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Summary Report from North Slope Gas & LNG Symposium in Anchorage

PFC Energy

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Section 1. Executive Summary

Gas is a fast growing segment of the global energy system—and liquefied natural gas (LNG) is the fastest growing segment within gas. Moreover, much of the growth in energy, gas and LNG is coming from Asia—meaning that Alaska is well positioned geographically to capture this market. Geography and scale are both assets that Alaska can leverage—yet at the same time, the opportunity set for gas producers and for LNG buyers is widening; the question to ask is why Alaska? Why should a company invest in Alaska? Why should a buyer come to Alaska to secure LNG?

This report summarizes the main findings of a weeklong symposium in Anchorage in August 2013. The conclusions of that symposium where:

- There is growing demand for gas and LNG, in particular in Asia, and most countries need to secure additional LNG to meet their energy needs post 2020. Alaska's proximity to Asia makes it a natural supply source, although it will face competition from a growing number of new supply sources.
- Shale gas in the United States Lower 48 and in Western Canada will compete with Alaskan LNG for markets—and the Lower 48 in particular are a primary destination for suppliers seeking long-term LNG. But current ($3-4/MMBtu, million British thermal units) prices in the United States will rise, potentially undermining the competitiveness of LNG from the Lower 48.
- The companies involved in Alaska's upstream and will likely be involved in LNG have substantial experience with and expertise in LNG. As such, the question is not whether they can do an LNG project but rather will they choose to given competing priorities and outlets for their capital.
- An LNG project from Alaska can be competitive with other projects that are seeking to supply Asian markets—but its competitiveness will depend critically on fiscal terms and on keeping costs down.
- LNG projects are big, complex, risky, multi-stakeholder endeavors that take a lot of time (often decades) and money (billions) to complete. There are multiple ways to structure an LNG project (who participates in which part and in what way) and it is important to develop a structure that aligns all the different partners and project participants and meets their risk-reward appetites.
- LNG shipping is an important component for project economics, and Alaska has a geographical advantage relative to most other emerging supply sources for LNG.

Section 2. Global Gas Markets and Macro Fundamentals

Overview. Alaska faces a robust and expanding market for its undeveloped gas resources in the North Slope. Global gas demand growth has accelerated in recent years: from 2000-2010, gas demand grew by 2.8% per annum (p.a.), more than double its 1.1% p.a. growth from 1990-2000. This is partly due to faster energy demand growth; but it also reflects the fact that gas is making inroads against other fuels—fuel switching accounted for about half of growth in gas demand from 1990 to 2000 and 56% of the growth from 2000 to 2010. The turn to gas has come mainly at the expense of oil. While gas' share in the energy mix has grown from 19 to 22% in 1990-2011, the share of oil declined from 37 to 32%. The shift towards gas is even more pronounced in the power sector, where gas' share rose from 15 to 24% in 1990-2012, while the share coming from oil has fallen from 11 to 5%.

How Gas Differs from Oil. Oil and gas differ not only in terms of their changing roles in the global energy mix; they have distinct demand drivers, supply sources, trade patterns, and pricing structures. Gas demand is more diverse compared to oil: while over half of oil demand comes from transportation, power is the largest source of gas demand globally, accounting for 40% of the total. Other sectors are important as well: the industrial sectors makes up 17% of gas demand, followed by the residential and commercial sectors (15%), non-energy/petrochemicals (6%), and transportation (3%). In terms of gas production, the largest suppliers are North America (27%) and Russia (18%), while the Asia-Pacific has been the fastest-growing region. The Middle East, on the other hand, is the largest supplier of oil (33%) and has been the second-fastest growing region. Production of oil is still far greater than that of gas, though gas production has been growing at a faster pace. The gas trade has also been expanding more rapidly: traded pipeline gas volumes have risen by over 5% p.a. and LNG has risen by 8% p.a. since 1999, compared to just 2.2% for traded oil.

Another difference between the two fuels is that gas pricing is more regional and local, versus oil where price tend to be set globally. For Asian LNG importers, the price of LNG is indexed at a discount to the price of oil. This pricing scheme was founded decades ago as importers looked to gas imports to replace oil use, and has been reinforced by the lack of any appropriate alternatives. The Japan Crude Cocktail (JCC) is the typical index to which gas prices are set. Several pricing schemes are present in Europe depending on the market. These vary from strong linkages to oil prices for pipeline gas or more robust trading hubs in the Netherlands (the Title Transfer Facility or TTF) and in the UK (the National Balance Point or NBP). In North America, gas prices are set at trading hubs, of which Henry Hub in Louisiana is the largest; other hubs trade at a premium or discount to Henry Hub.

