

SENATE FINANCE COMMITTEE
March 15, 2012
1:05 p.m.

[1:05:34 PM](#)

CALL TO ORDER

Co-Chair Stedman called the Senate Finance Committee meeting to order at 1:05 p.m.

MEMBERS PRESENT

Senator Lyman Hoffman, Co-Chair
Senator Bert Stedman, Co-Chair
Senator Lesil McGuire, Vice-Chair
Senator Johnny Ellis
Senator Dennis Egan
Senator Donny Olson
Senator Joe Thomas

MEMBERS ABSENT

None

ALSO PRESENT

Senator Cathy Giessel; Senator Joe Paskvan; Senator Hollis French; Gerald Kepes, Partner and Head of Upstream and Gas, PFC Energy.

PRESENT VIA TELECONFERENCE

Janak Mayer, PFC Energy, Washington, DC.

SUMMARY

SB 192 OIL AND GAS PRODUCTION TAX RATES

SB 192 was HEARD and HELD in committee for further consideration.

#sb192

SENATE BILL NO. 192

"An Act relating to the oil and gas production tax; and providing for an effective date."

1:06:01 PM

GERALD KEPES, PARTNER AND HEAD OF UPSTREAM AND GAS, PFC ENERGY, introduced himself.

Mr. Kepes discussed the PowerPoint Presentation: "Discussion Slides: Alaska Senate Finance Committee" (copy on file). He stated that since the current day's morning meeting, he had conducted some global context analysis for energy and petroleum and upstream investment. He stated that there was a focus on the Alaska Clear and Equitable Share Act (ACES); different cost-producing scenarios; and global comparison of average and marginal government take.

Mr. Kepes discussed slide 31, "ACES versus CS SB 192." He stated that the slide displayed the differences between ACES and CS SB 192. He explained that production tax was not bracketed in either case. He furthered that CS SB 192 decoupled oil and gas. He noted the difference in the rates for the production tax: ACES had a maximum of 75 percent and CS SB 192 had a maximum of 60 percent. He stated that the progressivity for ACES was 0.40 percent, and the progressivity for CS SB 192 was 0.35 percent. He added that CS SB 192 had an allowance for new oil.

JANAK MAYER, PFC ENERGY, WASHINGTON, DC (via teleconference), stated that CS SB 192 also held a flaw related to the minimum rate of production tax value at 10 percent of gross value for large producers. He explained that there would be a presentation of that analysis.

Mr. Kepes looked at slide 32, "ACES (Existing Producer)." He explained that the slide represented a 2000 barrels per day producer. He stated that the government take, displayed in the upper right hand table, varied from roughly 68 percent up to 81 or 82 percent as oil prices rose.

1:11:20 PM

Mr. Kepes discussed slide 33, "CS SB 192 (Existing Producer)." He noted similar producing characteristics with ACES. He pointed out some slight variations between ACES and CS SB 192: the peak of government take under CS SB 192 lowered from 83 percent to 79 percent; and the project net present value of producers under CS SB 192 rose slightly for existing producers.

Mr. Kepes looked at slide 34, "ACES (New Development)." He stated that the slide was an analysis of the higher cost development, peaking at 10,000 barrels per day representing a reserve size of approximately 65 million barrels, at \$100 a barrel. He noted that the total government take started at 75 percent and peaked at 85 percent.

Mr. Kepes discussed slide 35, "CS SB 192 (New Development)." He noted that the government take for new development was 80 percent at its peak. He stated that both new development projects were fairly marginal at \$100 per barrel, and it did not change from ACES to CS SB 192.

Co-Chair Stedman requested an explanation of each quadrant displayed in the slide. Mr. Kepes explained that the upper left hand quadrant represented the cash flow analysis. He pointed out the periods of negative revenue represented the initial capital expenditures (CAPEX) and operations expenditures (OPEX) for a particular project. He noted that the peak CAPEX in the third year of development was \$300 million, which was calculated after the capital credits were applied. He pointed out that the operating costs extended for the lifetime of the field. He furthered that the black line represented the after tax cash flow (ACTF). The upper right hand portion of the slide was a table that coincided with the cash flow analysis graph. He noted that the table displayed a summary at \$40, \$60, and \$100 per barrel; the net present value of the project investment to the investor; and the internal rate of return (IR) to the investor. At \$100 per barrel, the project represented a net present value of \$12 million, and an IR of 10 percent. He stressed that at \$100 per barrel, from the point of view of the investor, it was a relatively marginal project. The lower left hand corner graph displayed a breakdown of the different components of government take. The red represented the royalty, the yellow represented production tax, the light blue represented the property tax, the green represented the state corporate income tax (CIT), and the dark blue represented the federal CIT.

[1:16:42 PM](#)

Co-Chair Stedman wondered what the lower-right-hand corner represented. Mr. Kepes replied that it was a normalized representation of the level and composition of relative government take. He stated that the fiscal system breaks

down at \$40 to \$60 per barrel, because the price would be too low to maintain at the particular fiscal system. He furthered that as the price of oil rose; the royalty was a progressively smaller percentage of the overall government take. He pointed out the increase of the contribution of the production tax, because of the where the base was located, and the "stepping" at the upper price ranges.

Mr. Kepes stated that the same quadrant structure on the slide would be used throughout the presentation.

Mr. Kepes looked at slide 36, "Progressivity Impact on New Development Project Economics." He stated that the graph on the left hand side of the slide represented a comparison ACES and predecessor regimes (actual and proposed). The right hand side graph displayed a comparison with ACES and CS SB 192 with bracketed amendments.

Co-Chair Stedman wondered if the x-axis was ANS West Coast. Mr. Kepes responded that it was ANS West Coast at \$100 per barrel, with a net present value in millions of dollars for the investor.

Co-Chair Stedman requested an analysis of PPT and its evolution. Mr. Kepes thanked the chairman, and agreed to provide that information.

Mr. Kepes discussed slide 37, "New Oil Allowance: Incremental Production on a Declining Base":

Central to understanding the impact of the "allowance for 'new oil'" is an understanding of the impact of new source production on a company's total production volumes, when that new source production is added to a declining base portfolio.

The charts assume a 6 percent decline rate for an existing North Slope producer currently producing 200 million barrels per day (mb/d), and examine hypothetical new source projects that peak at 10 mb/d, 50 mb/d and 100 mb/d respectively (on a working interest basis).

Given the pace at which such projects typically reach peak production, only the 100 mb/d peak production new source development is actually capable of adding

production that is incremental to prior years' volumes.

[1:23:49 PM](#)

Co-Chair Stedman wondered why 200 mb/d was used in the analysis. Mr. Kepes replied with slide 38.

