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Clerk
Committee on Natural Resources
Subcommittee on Energy and Mineral Resources
1324 Longworth House Office Building

Subject: Nov. 7 Subcommittee hearing
Testimony provided by Prof. Eric N. Smith
Tulane Energy Institute, Tulane University
Regarding changes to the OCSLA
H.R._____ "ASTRO Act"

Ms. Konolige-

The following testimony is by Eric N. Smith in connection with his planned appearance before the Committee on Natural Resources, Subcommittee on Energy and Mineral Resources on November 7th at 2:00 pm. In room 1324 of the Longworth House Office Building.

I understand that the hearing is to consider testimony relating to the distribution of a portion of federal revenues from oil and gas leasing on the outer Continental Shelf to certain coastal States, to require the sale of approved and scheduled offshore oil and gas leases, to establish offshore wind lease sale requirements and to empower States to manage the development and production of oil and gas on available Federal land, and for other purposes.

Based on the Discussion Draft I received, the offshore portion of the proposed bill is focused on:

Sec.102) on updating the Outer Continental Shelf Lands Act, and by implication, the GOMESA Act of 2006, to improve the disposition of Federal revenues to producing States.

Sec. 103) Changes to limitations on the amount of distributed qualified OCS revenues under GOMESA,

Sec. 104) Providing a limit on the authority of President's to unilaterally withdraw areas of the Outer Continental Shelf (OCS) from active oil and gas leasing activity,

Sec105) modifying the OCS leasing program including adding certain offshore areas on the Atlantic Seaboard as well as in Alaska and expanding caps and modifying allocation formulas used to determine disbursements of defined offshore revenue,

Sec. 106 instituting a system of funding with respect to periodic inspections of OCS facilities,

Sec.107) negating the Arctic Rule,

Sec 108) extending OCSLA to include US territories,

Sec 109) Adding Offshore Wind lease sales to the planning agenda and

Sec.110) reducing permitting delays associated with the rules regarding the incidental taking of marine mammals.

There are also a Sections 201 through 207 in the draft which apply to onshore activities. My testimony follows the table of contents mirrored above but only pertains to the offshore changes.

General remarks

My general remarks focus on the positive macroeconomic results that can be tied to energy activity along the Gulf Coast.

The advent of shale oil and gas has fundamentally changed the energy outlook, not only on the U.S. Gulf Coast, but globally. On the positive side, we enjoy relatively low oil and gas prices with rapid increases in exports, not only of refined products, but also, since late 2015, significant increases in light crude oil, NGL derivatives including plastic pellets, and LNG. On the negative side, lower cost shale gas has negatively impacted offshore natural gas production in shallow water, although associated gas continues to be produced in deeper water.

All of these changes have resulted in significant new investment, by both US and international companies, in upstream, midstream and downstream assets designed to monetize these new supplies as well as in new, cleaner burning CCGT gas fired power plants. Access to the new supplies of natural resources both from the OCS, as well as from onshore sources, is allowing us to meet not only our nation's domestic energy demand, but also to supply a portion of global demand. While we will continue to import significant amounts of required heavy sour crude oil, increasingly it will be sourced from our preferred North American neighbors, Canada and Mexico.

Currently we produce about 9.5 mm bbl/day of which 5 mm is shale oil and 4.5 mm is conventional production. Of that, 1.7 mm is from the OCS while 2.8 mm is from conventional onshore sources. The bad news is that we use 19 mm bbl./day meaning that we continue to import about 9.5 mm bbl./day of both refined products and crude oil. Refined imports are chiefly into the North East states while rude imports are primarily into the Gulf Coast and the upper Mid-West.

From a crude oil pricing standpoint, we have seen a decline in crude oil prices from $93.26/bbl. in 2014 to $48.69 in 2015 and to $43.14 in 2016. Estimates for 2017 range from $51.00 to $59.00 and for 2018, from 55.20 to $75.00. Significantly, the quick response and relative predictability of shale oil is resulting in a relatively narrow band of prices.

From a natural gas pricing standpoint, we have seen a decline in actual natural gas prices from $4.39/mcf in 2014 to $2.63 in 2015 and to $2.52 in 2016. Estimates for 2017 range from $3.00 to $3.55 and for 2018, from 3.10 to $3.73. Significantly, the quick response and relative predictability of shale gas and gas associated with shale oil is resulting in a relatively narrow band of prices. The lack of volatility has, in turn, prompted significant investment in midstream and downstream energy infrastructure.