Outlook for Natural Gas Demand. From 2010-2030, gas demand is forecast to grow by 2.3% p.a. on average. Regionally, Asia is expected to be the largest source of new gas demand, followed by the Middle East and North America. By contrast, the EU/Eurasia region is expected to be the slowest-growing region (+0.9% p.a.), limited by lower energy demand growth due to higher energy efficiency and a declining population. By sector, power will continue to be the largest driver of demand, accounting for 43% of the growth. The industrial sector will continue to be a large gas consumer, while transport is expected to be the fastest-growing segment, driven by demand for compressed natural gas (CNG) and liquefied natural gas (LNG) vehicles in select markets.

Outlook for LNG Demand. Alaska is set to enter the LNG market during a period of rapid growth in LNG importing markets and demand. The UK was the first market to import LNG, supplied by Algeria in 1964. However, global LNG trade was limited for some time to just a few markets in Europe, Asia, and the US. Since 1990, LNG demand has held a pattern of doubling every decade. As of 2012, the LNG trade stood at 238 mmtons, up from just 50 mmtons in 1990. This growth has been driven not only by larger, established markets in Asia (Japan and South Korea), but by the proliferation of new importers. In 2013, there were 29 markets importing LNG, up from just 11 in 2000. These new importers accounted for 25% of global LNG imports in 2012 and are an important part of the total market. This rush to develop LNG imports, combined with growing demand at existing markets, will lead demand to exceed 360 mmtons by 2020 and 500 mmtons by 2030.

Regionally, the Asia-Pacific is expected to remain the most important destination for LNG. In 2012, it made up 70% of imports—a market share it will maintain through 2030. Europe is the second-largest destination for LNG (20%), followed by South America (4%), North America (4%), and the Middle East (2%). Through 2030, LNG demand in Europe is expected to slow in line with overall gas demand, causing the region to lose market share. North America, once an important demand center, has experienced a precipitous drop in LNG demand as domestic supply has reduced the need for imports. In contrast, South America, the Middle East, and Africa will make up a larger share of LNG demand.

Outlook for LNG Supply. Alaska will face widespread competition for LNG markets, as growing LNG demand has prompted an unprecedented interest in new LNG projects. Alaska will compete not only with proposed projects in the Lower-48 and Western Canada, but also new regions such as East Africa that are slated to become substantial new LNG suppliers.

As the LNG trade was developed, the Asia-Pacific region was the dominant source of LNG. Prior to 2000, Indonesia, Malaysia, and Algeria were the largest suppliers, making up over two-thirds of LNG exports. In 2004, the Middle East and Africa became the largest producer of LNG, as Qatar and Nigeria began to expand their footprint. In 2012, the Middle East and Africa accounted for 57% of LNG exports, followed by Asia Pacific (34%), the Americas (8%), and Europe (1%).

By 2030, this landscape will change dramatically as new sources of supply hit the market. Australia will overtake Qatar as the largest LNG supplier by 2017, adding 70 mmtons of capacity between 2012 and 2020. Another key region for new supplies will be North America, driven by the abundance of gas production and suppressed prices. PFC Energy expects that by 2020, North America will have 52 mmtons of capacity online, growing to nearly 80 mmtons by 2025. The first wave of capacity will come online in the Lower-48, followed by Western Canada in the 2020+ timeframe. East Africa is another promising region for new supply as substantial gas resources have been discovered offshore Mozambique and Tanzania. More limited growth is expected in the Middle East and North Africa and Southeast Asia.

Altogether, LNG capacity will expand from 281 mmtpa in 2012 to ~540 mmtpa by 2030. This is just over half of total proposed capacity, as each region faces unique risks which will prohibit LNG project development. By far, the greatest numbers of projects have been proposed in the United States (over 240 mmtpa of capacity). However, a number of factors will limit LNG development in the Lower-48, including approval delays from the Federal Energy Regulatory Commission (FERC) and Department of Energy (DOE), higher Henry Hub prices, and other project-specific constraints such as environmental opposition, market opportunities, or financing limitations. Projects that have made the most progress in receiving federal approvals have a significant first-mover advantage. In Western Canada, the upstream resource remains underdeveloped and proposals there will face challenges in proving up adequate reserves and ramping up production to meet announced project start dates.

Other regions are not without risk. The Australian liquefaction boom has led to rising project costs which are deterring new LNG investment in the country, while East Africa may be constrained by government capacity and must still finalize the ownership structure of the project. New LNG projects from Nigeria and Russia are expected to be much longer-term projects. Nigeria has mounting security issues and investment has been hampered by uncertainty around the Petroleum Industry Bill. Meanwhile, regulatory and political uncertainty is hampering LNG export projects in Russia, which are further complicated by uncertain project economics.

Outlook for LNG Supply-Demand Balances. Globally, the LNG market is well-supplied through the end of the decade when considering both finalized LNG contracts (sales and purchase agreements/SPAs) and preliminary LNG contracts (heads of agreements/HOAs and memorandums of understanding/MOUs). Post-2020, there is an expanded gap between demand and contracted volumes, caused by both expiring contracts and rising demand. Alaska can take advantage of this widening LNG supply-demand globally—and within Asia in particular—in the 2020+ timeframe.