Mr. Kepes looked at slide 38, "A Hypothetical 100 mb/d (Working Interest) Development":

A new source development that produced 100 mb/d at peak for a working interest partner would be a very significant new development. By way of comparison, Kuparuk, the second largest field in North America, peaked at approximately 320 mb/d gross production.

-This represented working interest production to ConocoPhillips (the operator and majority shareholder) of 170 mbo/d.

-Kuparuk took 11 years (from 1981 to 1992) to reach this peak level of production.

Co-Chair Stedman announced that there would be discussions about any particular tax structure's probability of producing great amounts of oil. Mr. Kepes replied that the prospectivity of finding an on-shore field that could produce 320 mb/d was fairly low. It was more likely that new field prospectivity would be substantially low.

Mr. Kepes discussed slide 39, "Assumptions":

The following analysis assumes

1. A 6 percent base portfolio decline, in the case of a producer currently producing 200 mb/d.

2. Costs for the base production portfolio of:

-\$12/ flowing bbl operating expenditure

-\$5/ flowing bbl maintenance capital expenditure

3. Costs for the 100 mb/d (working interest) New Development project of:

-\$13/ flowing bbl operating expenditure

-\$13/bbl reserves development capital expenditure

-\$1/ flowing bbl maintenance capital expenditure

4. These costs are deliberately somewhat lower than the previously referenced 10 mb/d new development, since the hypothetical development modeled is significantly larger, and thus likely to have somewhat lower costs on a \$/bbl basis.

[1:28:36 PM](#)

Mr. Kepes looked at slide 40, "CS SB 192 Excluding New Oil Allowance (Existing Producer)." He explained that the description of the investment, as discussed, was displayed in the slide, excluding the new oil allowance. The slide was attempting to isolate the impact of CS SB 192, excluding the new oil allowance. He stated that the in the total government take in the upper right hand corner ranged from 68 percent to 79 percent. The NPV at \$100 per barrel was approximately \$16.7 million.

Mr. Kepes discussed slide 41, "CS SB 192 Including \$10 New Oil Allowance (Existing Producer)." He stated that the slide followed the same model as slide 40. An existing producer with 200,000 barrels per day would develop a 100,000 per day working interest project at the same cost.

Mr. Kepes looked at slide 42, "CS SB 192 Excluding New Oil Allowance (New 100 mb/d Development)." He looked at the cash flow analysis graph in the upper left hand corner. He explained that the after tax cash floor in 2009 to 2014 was negative because of CAPEX pre-production. He stated that production would be initiated in 2013, and the cash flow would reach into the positive. He stated that the investment would represent an NPV of approximately \$276 million at 100 per barrel, and an internal rate of return at 11 percent. He directed the committee's attention to the table in the upper right hand corner of the slide, and noted the total government take rising from 69 percent to a maximum of 81 percent.

[1:33:24 PM](#)

Co-Chair Stedman wondered how back-out costs from production facilities were incorporated. Mr. Kepes deferred to Mr. Mayer.

Mr. Mayer stated that the costs, without existing production, would include some additional operating costs to account for no base production.

Co-Chair Stedman requested more detail regarding the inclusion of the back out fees that were negotiated with the existing producers to use facilities, to determine the overall impact. Mr. Kepes replied that there were some assumptions included in the OPEX, and deferred to Mr. Mayer to provide more information. Mr. Mayer furthered that the included OPEX in new development without base production, was relatively high.

Mr. Kepes discussed slide 43, "CS SB 192 Including \$10 New Oil Allowance (New 100 mb/d Development)." He explained that the \$10 new oil allowance provided added approximately \$50 million of NPV to a project, and the internal rate of return was the same. He surmised that the changes provided by the addition of the \$10 new oil allowance, were fairly modest with respect to the model without the new oil allowance.

Mr. Kepes looked at slide 44, "Oil/Gas Decoupling":

1. Under ACES, production tax value is assessed on a combined BTU-equivalent basis for both oil and gas production.

-So long as no major gas export project is under development, this has no impact.

-In the event of the development of a major gas export project, however, when gas prices are significantly lower than oil prices, this could lead to significant reductions in Government Take.

2. CSSB 192 includes a provision to de-couple the calculation of production tax value on North Slope gas sold out-of-state, in order to eliminate this impact of gas production.

-The impact of the decreased government take without decoupling is only pronounced with very low gas prices, and very large gas production.

-In order to illustrate the impact at the extreme, the following analysis thus assumes a \$1/mcf net-back sale price for North Slope gas, and a 2018 1bcf/d gas project. Under less extreme scenarios, the difference with and without decoupling would be significantly less.

[1:38:46 PM](#)

Co-Chair Stedman remarked that the "major line" would provide \$4.50 bcf per day. Mr. Kepes stated that it was larger than stated.

Mr. Kepes discussed slide 45, "CSSB 192 - Existing Producer with 2018 Gas Project, No Decoupling." He looked at the cash flow analysis graph in the upper left hand section of the slide, and remarked that in 2014 to 2018 there was a "dip" in the after-tax cash flow line. The substantial "dip" represented CAPEX. He furthered that the NPV in that particular portfolio was equally substantial. He remarked that the table in the upper right hand corner of the graph displayed a total government take range from 67 percent to 71 percent.

Mr. Kepes looked at slide 46, "CSSB 192 - Existing Producer with 2018 Gas Project, Including Decoupling." He remarked that the government take changed from a peak of 71 percent with no decoupling to 78 percent including decoupling. He felt that the impact was relatively modest. He suggested an analysis be conducted of \$4 bcf per day, because it seemed more realistic.

Co-Chair Stedman felt that cash flow numbers were more important than government take numbers, because the government take numbers "hid" the amount of cash that was moved around. He noted a letter from the Department of Revenue that stated that combining oil and gas cost the State \$80 million a year with no gas sales.

Mr. Kepes discussed slide 47, "Regime Competitiveness: Relative Government Take: Average Government Take of Global Fiscal Regimes at \$100/bbl." He stated that the slide displayed a comparison of different fiscal regimes against

a set of regimes globally. He pointed out that CS SB 192 was generating a government take of approximately 76 percent, and pointed out how that compared to ACES and other jurisdictions.

[1:43:54 PM](#)

Mr. Kepes looked at slide 48, "Regime Competitiveness: Relative Government Take: Average Government Take of Global Fiscal Regimes at \$140/bbl." He remarked that it was the same analysis as slide 47, but at \$140/bbl. He pointed out that both ACES and CS SB 192 moved "up the scale somewhat" relative the other less progressive jurisdictions.

Mr. Kepes discussed slide 49, "Regime Competitiveness: Relative Government Take: Marginal government Take of Global Fiscal Regimes at \$100/bbl." He stated that the analysis was conducted with a \$1/bbl step at a time, and looked at the change in government take on that marginal basis.

