Natural gas and CO$_2$ price variation: impact on the relative cost-efficiency of LNG and pipelines

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This article develops a formal model for comparing the cost structure of the two main transport options for natural gas: liquefied natural gas (LNG) and pipelines. In particular, it evaluates how variations in the prices of natural gas and greenhouse gas emissions affect the relative cost-efficiency of these two options. Natural gas is often promoted as the most environmentally friendly of all fossil fuels, and LNG as a modern and efficient way of transporting it. Some research has been carried out into the local environmental impact of LNG facilities, but almost none into aspects related to climate change. This paper concludes that at current price levels for natural gas and CO$_2$ emissions the distance from field to consumer and the volume of natural gas transported are the main determinants of transport costs. The pricing of natural gas and greenhouse emissions influence the relative cost-efficiency of LNG and pipeline transport, but only to a limited degree at current price levels. Because more energy is required for the LNG process (especially for fuelling the liquefaction process) than for pipelines at distances below 9100 km, LNG is more exposed to variability in the price of natural gas and greenhouse gas emissions up to this distance. If the prices of natural gas and/or greenhouse gas emission rise dramatically in the future, this will affect the choice between pipelines and LNG. Such a price increase will be favourable for pipelines relative to LNG.

Introduction

The natural gas from large fields is normally transported by one of two means: either by pipeline or in the form of liquefied natural gas (LNG) [1]. In recent years, the production of LNG has risen rapidly as new facilities have been brought online, increasing its share of internationally traded natural gas to 30% in 2011 [2]. For the period 2005–2020, LNG production is expected to continue growing at a clip of 6.7% per year [3].

The building of new LNG facilities has often resulted in local resistance due to fears over the risk of explosions. Interestingly, however, there has been limited discussion of the environmental impact of LNG in terms of greenhouse gas emissions. This question is becoming increasingly pertinent as natural gas is cast as the transitional fossil fuel for a low-carbon world: worse than renewable or nuclear energy, but better than coal and oil. LNG is relatively abundant, the necessary technology exists, and much of the

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infrastructure needed for its exploitation is already in place. If natural gas is part of the medium-term solution to reducing greenhouse gas emissions and this is going to lead to increasing amounts of it being moved around the globe as LNG, the emissions aspect of LNG will become increasingly salient. In Norway, for example, the new LNG facility at Melkoya is the country's fourth largest source of greenhouse gas emissions [4].

Regardless of the mode of transport for natural gas, some of the gas is used to generate the energy required to transport the rest of the gas. In pipelines, a portion of the gas is burned in order to run the turbines that force the rest of the gas through the pipeline to the consumers. In an LNG plant, a portion of the gas is burned in order to generate enough energy to cool the rest of the gas. When natural gas reaches a low of $-161°C$ ($-260°F$), it shrinks into a liquid that takes one 600th the amount of space of the gaseous form, becoming far more economical to ship [5,6].

Since both pipelines and LNG involve the burning of a portion of the gas, they also result in the emission of greenhouse gases. The market value of the gas that is burned as well as the cost of the resultant emissions will vary over time. Any major natural gas extraction project that has to choose between pipelines or LNG thus also has to take into account whether such future price variations may change the relative cost of the two infrastructure types. Some of the largest natural gas fields currently slated for extraction are located at distances from markets where such choices between pipelines and LNG need to be made, including those in the Barents Sea, on the Yamal Peninsula and possibly in the Persian Gulf.

Current assumptions in the literature

LNG and pipelines differ in their cost structures. Whereas the cost of pipelines tends to rise steeply and linearly with distance, the cost of LNG has a high initial threshold but a lower increase with distance [6]. When choosing between these two options for transporting natural gas from a new field, a break-even point somewhere between 3000 and 5000 kilometres is often mentioned in the literature [7]. For the transport of natural gas over shorter distances, pipelines are assumed to be cheaper, whereas transport using LNG is normally more cost-effective for distances longer than this.

The literature offers several different formulations of this break-even point. Tongia and Arunachalam note that, due to the expense of building LNG facilities – such as tankers, re-gasification facilities and reception and storage terminals – pipelines will have a lower cost over shorter distances of around 2000 miles (3219 kilometres) or less [8]. According to Cornot-Gandolphe *et al.* [9], in 2003 the break-even point was around 4500 km at a price level of \$1.60/MMBtu (\$1.90/MMBtu in 2010). The same year, Quintana [10] argued that LNG is the best option for markets located more than 4000 kilometres away from the gas field and which have a volume of more than 16 MMm^3/day.

In a 2009 report, Paul Stevens argued that the cost of LNG had risen significantly, and that the break-even point had therefore risen to around 5000 km [1]. Further nuancing the comparison of LNG and pipelines, Mäkinen [11] claimed that, 'In general, LNG becomes economically feasible in contrast to 3000 to 4000 kilometres of land pipe or 2000 km of offshore pipe.' The break-even point will differ from project to project, depending on the geography, logistics and legal and political factors involved [11].

The literature says little about the analysis and data upon which these break-even points are based. This leaves several important questions unanswered: are both construction and

$/MMBTU $/BBLOE
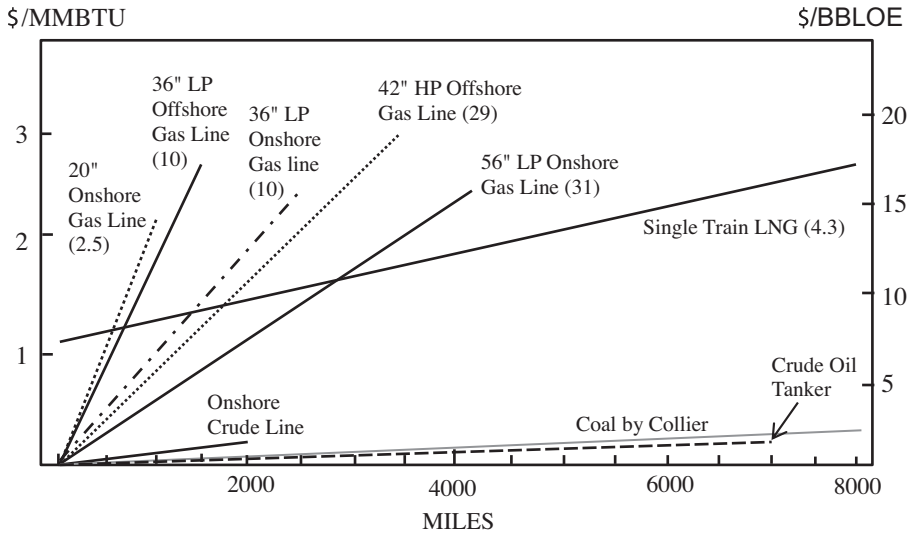
Note: Figures in brackets show gas delivery capability in BCM

Figure 1.   Break-even points.
Source of data: [6].

operating costs taken into account? If the price of natural gas rises, will the transport of natural gas as LNG still be cheaper than pipeline transport over distances greater than 4000 kilometres, taking into account the fact that the LNG chain consumes more gas than do pipelines? Are costs related to CO$_2$ emissions included in the calculations? This article aims to fill the void in the literature represented by these questions, by developing a formal model for estimating the impact of natural gas and greenhouse gas price variation on the overall cost of the two transport options.

