recreational activities that take place year-round and across the country at sites developed and supported by the hydropower industry."[1]

Outdoor Alliance is concerned that the discussion draft before the committee will severely limit the ability of local communities to advocate for recreational benefits in hydropower licensing by

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[1] http://www.hydro.org/why-hydro/other-benefits/

OUTDOOR ALLIANCE

shifting responsibilities away from states, federal land managers with locally-based recreation staff, and affected communities and place that responsibility exclusively in the hands of the Federal Energy Regulatory Commission (FERC), a regulatory agency with no local field staff who participate in licensing or likely to understand local community needs. FERC staff only have the ability to participate in one or two site visits in all, and typically have minimal experience and familiarity with local resources and values. The changes to the Federal Power Act contemplated by the discussion draft will not only hinder FERC's ability to process hydropower licenses in a timely fashion, but result in outcomes that are detrimental to outdoor recreation and local communities.

While hydropower provides many benefits, it also comes with significant impacts. This legislation would upset an important balance and the cooperative approach to hydropower licensing that effectively ensures that the interests of local communities and their interest in outdoor recreation are represented. Outdoor Alliance finds S. 1236 to be deeply problematic and opposes any effort to diminish the ability of local citizens and public resource agencies to ensure that hydropower licenses include provisions to protect the public river resources that are important to them.

Best regards,

Adam Cramer

Adam Cramer
Executive Director
Outdoor Alliance

cc:

Brady Robinson, Executive Director, Access Fund
Wade Blackwood, Executive Director, American Canoe Association
Mark Singleton, Executive Director, American Whitewater
Michael Van Abel, Executive Director, International Mountain Bicycling Association
Mark Menlove, Executive Director, Winter Wildlands Alliance
Martinique Grigg, Executive Director, The Mountaineers
Phil Powers, Executive Director, American Alpine Club

Chairman Murkowski and Ranking Member Cantwell, thank you for holding today's hearing on energy supply legislation, including the Southern Atlantic Energy Security Act, a bill that I co-authored with my friend from Virginia, Sen. Warner and introduced with Senators from the other affected mid- and South Atlantic states. South Carolina and the rest of the mid- and south Atlantic states are ready to play an important role in our nation's energy supply, while enjoying the economic and job creation benefits that come with offshore energy production and at the same time protecting our world-class tourism and costal recreation industry.

SOUTHERN ATLANTIC ENERGY SECURITY ACT

The purpose of our legislation is to make available safe, responsible offshore energy production in the mid- and South Atlantic that will provide fair revenue sharing to affected states, give the states more say in the entire process, and have absolutely no impact on our respective states vibrant costal tourism industry and pristine ocean views. I think we achieved all of these goals and more by working together, in a bipartisan way, to find a solution that meets all of our constituent's needs and desires.

As we see the Administration make moves to potentially open up the Arctic as well as the Atlantic for lease sales and production, it is important that we make sure South Carolina is prepared for these next steps, and federal law reflects priorities of our costal communities, which is what our bill aims to achieve.

South Carolina wants to help produce the energy that will lessen our dependence on energy from unfriendly countries. We also want to reap the economic benefits of revenues derived from lease sales, and a larger role for states in the process, while maintaining the same vibrant tourism industry that brings millions of people to our coast and beaches every year. Unfortunately, current law sends all revenue from bonus bids, rents, and royalties to the federal government, leaving South Carolinians empty handed and unsure about impacts to coastal communities.

Legislation like the Southern Atlantic Energy Security Act is absolutely essential for mid- and South Atlantic states to be prepared for the potential of future offshore leasing, development and production. We cannot sit back and wait for the federal government to decide when, where, and how offshore energy should occur along our states. Our legislation helps put the states, local government, and community stakeholders in a better position to influence the federal government's decisions regarding offshore energy production while sending vital revenues back to the state and local communities.

COSTAL VIEWSHEDS AND TOURISM

I have heard from many South Carolinians on the issue of offshore energy and while most of those who I speak to support the concept, there are some who have doubts or are unsupportive largely because they feel local communities are left out of the process or are concerned about the impact to tourism.

As a South Carolinian who was born and raised on the coast, in Charleston, I unquestionably understand the concerns of folks on the coast and it is important for me that everyone in South Carolina knows that I would not support any legislation that I thought would harm our coastal communities or would negatively impact our tourism economy.