Co-Chair Stedman noted a slight improvement. Mr. Kepes agreed.

Mr. Kepes touched on slide 50, "Regime Competitiveness: Relative Government Take: Marginal Government Take of Global Fiscal Regimes at \$140/bbl."

Mr. Kepes discussed slide 51, "Conclusions - Changes to Progressivity, Overall Government Take, and Oil/Gas Decoupling":

1. CSSB 192 uses two key mechanisms to reduce government take relative to ACES:

- A reduction in the rate of progressivity that applies above \$30/bbl Production Tax Value (PTV) from a 0.4 percent increase for each one dollar increase in PTV, to a 0.35 percent increase.

- A reduction in the maximum rate of production tax, from 75 percent at \$342 PTV, to 60 percent at \$202 PTV.

2. The impact of the reduction in the progressivity coefficient on overall levels of government take and

on project economics is limited to around a single percentage point of government take at \$100 ANS crude.

3. The impact of the 60 percent maximum rate for production tax is more significant, but only at very high oil prices.

-On a current-year basis, government take under CSSB 192 would be significantly lower than under ACES only at ANS crude oil prices above \$230.

-On a project-lifecycle basis, that threshold may be lower, as a result of the impact of bracket-creep (since progressivity thresholds are specified in nominal terms) - but the impact on project economics at likely price levels remains negligible.

Mr. Kepes looked at slide 52, "Conclusions - New Oil Allowance":

1. Even under highly aggressive assumptions regarding the potential for a new-source development for a given company, the impact of the \$10 allowance for "new oil" is almost undetectable.

-In the context of both a development by an existing producer, and a development by a new producer, Relative Government Take changes only by fractions of a percentage point, at most.

-For an existing producer, portfolio NPV rises by only a tenth of a percentage point.

-For a new producer, the impact on project value is greater, but remains insignificant in the context of a \$10 billion capital development.

2. The major reason for this is because rather than providing an ongoing allowance for new-source production, the amendment provides an allowance only for production that, in a given year, is incremental to the previous year's production.

-For an existing producer with declining base production, only a very large development is capable of producing "new oil" under this development at all.

-Even for a new producer, the value of the allowance remains highly limited.

3. An allowance which was instead provided for new-source production could potentially have a greater impact, however adequately defining such new-source production could be difficult in practice, particularly in an environment where most new production will come from existing areas.

[1:49:22 PM](#)

Senator Thomas looked at slide 51, and wondered how many of the various oil jurisdictions had a combined oil and gas tax. Mr. Kepes replied that very few jurisdictions had a combined oil and gas tax. He furthered that most locations treated gas slightly differently from one another. He stated that the differential in value, whether calorific or value-based, had become so large, that a combined oil and gas tax aggravates the system.

Mr. Kepes introduced the section, "Global Strategy and Portfolio Overview of Major Alaska Producers." He explained that the section provided an assessment of the major Alaska producers' portfolios, priorities, and strategies. He stated that the data that was used was either public or from PFC Energy's proprietary databases.

Mr. Kepes discussed slide 55, "BP: Global Areas of Upstream Operations":

Strategic Signature

-BP is a global integrated company, with production in 16 countries and upstream operations in an additional 10 countries.

-In 2010, total global production averaged approximately 3,773 mboe/d, making it the second largest company in the peer group (superseded by ExxonMobil (approximately 4,450 mboe/d). The Russia & Central Asia (RCA) and North America regions accounted for approximately 55 percent of 2010 production.

-BP recorded a 4.5 percent drop in production in 2010 over 2009, reflecting the impact of asset sales, the

post-Macondo slowdown in US GOM deepwater activity, and continued decline from the company's deepwater and mature shallow water assets.

-Much of the post-Macondo portfolio rationalization program (targeting \$30 billion in asset sales including mid/downstream assets) has been completed. The result is a pared down and more focused geographic portfolio.

-BP expects growth of 1 percent -2 percent per annum through 2015. BP's growth strategy is three-pronged based on Deepwater Basins, Global Gas, and Giant Oilfield Development. BP's deep water position is based on operations in the US GOM, Angola, Egypt and Brazil. The Global Gas position is principally comprised of US, Trinidad & Tobago, and North Sea. Giant oil fields are dispersed throughout the global portfolio. Based on PFC Energy projects, growth is unlikely before 2015.

-The growth strategy above includes approximately \$20 billion net investment commitment to 16 projects sanctioned over 2010-2011. This is expected to curb ROCE performance for the coming 2-3 years.

-With the burden of the Macondo oil spill and reparations continuing through the mid-term, BP will be hard pressed to outperform its peers on any key metrics, leaving the company open to calls for more radical restructuring

He stated that, according to PFC Energy's analysis, BP considered Alaska a "harvest area."

[1:59:56 PM](#)

AT EASE

[2:10:02 PM](#)

RECONVENED

[2:10:09 PM](#)

Mr. Kepes discussed slide 56, "BP Global Production Portfolio - 2010":

Russia: BP's largest producing country (963 mboe/d), representing approximately 26 percent of 2010 output. Substantial long term growth potential. Continued interest in Russia (and Arctic) expansion, despite limitations arising from the TNK-BP joint venture.

Canada: modest conventional production, with future potential tied to oil sands.

US: 2nd largest producing country, with core deepwater area. Activity slowed post-Macondo, yet expect strong future growth. Onshore L48 is key gas area (approximately 22 percent of 2010 global output), with focus on unconventionals. Alaska potential tied to commercialization of Prudhoe Bay resources.

UK: Declining position from mature offshore assets. High-value operating area, generating large cash flows.

Trinidad & Tobago: Core gas producing area tied to Atlantic LNG.

Azerbaijan: Participation in 2 large-scale projects: Azeri-Chirag-Guneshli & Shah Deniz.

UAE: Core position through equity affiliates, though concession are being re-negotiated.

India: 2011 Partnership with Reliance for exploration in shallow and deepwater.

Australia and Indonesia are key gas producing areas tied to investments in LNG.

Iraq: Development of Rumailia oil field.

Angola: Sole presence in SSA is Angola deepwater. High growth from 2002-2009, now challenged with start-up of several unsanctioned projects.

Argentina: onshore & shallow water assets (held by PAE) were to be sold to Bridas, but transaction failed in 4Q:11.

He stressed that the analysis was based on PFC Energy's assessment and opinion. He stated that the slide pointed

out asset type, conventional on-shore, and conventional shallow.

Mr. Kepes looked at slide 57, "Total Portfolio Evolution: BP vis-à-vis the Competition":

In 2010, BP was the second largest producer of the peer group. Yet, from 2010 to 2015, BP and COP are the only two companies to experience a reduction.