The prices of natural gas and greenhouse gas emissions are, however, only two out of many factors that determine the cost of LNG and pipelines. In order to understand their impact on overall costs, we must view these prices in the context of the other factors upon which the overall costs depend, in particular the amount of natural gas and the distance it must be transported. As the comparative advantages of LNG and pipelines change in accordance with these factors, we need to understand their impact before examining how variation in the prices of natural gas and greenhouse gas emissions plays into the relative cost-efficiency of LNG and pipelines.

In addition to the various factors that affect the cost structure of LNG and pipelines that we will cover here, there are many other factors which might affect the choice of transport method, for supplier and importer: taxes, capital charge, interest rates, insurance, the economic lifetime of capital, the flexibility of the LNG spot marked, demand and supply security, the risk of terrorist attacks, and the value of scrap metal at end of capital's lifetime. Putting a general price on these conditions is difficult, so they are not included in this analysis – but they remain important for the decisions made about such infrastructure.

Before developing a model for comparing LNG and pipelines, it is necessary to explain some of the basics of pipelines and LNG. We start with pipelines, as this is the older, baseline technology.

Pipeline economics

The costs of pipelines and LNG can be divided into capital (construction) expenditure (CAPEX) and operating expenses (OPEX). CAPEX consists of pipe materials, installation and coating of the pipe, the building of compressor stations, construction management and right-of-way clearance. OPEX include compressor station fuel, pipe repairs, environmental permits and administrative costs [12].

Both construction and operating costs may vary significantly from one region to another. Differences in terrain, climate, labour costs, population density and the degree of competition between different natural gas provinces make pipeline economics highly project-specific [9]. Pipeline planners are therefore often hesitant to generalise the costs of constructing pipelines. A pipeline that runs through a dense urban area might cost five times more than a pipeline of the same length and diameter crossing a rural area [13]. The generic model for estimating the impact of variations in natural gas and emissions costs developed in this article will therefore have to be adapted when applied to individual cases.

Pipeline CAPEX

This article focuses on onshore pipelines, which are more common and normally less expensive than offshore pipelines. Several approaches will be used in this section in order to make an estimation of the costs of transporting natural gas by pipeline. The estimation will mainly follow the 'cookbook' approach developed in Jung *et al*. [14] for East Asian projects, drawing on Kubota [15]. This is combined with a formula for cost per pipe diameter per distance as suggested by the Canadian Energy Pipeline Association [16], while pipeline data from the USA published by Parker [13] are used to discuss the costs of constructing and operating natural gas pipelines.

Pipeline construction costs depend mainly on the cost of material (carbon steel), cost of labour, pipeline length and diameter and the number and capacity of the compressor stations. The data published in the *Oil & Gas Journal* were derived from the US Federal Energy Regulatory Commission and are divided into four categories: material, labour, right of way and miscellaneous costs [17]. The latter category includes surveying, engineering, supervision, administration and overhead, interest, contingencies and allowances for funds used during construction, and regulatory filing fees [18].

The capital costs (C) for a common onshore pipeline can be calculated by means of the following equation:

$$C = \$52,675\mu\delta + (\$3 \times 10^7)\alpha + \$3091c$$

The costs of constructing the pipeline are calculated by multiplying a constant cost by the diameter (μ) measured in inches, and by the length of the pipeline (δ) measured in km. α is the number of compressor stations and c is the total capacity of the compressor stations, measured in horsepower. Jung *et al*. [14] used \$21,300 as the cost per inch per kilometre for a common onshore pipeline in 2000. The estimated costs used in Jung *et al*.'s report [14] are more than 10 years old, and may no longer be valid for new projects. The costs of labour, materials or other components may have risen, or new cost-reducing technology may have been introduced to the market. We will ignore the last problem because, as pipeline transport is less complex, there have been only small cost reductions for pipeline transport compared to LNG in recent years [9] . The cost estimates from 2000, however,

do need to be revised in view of the increased costs of vital inputs. In the USA, actual costs per pipeline mile rose by an average of 247.3% from 2001 to 2010, rising from approximately $1,310,000 per mile to $4,550,000 per mile in the same period. This increase was caused mainly by higher costs of labour and materials [18]. In the absence of more reliable data, we will use these figures to revise the figures from Jung *et al.*'s [14] report.

Nevertheless, price levels may have changed differently, depending on the country in question. The figures used by Jung *et al.* [14] are for a 'Common Onshore Pipeline', and it is unclear upon which country's prices the estimates are based. For example, the USA, Russia and Japan have seen the price level of investment (PPP over investment) develop in different directions over the past decade. In the USA, 2000–2007, the price level of investments decreased by 11.7% (although it has probably increased sharply since then) and in Japan by 32.8%, whereas in Russia the price level of investments increased by 124.1% during the same period [19]. But it is nevertheless important to revise the pipeline costs from 2000 to make them comparable with the revised LNG costs.

It is possible to check the accuracy of these estimates by comparing them with a proposed pipeline where the estimated costs are more or less current. We have estimated the costs of the Nabucco pipeline by entering the pipeline details (diameter of 56 inches, 11 compressor stations, distance 3893 km) into the equation below [20,21]. The equation calculates a total construction cost of almost $16.8 billion – a figure much higher than the estimated €7.9 billion ($11.5 bn) stated on the Nabucco project website [22]. According to Webb [23], however, the oil and gas company BP has produced a new estimate of €14 billion ($20 bn) for the same construction costs. These differing estimates exemplify the difficulty of determining pipeline construction costs.

Compressor stations constitute a large percentage of total construction costs. Jung *et al.* [14] use a fixed cost per compressor station (α) and then a variable cost per unit of horse-power. We assume that average distance between the compressor stations is 200 km [24] and that average capacity per compressor station is 110 MW. The latter assumption was made after a comparison of several proposed Russian pipelines and their capacities [25].