The Southern Atlantic Energy Security Act creates a new consultation process with the Governor of each affected state to protect Atlantic costal viewsheds by giving states more control over offshore areas closest to their shoreline. This unprecedented consultation process directs the Secretary of the Interior to consult with Governor before a lease sale to mitigate any potential concerns to costal viewsheds within 30 miles of shoreline. Further, if lease occurs within 30 miles, the Secretary must ensure impacts to costal viewsheds are minimized to maximum extent before development or production is approved.

These are protections and consultation requirements never before mandated of any offshore lease and will ensure South Carolina remains a world-class tourism destination while we expand our economic and job creation opportunities. This is why tourism focused organizations like the Myrtle Beach Chamber of Commerce supports our legislation.

REVENUE SHARING

Our legislation also takes a unique and innovative approach to revenue sharing, which was the process of bipartisan negotiations and consultations with local stakeholders. Just like states that produce onshore energy, 50 percent of revenues from the Southern Atlantic Energy Security Act go to the general fund of the Treasury and 50 percent are fairly divided between the four mid- and South Atlantic states for general and specific purposes.

Of the 50 percent that goes to the states, 37.5 percent of all revenues allocated are for use as state law allows, 10 percent of state allocated funds must be used on one of the following program(s), at the discretion of the Governor: (a) enhance State land and water conservation efforts; (b) beach nourishment and costal dredging; (c) improve State public transportation projects; (d) or to fund alternative, clean or renewable energy production.

Finally, because I believe new offshore energy production in Atlantic states is an excellent opportunity to grow new STEM education opportunities, the remaining 2.5 percent must be used on a public-private partnership between industry, institutes of higher education and Historically Black Colleges and Universities (HBCU) to enhance and broaden the study of geological and geophysical sciences, encourage new STEM studies of offshore energy resources and educate the next generation of America's offshore energy scientists.

ENERGY FUTURE

There is no doubt in my mind that American energy production has been one of the only bright spots in our still recovering economy despite this Administration's efforts to block energy production on federal lands and waters. We cannot continue to rely on energy produced from state and private lands and the exact same areas offshore that have been producing for decades. America has been blessed with an abundance of energy resources and we cannot afford to ignore them to the detriment of our national security and economic wellbeing.

Seven years ago, before President Obama took office, nearly 100 percent of America's offshore was available for leasing. Yet, today thanks to restrictive policies by this administration only 15 percent of America's offshore can be leased, leaving 85 percent of America's offshore energy resources under lock and key. After years of making the case to this administration through strong support throughout the mid- and South Atlantic states from the Governors on down through local levels of government, President Obama has finally proposed opening a portion of offshore areas in Virginia, North Carolina, South Carolina, and Georgia for leasing.

In addition, the Obama Administration has recently approved offshore seismic testing, which will finally provide for the ability to update 30 year old data to give us a better scientific understanding of the resources available in the Atlantic Outer Continental Shelf. This new data will be invaluable in better informing potential offshore leasing, development and production decisions going forward.

While I have concerns about the limited number of lease sales and arbitrary buffer zones included in the President's Draft Proposed Five-Year 2017-2022 Program for the mid- and South Atlantic Outer Continental Shelf, this proposal is a small, but important first step in expanding future offshore energy production.

CONCLUSION

As a recent study reminds us, opening the Atlantic to energy production could create 280,000 jobs, add $24 billion to the economy, generate $51 billion in government revenue, and help produce over 1 million barrels of oil and natural gas per day.

However, if this step is to be realized, legislation such as the Southern Atlantic Energy Security Act must be enacted to provide states a stronger role in the process, protect coastal communities and their tourism economy, and allow for fair revenue sharing to improve infrastructure, improve educational opportunities, create jobs, and fund important conservation projects.

Thank you again for holding this hearing and I look forward to working with the Committee and the rest of my colleagues in advancing this legislation through the Senate.

State of Washington
DEPARTMENT OF FISH AND WILDLIFE

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Main Office Location: Natural Resources Building · 1111 Washington Street SE · Olympia, WA

June 3, 2015

The Honorable Lisa Murkowski, Chairman
U.S. Senate Committee on Energy and Natural Resources

The Honorable Marie Cantwell, Ranking Member
U.S. Senate Committee on Energy and Natural Resources

Re: May 19th, 2015 Hearing on S. 1236 in the United States Senate Committee on Energy and Natural Resources

Dear Senator Murkowski, Senator Cantwell, and members of the Committee:

The Washington Department of Fish and Wildlife (WDFW) appreciates the opportunity to provide a statement for the record on S. 1236, the "Hydropower Improvement Act of 2015".