2000-2010: Production increases from approximately 3,080 mboe/d to approximately 3,780 mboe/d due to addition of Russia (approximately 960 mboe/d), Trinidad & Tobago (approximately 250 mboe/d) and Angola (approximately 170 mboe/d). This expansion offsets declines from Europe (approximately 660 mboe/d and North America approximately 350 mboe/d).

2011-2015: BP's production is expected to decline from 2000-2015, due mostly to the post-Macondo asset divestiture program, combined with curbed activity in the GOM deepwater.

Mr. Kepes discussed slide 58, "Reserves and Production: BP vis-à-vis the Competition":

2000 - 2003: BP experienced significant reserve growth (from approximately 15,000 mmboe to approximately 18,000 mmboe) equivalent to approximately 6.5 percent CAGR. The increase is the result of added reserves in Africa (Angola), Equity Affiliates (Russia) and Asia-Pacific. Production grew at a slower pace (approximately 3 percent CAGR) during this period.

2003 - 2004: The formation of TNK-BP results in an increase of approximately 600 mboe/d from 2003 to 2004.

2005-2010: Production and reserves remain relatively unchanged. Reserves remain within the range of 17.4 - 18.0 billion boe. Production remains within the range of 1,462-1,389 mboe/d.

[2:16:07 PM](#)

Mr. Kepes looked at slide 59, "Reserves and Production: BP Intra-Portfolio Performance":

Roughly 60 percent of production and reserves are concentrated in the US and Equity Affiliates (mostly comprised of TNK-BP since 2003).

European production (and reserves) declined rapidly from 2000-2006 (Area is now reported as UK and Rest of Europe).

Africa (mostly Angola deepwater) production more than doubled from 2002 to 2009.

Mr. Kepes discussed slide 60, "How the Portfolio is Financed: Sources and Uses of Cash":

Over the decade, Africa (mostly Angola deepwater) has rapidly progressed from an area of investment to an area generating cash surplus. Africa was BP's second largest cash generator in 2010.

The US is the leading generator of cash flow this decade, allowing for re-investment in other areas.

Mr. Kepes looked at slide 61, "Global Production: Evolution of the Portfolio."

Asia Pacific: Relatively small producing area (approximately 6 percent of 2010 output). Production largely from offshore Australia and Indonesia with lesser volumes from China. Partnership with Reliance (India) creates exploration opportunities. Focus on deepwater and CBM. Divested assets in Pakistan and farmed down in Vietnam.

Europe: Mature and generally declining production position in the UK and Norway, mostly in shallow waters. Exploration and development projects are ongoing, often leveraging BP's existing infrastructure and assets in the region.

Latin America: Growth driven by shallow water gas developments in Trinidad & Tobago. Focus on onshore gas commercialization in Bolivia. Failed to sell Argentine assets (held through PAE) to Bidas in 2011.

Brazil deepwater offers mid- to long-term potential from newly acquired deepwater acreage.

Middle East and North Africa: Position built from collaboration with NOCs (Adma-Opco, GUPCO, Sonatrach, LNOC, etc.). Substantial new source growth expected from Iraq, Egypt deepwater, offshore Oman. Exploration opportunities in Jordan.

North America: Second largest production region & largest cash flow generator. Deepwater GOM holds significant growth potential after years of investment. US L48 portfolio is material, yet declining, source of gas, with a growing emphasis on shale gas. Additional future growth from Canadian oil sands.

Russia and Central Asia: Principally comprised of TNK-BP venture created in 2003, now BP's largest source of production, characterized as long-life, slow decline output. In Azerbaijan, production is from large-scale ACG and Shah-Deniz. The Region is the largest source of new source volumes through 2015.

Sub-Saharan Africa: Operates only in the Angola deepwater play, which quickly emerged as a key oil-producing country. BP has collaborated with operators TOTAL (Block 17) and Chevron (Block 15). In the future, development of BP-operated blocks 31 and 18 is expected to reverse the recent decline in production.

[2:23:51 PM](#)

Co-Chair Hoffman wondered if slide 61 portrayed potential development, such as the Beaufort and Chukchi conventional shallow. Mr. Kepes replied that if there was a viable potential project, it would be included in the analysis. He furthered that if there was a pure expiration play, without commercial field development, it would not be included in the analysis. He added that a project would not be included if there was a heavy oil or viscous oil project that was not considered commercial under existing commercial terms.

Co-Chair Stedman requested further detail regarding the Chukchi project. Mr. Kepes agreed to provide that information. He noted the potential in the off-shore

drilling, but felt that it would not be development for a few years down the line.

Mr. Kepes discussed slide 62, "Global Production: Country Growth Project Analysis":

Russia is a leading source of mid-term new source volumes. Production (from TNK-BP) include expansions to existing areas such as Orenburg, and greenfield developments such as the Uvat and Verkhnechonskoye fields.

BP's participation in Azerbaijan's ACG Phases 1-4 is among the largest net new source projects in the BP portfolio.

Angola deepwater provides large share of new source oil.

The Asia-Pacific Region (Indonesia, Australia) and the MENA Region (Egypt, Algeria, and Oman) are the key providers of new source gas in the medium term.

By 2015, the US represents the largest area for BP, by number of project. The US holds 11 new source projects, of which 9 are GOM deepwater and 2 are onshore Alaska.

BP's new source Canadian oil sands projects are expected on stream post-2015.

BP's new source portfolio is driven by (1) Deepwater projects (Angola and US GOM); and (2) Russia (mostly onshore oil).

The Asia-Pacific remains a mostly gas-production area.

Unconventional (Asia-Pacific and North America) and oil sands (Canada) projects are largely immaterial until 2020 or so.

Co-Chair Stedman wondered if there was further information regarding BP's two onshore sights in Alaska. Mr. Kepes agreed to provide that information.

[2:27:42 PM](#)

Mr. Kepes touched on slide 63, "BP in Alaska." He stated that BP held North Star, Prudhoe Bay Gas, Liberty, and Pt. Thomson Gas fields in Alaska.

Mr. Kepes stated that slide 64, "BP Alaska Activity and PFC Energy Assessment":

ACTIVITY:

Most of BP's assets are located on the North Slope, where production volumes have generally declined because of the maturity of the asset base and/or gas infrastructure constraints. Liquid production has declined from approximately 224 mboe/d in 2006 to approximately 166 mboe/d in 2010, while gas production has fallen from approximately 67 mmcf/d to approximately 46 mmcf/d over the same period.

BP's largest source of production is the Greater Prudhoe Area (26 percent w.i., operated), covering approximately 150,000 acres with more than 1,000 active wells. Gas resources are currently stranded because of the lack of pipeline capacity to southern markets. BP and ConocoPhillips had teamed up to propose a new natural gas pipeline (Denali) to run from Prudhoe Bay through western Canada to US markets. However, in May 2011, the partners announced that plans for the pipeline had been terminated, citing the lack of long-term purchase contracts. The proposed pipeline would have accommodated 4 bcf/d of natural gas.