In terms of the offshore arena, the Gulf of Mexico, since 2009 has seen increasing production, in large part because of investment decisions made prior to 2010 to develop deep water offshore fields. This "delayed reaction" is a well-known feature of developing deep water offshore fields. Unfortunately, it follows that the paucity of new offshore developments since 2010 will necessarily result in a decline in production starting as soon as 2020, if new incentives and priorities regarding offshore production are not developed soon. One mitigating effort that may be seen is a recent effort, by both independents and majors active in the Gulf to standardize their development efforts, thereby saving both time and money. The pioneer in this effort has been LLOG, a Louisiana independent which has rapidly become the largest private operator in the Gulf of Mexico.

By providing enhanced access to oil and gas resources and by establishing equitable revenue sharing structures, we can create more of the high paying jobs associated with upstream development as well as with midstream and downstream infrastructure. In addition, this incremental activity can also provide sorely needed new funds to both the federal treasury and to coastal states and coastal communities within those states.

Louisiana's experience is that, whether it's a blue color or a white collar job, the oil and gas industry, pays almost 100% more than comparable non-oil and gas jobs. While the typical jobs analysis will point out the disparity between low labor intensity and high capital intensity when it comes to hydrocarbon extraction, pipelines, and downstream refineries and petrochemical plants, The Louisiana Center for Energy Studies at LSU is tracking ~$240 billion of new energy based manufacturing due to come online between 2015 and 2019. While Alabama and Mississippi both are represented, the bulk of the new investment is roughly split between Texas and Louisiana.

Beyond the Gulf Coast, the advent of energy production offshore the Atlantic and Pacific states targeted by this bill will inevitably result in added manufacturing activity similar to that already being seen as a result of shale oil and gas production onshore in the Marcellus and Utica shales of Pennsylvania, Ohio and West Virginia. Even Maryland has seen renewed LNG activity tied to natural gas production in neighboring Pennsylvania.

Here in Louisiana, beyond LNG export activity, large investments are being seen in Methanol and Ammonia plants as well as in new Steam Crackers which produce the olefins required to support new plastics polymerization activity.

When it comes to employment, Louisiana upstream oil and gas employment is forecast to reach about 42,000 in 2019, up from 40,000 in 2005. Similarly, Louisiana's refining and chemical sector employment has grown steadily from a low of 32,000 in 2005 and is forecasted to reach 39,000 by 2019. We see the same pattern in Texas where oil and gas employment has grown from 150,000 in 2005 to a forecasted 250,000 in 2019 while refining and petrochemical activity has grown from 95,000 in 2005 to 104,000 in 2019.

While we cannot convert the US into an energy island, by continuing to take advantage of the low cost feed stocks provided to us by nature and by our adoption of innovative extraction and processing technologies, we can certainly enhance our national security and minimize our imports of hydrocarbon raw materials. Certainly by concentrating unavoidable imports such as heavy sour crude oil, to countries like Canada and Mexico, we can lessen the potential adverse impacts of actions by OPEC and non-OPEC sympathizers.

We will always have a need to both import and export crude oil and refined products, but being able to increase our offshore production will allow us to positively impact our exports of both crude oil and refined products while limiting our imports of the heavier crudes needed by the majority of our refining capacity.

The previous administration precluded 94% of the OCS from oil and gas development. It is crucial that we expunge the detrimental policies that came, in the form of executive actions, at the expense of all Americans. Permitting inefficiencies, non-transparent bonding pronouncements and unilateral presidential withdrawals created considerable uncertainty for OCS operators, uncertainty that remains and that is actively discouraging investment. Post Mccondo attempts at reorganizing federal offshore regulations based on political, not economic, objectives practically shut down much of the upstream offshore oil and gas industry. In the downstream environment, similar efforts hobbled, or potentially hobbled, power generation, refining and petrochemical manufacturing.

The US is blessed with an incredible amount of diverse energy sources. We have oil, gas, NGL and renewable sources of energy that are the envy of both the developed and developing world. The oil and gas industry is a global one, and we are in competition with aggressive producers around the world. Our neighbors to the north and south are actively developing their hydrocarbon resources offshore, and have attracted considerable American investment. For example, Canada has continued to develop additional heavy oil production that our Gulf Coast refineries need in order to operate efficiently. Heavy oil imports that are secure and that can be paid for by our increasing exports of light and medium grade crudes which we possess in abundance.

Mexico has completely overhauled its national energy policy, allowing foreign investment for the first time in decades. Valuable oil and gas resources have been located off of the Yucatán Peninsula, just south of the American OCS as well as at multiple onshore locations. American exploration and service companies are actively participating in these ventures. It is vitally important that we create a healthy regulatory policy at home in order to maintain and increase the investment that allows our citizens to realize a fair return on the mineral resources off our coasts.