Section 3. Impact of Shale Gas

Overview. The success of shale gas in the Lower-48 in recent years has increased visibility to this once obscure segment of exploration and development. Naturally, increased visibility raises awareness, questions, and comparisons. In general, unconventional resources are more difficult and costly to develop. This is due largely to differences in resource deposition. Unconventional resources tend to extend laterally over wide expanses of territory whereas conventional resources tend to be concentrated in confined reservoirs.

Because of their depositional tendencies, shale gas resources produce few, if any, dry holes. That is not meant to imply that all shale gas wells are successful. In fact, many shale gas wells are uneconomic. A chief reason for this is due to the inherent variability in well performance within shales.

Critical Success Factors. A number of factors are critical to the success of a gas shale play, and some are more critical than others. One of the most important is the early establishment of a critical mass of operators actively engaged in the play. Other critical factors include willingness by companies to experiment and to embrace a certain amount of openness with peers. These are notable departures from processes typically encountered around conventional plays.

Two mechanisms serve to facilitate a quick transfer of technical knowledge – a leaky service sector and joint-venture activities. Notably, these factors, and others, diminish the advantages of operator competence as a differentiator in most unconventional plays. Instead, success is even more dependent on establishing the best land position early in the lifecycle of a play. Fortunately, unconventional resources are modular in nature. As a result, operators are able to make adjustments as business conditions and needs warrant and the economics of their relative position.

Impact on Lower-48 Balances. Shale gas development has been transformative to the Lower-48 natural gas supply picture. Prior to the advent of shale gas, expectations for LNG imports were widespread. Now, discussions of LNG exports are the norm. Discussions of LNG exports became credible only after prospects in leading shale gas plays, including the Barnett, Haynesville and Marcellus, were proven through ongoing development. PFC Energy believes Lower-48 production will continue to expand for many years due primarily to growth in shale gas.

Shale Gas Internationally. However, the absence of similarly suitable conditions outside North America also means that shale gas is expected to develop more slowly there. In some markets (Poland, China, Australia, Argentina), shale gas could make a material contribution to supply before 2020—but in most places, production growth is expected to come post 2020.

Section 4. Markets for Alaskan LNG

Overview. Rising demand in existing markets and the addition of new markets will both drive LNG demand growth and create market opportunities for Alaskan LNG. The Asian LNG market is a particularly favorable destination for Alaskan LNG given its proximity and high demand growth.

Countries turn to LNG to solve a number of energy supply, demand, and security objectives. Some markets use LNG to offset declining or stagnating production (India, Thailand, and Europe). A number of markets utilize LNG to diversify both their energy mix and gas supply sources (China), while others use it as a flexible fuel to meet seasonal demand or supply geographically remote demand centers. On the demand side, LNG is almost always utilized in power generation and frequently is used as a substitute for oil products (e.g. Japan, Korea, and the Middle East). Carbon objectives and energy security targets are other important factors driving countries to import LNG.

The advent of floating LNG import terminals has opened up a number of new LNG markets. Floating storage and regasification units (FSRUs) offer several benefits to smaller markets compared to onshore terminals: they are cheaper, faster to build and allow developers to bypass onshore permitting or land use issues. South America and the Middle East in particular have adopted floating LNG to address seasonal demand needs, though a number of other markets are looking to develop offshore terminals as well.

Markets for Alaskan LNG. Asia is likely to be the primary market for Alaskan LNG given its proximity and growth potential. Most LNG occurs within regions or between neighboring regions (Middle East and Asia, for example). Alaska's location in the Asia-Pacific Basin leaves it well-positioned to supply Asian markets, whose demand is forecast to rise by ~180 mmtpa through 2030, driven largely by China, India and Korea.

LNG will make up a rising share of gas demand in the region: from ~35% in 2012 to 38% by 2030. Gas demand growth from Japan, Korea, and Taiwan will be exclusively met by LNG, while China and India are actively securing new LNG supplies to cover their energy needs. Southeast Asia will import ~20 mmtpa by the end of the decade. All of these Asian markets need additional LNG from 2020 onwards—and this LNG will have to come from existing as well as new suppliers such as Alaska.

Outside Asia, LNG demand will rise in Europe, South America, and the Middle East and Africa. In Europe, a large share of LNG demand growth will come from a recovery in demand from markets where imports fell after 2011, although new importers (e.g. Poland, Lithuania) will also add to demand. In South America, the main sources of LNG demand will be Brazil, Argentina, and Chile. Demand from North America (Mexico, the United States, and Canada) will stagnate as imports are replaced by rising gas production. The UAE and Kuwait will ensure steady LNG demand from the Middle East, as these importers face rising electricity generation needs. While Africa is not yet importing LNG, the region serves as a large potential source of demand in the longer term, if constraints such as government capacity and financing can be overcome.