BP and partners are moving forward with the development of gas liquids on the approximately 8 tcf Point Thomson field (32 percent w.i., non-operator). The gas cycling project is expected to produce approximately 10 mb/d of liquids; first production is targeted for 2014. Full field development awaits gas transport infrastructure.

In the Beaufort Sea, BP has suspended work on the extended-reach drilling program on the Liberty oil field (100 percent w.i.), pending revision of project design and schedule.

BP is also seeking to develop viscous (Kuparuk) and heavy (Milne) oil resources on the North Slope.

PFC ENERGY ASSESMENT:

Current production volumes are modest and declining, yet significant potential lies in the long-term commercialization of Prudhoe Bay and Point Thomson gas resources. Cancellation of the Denali gas pipeline proposal leaves BP as a potential supplier to an alternative pipeline-export option, should one be approved and developed.

Co-Chair Hoffman looked at slide 63, and wondered where the project was that was planned for the following summer.

Mr. Kepes stated that there were many wells that were being drilled, but were not considered official projects.

Co-Chair Hoffman queried Shell's offshore drilling projects. Mr. Kepes replied that the wells were still expiration wells, but were still fairly speculative.

Mr. Kepes looked at slide 65, "PFC-Identified Challenges":

1. Re-establish its operator profile in the global deepwater: While its competitors extend their commitments to global LNG, unconventional shale gas exploitation, and oil sands development in order to drive future portfolio growth, BP has deepened its commitment to the global deepwater play, despite the ongoing fallout from the Macondo oil spill. Expansion of its US GOM lease holdings (through the Devon portfolio acquisition), entry into the Brazil deepwater, and a material commitment to the K-G Basin deepwater play in India, together with phased field development offshore Angola and West Nile Delta in Egypt, positions BP as arguably the premier deepwater player in the Global Player peer group. BP will be under the spotlight regarding its future conduct and performance throughout the global deepwater basins.

2. Resolve shareholder relationship issues within the TNK-BP JV: Accounting for approximately 26 percent of total worldwide production in 2010 (and approximately 36 percent of total worldwide oil production), the TNK-BP position is absolutely core to the BP portfolio from a volumetric perspective. However, the unsuccessful attempt to partner with Rosneft in the

Russia Arctic raises concern over how much value TNK-BP can continue to create for BP. With TNK-BP now focused on international expansion, must BP settle for lower returns from what has until now been a highly lucrative position?

3. Complete the portfolio rationalization process: The strength of the global asset transactions market prompted BP to expand its divestiture program from an initial \$20 billion to \$30 billion, divesting large swaths of its portfolio deemed non-Core and/or non-aligned with the company's growth focus. While the company did not plan on the depth of portfolio rationalization undertaken to date, this is a rare opportunity to high-grade asset holdings with the blessing of shareholders and analysts alike. BP is expecting to complete the divestiture process by end-2011.

4. Determine a path forward in the Brazil deepwater: Having secured Brazil government approval to acquire the Devon asset portfolio, BP has established a foothold in the Brazil deepwater, with potentially the largest operated pre-salt portfolio outside Petrobras. The next step is to determine the appropriate approach to growth in the pre-salt play. With legislation now in place granting NOC Petrobras a minimum 30 percent w.i. and operatorship in all unlicensed pre-salt acreage, this may be another case of executing a strategic alliance (similar to that secured with Reliance in India and proposed with Rosneft in the Russia Arctic).

5. Accelerate development of US Onshore unconventional gas resource: BP received a very competitive price for the Permian Basin and Western Canada conventional gas assets sold to Apache (totaling approximately 75 mboe/d of production and approximately 340 mmboe of reserves, equivalent to approximately \$24.60/boe of reserves in the ground or approximately \$109,000/flowing boe of production). This is particularly so given what is shaping up to be an extended period of gas price weakness in the North America market. To make up for lost volumes, BP may look to accelerate production from its approximately 10 tcf of reserves in the Woodford, Fayetteville, Haynesville, and Eagle Ford shale gas plays.

6. Accelerate development of BP's oil sands leases: BP has built up a material oil sands lease portfolio in Western Canada, including 50 percent w.i. in the Sunrise in situ development project (sanctioned in November 2010), a 75 percent w.i. in the Terre de Grace in situ project (secured in March 2010 from Value Creation for approximately \$900 million), and 50 percent w.i. in the Kirby in situ oil sands leases (with the other 50 percent divested to Devon in March 2010). Full development of these projects could represent 500-600 mbo/d of stable, long-life oil production, complementing the "Giant Oil Fields" growth platform and providing a portfolio buffer against the steep decline production profiles associated with deepwater developments.

[2:33:53 PM](#)

Mr. Kepes discussed slide 66, "ConocoPhillips: Company Overview":

Strategic Signature

Following two years of corporate net income losses, steep decline in its share price, and a persistently high debt-to-capital ratio, in March 2010 ConocoPhillips announced a new strategic pathway, directing proceeds from an approximately \$15 billion asset and joint venture divestment program to reduce its debt-to-capital position, increase near-term shareholder returns, shift further out of the downstream, and position the company for future growth from a smaller but higher-value portfolio position.

Since the announcement of the 2010-2012 Restructuring Plan, ConocoPhillips has executed on approximately \$7 billion in asset sales, divested its entire 20 percent equity interest in LUKOIL, and directed proceeds from these sales to debt reduction and share repurchase. In July 2011, ConocoPhillips announced the next step in its restructuring: the creation of two separate corporate entities, Downstream and a pure play, E&P.

With production in 15 countries and upstream operations in an additional 7 countries, ConocoPhillips' most recent guidance suggests

production reaching a low of approximately 1.5 mmb/d in 2012, recovering to 1.64-1.69 mmb/d by 2015. The company will rely on a large, diversified upstream portfolio positioned heavily in OECD countries (namely the US, Canada, Australia, UK, and Norway, which accounted for approximately 72 percent of worldwide production in 2010).

Growth of 0.5 percent per annum from 2012 through 2015 is forecast to come from Global Gas/LNG, SAGD Oil Sands, and Unconventional developments. However, as ConocoPhillips now stands to compete with the Independent, non-integrated oil & gas companies, the company's future strategy remains uncertain.

Mr. Kepes discussed slide 67, "ConocoPhillips: Global Areas of Upstream Operations." He felt that Alaska should be considered a "core area" for ConocoPhillips. He explained that ConocoPhillips had several areas of activity in Alaska: expiration activity off-shore, Cook Inlet, and North Slope. He opined that the North Slope would be considered a harvest area for ConocoPhillips.