Washington State is the largest producer of hydropower in the nation, and WDFW supports efforts to identify opportunities for efficiencies in the regulatory process for hydropower operators, agencies, and other stakeholders. WDFW is prepared to work with the Committee and Congress on meaningful process reforms that resolve relicensing concerns while protecting state fish and wildlife agencies' management authority for their public trust resources.

As an agency of the State of Washington, WDFW has jurisdiction over state fish, shellfish, and wildlife resources, and is charged with the duty of protecting, conserving, managing, and enhancing those resources (RCW 77.04.012). WDFW submits these comments with consideration of its role in hydropower licensing pursuant to the Federal Power Act (FPA), 16 U.S.C. § 803, as amended, the Fish and Wildlife Coordination Act (FWCA), 16 U.S.C. § 661 et seq, as well as the State Environmental Policy Act (SEPA), and the National Environmental Policy Act (NEPA).

We have concerns about S. 1236, and we oppose provisions therein that restrict WDFW's responsibilities for conserving the fish and wildlife resources of Washington.

Section 11 (LICENSING PROCESS IMPROVEMENTS AND COORDINATION)

- Adds to the Federal Power Act (16 U.S.C. 792 et seq.) Section 35 (LICENSING COORDINATION). WDFW is concerned this section is in conflict with state authorities. This section appears seeks to redefine Clean Water Act Section 401 certifications as federal authorizations and places the Federal Energy Regulatory Commission (FERC) as lead agency for such certifications. In Washington, 401 certifications ensure that not only will water quality be protected, but also fish habitat, fish passage, shoreline management, and water-based recreation. WDFW believes Section 35 turns back the clock on environmental protection on hydropower licensing, backtracking on the U.S. Supreme Court decision successfully argued by Washington Attorney General Christine Gregoire allowing states Clean Water Act authority to set instream flows via Section 401 Water Quality Certification.

- Currently state fish and wildlife agencies have authority to require protection, mitigation, and enhancement measures (such as flow regulation) for exempted projects. Section 35 appears to strip mandatory authority for the state and federal agencies allowed under 30(c) and grant FERC the authority to determine which conditions are necessary to prevent loss of or damage to, or to mitigate adverse effects to, fish and wildlife resources directly caused by the project compared to the current environmental baseline. This is problematic because the FERC currently has the authority to reject fish and wildlife agency recommendations it solicits under section 10(j) of the FPA for licenses and has a proven track record of rejecting meaningful 10(j) recommendations not supported with a mandatory filing under section 18 or 4(e). Because exemptions are issued in perpetuity, the FERC's new authority to veto protection for fish and wildlife could never be rectified.

- Adds to the Federal Power Act (16 U.S.C. 792 et seq.) Section 34 (LICENSING PROCESS IMPROVEMENTS). This section directs FERC to compile and make public a comprehensive collection of studies and data; to use existing studies if practicable; and to ensure that studies required for federal authorizations are not duplicative. States' and tribal authorities to obtain environmental data and information necessary to write CWA 401 certifications to protect waters and beneficial uses such as aquatic resources in their jurisdiction and recommend protection, mitigation, and enhancement measures pursuant to Section 10(j) of the FPA or required terms and conditions under section 30(c) of the FPA would be jeopardized if FERC is designated as the lead agency to set schedules and coordinate all needed authorizations under Section 35 above.

The Washington Department of Fish and Wildlife is available to offer further information on its position on S. 1236 at the Committee's convenience, and looks forward to working with you on hydropower reform.

Sincerely,

Justin Allegro

Justin Allegro
Energy Policy Lead

cc: Sam Ricketts, Office of the Governor

TROUT UNLIMITED

Steve Moyer
Vice President for Government Affairs

June 11, 2015

The Honorable Lisa Murkowski, Chair
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

The Honorable Maria Cantwell, Ranking Member
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Chair Murkowski, Ranking Member Cantwell and members of the Committee:

On behalf of Trout Unlimited's (TU) more than 150,000 members nationwide, I am writing to provide comment for the record of your May 19, 2015 hearing, which was focused on energy supply legislation. In this hearing, the Committee considered a large number of proposals related to energy supply. However, the comments below are limited to S. 1236. the Hydropower Improvement Act of 2015.

TU has a huge stake in the health of rivers affected by hydropower dams. TU members live, recreate, hunt and fish along the waterways impacted by hydropower development. We partner with agricultural users at non-powered dams and hydropower producers at powered dams to help maintain a balance between various competing water needs.