Parker [13] uses construction cost projections for over 20,000 miles of pipelines in the USA to generalise the construction costs for a pipeline of a given length and diameter. Parker concludes: 'Materials costs account for approximately 26% of the total construction costs on average. Labour, right of way, and miscellaneous costs make up 45%, 22% and 7% of the total cost on average, respectively.' These shares are estimated on the basis of US data for the years 1991–2003. The data refer to pipelines between 4 and 42 inches in diameter, which is less than many of the long-distance pipelines in Russia. For example the diameter of the pipeline running from Yamal to Europe is 56 inches (1420 mm) [26]. The small pipeline size is a problem, as pipeline diameter determines the share of the total costs within the four construction cost categories. For example, for a 4-inch diameter pipeline, materials account for 15% of total construction costs, but this figure rises to 35% for a pipeline 42 inches in diameter [13].

The cost of labour often differs significantly between countries or regions, as does the cost of materials (steel not least), which are never exactly the same throughout the world [27]. Furthermore, pipeline construction costs do not remain static within a country. Therefore, the relative share of construction costs depends on a range of interlinked factors with, for example, material or labour costs fluctuating as wages or steel prices change. Figure 2 shows the average breakdown of construction costs in the USA for the period 2009/2010.
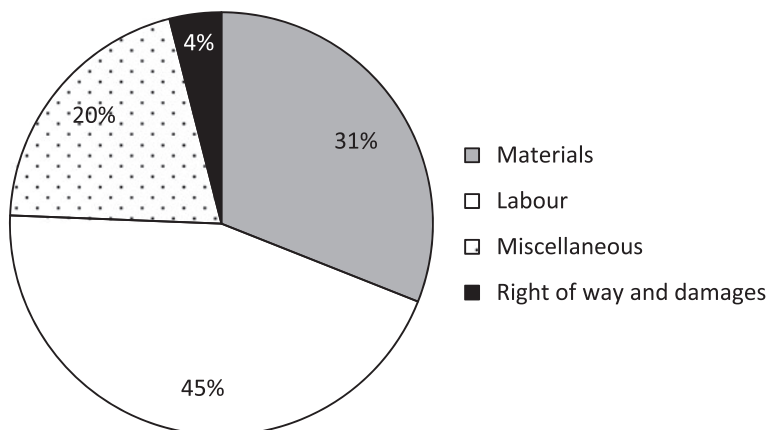
Figure 2.   Pipeline construction cost components.
Source of data: [18].

Here, the cost of materials differs markedly from the 26% share mentioned by Par-
ker [13] above. The reason is that Parker's data are from 1991–2003, whereas the data
presented in the figure are from July 2009–June 2010. Figure 3 below shows the
development of the share of material and labour costs in the USA over the past 10
years.

According to Chandra [28], steel may account for as much as 45% of the total cost of a
typical pipeline. It is possible to estimate the cost of steel in the overall share of
construction costs in greater detail by using the Figure 3 graph above, Figure 5, and the
US Carbon Steel Plate Prices from Figure 7 fig7 below. The estimates show that steel
accounted for 5.6% of total construction costs from 2001 to 2003. The share rose mark-
edly in 2004, due to a steep increase in steel prices, and was as high as 14.5% of total
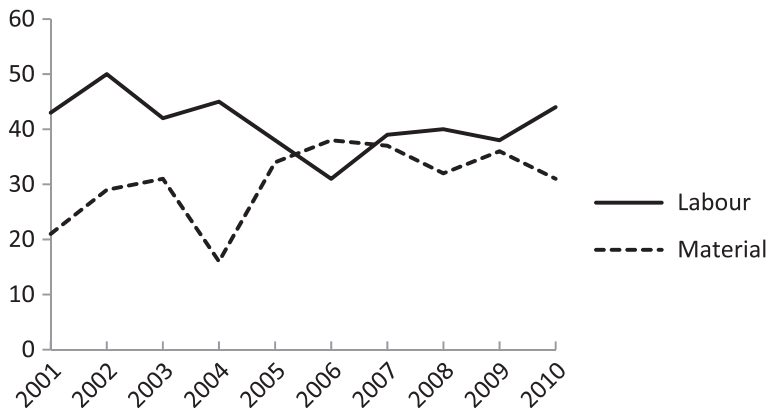costs from 2005 to 2008. This may even be an underestimate.

Figure 3.   The share of the two major cost components in pipeline construction, 2001–2010.
Source of data: [18].

Pipeline OPEX

A pipeline has annual operating costs such as fuel for the compressor stations, repair costs, SCADA and telecommunications, lease and rental, wages and administrative costs [12]. Operating costs are relatively project-specific, but may be broken down into two categories: operating costs as a fixed percentage of the construction costs and fuel.

Operating costs for a typical onshore pipeline can be estimated as follows:

$$O_p = C\tau + \left(1 - (1-l)^{\frac{\delta}{\eta}}\right)Np$$

N is the volume of natural gas, measured in cubic meters per year, p is the price of natural gas, measured in dollars per cubic meter, and η is the number of kilometres between the compressor stations. The operating cost as a share of the capital costs (τ) is 3.5% for a common onshore pipeline. The percentage of the natural gas used as fuel in the compressor stations (ℓ) is 0.4% per every 100 miles (according to Jung *et al.* [14]). The reason why authors use the term 'every 100 miles' is probably that they account for compressor stations every 100 miles on average. But 100 miles (161 km) between the compressor stations seem short compared with long-distance pipelines like the proposed Nabucco pipeline and the Altai project. The Nabucco pipeline route is 3893 km long, with an estimated 11 compressor stations [20,22]: thus, the average distance between compressor stations will be 354 km. Furthermore, the Altai gas pipeline will be over 2600 km long and will have 10 compressor stations [25], corresponding to one compressor station every 260 km. In contrast, the Gryazovets–Vyborg pipeline will have a compressor station every 131 km, and the Ukhta–Torzhok pipeline every 198 km on average. The estimated distance between the compressor stations (η) will therefore be 200 km, as mentioned in Whist's article [24].

LNG economics

The production and transport of liquefied natural gas is a three-step process: first liquefaction of the natural gas, then tanker transport and finally re-gasification. Here we will ignore the transport of natural gas from the field to the liquefaction plant, which is usually situated on the coast, because this stage is necessary for both pipeline and LNG transport and will not make a difference in the comparison[29]. The costs of LNG projects are difficult to generalise because they vary significantly from location to location, and depend on whether the project is greenfield or an expansion of an existing plant [30].

The liquefied natural gas is made in a liquefaction plant where the gas is refrigerated to −161°C (−260°F). The gas becomes a liquid, in the process shrinking to 1/600th of its volume in gaseous form. The liquefaction plant consists of so-called 'trains', processing modules, the size of which depends on the available compressors. In 2004, the largest trains could produce around 4 million tonnes per year (tpy). But, with improved compressor technology it is now possible to produce larger trains and further exploit the economies of scale. These costs may be further reduced by around 25% by replacing two 2-million-tonne trains with one 4-million-tonne train [6]. Today, Qatar has several single-train liquefaction plants with a capacity of 7.8 million tpy per train [31].