Section 5. Gas Strategies and Portfolios of Key Companies

Overview. Alaska's proposed LNG project involves three companies with considerable LNG project experience, but also a diverse set of strategic priorities. With substantial gas resources on the North Slope in need of a viable commercialization option, upstream equity holders BP, ConocoPhillips and ExxonMobil have so far agreed to collaborate with a fourth stakeholder, TransCanada, on a gas pipeline. The proposal to commercialize North Slope gas via LNG will ultimately depend on further deliberations to determine whether pursuing the project is a relatively attractive investment.

The upstream partners possess the prerequisites for carrying out an LNG project. BP, ConocoPhillips and ExxonMobil have a track record of undertaking large-scale infrastructure investments in the oil & gas sector. This includes managing substantial equity investments in LNG projects. Nonetheless, each company's willingness to move forward with a new LNG project investment will also depend on a range of more subjective criteria. In addition to the objective strength of their balance sheets, a final investment decision will also depend on each company's internal view of their financial outlook and strategic priorities.

Although BP, ConocoPhillips and ExxonMobil are all large energy companies with existing LNG businesses, their financial positions and strategic priorities are distinct. These distinctions will likely influence how each company views LNG as a source of growth compared to its other business lines.

- **BP.** In response to the company's involvement in the Deepwater Horizon oil spill, BP has repositioned its upstream portfolio and corporate strategy through the sale of many legacy assets and ventures. The company has renewed its commitment to deepwater exploration and production to achieve future growth.
- **ConocoPhillips.** In 2012, ConocoPhillips spun off its downstream business to focus on oil & gas exploration and production. No longer an integrated player, the company will define itself by achieving production growth as an Exploration & Production (E&P) independent. To this end, ConocoPhillips has undertaken an upstream portfolio rationalization to focus its resources on core upstream regions primarily in North America and Asia Pacific.
- **ExxonMobil.** The company has achieved the world's top market capitalization through its selective development of large-scale projects that offer superior returns via project management efficiencies. ExxonMobil's substantial financial commitments to shale in the Lower 48, Canadian oil sands production and new LNG projects represent the most recent examples of this approach.

All the upstream stakeholders also bring LNG project and LNG marketing experience to the table. The three companies are equity participants in and market LNG from eight existing LNG projects. In addition, BP is an equity participant in one commissioning LNG project, ConocoPhillips an equity holder in one under-construction project and ExxonMobil in two under-construction projects. Experience is usually very helpful in successfully moving a project from an early proposal stage to production. While the project management experiences of BP, ConocoPhillips and ExxonMobil do not offer a guarantee, they do improve the likelihood of commercial success.

The most salient issue is therefore not commercial capability to develop an LNG project in Alaska, but each company's level of commercial interest to move forward. Commercializing North Slope gas via LNG requires a massive allocation of capital for each company. Depending on each company's alternative uses of capital, there is no guarantee that each will view an Alaskan LNG project as the best way to achieve their corporate goals. In addition, all project stakeholders must agree at the same time and under the same investment terms that an Alaskan LNG project is a desirable use of their available capital.

North Slope Gas commercialization via a LNG project represents just one call on available capital within the spectrum of investment opportunities available to BP, ConocoPhillips and ExxonMobil. All three companies not only confront a range of new upstream frontiers and proposed LNG projects into which they could potentially invest, but they also have options to re-invest in existing areas of operation that may offer more investment certainty. The proposed Alaskan LNG project will compete with alternative investment opportunities, which broadly include:

- **Emerging Upstream Frontiers.** These include, but are not limited to, North America unconventional (shale and oil sands), pre-salt plays in the southern Atlantic Basin, East Africa offshore, Australian conventional and coal-bed methane, and the Russian Arctic. Each frontier involves a different set of risks that a company will have to consider prior to making a decision on capital allocation. Key risks include: upstream bid round success and cost, likelihood of producing oil vs. gas, conventional vs. unconventional expertise, and deepwater expertise.
- **Emerging LNG Project Frontiers.** US LNG exports from the Lower 48, Western Canada, Australia, and East Africa. Each project proposal involves a different set of risks that a company will have to consider prior to making a decision on capital allocation. Key risks include: alignment of partners, government relations, project economics and the potential for cost overruns.
- **Pure Upstream vs. LNG.** LNG projects require substantial upfront capital expenditures, which are compensated by stable, long-term cash flows over the operating life the LNG project. Depending on the company's corporate strategy, this investment profile may be less desirable compared to focusing on upstream investments that can deliver much more immediate cash flow with significantly less upfront capital expenditure.