TU has a long history of engagement in hydropower project development and regulatory processes, partnering with utilities and project developers to identify and implement collaborative solutions balancing the needs of fish and wildlife with power production goals. In 2013, TU supported Representative Tipton's *Bureau of Reclamation Small Conduit Hydropower and Rural Jobs Act*, which became Public Law No: 113-24. The bill was aimed at improving the process for hydropower development at Bureau of Reclamation Facilities. TU has partnered with industry and other stakeholders in a number of licensing settlements and related processes. We engaged in cooperative stakeholder processes to restore valuable fisheries and relicense dams owned by Avista Corporation in northwest Montana and PPL on the Penobscot River, Maine. TU worked with stakeholders to develop and implement the Klamath River Restoration agreements, a tremendous solution that is supported by more than 40 parties, including PacifiCorp, the Klamath Project irrigation districts, Tribes, and commercial fishermen.

We supported these efforts because they were focused on improving the regulatory process or promoting project development without sacrificing natural resource safeguards. S. 1236 fails to strike that balance.

Trout Unlimited strongly opposes S. 1236, the "Hydropower Improvement Act of 2015." This bill would dramatically weaken fisheries conservation standards in the Federal Power Act, some of the most useful resource provisions in federal law. Not only does S. 1236 substantially weaken federal standards, but state standards as well. Among our key concerns, this legislation would have the following results:

- Reduce local and regional control over resource protections and priorities by taking authority away from federal and state resource agencies.
- Severely restrict data collection and disadvantage the use of updated and site-specific science;
- Weaken state and federal authority to ensure safe, timely and effective fish passage around dams and hydropower projects;
- Allow for off-the-record industry-only meetings between FERC staff and energy corporations with no prior notice or transcript available to excluded parties;
- Minimize or eliminate a developer's responsibility to comply with state and federal resource protection laws (like the ESA and CWA), which will place a greater burden on surrounding businesses and communities.
    - Impose fisheries and wildlife management costs on commercial fishermen, farmers, taxpayers and local communities by exempting hydropower dam owners from reasonable measures to protect fish and wildlife;
    - Shift the costs and burdens of meeting state water quality standards off of the hydropower industry and onto municipal water treatment facilities, factories, farmers and taxpayers.

Diminished State and Federal Agency Authority in Licensing Processes.

S. 1236 would effectively gut the Federal Power Act's mandate to ensure a balancing between power and non-power interests by transferring key protection determinations away from state and federal resource managers and centralizing that power at FERC. Although the Commission has a skilled staff, the agency does not have the statutory mandate to protect the lands and resources that are currently within the jurisdiction of its sister agencies in the Department of the

Interior and Commerce, such as fish and wildlife, endangered species, and public lands. These federal resource agencies have local and regional field staff with on the ground knowledge of the resources involved in any particular licensing process. Their level of familiarity and connection to the resources helps bring a deeper level of knowledge to the process, which is necessary to optimize a license for all uses.

TU relies on these agencies to protect and restore our fisheries resources and to help ensure equal consideration of non-power values in FERC's licensing processes. Because hydropower licenses can last as long as 50 years, natural resource agencies' roles in the licensing process provides a crucial opportunity to ensure that projects will be properly developed and operated to ensure our river resources are preserved for future generations. This opportunity is all the more crucial for re-licensing, as many of our nations' existing hydropower projects were developed before the existence of most major natural resource laws. The relicensing process provides our resource managers with the much needed opportunity to ensure that these projects are upgraded to meet modern day laws and standards for conservation performance.

Overly Restrictive Time Limits.

S. 1236 adds a new Section 35 to the Federal Power Act, which directs the Commission to establish a schedule for the issuance of all Federal authorizations. If a federal agency fails to process and issue permits or authorizations within the timeframe provided by FERC, those authorizations will be considered waived, or treated as a recommendation for "potential" inclusion in the license.

TU supports the concept of a single timeline shared by multiple agencies to help ensure predictability in the licensing process. However, S. 1236 takes this idea too far, imposing potentially arbitrary deadlines that do not account for the agency specific processes or information gathering needs of fellow agencies. This language aims to solve an alleged problem of too much delay by attacking the symptom, not the underlying cause. Rather than a lack of clear timeframes, delays seem more often connected to agency budget constraints or other administrative hurdles.