Figure 4.   The LNG chain.

The liquefaction plant is usually the most expensive link in the LNG chain. This is because the liquefaction process demands a considerable amount of the gas delivered to the plant [32], but also because of the remote locations, strict design and safety standards and the large amounts of materials required [30].

Most LNG plants have their own fleet of LNG carriers, '... operating a "virtual" pipeline', according to Chandra [28]. This might change, however, with the increasing spot-trade market [28]. According to Jensen [6], a typical LNG carrier can transport 135,000 to 138,000 cubic meters of cargo: this capacity is currently increasing, due to better designs. By March 2011, the world fleet of LNG carriers had 44 active carriers with a capacity of over 200,000 cubic meters. The largest LNG carriers have a capacity of 266,000 cubic meters of LNG [33].

The final link in the LNG chain is the re-gasification terminal with vaporisers which warm the liquefied natural gas from −161°C to about +5°C, and into its normal gaseous form. Other main components of the re-gasification facilities are the offloading berths, LNG storage tanks and pipelines to the local gas grid [28].

Due to new technology and designs, there will be several changes or options coming in the near future that might improve the LNG chain. Floating LNG production, which will make the costly gas transport from the field to the onshore LNG plant unnecessary, is on its way. Vautrain and Holmes [34] claim that for a remote offshore field the cost of bringing the gas to an onshore plant might add as much as 40% to the total cost of the LNG plant.

Furthermore, the possibility of offloading the LNG offshore is currently under study, as is ship-to-ship transfer. This might lead to larger ships offloading some of the LNG onto smaller ships which could transport it directly into port, warm the LNG into gaseous form and offload it directly into the local pipe grid [28]. As this technology is not in widespread use, it is therefore outside the focus of this paper.

LNG CAPEX

The costs of LNG projects are difficult to determine because the costs of the components, such as steel, nickel, wages and services may vary significantly over time. For example, in 2004 the cost of building a liquefaction plant had fallen to less than $300 tpy, due to the exploitation of economies of scale and the development of trains with larger capacity. Because of rapid increases in the price of materials and services, however, the cost of a liquefaction plant rose to $650 tpy in 2008 – more than double the 2004 price [35].

This corresponds well with the figures used in the report 'Natural Gas Pipeline Development in Northeast Asia' by Jung *et al.* [14], which will be used as a basis for the cost composition, but with revised figures. Jung *et al.* [14] break the total LNG costs into LNG liquefaction plant costs, LNG carrier costs and LNG re-gasification terminal costs.

The capital costs of the LNG liquefaction plant (P) are divided into a fixed cost for a greenfield plant with a capacity of 4 million tpy of LNG (5.5 bcmpa) and a variable cost per extra million tonne, if further expansion is needed. L is the amount of LNG, measured in million tonnes per year.

$$P = (\$5.5 \times 10^9) + (\$1 \times 10^9)(L - 4)$$

The cost of a single-train 4-million tpy onshore LNG plant is $5.5, billion according to Vautrain and Holmes [34]. Train sizes of around 4 million tpy are the most common capacities, but this will probably change as the designs are further developed. Qatar already has several 7.8 million tpy trains [31]. Moreover, adding a train to an LNG plant
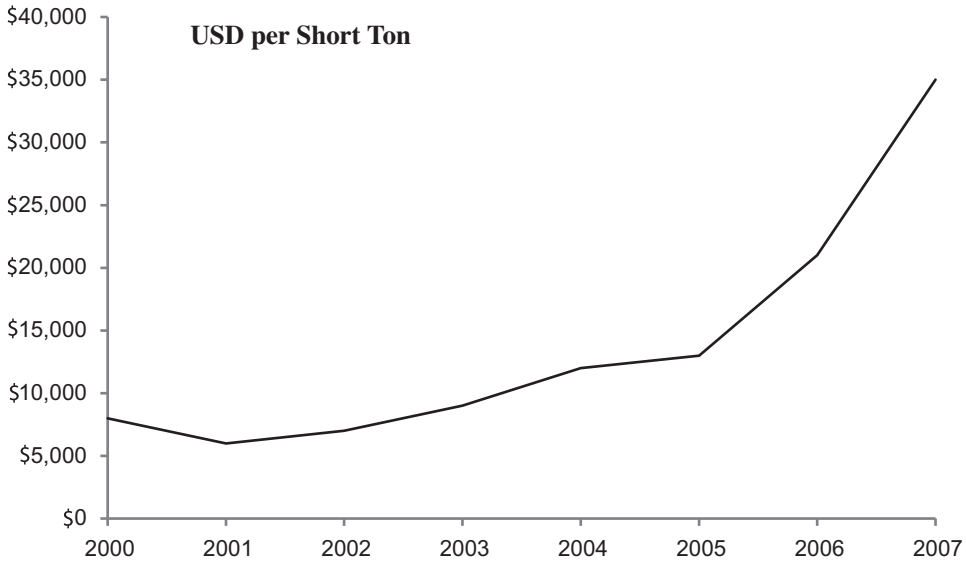
USD per Short Ton

Figure 5.   Nickel prices.
Source of data: [35].

in order to expand the capacity is far cheaper than a greenfield project. Adding a second train can reduce the unit costs per train by 20 to 30% [9], because many of the expensive facility components are already constructed and can be shared [30]. The Qatargas 4 project, where Qatargas added another train, with a capacity of 7.8 million tpy, to the existing Qatargas 2 and 3, will have a cost of around $8 billion [36,37].

According to the US Energy Information Administration [30] around 50% of LNG liquefaction plant costs are construction and related costs, 30% are equipment costs and 20% are for bulk materials. These shares are only approximations and may change as the prices of the various components change.

The sizes of LNG carriers are also increasing due to better designs and technology. Today, a carrier might have a capacity of 266,000 cubic meters. There are 10 carriers of this size; these are also among the newest. Qatar Gas Transport Company's *Rasheeda* was delivered in August 2010. All the largest carriers have a speed of 19.5 knots, or about 36 km/h.

The cost of an LNG carrier with a capacity of 266,000 cubic meters is about $290 million. The size of the fleet needed to transport the LNG depends on the distance (δ) from the market, the speed (λ) and the capacity (k) of the LNG carriers, and annual production at the liquefaction plant (N). λ is measured in kilometres per hour and k is measured in cubic meters of natural gas. The following equation is derived to find the number of carriers required and the capital cost of the LNG carriers (s). Here 266,000 cubic meter carriers will be used irrespective of the size of the field, because the aim of this paper is to analyse long-distance and large-scale transport.

$$S = \frac{\frac{(\$29 \times 10^7)N}{365}}{\left(\frac{\delta}{24\lambda}2\right) + 2}K$$

According to the US Energy Information Administration [30], 'the costs of building regasification or receiving terminals show wide variation and are very site-specific'. Therefore, it is also difficult to estimate the cost of a general LNG re-gasification terminal. The most expensive components are the storage tanks, which may account for one-third to one-half of the total construction costs, and the marine facilities [30].