Mr. Kepes looked at slide 68, "ConocoPhillips Global Production Portfolio - 2010":

Russia: LUKOIL sale leaves ConocoPhillips with modest production from its two joint ventures in Russia (Polar Lights Company and Naryanmarneftegaz). Regional production is forecast to drop from 21 percent of worldwide production in 2009 to a projected 3 percent in 2011.

Canada: Among the largest natural gas producers in Canada. Three SAGD oil sands developments—Christina Lake, Foster Creek, and Surmont—have added long-life production volumes to ConocoPhillips' portfolio.

US: Largest producing country, with core L48 production where liquid-rich areas (Eagle Ford) will be prioritized over gas assets. Declining mature assets in Alaska could be offset by prospective deepwater volumes in long-term.

UK and Norway: Region characterized by mature, declining assets; satellite projects planned to offset regional base declines.

China: Modest offshore production from Bohai Bay.

Qatar: Qatargas 3 (onstream in 2010) is key driver to regional gas growth.

Nigeria: Interests in six onshore assets, serving as feedstock to Nigeria LNG Trains 4-6.

Australia: APLNG Phase 1 sanctioned in 2011; longer-term upside in Australia could stem from assets in the Browse Basin or Timor Sea (e.g. Greater Sunrise).

Vietnam: Continued development of mature Cuu Long Basin; potential divestment target.

Malaysia: Development of deepwater fields (Gumusut-Kakap and Keabangan) will bring Malaysia into ConocoPhillips' producing country portfolio.

Indonesia: Largest contributor to Asia-Pacific production; ongoing development of Corridor PSC and South Natuna Block B.

Libya: Legacy onshore Waha concession; above ground conflict will delay new source oil projects.

Algeria: Onshore oil field production; additional volumes from El Merk (EMK) expected for 2012 start-up.

[2:37:57 PM](#)

Mr. Kepes discussed slide 69, "Total Portfolio Evolution: ConocoPhillips vis-à-vis the Competition":

ConocoPhillips' 2010-2012 Restructuring Plan will see the company become the largest of the Independent, non-integrated international oil & gas companies, compared to its former position as the third-smallest of PFC Energy's expanded Global Player peer group.

2000-2010: Production increases largely driven by the merger of Conoco and Phillips in the beginning of the decade (growing volumes from 698 mboe/d in 2000 to 1,082 mboe/d in 2002) and the Burlington Resources purchase in 2006 (growing volumes from 1,824 mboe/d in 2005 to 2,358 mboe/d in 2006). The gradual acquisition

of a 20 percent stake in LUKOIL was a key driver to mid-decade growth.

2011-2015: ConocoPhillips's production is expected to decline from 2010-2015, due to the company's intensive asset divestiture program (the initial approximately \$15 billion asset and joint venture divestment program was expanded in 2011 when ConocoPhillips announced it would shed an additional \$5 billion - \$10 billion in non-Core assets by end-2012). Volumes are forecast to decline from approximately 2,078 mboe/d in 2010 to approximately 1,674 mboe/d in 2015.

Mr. Kepes looked at slide 70, "Reserves and Production: ConocoPhillips vis-à-vis the Competition":

2000-2006: Production and reserves grow steadily, largely a result of acquisition: from 271 mboe/d and 5,019 mmboe in 2000 to 682 mboe/d and 11,469 mmboe in 2006. R/P ratio declines from approximately 18 to approximately 13 years.

2006-2010: Both production and reserves experience a reversal in growth; however reserves fall more steeply. By 2010, production was 776 mboe/d and reserves decreased to 8,310 mmboe, resulting in the lowest R/P ratio recorded in the decade at approximately 11 years. In 2010, declines in production were primarily due to field decline, the impact of higher prices on production sharing arrangements, and the sale of Syncrude.

Mr. Kepes discussed slide 73, "Global Production: Evolution of the Portfolio":

Asia Pacific: Project queue 14 projects deep makes Asia-Pacific the largest development pipeline in all of ConocoPhillips' portfolio. Region estimated to occupy 20 percent of 2011 upstream CAPEX. New projects in both legacy countries (Indonesia, Vietnam) are being complemented by startups in Malaysia (Gumusut-Kekap, Kebabangan) and Australia (APLNG).

Europe: Mature and generally declining production position in the UK and Norway, mostly in shallow waters. Satellite projects poised to somewhat offset base declines.

Latin America: After reaching historic peak production in 2005, volumes fell to zero in 2009. The Latin America portfolio, largely acquired through the Burlington transaction, has never been a material part of ConocoPhillips' global operations. With no new volumes anticipated in the portfolio, a complete exit from the region could be likely.

Middle East and North Africa: Future growth is largely tied to the Qatargas 3 LNG project and El Merk (EMK) in Algeria. Longer-term growth is poised to stem from Libya (as yet unsanctioned joint NC 98 and North Gialo developments) assuming a timely re-commencement of upstream activities.

North America: Largest production region and cash flow generator. New growth initiatives focus on exploitation of Eagle Ford shale liquids and Canadian oil sands (Christina Lake, Foster Creek, and Surmont), which are projected to reverse the decline in Canadian production by 2014 and deliver medium- and long-term volume growth.

Russia and Central Asia: LUKOIL sale leaves ConocoPhillips with only modest production from its two joint ventures in Russia and few growth opportunities within the remaining portfolio. The sole growth asset is an 8.4 percent stake in the Kashagan field, which continues to face major challenges.

Sub-Saharan Africa: Onshore assets serve as feedstock to Nigeria LNG Trains 4-6. Longer-term upside tied to feedstock for the yet-to-be-sanctioned Brass LNG plant, while 2011 re-positioning in Angola could provide exploration opportunities critical to securing new source ventures for long-term growth.

Mr. Kepes looked at slide 74, "Global Production: Country Growth Project Analysis":

ConocoPhillips's new source portfolio is driven by (1) Shallow water gas production (Qatar); (2) Canadian SAGD Oil Sands Developments; and (3) US Unconventional production (Eagle Ford).

Deepwater projects sourced mainly from the Asia-Pacific region (Malaysia) and the US GOM deepwater (mostly non-operated positions), will ramp up steadily over the decade; by 2020 deepwater is poised to represent 7 percent of global volumes (compared to approximately 2 percent in 2010).

[2:42:04 PM](#)

Mr. Kepes looked at slide 79, "PFC-Identified Challenges":

Competing as a "Pure Play" E&P Company: The separation of ConocoPhillips into two, stand-alone Upstream and Downstream entities is scheduled to be finalized in 1H: 2012. The approximately 85 percent of total portfolio value residing in E&P assets will thereby become the largest "pure play" E&P Independent, a competitor landscape position the company held uncomfortably prior to the Burlington Resources acquisition in 2006. Can ConocoPhillips Upstream compete successfully in the Independent's space by delivering either leading shareholder returns or leading production growth? Or has it simply re-established its original dilemma—too large to compete with the faster moving International Independents, and too small to compete with the Global Players? And if so, does it survive?