For example, agency authorizations are often delayed where the agency is unable to obtain the necessary information as a part of the FERC study process. Rather than further restricting the agency, delay could be minimized by improving coordination at the study phase to ensure all agencies – not just FERC – are able to obtain the necessary information to complete review and processing of necessary permits and authorizations without additional delay for data collection. Similarly, for agencies struggling with backlogs due to budget constraints, installing a new time limit will not solve the problem. Rather, these time constraints are likely to exacerbate the problem – forcing states to either (a) deny permits, causing delay for the applicant; (b) issue a permit with potentially onerous requirements as a precautionary approach when faced with insufficient resources to make a more informed decision; or (c) waive their authority, leaving the affected waterways unprotected at the state level.

Encouraging Ongoing Investment.

Section 8 of the bill directs the Commission to consider certain "project-related investments" made by the licensee over the term of the project license (where those investments did not already result in an extension of the license term by the Commission) as a factor in determining the length of a project license during relicensing. This section seems aimed at encouraging project owners to make early or ongoing project investments that may be above and beyond what their underlying FERC license requires by clarifying that FERC will take these investments into account when evaluating a future relicensing proposal. Trout Unlimited supports this concept and would be interested in working with proponents to find language that encourages new investment in hydropower projects' generating capacity *and* environmental performance. To ensure an adequate balancing of beneficial uses, environmental conditions must be sufficiently protective to justify license terms and consideration of operational and capital improvements should not come at the expense of resource protections.

Project Studies.

S. 1236 would add a new "Section 34. Licensing Process Improvements" to the Federal Power Act. This new section directs the Commission to evaluate and compile a comprehensive collection of data and best practices related to the process, methodology and sharing of information from licensing studies. This new section also directs the Commission to use existing information and avoid duplicating studies that were conducted in other FERC proceedings.

Trout Unlimited supports the value of sharing relevant information to minimize or avoid duplicity in the FERC study process. However, hydropower projects are uniquely site-specific and will require project-specific data collection to help inform the process and evaluate a project's impacts. Because of this, we are concerned that the "non-duplication requirement" proposed in S. 1236 is overly restrictive and will lead to less informed decision making.

Modification to FERC's Ex Parte Rules to Support "Informal" Communications.

This section also adds a new approach to allow "Informal meetings with Commission Staff." We generally support the concept of greater flexibility to allow more efficient and open communication between FERC and the licensing parties during the licensing process. However, the proposed language goes too far by creating a process that allows unilateral discussions between FERC and individual participants with no advance public notice and no opportunity for an excluded participant to obtain a record of the discussion or even the relevant details. Increased flexibility should not come at the expense of transparency, fairness and integrity in FERC's decision making process. This proposal steps beyond constructive flexibility and would result in increased conflict in the licensing process.

Federal Purchasing of Renewable Energy – Hydropower.

Section 203 of the Energy Policy Act of 2005 requires the federal government to "seek to ensure" that a certain amount of the energy consumed by the government comes from renewable sources. The existing law limits eligibility of hydropower for this program to new generation capacity achieved from "increased efficiency or additions of new capacity at an existing hydroelectric project." Changing this language to allow inclusion of *all* hydropower would (1) provide unwarranted incentives for construction of new dams and projects, further taxing our nation's already stressed waterways; (2) discourage investments in truly new sources of renewable energy by crediting the more than 100GW of existing hydropower already in production.[1] Focusing on new capacity gained through efficiency or capacity upgrades to existing dams helps to incentivize improvements and upgrades to existing, aging infrastructure as the preferred method of expanding hydropower resources, rather than creating an incentive or federal subsidy for new dam construction. We recommend keeping the existing definition of qualifying hydropower focused on efficiency improvements and capacity upgrades.

Agency Reporting to Congress.

S. 1236 creates a new "Annual Reporting" requirement for federal and state agencies participating in hydropower licensing processes. This new requirement establishes an unfunded mandate – imposing significant and unreasonable amount of new process and reporting obligations on already strapped resource agencies. Additionally, the reporting criteria for the agencies and for FERC appear to carry an unbalanced focus on promoting power benefits while ignoring or downplaying natural resource detriments. For example, the bill would require FERC to quantify "the loss of energy, capacity or ancillary services" as a result of new license conditions, but does not require a similar requirement to report on the increase in ancillary services or resource improvements that might be gained.

A better way forward.