The capital cost of a re-gasification terminal (R) is highly site-specific, but a rough estimate might be $1 billion for every 10 million tpy of LNG (L), or $100 million per million tpy LNG:

$$R = (\$1 \times 10^8)L$$

A US Energy Information Administration report from 2003 estimated that a new re-gasification terminal in the United States, with capacity between 3.8 and 7.7 million tpy, would cost $200 to $300 million. That estimate is probably too low today, because of the escalation of costs for materials and wages that started in 2004 and has not been reversed [36]. Furthermore, two LNG regasification terminals, the Gulf terminal in the United States and the Gate terminal in the Netherlands, which will both be operating from 2011, have announced their estimated total project costs to be $1.1 billion [38,39]. The Gulf terminal has a capacity of 5 million tpy; the Gate terminal has a capacity of 8.8 million tpy (12bcmpa), but this can be expanded to 16 bcmpa [31,39]. Jung *et al.* [14] use $500 million as an estimate for the cost of a 6-million-tpy re-gasification terminal.

LNG OPEX

Annual operating costs for the facilities needed to transport natural gas as LNG include maintenance costs, port charges, capital charges, taxes, fuel and boil-off. Boil-off is the small amount of LNG that evaporates from the storage tank during transport [40]. Fuel costs include liquefaction of the natural gas, fuel for the LNG carriers and re-gasification of the LNG [14,35][35] [14]. Operating costs are first divided into different shares of the construction costs, mainly covering operational and maintenance costs. Thereafter the amount of the natural gas used as fuel deserves discussion (see below).

Annual operating costs for the transport of natural gas as LNG may be estimated as follows:

$$O_L = P\varsigma + Sv + R\sigma + N\omega p$$

Operating costs as a share of capital costs (ς,v,σ) are 3.5% for the LNG liquefaction plant (P), 3.6% for the LNG carriers (S) and 2.5% for the LNG re-gasification terminal (R) [14].

The variable *share used as fuel* (ω) depends on several parameters. These include the share of natural gas used in the liquefaction process (Θ), the share of natural gas used in the re-gasification process (Ω), boil-off per day (ξ) and shipping fuel per day (φ).

$$\omega = \Theta + \Omega + (1 - (1 - \xi)^{\frac{\delta}{24\lambda}}) + (1 - (1 - \varphi)^{\frac{\delta}{24\lambda^2}})$$

The liquefaction process whereby the natural gas is cooled down to $-161°C$ consumes a considerable share of the natural gas. Re-gasification and shipping consume a portion of the gas as fuel. The quantity of natural gas used for cooling, heating, boil-off and LNG carrier fuel depends on the design, efficiency and the size of the liquefaction plant, the LNG carrier and the re-gasification terminal [41].

According to the engineer Kandiyoti [42], a total of up to 20% of the natural gas is used in the process of liquefaction, shipping and re-gasification. This was supported by ship-owner Trygve Seglem in 2007, who stated that 20–25% of the natural gas is needed for the entire LNG transport chain [43]. Nevertheless, others have claimed that less natural gas fuel is necessary for LNG transport. An anonymised source in an international oil company [44] informed us by email that only 5–6% is needed specifically for the liquefaction process, 1–2% for transport by LNG carriers and 1% for re-gasification. According to a report from 2004 by the Norwegian Directorate for Watercourses and Energy [45], between 5 and 15% of the natural gas is used in the liquefaction process [46].

A share of only 5–6% for the liquefaction process, however, seems too low compared with figures given in the majority of the published sources available. Furthermore, the figure of 1–2% natural gas usage for shipping must refer to shorter distances only, where the return journey is not accounted for. Jung *et al.* [14] cite the following figures: 9% for liquefaction, 2.5% for re-gasification and 0.17% per day to boil-off. LNG carriers may also use some of the natural gas as fuel. These figures fit well with those indicated by Kandiyoti, who claims that the liquefaction process takes up to 9–10% of the natural gas, and that up to 6% is needed for a 20-day voyage. This seems to include both boil-off and fuel, but not fuel for the return voyage. This means that a little less than 0.14% per day is fuel only (not including boil-off). The re-gasification process claims 2–3% of the natural gas [47].

These shares may vary due to differences in design, efficiency and technology, among other factors. The natural gas that boils off during shipping may be used as fuel – or other fuels, such as bunker fuel or diesel, may be used instead [47]. This will probably reduce the share of the natural gas needed for the LNG chain. We assume that the boil-off is lost, and that the fuel for the LNG carriers is natural gas taken from the cargo.

Comparison of LNG and pipeline CAPEX

We will first discuss the break-even point between the two transport options by examining only the capital costs. The 'break-even point' refers to the position when the cost of constructing the pipeline infrastructure is equal to the cost of constructing the LNG chain needed to transport the natural gas. As mentioned, the literature assumes a break-even point somewhere between 3000 and 5000 km. Because the cost of pipeline construction starts from a low level and rises relatively steeply with distance (whereas LNG has a high threshold, but thereafter increases less), LNG construction costs will be lower after the break-even point has been reached. The costs of pipeline constructions will be lower for distances shorter than the break-even point.

Not only the distance, but also the quantity of natural gas transported affects the costs and the break-even point. According to our calculations, the economies of scale are more pronounced for pipelines than for LNG. Even though there are significant cost reductions for adding trains to an already-planned LNG greenfield plant, the cost reductions are higher for increasing the diameter of a pipeline (not yet constructed) to expand the capacity. Not only the pipeline diameter, but also the power of the compressor stations must be increased in order to expand the capacity of a pipeline [48]. That point is not accounted for in this analysis because we have used a fixed capacity per compressor station (110 MW). In any case, this seems to be a relatively high figure, as a 110 MW compressor station every 200 km will probably be able to pump relatively large amounts of natural gas through the pipeline. In addition, the LNG chain might gain something from economies of

scale, because it is cheaper to increase the size of an existing plant than to build a greenfield plant. It is also cheaper to use a large LNG carrier than several carriers with smaller capacities. But, the transport of natural gas is not associated with economies of scale to the same degree as is pipeline transport.

The break-even point for an annual transport of 30 bcm is about 5100 km, assuming a pipeline diameter of 1420 mm (56 inches). If, however, if the amount of natural gas is 20 bcmpa, and the pipeline has a diameter of 1220 mm (48 inches), the break-even point is around 3750 km. For 10 bcmpa, with a pipeline diameter of 1020 mm (40 inches), it is around 2200 km.