Re-Establishing a Value Proposition: ConocoPhillips' new strategic focus on Sustained Value Generation is intended to re-establish the company's competitive advantage in the E&P space. In the near-term, the 2010-2013 Restructuring Plan will deliver a smaller company with limited medium-term production growth and improved, but unlikely to be leading, ROCE and financial performance. Clearly, the cannibalization of the company's assets and recycling of proceeds to shareholders in order to shore up share valuation and total shareholder returns is a stop-gap strategy at best. Given continuing financial and operational challenges (ROCE, production cost, upstream net income, etc.), ConocoPhillips may struggle to deliver a value proposition that will compete successfully in either the Global Player or International Independents peer group.

Improving Operational Performance: While showing improvement in finding and development costs, ConocoPhillips ranks at or near the bottom of the expanded Global Players peer group in net income/boe, production costs/boe, and Upstream ROCE. The current portfolio high-grading has already delivered Upstream ROCE improvement (from 7 percent in 2009 to 10 percent in 2010) and should deliver improvement in operational metrics; both Syncrude and the LUKOIL holdings were arguably underperforming positions. With long lead time, large scale, capital intensive developments like Qatargas 3, Jasmine, Kashagan Phase 1, and Surmont poised to deliver material production and cash flow, ConocoPhillips should see the flow-through benefits in terms of more competitive ROCE and operational metrics.

Delivering Production Growth: The share repurchase program accompanying portfolio rationalization under the Restructuring Plan is projected to deliver approximately 3 percent growth in per share production in 2010 and 2011. However, physical volumes will decline in absolute terms over the 2010-2011 period—by approximately 208 mboe/d in 2010 from 2009 levels and a further approximately 360 mboe/d in 2011 from 2010. The only region poised to deliver higher production volumes in 2020 versus 2010 is the relatively minor MENA region, projected to reach approximately 177 mboe/d in 2020 versus 72 mboe/d in 2010. New source volumes in Canada and the North Sea will struggle to offset mature asset declines, delivering flat production in the core North America and Europe regions, while the LUKOIL sell-down will dampen what was once considered a core driver of future growth for the company. While boasting a 10 billion boe resource base, it is not clear how ConocoPhillips will deliver the promised surge in organic growth over the 2015-2020 period from its captured portfolio—although the enhanced CAPEX spend in the Eagle Ford play is a good starting point. Barring a material acquisition (certainly not out of the question), the company will be looking to its exploration portfolio to deliver a medium term "engine of growth".

Mr. Kepes discussed slide 80, "ExxonMobil: Company Overview":

ExxonMobil is the largest global integrated company (volumes averaged approximately 4,450 mboe/d in 2010), with production in 21 countries and upstream operations in an additional 20 countries.

ExxonMobil has long adhered to a growth strategy based on scale, basin dominance, and execution excellence, which has required the company to seek continuous access to investment opportunities of adequate size and materiality.

In 2010, faced with the commissioning of the final elements of the company's Qatar project portfolio (the final four approved LNG trains at RasGas and Qatargas, and Phase 2 of the Al Khaleej gas project), declining production in Europe and Asia-Pacific, and already holding a considerable stake in the Canadian oil sands, ExxonMobil took an aggressive move into unconventional shale gas exploitation.

The 2009 acquisition of XTO Energy brings materiality to ExxonMobil's technical expertise in tight gas, CBM, and shale oil and gas exploitation, with approximately 2.3 bcf/d and 87 mboe/d of production, proved reserves of approximately 2.3 billion boe, and a resource base of 7.5 billion boe. From a position of basin dominance in the US Onshore, ExxonMobil will seek to build a global unconventional portfolio; as such, the company has already begun purchasing prospective acreage in Argentina, Germany, Poland, Indonesia, and, most recently, China.

Largely a result of the acquisition, ExxonMobil recorded a 13 percent increase in production in 2010 over 2009. The company will seek growth of 4-5 percent per annum over the 2009-2014 period.

Mr. Kepes looked at slide 81, "ExxonMobil: Global Areas of Upstream Operations." He explained that PFC Energy analyzes each company's portfolio to look at the growth prospects, decline rates, amount of re-investments, and materiality. He remarked that 50,000 barrels per day to a company that produces 4.4 million barrels per day was much different than 50,000 barrels a day to a company that produces 200,000 barrels per day. He stressed that relative materiality must be factored into the analysis. He stated that Qatar was the largest single country contribution to

the United States as of 2011. In 2011, ExxonMobil bought a large shale gas company, XTO, which made the United States the largest single country producer again. He noted that it was remarkable for Qatar to contribute so much, because the country was so small. He added that Alaska was a "harvest area" for ExxonMobil.

Mr. Kepes discussed slide 82, "ExxonMobil Global Production Portfolio - 2010":

UK and Norway: Mature North Sea assets have delivered volume declines of approximately 5 percent per annum in Europe over the last 5 years.

Russia: Strong performance track record at Sakhalin I and Arkutun-Dagi. Rosneft Strategic partnership could be a dial-turner in Russia (Arctic exploration & tight oil resource exploitation).

Kazakhstan: Participation in 2 large-scale projects: Tengiz & Kashagan.

Canada: Oil sands volumes (Cold Lake, Syncrude, and Kearl projects) will dominate out-year production growth.

Germany: Legacy gas assets; recent unconventional acreage acquisition.

US: Largest producing country; regional decade-long decline reversed with purchase of XTO. XTO combined with three additional unconventional acquisitions will make the Onshore L48 the cornerstone of future growth.

Qatar: Represented approximately 20 percent of 2010 output. Decade-long double digit growth driven by final tranche of sanctioned LNG capacity in Qatar.

Nigeria: Generally declining shallow- and deep-water assets.

Australia: Gas oriented region, with growth stemming from Gorgon LNG project and Gippsland Basin shallow water projects (Kipper and Turrum).

Indonesia: Near-term gas volumes will hold production steady as ExxonMobil positions for new ventures in the unconventional space (coal bed methane).

Malaysia: Key gas producing area; focus on enhanced oil recovery (EOR) and field life extension schemes.

Argentina: legacy, declining gas assets; recent acreage positioning in prospective shale Neuquen Basin.

Angola: Multi-field new source developments (Kizomba Satellites Phase 1, Pazflor, and CLOV) drive regional growth.

Papua New Guinea: Formerly small contributor to the ExxonMobil portfolio, PNG will rise in prominence within the portfolio through the monetization of gas reserves at PLNG.