Trout Unlimited recognizes the value and role hydropower in our nation's overall mix of energy sources and we support the goal promoting efficiencies and minimizing unnecessary

[1] Existing production estimate obtained from the National Hydropower Association website: http://www.hydro.org/why-hydro/available/industrysnapshot/

delay in the hydropower licensing process. Trout Unlimited supports common-sense reforms that will improve administrative processes without sacrificing resource protections. S. 1236 fails to strike that balance.

Rather than minimizing the ability of regional resource managers to include and enforce resource protection and enhancement measures, we suggest that the existing process could be improved through more effective agency coordination and communication, additional process support to first-time applicants, and through enhancements to the power purchase and power interconnect processes.

We anticipate continued activity and interest from this committee and its members related to hydropower regulatory improvements or reforms. As this discussion moves forward, we encourage the committee to seek broader input on the underlying goals of this proposal – i.e., what legislative reforms, if any, are needed - and to work with agencies, industry and members of the affected public to design more balanced solutions to any problems identified. TU stands ready to continue work with representatives from industry, resource agencies, the Commission and members of this committee to identify process improvements that do not sacrifice the protection, mitigation and enhancement of our nations' rivers and streams.

Thank you for the opportunity to provide comments on the S. 1236, the "Hydropower Improvement Act of 2015."

Sincerely,

Steven N. Moyer

Steve Moyer
Vice President, Government Affairs
Trout Unlimited

Statement for the Record by U.S. Sen. Mark R. Warner (D-VA)
U.S. Senate Energy and Natural Resources Committee
Hearing on Energy Supply Legislation
Tuesday, May 19, 2015

Madam Chairman and Ranking Member Cantwell, thank you for taking the time to host a hearing on energy supply legislation. I am pleased the committee has dedicated time to focus on this issue and look forward to lending my voice to the conversation over the coming weeks as you consider appropriate bills to move forward in this arena. I have long supported an "all of the above" approach to energy policy that allows the country to take advantage of a variety of resources for the purposes of encouraging our nation's energy independence, including the usage of renewable technologies. Allowing offshore drilling off the coast of the Southern-Atlantic Region would allow one more mechanism for the country to utilize in building a stronger energy infrastructure and creating a more energy secure America for years to come.

I also have to include one caveat for this support. We have to ensure that states which accept the risks of extraction also share in the revenues and proceeds from drilling operations. As you know Madam Chairman, there has already been precedent set for such revenue sharing arrangements in the Gulf of Mexico Energy Security Act of 2006, and various onshore formulas for fracking operations. I firmly believe that if regions are willing to take on the risk that can often accompany hosting extraction sites for the resources that power our country, they should be rewarded for helping to support our country's energy needs.

In years past I have introduced various versions of offshore legislation to permit responsible energy production off the coast of Virginia. I am proud to, for the first time, introduce such measures in a bipartisan bill with my friend Tim Scott of South Carolina. Our legislation, the Southern Atlantic Energy Security Act (S. 1279), would provide Southern Atlantic States (defined as the northern most lateral point of Virginia, to the southern most lateral point of Georgia) with 50% of collected revenue from energy development off states' coasts in the 2017-2022 BOEM 5YR program. This percentage is comparable with what most states receive from energy exploration royalties onshore. The bill includes the appropriate protections for the environment and would also ensure that a portion of funds from offshore exploration are used for clean energy, public transportation, or land and water conservation projects in each applicable state. Additionally, states must direct a percentage of funds received to two institutions of higher education, including one HBCU, to encourage new STEM studies of offshore energy resources and educate the next generation of America's offshore energy scientists.

Legislation like the Southern Atlantic Energy Security Act (SAESA) also helps grow the economy by creating jobs and spurring development in the offshore industry while also accounting for environmental and national security concerns. So Madam Chair, as you consider the inclusion of certain bills and provisions into the committee's comprehensive energy bill, I look forward to working with you and the Ranking Member on moving this very important piece of legislation forward and giving assurance to the Southern Atlantic States that they will be treated in the same manner as the Gulf Region and other onshore states with revenue sharing operations.

THE WILDERNESS SOCIETY

May 18, 2015

Chairwoman Lisa Murkowski
Senate Energy & Natural Resources Committee
304 Dirksen Senate Building
Washington, D.C. 20510

Ranking Member Maria Cantwell
Senate Energy & Natural Resources Committee
304 Dirksen Senate Building
Washington, D.C. 20510

Dear Chairman Murkowski & Ranking Member Cantwell,

In advance of the Senate Energy and Natural Resources Committee hearing on energy supply legislation we would like to submit for your hearing record our views on a number of bills related to energy supply under consideration tomorrow. We thank you for your leadership and hope you will keep these thoughts in mind as you continue to craft a comprehensive energy package.