Comparison of LNG and pipeline OPEX

We have used the actual market price for natural gas sold by Russia to Germany in 2010 to price the natural gas throughout this comparison, $296 per 1000 cubic meter [49].

Even though construction costs might be lower for LNG when considering long distances or relatively small volumes of natural gas, this does not necessarily mean that LNG will be the cheapest transport option. The large amounts of natural gas needed during the LNG chain usually make annual operating costs higher for LNG than for pipelines.

The break-even point for constructing the transport facilities needed to transport 20 bcmpa is around 3750 km. Pipeline construction costs will be the lowest for shorter distances, whereas LNG construction costs will be lower for longer distances. But, if we include the operating costs and assume that the project will run for 20 years, the distance break-even point for 20 bcmpa will increase to around 4550 km; for 30 bcmpa it will increase from 5100 km to 5900 km when operating costs are included. The break-even point for 10 bcmpa will be 2800 km, increased from 2200 km.

Operating costs will not always be higher for LNG than for pipeline transport. Our estimates show that for transporting 30 bcmpa over distances greater than 6550 km, annual operating costs for pipelines exceed those for LNG. One reason is that pipeline construction costs are higher, and we have developed operational and maintenance costs as a share of construction costs. Furthermore, for long distances the share of natural gas used as fuel for the compressor stations will approach the share of fuel used in the LNG chain. For particularly long distances, the fuel share will be higher for pipelines than for LNG
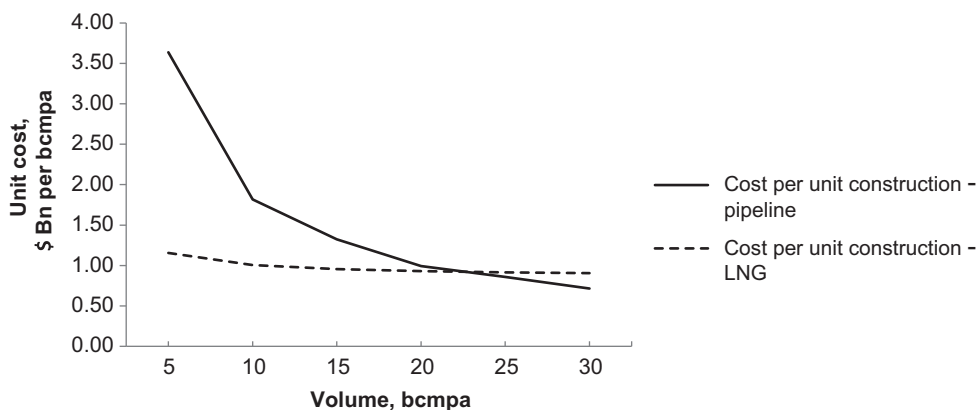

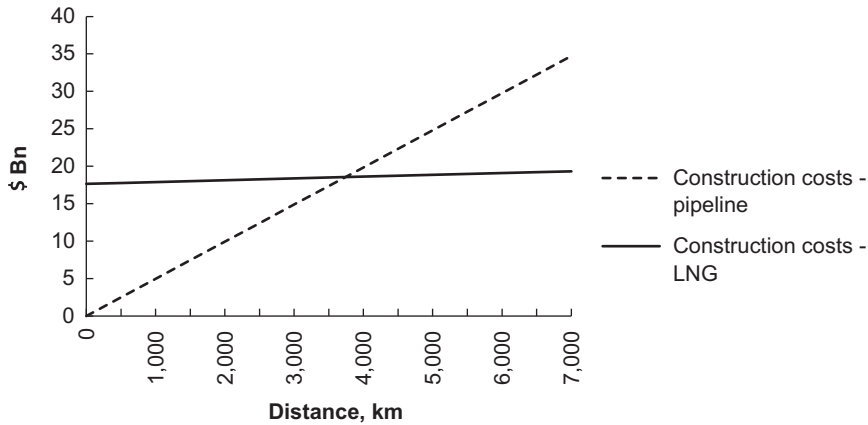Figure 6.   Capital cost per unit for 4000 km.

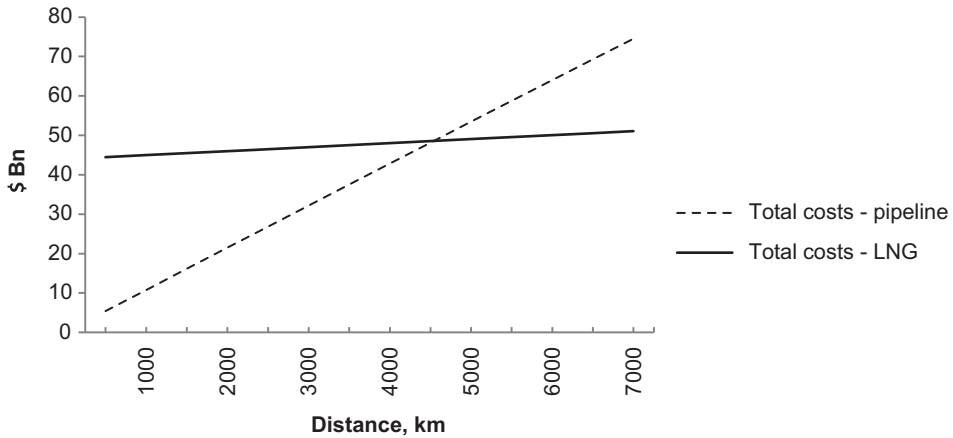Figure 7.   Break-even point for 20 bcmpa.

Figure 8.   Break-even point for 20 bcmpa.

transport. If the natural gas is transported more than 9100 km, pipeline transport will demand a greater share of the natural gas than LNG transport, regardless of transport volume. Nevertheless, LNG transport is more exposed to changes in the natural gas price than pipeline transport for reasonably long distances. This is shown in Figure 9, which is based on a distance of 4550 km from the field to the market, a volume of 20 bcmpa and a project life of 20 years. The costs of European Union Allowances (EUAs) are also included here.