BP, ConocoPhillips and ExxonMobil must consider which collection of risk/reward profiles will formulate a global investment portfolio meeting internal criteria for capital allocation and strategic priorities. The extensive deliberation undertaken by each company can be highly dynamic. Not only do each company's set of investment opportunities change over time, but so do each company's financial position and internal criteria for investment. For an Alaskan LNG project to ultimately move forward, all three companies will need to concurrently align their corporate priorities and willingness to allocate capital.

Section 6. Indicative Costs and Economics for Pipeline & LNG Projects

Overview. LNG projects involve enormous capital commitments that are recovered only over a very long timeframe. Of the LNG currently under construction, five will spend over US $10bn on the liquefaction portion of the project alone (excluding investment in upstream), while all will spend upward of $2bn. Generally, companies undertake these investments not because they provide high rates of return, but rather because once completed, they provide long-term and predictable cash flow over a timeframe of 30 or more years. Compared, for example, to a large deepwater oil project, an LNG project that generates equivalent economic value (in Present Value terms) will generally require many times the reserves size in oil-equivalent barrels, many times the initial capital expenditure, and will generate a far lower internal rate of return (IRR). However, where a deepwater oil project will produce at a relatively high peak rate and will experience production declines after a few years, the LNG project will produce at a steady plateau rate for multiple decades, generating stable cash flow long into the future. Because this steady, long-term cash flow is central to the value proposition of an LNG project, the stability of factors affecting that cash flow – such as hydrocarbons fiscal terms, for instance, or other forms of contract or sovereign risk – are of paramount importance in enabling a commercial LNG development.

Trends in Breakeven Pricing and Unit Costs. Recent years have witnessed a dramatic escalation in construction costs for LNG projects. Between 2000 and 2009, average capital spending per metric ton of nameplate LNG capacity for all liquefaction facilities was $505/ton. For all projects coming on line between 2010 and 2019, PFC Energy forecasts that the average will more-than-double to $1,043/ton. The Pluto LNG project in Australia presents a compelling example of the impact of such cost escalation. At the time of Final Investment Decision (FID) in 2007, the combined upstream and liquefaction cost was expected to be $2,256/ton. By the time of completion, that figure had risen by 54% to $3,477/ton, with the liquefaction alone reaching $1,700/ton. As a result of such cost escalation, PFC Energy estimates that the Pluto LNG project now requires a free-on-board (FOB) price of more than $15/MMBtu in order to achieve economic breakeven. Assuming an oil-indexed sales contract with a coefficient of 0.15 to crude oil, this means that to achieve an acceptable rate of return on the capital employed in the project, the project requires sustained crude prices above $100/bbl over the next several decades. Had the true cost been known at time of FID, it is far from certain that such a project would have proceeded.

Pluto LNG is far from alone in this trend. More than half of all currently under-construction projects in the Asia-Pacific basin have liquefaction costs above $1,200/ton, and breakeven prices above $10/MMBtu. By comparison, breakeven prices for existing projects can often be at or below $5/MMBtu. With many of these under-construction projects being in Australia, cost factors specific to Australia play a role in some of this escalation. These factors include the dramatic increases in labor costs and the value of the Australian dollar that have occurred in recent years, as Australia has experienced a massive boom in resource-sector investment, seeing massive new investment in coal, iron ore, copper and other minerals projects competing for capital and labor. But Australia has not been the only place to experience substantial cost increases; projects in Papua New Guinea and Angola have also experienced substantial increases in construction costs and in estimated breakeven prices.

Competitiveness vis-à-vis the US Lower 48. With such significant cost challenges characterizing new LNG projects in many parts of the world, there has been a recent explosion of interest in exporting LNG from North America, and in particular from the United States Lower 48 as well as Western Canada. Fully 40% of all proposed new liquefaction projects at the moment are located in the United States, while a further 17% are in Canada. Interest in North American exports has been driven by the divergence in recent years in Henry Hub pricing from other international benchmarks, with Henry Hub trading at $3/MMBtu or below in recent times, while average LNG prices into Japan have risen in excess of

$17/MMBtu, creating substantial arbitrage potential. Interest has been particularly intense because of the potential cost advantages offered by a range of sites in the Lower 48 states, created as a result of the rush over the previous decade to build LNG regasification capacity on the US Gulf Coast. Such sites were built in anticipation of the United States needing to import substantial volumes of LNG; ultimately, increases in gas production from unconventional sources left such regasification projects without a market to serve. With foundations laid, storage tanks built, ports dredged, jetties constructed and connections established to the pipeline network, such sites already have much of the infrastructure needed for the establishment of a liquefaction project. This leads to costs that are closer to those of a brownfield expansion at an existing site than they are to most new greenfield LNG projects. Substantial semi-stranded gas in North America – especially in Western Canada, where wellhead gas prices are often at a substantial discount to Henry Hub – have also added significantly to the impetus for such projects. With Henry Hub prices around $3/MMBtu, Asian buyers have proved very keen to sign contracts to import LNG from US Gulf Coast projects priced against Henry Hub rather than indexed to crude oil.