The Wilderness Society believes we can develop new energy resources we need while protecting the places Americans love. Our public lands have long provided the nation with not only energy, but also recreation opportunities, unique and irreplaceable wild places, world class hunting and angling, and other amenities that draw tourists from around the world and contribute significantly to local and regional economies. Americans deserve policies that fully and fairly value public lands and resources, and reinvest a significant portion of the revenues in conservation activities. Decades of experience working on energy development and planning on public lands has shown that, with smart planning, we can meet the energy needs of today while safeguarding these values for future generations

As you evaluate these proposals we hope that you will prioritize legislation that establishes responsible, proactive and forward-looking development practices such as the ideas presented in the following bills:

S. 822, the Geothermal Production Expansion Act of 2015. This bill would promote geothermal activity by clarifying that public lands are available for geothermal leasing and assert the need for fair market value for the land.

S 1057, the Geothermal Opportunities (GEO) Act. This bill would create more opportunities for geothermal production by directing the Secretary of Interior to set goals for new geothermal capacity on public land alongside a public-private partnership and competitive grants from the Department of Energy for geothermal exploration.

S. 1264, the Renewable Electricity Standard. This bill would amend the Public Utility Regulatory Policies Act to establish a national renewable electricity standard. It would set national thresholds for retail electricity generation from renewable sources through a Renewable Electricity Standard (RES), requiring that utility companies derive a certain percentage of their electricity from renewable sources, achieving 30% in 2030.

S. 1271, the FLARE Act. This bill would require the Secretary of Interior to issue regulations to prevent and minimize the waste of taxpayer-owned oil and gas resources through a common practice known as flaring. Flaring is directly attributable to localized air pollution impacts, which has prompted states including North Dakota to take action. Current regulations have not kept pace with the remarkable growth in recapture technologies that could cost-effectively reduce emissions by more than 40 percent, according to a study by ICF Consulting. States alone do not have the authority to improve operational practices on federal leases, and thus the ongoing rulemaking should be completed with all due haste.

S. 1280, the Use It Act. This bill would direct the Secretary of Interior address the number of lands under lease through the Department of Interior but lack development activity and to create a production incentive fee for onshore and offshore oil and natural gas leases that produce for less than 90 days in a calendar year. These deposits to the Treasury's General Fund would ensure that leases on public lands are utilized and American citizens are reaping the benefit of land use contracts.

S. 1304, the 21st Century Energy Workforce Act. This bill would direct the Secretary of Energy to establish an advisory board consisting of key energy stakeholders to support and develop training and science education programs to meet labor needs in the energy sector. The Energy Secretary would also work with the Secretaries of the Departments of Labor and Education to establish an energy workforce pilot grant program that would provide competitive grants to public and nonprofit entities. Grantees would be selected based on their in-house job training and education programs, ability to transition Members of the Armed forces and veterans to careers in the energy sector, and ability to apply best practices to existing job training programs

S. 1199, the Alternative Fuel Reimbursement Act. This bill encourages the use of renewable fuel sources by authorizing federal agencies to construct, operate, and maintain, alternative fuel infrastructure on federal property for federal employees to access and to allow reimbursement for the purchase of renewable fuel.

Furthermore, The Wilderness Society has concerns regarding the following proposals as written:

S. 562, the Geothermal Exploration Opportunities Act. While The Wilderness Society supports the promotion of geothermal development, and many of the elements of this legislation, but we are concerned that the categorical exclusion for test wells on public lands is unnecessary. While we appreciate that such determinations are subject to the extraordinary circumstances test, the Secretary already has the authority to establish categorical exclusions under current law if there truly is a need.

S. 1026, the North American Alternative Fuels Act. This bill would repeal Section 526 of the Energy Independence and Security Act, which is intended to promote the use of clean technology within the federal government. Unfortunately, this bill would remove language that currently requires federal agencies to only enter into procurement contracts for alternative fuel sources that do not emit more greenhouse gas than conventional fossil fuel. In the past, this has ultimately put pressure to develop resources like oil shale and tar sands on federal lands – resources for which there is otherwise no market.