CO_2 emissions

Because of the relatively large amount of fuel required by the LNG process compared to pipelines, LNG causes greater CO_2 emissions than pipeline transport. CO_2 emission allowances will therefore be used in order to estimate the extra costs associated with the environmental damage brought on by LNG.
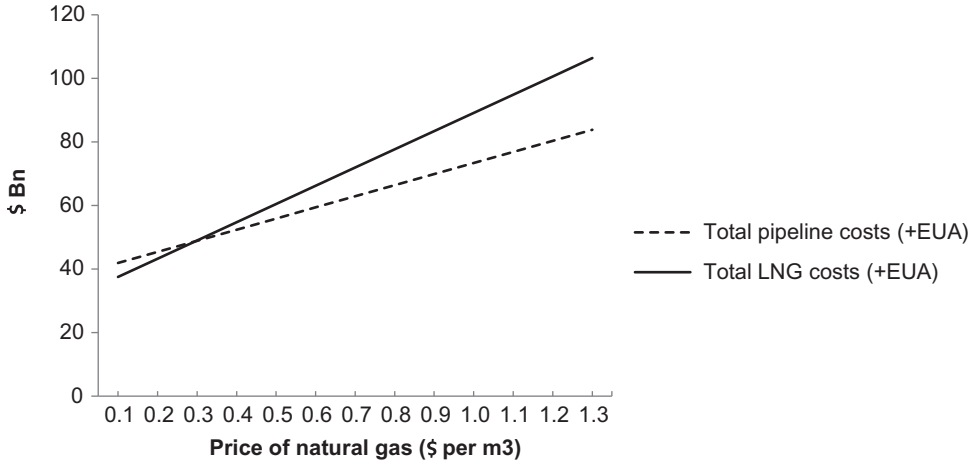
Figure 9. Total transport costs and gas price.

The extra operating costs can be calculated as follows:

$$E_p = \frac{36N\epsilon\left(1 - (1 \times (1 - l)^{\frac{\delta}{n}})\right)}{10^6}A$$

$$E_L = \frac{36N\epsilon\left(\Theta + \Omega + (1 - (1 - \xi)^{\frac{\delta}{24\lambda}}) + (1 - (1 - \varphi)^{\frac{\delta}{24\lambda^2}})\right)}{10^6}A$$

CO_2 emissions (ϵ) from natural gas are around 53.06 kg CO_2 per million Btu [50]. The price per ton CO_2 of emissions (A) is currently \$29.84 when buying from the European Union emission trading scheme, the European Union Allowance (EUA) [51]. As shown in Figure 10, LNG transport is more exposed to changes in the price of CO_2 emission allowances than pipeline transport. Figure 10 is based on a distance of 4550 km from field to market, a volume of 20 bcmpa and a project life of 20 years.

The model

Combining all the equations results in a model that may help to answer the question about the relative cost-efficiency of pipelines and LNG. Let **f** be equal to total pipeline costs and let g equal total LNG costs, measured in dollars. (A full list of variables and parameters is provided at the end of the article.)

$$\frac{f\,(\delta, \mu, \alpha, c, \gamma, N, p, \tau, \ell, \eta, A, \epsilon)}{g(\gamma, N, L, p, A, \epsilon, \varsigma, \nu, \sigma, \delta, \lambda, k, \Theta, \Omega, \xi, \phi)}$$

$$= \frac{(\$52{,}675\mu\delta \,+\, (\$3 \times 10^7)\alpha \,+\, \$3{,}091c)(1 + \tau\gamma) + N\left(1 - (1 - \ell)^{\frac{\delta}{\eta}}\right)\left(p + \frac{36\epsilon}{10^6}A\right)\gamma}{((\$5.5 \times 10^9) + (\$1 \times 10^9)(L - 4))(1 + \varsigma\gamma) + \dfrac{(\$29 \times 10^7)N}{365}\left(\dfrac{\delta}{24\lambda} - 2\right) + 2}k\,(1 + \nu\gamma) + (\$1 \times 10^8)L(1 + \sigma\gamma) + N\left(\Theta + \Omega + \left(1 - (1 - \xi)^{\frac{\delta}{24\lambda}}\right)\right)}$$
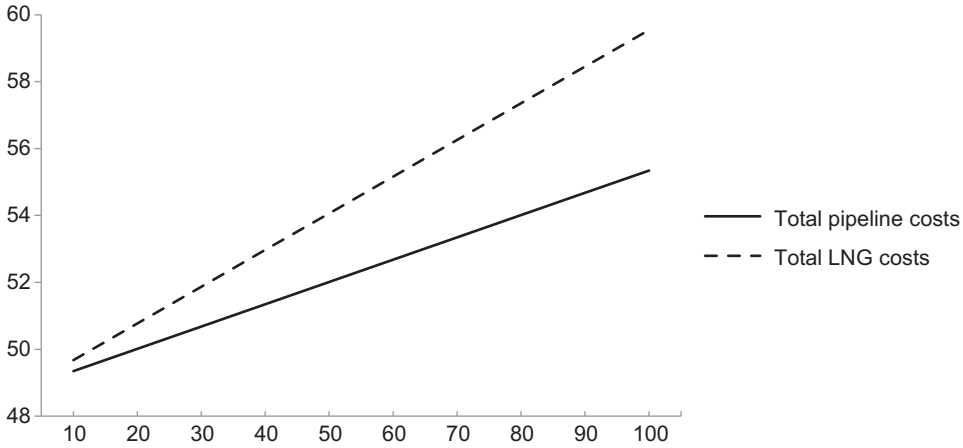
Figure 10.   Transport costs and EUA prices.

If the equation yields a figure higher than 1 for a given set of parameters, then LNG transport has the lowest costs. If the equation gives a figure smaller than 1, pipeline transport is economically preferable.

Such a large and complicated equation is not particularly elegant, and one may question whether it is necessary. But, according to our analysis, this equation captures the main factors that must be taken into account in choosing which type of infrastructure to build. Thus it mirrors the calculations that anyone choosing between LNG and pipelines must make, and the complexity of these decisions about crucial infrastructure. It is also possible to calculate the partial derivatives of **f** (total pipeline cost) and (g) (total LNG cost) with respect to the natural gas price (p) or with respect to the price of CO_2 emission allowances (A), where all other variables are held constant, in order to calculate how a one unit price increase affects total pipeline and LNG costs.

$$\frac{\partial f}{\partial p} = N\left(1 - (1-\ell)\frac{\delta}{\eta}\right)\gamma$$

$$\frac{\partial g}{\partial p} = N\left(\Theta + \Omega + \left(1 - (1-\xi)\frac{\delta}{24\lambda}\right) + \left(1 - (1-\varphi)\frac{\delta}{24\lambda}2\right)\right)\gamma$$

$$\frac{\partial f}{\partial A} = N\left(1 - (1-\ell)\frac{\delta}{\eta}\right)\frac{36_\epsilon}{10^6}\gamma$$

$$\frac{\partial g}{\partial A} = N\left(\Theta + \Omega + \left(1 - (1-\xi)\frac{\delta}{24\lambda}\right) + \left(1 - (1-\varphi)\frac{\delta}{24\lambda}2\right)\right)\frac{36_\epsilon}{10^6}\gamma$$

For example, the transport of 10 bcmpa over a distance of 3000 km during 20 years, and with the values of the other parameters as discussed above, gives:

$$\frac{\partial f}{\partial p} = 11,669,754,730 \quad \frac{\partial g}{\partial p} = 27,114,448,860$$

This demonstrates how the costs of LNG transport (g) are more sensitive to changes in the price of natural gas than pipeline costs (f).