While such contracts look highly desirable at current Henry Hub gas prices, this is not always guaranteed to be the case. A brief examination of KOGAS's contract with the Sabine Pass LNG project reveals the extent to which volatility in the Henry Hub / crude oil spread can impact the competitiveness of Asian imports under a Hub-linked contract. Although at current Hub prices, Hub-linked imports from Sabine Pass into Japan would be substantially cheaper than typical oil-linked imports, examining historical prices for Henry Hub makes it clear that had such a contract been in existence from 2000 to 2008 (a period of substantially higher Henry Hub prices), it would have been a far more expensive source of LNG for Japan than oil-linked LNG volumes. With Henry Hub at $4/MMBtu, PFC Energy estimates the FOB breakeven price from Sabine Pass to be less than $8/MMBtu. If Henry Hub prices over coming years rise only as far as $6/MMBtu, however, US Gulf Coast exports will become significantly less competitive, with Sabine Pass likely to require around $10/MMBtu to achieve economic breakeven – a level similar to many of the more expensive recent greenfield projects. Based on analysis of breakeven prices of available US future shale gas production, PFC Energy forecasts a long-run rise in the Henry Hub price toward $6/MMBtu. At that price, LNG exports from Alaska could indeed compete with exports from the Lower 48 states.

Potential Competitiveness of an Alaska South Central LNG Project. The project partners for the proposed Alaska South Central LNG project have put forward an estimate of $45 bn to $60 bn in total upstream, pipeline and liquefaction cost for the project. Such an investment would cover:

- Adding fourteen wells to the Initial Production System at Point Thomson
- Adding new gas facilities to the existing central pad at Point Thomson
- Constructing a new 30" gas line from Point Thomson to Prudhoe Bay
- Installing a new Gas Treatment Plant at Prudhoe Bay, to be tied in to the Prudhoe Bay Central Gas Facility
- Constructing an 800+ mile 42" gas pipeline to tidewater, capable of carrying 3-3.5 bcf/day of gas
- Constructing a liquefaction and offloading facility at tidewater with three liquefaction trains each with a 5.8 mmtpa nameplate capacity, with actual capacity varying from 4.9 to 6.3 mmtpa, depending on ambient temperature

While no breakdown of the total cost estimate between components has been issued at this point, PFC Energy has assumed, for a low-case breakeven estimate, a $46 bn project with the following distribution of costs:

- $14 bn for Upstream and Gas Treatment capital costs
- $12 bn for Pipeline

- $20 bn for Liquefaction

$20 bn for an 18 mmtpa liquefaction facility implies a unit cost of $1,111/ton. Compared with other recent LNG projects, this is solidly in the middle of the cost curve, which ranges from as low as $550/ton to as high as almost $2,400/ton. Recent or currently under construction projects with useful (and higher) comparison unit cost points include:

- PNG LNG (Papua New Guinea) and Asia Pacific LNG (Queensland, Australia) - $1,300/ton
- Pluto LNG (Western Australia) and Snøhvit LNG (Norway) - $1,700/ton
- Angola LNG (Angola) and Wheatstone LNG (Western Australia) - $1,900/ton

PFC Energy estimates the FOB economic breakeven cost for a $46 bn project, with a $1,111/ton liquefaction costs and a fiscal regime consisting of a 12.5% royalty with no additional production tax to be $10.44/MMBtu. This is a cost level that is broadly competitive with LNG Exports from the US Gulf Coast, assuming a long-run $6/MMBtu Henry Hub price, and with other potential new source of supply. Low shipping costs from Alaska to Asia significantly assist this competitiveness, since PFC Energy estimates the breakeven tariff for shipping to Korea or Japan to be only $0.70, resulting in a Delivered Ex-Ship (DES) breakeven cost of $11.14/MMBtu. US Gulf Coast projects, by comparison, face shipping costs as high as $2.60/MMBtu without Panama Canal access, with a lower bound of $1.80/MMBtu in the future, depending on as yet unknown toll fees for shipping through the expanded Panama Canal. A $46 bn South Central LNG project with relatively attractive fiscal terms could thus be a competitive and attractive project.