S. 1276, the Offshore Energy and Jobs Act. This bill would amend the Gulf of Mexico Energy Security Act of 2006 (GOMESA) to increase energy exploration and production on the outer continental shelf in the Gulf of Mexico. It would change the boundaries of eligible waters, shrinking areas set aside for military use, and require annual lease sales for three years with a one-size-fits-all environmental review regardless of changing circumstances. Because Land and Water Conservation Fund funds are derived from offshore oil and gas receipts, a natural and historical connection exists between revenue sharing and LWCF that was incorporated into GOMESA, which included revenue sharing for the stateside portion of LWCF. S. 1276 mirrors that provision, but it is now critical that unlike GOMESA, all accounts in LWCF, including both federal and state programs, are included in revenue sharing. It is time to ensure that there is honest budgeting for LWCF of these OCS funds, which have been consistently diverted for other purposes leaving a backlog of state, local and federal needs. LWCF reinvests these revenues from the sale of our national resources into future resources for all Americans - asset for asset, honoring the principles of fiscal conservatism.

S. 1278, the Alaska Outer Continental Shelf Lease Act. This bill would provide revenue sharing to Alaska, require additional lease sales in the Chukchi and Beaufort seas, and extend existing and new Chukchi and Beaufort leases. Additionally, the bill excludes revenue generated from the Land and Water Conservation Fund. Development in the Arctic is unproven and too risky to rush to additional leasing.

We appreciate the opportunity to engage in the committee's deliberations and request that this letter be included in the hearing record.

Respectfully,

The Wilderness Society

Statement of Senator Ron Wyden
Senate Energy Committee Legislative Hearing
May 19, 2015

Chair Murkowski and Ranking Member Cantwell, thank you for holding this hearing today. It's great to see so many senators from both sides of the aisle putting forward legislative ideas on energy.

As part of today's hearing, I have three bills for consideration that would promote clean energy resources:

The first is the *Geothermal Energy Opportunities Act*, or *GEO Act*. Clean, low-carbon geothermal energy can play an important role in the fight against climate change, and this legislation would encourage the development of the geothermal resource in a number of important ways.

The *GEO Act* helps prospective geothermal developers explore for and develop geothermal resources through a public-private grant program. As part of the partnership, developers report their findings, contributing to a nationwide map of geothermal potential that will reduce the risk of exploring for geothermal deposits and drive down future costs of geothermal energy.

In many cases, federal lands already under production for oil and gas also have a geothermal resource, and the *GEO Act* would allow for oil and gas leaseholders to co-produce geothermal energy without going through an additional competitive lease process. The *GEO Act* also fully incorporates the bipartisan *Geothermal Production Expansion Act*, a bill that passed the Senate unanimously in the last Congress and that I reintroduced with a number of my colleagues earlier this year. That provision would streamline the federal geothermal leasing program to prevent speculative bidders from unproductively driving up the price of leases for developers of geothermal "hot spots" that extend into lands directly adjacent to their existing geothermal lease.

The second bill is the *Marine and Hydrokinetic Renewable Energy Act of 2015*, that I introduced along with my colleagues Senators Merkley, Schatz, and King, to spur development of renewable electricity from the water power in oceans, rivers, and lakes. This bill would reauthorize the Department of Energy's marine renewable energy programs, including the national marine renewable energy research, development and demonstration centers around the country, one of which is run by Oregon State University. The Department of Energy estimates that there is enough potential energy in these nontraditional forms of hydropower to one day power millions of homes.

The third bill is the *Bioenergy Act of 2015*. Managed in an environmentally responsible way, woody biomass presents a carbon-neutral alternative to fossil fuels for heating and powering homes, schools and businesses. Much of the woody biomass in the U.S. that could be used for energy production is either scrap from logging, or small trees that overcrowd forests and worsen the risk of wildfires. Harvesting and preparing this biomass can help prevent wildfires while providing a stable source of jobs for rural communities across the country. The bill would establish a competitive cost-share grant program at the Department of Energy to improve technologies for processing woody biomass and bringing down transportation costs, as well as innovative technologies for using biomass for heat and power – from new power plant designs to neighborhood heating systems.

The *Bioenergy Act of 2015* would also create a cost-share grant program through the U.S. Forest Service to support *proven* biomass technologies, like combined heat and power. To help with financing, the bill would expand a loan program run by the USDA Rural Utilities Service to include bioheat and biopower, and establish a new loan program for projects that are not located in a rural utility service territory.

These three pieces of legislation will each promote the production of clean, domestic energy resources and in doing so help the United States take on a leading role in the fight against climate change. I strongly urge my colleagues to support them, and hope that they will be included in any energy package that the Committee puts together in the coming months.