Similarly, the parameters give the following expressions for the partial derivatives with respect to A:

$$\frac{\partial f}{\partial A} = 22,291,099 \quad \frac{\partial f}{\partial A} = 51,792,936$$

Again, LNG transport appears more exposed to price variations than transport by pipeline. A one unit increase in the price of greenhouse gas emission allowances results in a considerably larger cost increase for LNG than for pipelines, as shown below:

C= (\$52,675 × 56 *inches* × 1615*km*) + (\$3 ×10^7)11 + (\$3091 × 1,327,612 *hp*) = \$9,189,537,160

$$C = \$9,189,537,160 + \frac{\$10,750,000,000 + \$2,000,000,000}{2} = \$15,564,537,160$$

C= (\$52,675 × 56 *inches* × 1365 *km*) + (\$3 × 10^7)10 + (\$3091 ×1,206,920 *hp*) = \$8,050,272,517

$$P + S + R = (\$5.5 \times 10^9) + (\$1 \times 10^9)(20.3 - 4) + \frac{\frac{(\$29 \times 10^7)(28 \times 10^9)}{365}}{\left(\frac{3520}{24 \times 36}2\right) + 2}152,950,000$$

$$+ (\$1 \times 10^8)20.3 \approx \$ 25,280,000,000$$

$$O_p = (\$21,939,537,160 \times 3.5\%) + (28,000,000,000 - (28,000,000,000$$
$$\times (1 - 0.4\%)\frac{2839}{200}) \times \$ 0.296) = \$ 1,226,257,190$$

$$O_L = ((\$5.5 \text{ bn} + (\$1.0 \text{ } bn \times (20.3 - 4))) \times 3.5\%) + ((\$ 290 \text{ MM} \times 5) \times 3.6\%)$$
$$+ ((\$100\text{MM} \times 20.3) \times 2.5\%) + (28,000,000,000 \times 13.8\% \times 0.296))$$

Conclusions

Many variables affect the cost of pipeline and LNG transport of natural gas. In this article we have developed a generic model for the comparison of pipelines and LNG that can be adapted to different projects by revising the prices for the various factors included in the model.

The exact break-even point between LNG and pipelines will depend on the volume of natural gas and the distance that it is transported. Pipeline transport is a better option for larger volumes and shorter distances. LNG transport has the lowest costs for smaller volumes (up to 15 bcmpa) and for longer distances.

A substantial amount of natural gas is required as fuel for internal use in the liquefaction process, and for compressor stations in the case of pipelines. This causes the costs of both transport options to vary with the price of natural gas and greenhouse gas emissions. For distances up to 9100 km, LNG transport is more exposed to fluctuations in the prices of natural gas and greenhouse gas emissions than pipeline transport. This is because the LNG process – liquefaction, shipping and re-gasification – requires a larger share of the natural gas than do pipeline compressor stations over such distances. At greater distances, pipelines will expend more gas than will LNG, making pipelines more sensitive to changes in the price of natural gas and greenhouse gas emissions. We have thus identified 9100 km as an important threshold for the comparison of LNG and pipelines. In addition to this threshold, the amount of gas transported also impacts significantly on the comparison. In general, an increase in the price of natural gas and/or greenhouse gas emissions will favour the choice of pipeline transport.

If the aim is to replace coal and oil with natural gas in order to reduce greenhouse gas emissions, account should also be taken of the emissions associated with the different transport options for natural gas. On the other hand, more effective technologies developed in the future may reduce the burning of natural gas in connection with its transport. This is particularly true in the case of LNG, where the technology is newer and far more complex than the technology involved in pipelines. Future innovations within LNG may improve the viability of LNG relative to pipeline transport, as well as relative to coal and oil.

Additional conditions must also be taken into account when considering the transport of natural gas. LNG transport avoids transit countries and the associated, possible legal and political risks, and provides flexibility to sell on the market where the price is highest. Price differences for natural gas on different regional markets can be so great as to cancel out the impact of the higher fuel consumption and greenhouse gas emissions involved in LNG.

This article has not taken into account greenhouse gas emissions from the production of steel for pipelines, or the materials for LNG facilities and tankers. We have shown the effect of variations in the prices of natural gas and greenhouse gas emissions on the relative cost-efficiency of LNG and pipelines, but with only a partial analysis of the full climate impacts. Full assessment of the full carbon footprint of these two transport options for natural gas would require expanding the model to cover also the production of steel for pipes. That would be a logical next step for further research.

List of variables

N = natural gas (cubic meter per year)
L = LNG (million tonnes per year)
p = price of natural gas (US$ per cubic meter)
δ = distance (in km)
γ = number of operating years
C = pipeline capital costs (US$)
μ = pipeline diameter (inches)
α = number of compressor stations
c = total capacity of compressor stations (horsepower)
O_P = pipeline operating costs per year (US$)

τ = OPEX as a share of CAPEX – pipelines (%)
ℓ = loss per compressor station (%)
η = distance between compressor stations (in km)
P = capital cost of liquefaction plant
S = capital cost of LNG carriers
λ = speed of LNG carrier (km/h)
k = capacity per LNG carrier (cubic meter natural gas)
R = capital cost of re-gasification terminal
O_L= LNG operating costs per year (US$)
ς = OPEX as a share of CAPEX – liquefaction plant (%)
ν = OPEX as a share of CAPEX – LNG carriers (%)
σ = OPEX as a share of CAPEX – re-gasification terminal (%)
ω = share of natural gas used as fuel for the LNG chain (%)
Θ = liquefaction – share of natural gas used in the liquefaction process (%)
ξ = boil-off per day (% of natural gas)
ϕ = shipping fuel per day (% of natural gas)
Ω = re-gasification – share of natural gas used in the re-gasification process (%)
E_P = pipeline CO_2 emission costs
E_L = LNG CO_2 emission costs
A = price of CO_2 emission allowance (US$ per ton CO_2)
ϵ = CO_2 emission (kg per million Btu of natural gas)

List of parameters

p = $0.296 per m^3 [49]
γ = 20 [45]
μ = 40", 48", 56"
c = 147,512 per compressor station
τ = 3.5% [14]ℓ = 0.4% [14] η = 200 km [24]
λ = 36.114 [33]
k = 152,950,000 [33]
ς = 3.5% [14]
ν = 3.6% [14]
σ = 2.5% [14]
Θ = 9.5% [14,47]
ξ = 0.17% per day [14]
ϕ = 0.1389% per day [47]
Ω = 2.5% [14,47]
A = $29.84 per ton CO_2 [51]
ϵ = 53.06 kg per MMBtu [50]

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