If costs rise significantly above this level, however, or if other elements such as fiscal terms prove more adverse, project competitiveness can be quickly diminished. The impact of cost increases to the $1,300/ton, $1,700/ton and $1,900/ton levels for the projects noted above demonstrates the substantial impact of higher liquefaction unit costs on breakeven economics. At these cost levels, FOB breakeven costs would rise to $11.07/MMBtu, $12.73/MMBtu and $13.65/MMBtu respectively – levels that are substantially less competitive with investment alternatives in the US Lower 48 and elsewhere. The additional imposition of a 35% production tax on gas (as Senate Bill 21 currently entails), and a higher 16.7% royalty level would result, at the upper end of the cost spectrum, in a breakeven cost above $14/MMBtu. If, in addition to these increases, Upstream and Pipeline costs were also to be 25% above the low-case estimate, total construction costs would be around $64.5 bn, or roughly the upper-bound estimate provided by the producers of the project. At this cost level, FOB breakeven costs would be as high as $15.26, on par with the most expensive projects seen to date (such as Pluto LNG). This is a level that is substantially less likely to be seen as attractive from an investment perspective by the producers.

Cost control, fiscal accommodation and fiscal terms stability will thus be crucial elements to enabling an Alaska LNG project to be a competitive supplier into Asian markets, and competitive for capital within the portfolios of the major producers.

Section 7. LNG and Pipeline Commercial Structures and Practices

Overview. LNG projects are big, complex, risky, multi-stakeholder endeavors. Project management—the ability to bring all the pieces together—is the critical factor for a successful LNG project. How a project is structured, however, matters a great deal for allocating risk and reward—several projects have regretted the project structure and resulting contract decisions that they made. The most important question for Alaska is whether it wants to participate as an equity partner and along which parts of the chain.

Components of an LNG project. Most of the money for an LNG project is spent after the project sponsors take a Final Investment Decision (FID). To reach FID, the project developers: (a) certify reserves to ensure that the gas is there; (b) sign sales and purchase agreements (SPAs) with buyers, which reassure the project developers that they will be able to sell their product. These are usually long-term and obligate the buyer to take the gas; (c) secure financing, often external and often non-resource (whereby the debt is guaranteed by the cash flow of the SPA). External financing is supported by loans and equity from the sponsors; (d) award an engineering, procurement and construction (EPC) contract to a company/consortium to build the plant; (e) finalize all approvals (country, local).

Contact terms. An SPA contains several components but the most important are: (a) the price at which the gas will be sold; (b) the duration of the contract (usually long term); (c) whether the LNG is destined for one market or whether the buyer has the flexibility to re-sell the gas elsewhere; (d) the annual volume flexibility that buyers and sellers have (above or below the average quantity); (e) any profit sharing from diverting LNG from its original destination to take advantage of arbitrage opportunities; (f) any non compliance provisions for failure to meet contract terms; and (g) any renegotiation provisions that allow parties to revisit key terms (such as price) over specified intervals (usually 3-4 years).

Project structure. Each project has several components: upstream (producers), midstream (pipeline and liquefaction), shipping and an end market (regasification, transmission, distribution, etc.). Not all participants share equally in each part of the chain—as a result, there are projects with different ownership structures along different parts of the chain. How a project is structured affects not just the risk-reward profile of each partner but also the distribution of value among the different participants.

Implications for Alaska. The State of Alaska could participate in an LNG project either a pure supplier (selling royalty gas) or as an equity shareholder. Besides deciding which model best fits the state’s risk-reward appetite, it is also crucial to ask: under what conditions is there strong alignment between the project partners where they all share equally in the up and downside. Partner misalignment is often a source of contention given the size of the capital needed and the variation in market conditions for projects that have a very long-term investment horizon and payback period.

Section 8. LNG Shipping

Overview. Shipping is one of many costs that determine the competitiveness of an LNG project. Compared to other elements of the value chain that bring a molecule of gas from a field to a regasification terminal in a distant market, the added cost of shipping is relatively small compared to those associated with upstream production or liquefaction. Nonetheless, shipping costs will differentiate a project's advantage in marketing LNG into a particular geography. On some trade routes, shipping can account for as much as 10-15% of the total delivery cost of a cargo.

Timing and Decision-Making. Within the chronology of LNG project development, decisions about shipping assets typically occur following final investment decision (FID). In general, investments in new shipping assets are a function of the marketing terms of the Sales and Purchase Agreements (SPA) finalized at FID. Not until final agreement on the size, end market destinations, and which party will be in charge of logistics, can the conversation regarding LNG vessels truly begin. In general, new long-term LNG contracts are paired with new vessels in order to take advantage of the most recent efficiencies in vessel design. Based on a roughly two-year construction timeline for most conventional LNG vessels, shipyard orders associated with new LNG projects usually take place during the second full year of liquefaction plant construction.

Given the premium cost of more technically challenging LNG vessels, growth in the existing LNG vessel fleet has closely traced growth in LNG production. To a lesser extent, increases in the number of bilateral trade routes and the total distance required to achieve global trade have also contributed to demand for new vessels. This compares to the shipping market for crude oil carriers, which require significantly less capital per vessel and serve a much more geographically diverse and volumetrically superior global trade in crude oil.