California imports oil and gas from several foreign countries, notably Canada, Columbia and Ecuador, but also countries in the Middle East and on the Pacific Rim. Their dependence and support of foreign oil stems from their refusal to fully develop crude oil resources at home. By realizing additional production from offshore Alaska and Mexico, California and the other West Coast States can at least reduce their need for crude oil imports from more remote locations.

This bill will encourage development in Alaska by creating revenue sharing provisions for the state. This Act also nullifies the Arctic Rule, which imposes burdensome regulations on offshore operations in the Arctic. Our Arctic neighbors, including Canada, Norway, and Russia, all safely conduct oil and gas operations in Arctic waters, and it is time that we join them.

This bill also expands OCSLA jurisdiction to include US Territories that could potentially contain significant offshore energy resources, and applies to the waters around those Territories. By providing the opportunity for local energy development, the Territories are empowered so that areas like Puerto Rico and the US Virgin Islands can pursue development that can lead to reduced imports and improved economic performance for their economies.

Finally, this bill provides for improvement in planning certainty – The previous administration's headstrong policies actively discouraged offshore energy development and created so much regulatory uncertainty that new, major deep water developments are scarcely to be seen. Prior to 2008, it was common to have one or two major, multi-billion dollar developments underway simultaneously in the US Gulf. Efforts dwindled over the past administration to a series of low capital cost "step outs" which could be accomplished relatively quickly and without expensive deep water infrastructure.

The current leasing schedule was established through a Five Year Planning process that has become something of a political football. However, as new Secretaries of the Interior call for revised plans that could effectively wipe clean existing scheduled lease sales, language has been included in this bill to ensure certainty into the future. This bill requires a sitting Secretary to hold all scheduled sales, even while he argues for a revised plan, whether his particular plan favors new leasing extensions or not. The goal of establishing the existing plan as a floor means that operators can confidently expend the funds necessary to actively bid on new properties without the uncertainty that the leasing plan will be modified and in the process destroy their investment to bidding on new leases.

This concludes my testimony. Should there be any questions, I am happy to answer them.

Following my testimony is a listing of specific comments on the current draft that may prove useful to the sub-committee as it continues the work of finalizing this draft for review by the full committee and eventually the full House of Representatives.

Bullets for non-spoken testimony-

1) Provide mechanism for currently non-participating coastal states to join the program at their option, perhaps with a mandatory waiting time before financial participation

2) Reduce the Phases apparently based on five year leasing programs to Phases based on annual lease cycles.

3) Simplify allocations for ONRR by using larger geographic area (Mississippi Canyon vs a single lease)

4) Allow states to decide whether they want political subunits to participate or not.

5) Strengthen the language to require future distributions without requirements for appropriation. States should have title to their portion of the revenue stream at the point it is received from the operator. This would be similar to a limited partner with the US Government being the general partner.

6) CAPS are improved, as is timing and amount, but more needs to be done. $500 mm just doesn't go very far in funding coastal restoration. Louisiana is looking at needs of $1.5 billion per year with a cumulative total of $50 billion and on a $28 billion annual budget. Moreover, the individual restoration projects can last a decade

7) It is unclear how anyone can add or reduce Marine Sanctuary territory. Wording is not consistent with current treatment of onshore sanctuaries

8) The section on inspections needs to be expanded to include more classes of assets as well as to adequately provide for inspections of subsea installations (pipelines, separators, well heads, PLETS, PLEMS, Drilling risers, Production risers etc.). Moreover, it makes no sense to bill an operator for inspecting an asset he doesn't own or control. Rather, the contractor should be billed, on an annual basis, for assets that are active in US waters, regardless of which operator he is supporting at the time of billing by the Treasury department. The contractor can then apportion the charge for each of the Operators he supports.

Details on references to the existing text.

Section 101 Title I – Offshore

Section 102 Disposition of Revenues

Page 4 line7- Rather than limiting the added states to Virginia, North Carolina, South Carolina, Georgia and Alaska, I would suggest providing an option for other Atlantic and Pacific coast states not currently included to opt in to the program. The rationale is that if, otherwise qualified states not included, later decide to join in, there should be a relatively straightforward way for them to be added to the agreement.

Page 5 line 15- Rather than having three phases with an increasing proportion running to the States in aggregate, I would suggest fewer phases or more frequent revisions, perhaps based on annual leasing cycles rather than recurrent 5 year plans.

Page 7 line 3 The GOMESA allocation system requires details on each lease that can change over time. Perhaps using a larger geographic unit made up of multiple leases would simplify the paperwork while not appreciably affecting the ultimate distributions.