[2:47:13 PM](#)

Mr. Kepes looked at slide 83, "Total Portfolio Evolution: ExxonMobil vis-à-vis the Competition." He pointed out that ExxonMobil was not designed to "grow", because their focus was on the financial efficiency and return. He stressed that ExxonMobil would not pursue an investment opportunity for growth purposes.

Averaging approximately 4.45 mmb/d in 2010, ExxonMobil continues to lead its peer group in terms of production.

2000-2010: For much of the last decade, production oscillated, rising between 2000 and 2002 and then again 2005-2007; however, by 2009 production volumes were only slightly above levels recorded at the start of the decade, averaging approximately 3.92 mmb/d. In 2010, ExxonMobil secured production growth of approximately 13 percent (approximately 6 percent excluding the XTO acquisition), reaching approximately 4.45 mmb/d. For a company that has prided itself on organic reserves and production growth, the XTO acquisition marks a considerable departure in growth strategy for ExxonMobil.

2011-2015: ExxonMobil's production is forecast to grow modestly between 2010 and 2015, reaching only approximately 4.54 mmb/d in 2015. While PFC Energy estimates are lower than ExxonMobil targets, the absence of guidance regarding growth projects associated with the XTO portfolio make the pace of future growth uncertain.

Mr. Kepes discussed slide 84, "Reserves and Production: ExxonMobil vis-à-vis the Competition":

ExxonMobil has recorded one of the most consistent R/P ratios of all of the Global Majors. A slight increase over the past decade (from approximately 13 years in 2000 to approximately 15 years in 2010) reflects the increase of reserves in the context of generally flat line production.

[2:50:08 PM](#)

Mr. Kepes looked at slide 87, "Global Production: Evolution of the Portfolio":

Europe's dwindling R/P ratio is largely due to the maturity of the asset base.

A focus on exploitation (as compared to exploration) in Africa has resulted in a decline in the region's R/P ratio.

Largely due to the XTO acquisition, both reserves and production experienced a large bump in 2010; in turn, the US R/P ratio grew from approximately 17 years to approximately 21 years.

In 2009, ExxonMobil began reporting Bitumen and Syncrude as distinct reporting regions, which, in turn, resulted in a sharp decrease in oil reserves and production reported under the Canada/South America reporting region.

Mr. Kepes discussed slide 88, "Global Production: Country Growth Project Analysis":

ExxonMobil's US new source portfolio will dwarf new source production from all other countries. Through 2015, the US will contribute nearly 40 percent of

global new source incremental volumes, 99 percent of which will stem from the company's unconventional activities (acquisitions plus the Piceance tight gas development).

Production from Qatar will primarily be tied to development of the North Field and the Qatargas and RasGas LNG projects, while the rest of the new source landscape reflects ExxonMobil's expansive upstream portfolio.

International unconventional developments are likely to be largely immaterial until 2020 or thereafter

Mr. Kepes looked at slide 90, "ExxonMobil Alaska Activity and PFC Energy Assessment":

ACTIVITY:

In Alaska, ExxonMobil holds interests in the Greater Prudhoe, Greater Point McIntyre, and Greater Kuparuk areas. The company is one of the largest North Slope producers, although production from the region is declining; 2010 net production averaged 117 mb/d of liquids.

Development activities continued at Point Thomson in 2010 (35 percent w.i., operated), and first production of gas liquids is anticipated in 2014. The longer-term potential lies in commercialization of the gas reserves, which is dependent on building a gas pipeline.

PFC ENERGY ASSESSMENT:

Material harvest position. As the largest holder of discovered gas resources on the North Slope and a co-operator of the Prudhoe Bay Western Region development, ExxonMobil holds a leading position in Alaska.

[2:54:56 PM](#)

Mr. Kepes discussed slide 91, "PFC-Identified Challenges":

Deliver on unconventional resource positioning: The XTO Energy acquisition and subsequent shale gas

acreage transactions have made ExxonMobil a force in the North America unconventional resource play. That said, the company has provided limited guidance on pace of forward development despite continued acreage accumulation. Furthermore, given the weak US gas price environment, it is unclear how rapidly ExxonMobil's management will grow sales volumes. ExxonMobil is counting on additional long-term value arising from the XTO transaction through development of its expanding portfolio of International unconventional resource holdings.

Execute on Asia-Pacific LNG Projects: ExxonMobil has a queue of LNG developments in Asia-Pacific, including Gorgon LNG (operated by Chevron), PNG LNG, and the potential Scarborough gas field development, all of which are poised to generate longer-term volume growth. Each of these projects comes with significant technical challenges—CO2 capture and disposal at Gorgon LNG, remote gas field development and long distance pipeline transport in the case of PNG LNG, and the remote offshore location of the Scarborough field in the Carnarvon Basin (which may result in the field being dedicated as feedstock supply to the Pluto or Wheatstone LNG projects, rather than a greenfield LNG development). Performance will be critical to ensuring long-term regional portfolio growth.

Maintain leadership in share buy-back and dividend performance: ExxonMobil has been a clear peer group leader in returns to shareholders, distributing approximately \$19.7 billion through dividends and share buy-backs in 2010 and spending approximately \$114 billion on share repurchase over the 2006-2010 period. With the increased emphasis being placed on unconventional gas resources to deliver future volume growth, shareholders will be looking for ExxonMobil to continue its leading dividend and share buy-back performance, as the core differentiator from its faster growing (in volumetric terms) peer group companies.

Replace volume growth from Qatar North Field commercialization: With full ramp-up of the final four liquefaction trains at the RasGas and Qatargas LNG complexes, and continued imposition of a development moratorium for the North Field resource by

the Qatar government, ExxonMobil will be challenged to deliver material global growth.

-It is not clear how aggressively ExxonMobil will look to develop its US Onshore unconventional gas resources, given current and projected gas pricing in the North America market;

-Monetization of captured frontier gas resources in North America (Alaska North Slope, Mackenzie Delta) continues to face delays in the form of regulatory hurdles (recently removed for the Mackenzie Valley gas pipeline project) and gas market supply-demand balances;

-Development of captured oil reserves in the Caspian region have experienced significant delays and cost over-runs, and are coming under increased political risk through accelerating resource nationalism;

-ExxonMobil was successful in securing a growth position in Iraq through the West Qurna-1 redevelopment project, but will have to share the larger Iraqi resource prize with a number of IOCs and NOCs. It is not clear that Iraq can become a Core growth area for the company.

SB 192 was HEARD and HELD in committee for further consideration.

Co-Chair Stedman discussed the following day's agenda.

#

ADJOURNMENT

2:57:35 PM

The meeting was adjourned at 2:57 PM.