New-building and Ownership Composition. The majority of the ~360 vessels in the current fleet are commercially linked to LNG contracts produced by existing LNG projects. The small size of spot LNG trade ultimately restricts the numeric depth of the number of vessels required by the spot shipping market. In 2012, the average price for a newbuild vessel was approximately $200 million depending on the exact technical specifications of the order and the location of the shipyard. A large number of shipyards, located in countries in Europe, North America and Asia, have built LNG vessels. In recent decades, shipyards located in northeast Asia have achieved market dominance, reflecting the majority share of LNG demand associated with the countries in this region. Shipyards in South Korea overtook their Japanese counterparts in the 2000s and now account for the construction of 56% of the current fleet.

LNG vessel ownership is diverse, reflecting a range of both shipping-focused and energy-focused companies. In general, ownership entities fall into four main categories: independent shipping companies, international oil companies (IOCs), utility companies that regularly import LNG, and LNG projects. The multitude of ownership structures within the LNG vessel fleet reflects the significance of LNG contracting on decisions related to logistics and vessel ownership. A key ingredient of any SPA is a clause that indicates whether the contract is an Ex-Ship or Free on Board (FOB) agreement:

- **Ex-Ship.** The seller delivers a good to a buyer at an agreed port of arrival.
- **FOB.** The seller delivers a good on board a vessel designated by the buyer.

The commercial profile and strategy of an LNG offtaker typically determines its interest in (a) overseeing logistics responsibilities and (b) having an equity stake in the vessels that will execute the logistics. For example, certain IOCs have traditionally decided that vessel ownership is a value-adding business, and have therefore decided to allocate capital to equity stakes in shipping. Other IOCs have been less interested in using capital on shipping assets, preferring to instead commit to a predictable flow of charter payments to an independent shipping company. The point on this capital allocation spectrum with which each LNG offtaker identifies will ultimately determine whether a LNG contract is signed on an Ex-Ship or FOB basis, and furthermore which category of shipping company assumes responsibility for procuring the necessary vessels. In certain cases, liquefaction projects have elected to take control of shipping responsibilities, signing only Ex-Ship LNG contracts, which in turn justify the liquefaction project organizing its own fleet.

Contract Terms. The long-term nature of most LNG contracts dictates that shipping tenders are also typically conducted on a long-term basis. Equity-owned vessels associated with a long-term LNG contract are traditionally intended to serve the duration of the contract and potentially continue into a second, renegotiated stage. Similarly, the duration of a contract for a chartered vessel typically matches the length of the underlying LNG offtake contract. In the latter cases, charter rates are signed at the long-term charter rate – effectively the discounted cost of buying the vessel, plus a premium, denominated on a daily basis. Long-term charter rates based on a modern vessel costing approximately $200 mn would cost approximately $75,000/day based on current interest rates. In the case of charters, additional costs related to daily operation of the vessel are paid by the charterer and not the vessel owner.

Alaska's competitiveness. On the basis of shipping costs, an Alaskan LNG project would have the greatest shipping cost advantage serving markets in northeast Asia. The round-trip delivery time of a single cargo to Japan or South Korea would average just over two weeks and cost approximately $0.67/MMBtu. These costs and times are competitive with existing and under-construction LNG projects in Australia, and are significantly lower than US LNG exports from the Gulf of Mexico even with access to the expanded Panama Canal. An Alaskan project's advantage in shipping costs is less decisive for end markets located in South Asia, Southeast Asia and in the Atlantic Basin. Compared to the overall price, shipping costs will likely not play a decisive role in determining the commercial viability of LNG exports to a distant market. However, the economics of shipping and the profile of the buyer will inform the terms of the LNG SPA agreement.

Section 9. Glossary and Units

Glossary

CAGR: Compound Annual Growth Rate

CAPEX: Capital Expenditure

CIF: Cost Insurance Freight

DES: Delivered Ex-Ship

EPC: Engineering Procurement and Construction

FEED: Front-End Engineering and Design

FID: Final Investment Decision

FOB: Free on Board

FSRU: Floating Storage and Regasification Unit

HOA: Heads of Agreement (preliminary contract)

IOC: International Oil Company

JV: Joint Venture

JCC: Japan Customs Cleared

MENA: Middle East and North Africa

MOU: Memorandum of Understanding (preliminary contract)

NOC: National Oil Company

OECD: Organization Economic Cooperation and Development

PSC: Production Sharing Contract

SPA: Sales and Purchase Agreement (finalized contract)

Units

$/B: Dollars per barrel (oil)

BCF/D: Billion cubic feet per day

BCM: Billion cubic meters

CM: Cubic meters

KTOE: Thousand tons of oil equivalent

MMBTU: Million British thermal units

MMCF/D: Million cubic feet per day

MMT: Million tons (LNG)

MMTOE: Million tons of oil equivalent

MMTPA: Million tons per annum (LNG)