Page 8 line 5 Allocation to local political entities should be at the option of the state involved rather than codified as is the current case. It may well be that the states are happy with this arrangement, but to the degree that certain states, including Louisiana have already dedicated their eventual receipts directly to coastal restoration, this 20% exclusion dilutes the beneficial impact of the total State receipts from the program. From the Federal standpoint it also adds complexity in terms of enforcing appropriate investments.

Section 103 Limitations on Amounts Distributed

Page 10-line 1- This is a key positive addition which will preclude subsequent administrations from failing to appropriate disbursements specifically authorized by the Act.

Page 11 lines 3-6 - Two stages of caps, $500 mm through 2027 and $749.8 mm thereafter should be increased. While these caps seem like large amounts, the variability in calculated disbursements will complicate any attempt at long range planning by States attempting to even partially cover multiyear aggregate expenditures in the $50 billion range.

Section 104 Limitation on Presidential Authority

Page 11 line 22 – It is unclear how a president may withdraw unleased lands already located in a National Marine Sanctuary or what would happen to unleased segments in the event that a current Marine Sanctuary is truncated or terminated. With the plan to have periodic area wide leases of all unleased property this could become problematic.

Page 13 line 3 – This states that previously established marine sanctuaries are not impacted by this act. However, in the onshore area, several monuments are currently being proposed for reductions.

Section 105 No comments

Section 106 Inspection fee collection

Page 14 line 4 – The implication is that this will be an annual fee, but in some cases, platforms may go beyond a year between inspections or, if there is a problem, they may have multiple inspections in one year. In line 7 the fee is designed to offset the annual costs of BSEE inspections but there is no linkage to the timing basis for any given inspection.

Page 14 line 9 - There is an apparent misunderstanding of the ownership of drilling rigs as well as of their relative mobility. First, rigs are rarely owned by E&P companies but rather operate as independent contractors. Platform rigs can be present on a platform for years, but are only operated during periodic drilling campaigns. Drill ships and Semi-submersibles come in to an area for drilling one or more wells on a lease, but have no equity interest in the wells they are drilling. If these assets are to be inspected, it would follow that the fees would be charged to the drilling contractor who would then rebill the charge to the E&P operator. Beyond ownership and mobility, there is no provision for inspection or fees related to offshore service equipment such as heavy lift barges, pipe lay barges, supply boats, anchor handlers, etc.

Page 16 line 5 – The limits inspections (and presumably inspection fees) to equipment above the water line. However, in shallow water, the mandatory inspections that occur after hurricanes also include inspections of foundations and jackets which are below the water line. Moreover, in deep water an increasing proportion of field development installations exist below the water line. While the deep water subsea installations are not particularly vulnerable to hurricanes, the last two major spills in the US Gulf occurred in close proximity to the subsea well heads. This draft makes no provision for inspections or the reimbursement of their cost, using ROVs and DP-2 support craft. Such inspections can draft the money being collected for above the waterline inspections.

Page 17 line 3 – Billing annually to operators is mentioned, but operators don’t own drilling rigs and if they are present, in many cases the time on site is variable. (See comments on Page 14, line 4)

Section 107 Arctic Rule no comments

Section 108 Territories of the US no comments

Section 109 Wind lease sales

Page 20, Line 3 - -Speaks to a requirement for at least two lease sales off of each State. Since we don't conduct oil and gas lease sales on a state by state basis, why should we institute a new regime for Wind lease sales? Some larger aggregation of states (Annual East Coast, West Coast sales would seem more reasonable and cost effective. Similarly, assuming the required feasibility reports are positive, annual sales for each territory would also be more than reasonable.

Section 110 reducing delays associated with incidental taking of marine animals no comments

9) Wind lease sales should be conducted on a less frequent basis and should reflect multistate geographic areas, not individual states or territories. Using a state by state basis merely reflects existing progress in onshore power generation. Get FERC involved.

Miscellaneous Comments

Without clarification on the need and level of surety bonding, the Federal offshore oil and gas leasing program in the US Gulf will remain in the doldrums. Uncertainty created by BSEE and BOEM regarding differences between historical levels of coverage and those proposed and held in abeyance, based on non-transparent estimates, has made valuing of mineral property transfers practically impossible. Perhaps this act could help the situation by mandating a return to the original rules grandfathering all currently active leases, but with a 10 year notice period for any material changes. A narrow exception for "naked" leases could be incorporated into this Act. These are leases to new OCS operators which don't include former leaseholders. In the past, such legacy owners have always been contingently liable for P&A liabilities in the event that a current lease owner defaults on P&A obligations. The "naked" leases have no such support. While they are a tiny portion of the total leases outstanding, they are at disproportionate risk of default due to their over leveraged condition.