Fueling electricity generation in Northeast Asia: full fuel-cycle impacts of energy imports

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by David F. von Hippel

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I. Introduction

In this Special Report David von Hippel first provides a general description of the elements of the full energy cycle that should be included in any comparison of different options for supplying electricity, followed by a description of the potential categories of "costs", broadly defined to include a wide range of costs and impacts, that may be incurred as a part of each element of the energy cycle. He then applies these fuel cycle elements and costs to qualitatively examine some of the key potential relative costs and impacts of three potential options for providing electricity in Northeast Asia—coal-fired, gas-fired, and nuclear power. Following this qualitative treatment, von Hippel presents the assumptions and results of an initial quantitative analysis at two specific categories of costs/impacts for these generation options: direct costs and greenhouse gas emissions, focusing on coal- and gas-fired options in NEA fired with fuels imported from the United States (or North America more generally). A concluding section summarizes the findings of this Working Paper.

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ii. Special Report by David F. von Hippel

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1. Introduction

The need for electricity in Northeast Asia continues to grow rapidly. China's electricity output increased by an average of over 12 percent annually in the last decade (2001-2011), and electricity production in the Republic of Korea (ROK), while not increasing at the same pace, has shown a healthy 5.3 percent per year growth over the same period[1]. Though Japan's electricity consumption has shown much more limited growth in recent years, particularly since the March 2011 Sendai earthquake and tsunami and the related accident at the Fukushima nuclear plant, the reverberations of that accident caused all of Japan's remaining nuclear generation capacity to be shut down for inspection. The slow return to service of Japan's reactors[2] has put a strain on the nation's electricity providers, who in the absence of nuclear generation have been obligated to provide much more power from fossil—mostly coal- and gas-fired— generation, at average costs significantly higher than generation costs incurred from their mostly-older nuclear units[3].

A number of recent news articles and other reports have suggested that the United States, with its glut of low-priced natural gas stemming from a boom in shale gas production in many locations, could become a significant supplier of energy to the energy-poor economies of East Asia[4]. The low prices of natural gas in the US, averaging, in 2012, not much more than a quarter of typical prices in

Japan and the ROK, and significantly less than in China as well, suggest that it could be beneficial for gas producers in the US and gas consumers in the East Asia to enter into an export/import arrangement. Similarly, coal producers in the interior US West have been proposing transporting coal by rail to ports in the US Pacific Northwest for shipment to consumers in Northeast Asia. This is an interesting twist on the energy situation of past decades, as the US has until very recently been increasingly dependent on energy imports, while the economies of East Asia have looked elsewhere—Indonesia, the Middle East, and Australia, for example—for gas and coal imports, as well as, for the future at least, northward to the Russian Far East.

Apart from the economic benefits—in theory for both exporting and importing nations—from sending US gas to Northeast Asia (NEA), it is also argued that there could be a considerable environmental benefit if clean-burning gas displaces dirty coal in power plants in NEA. Particularly in China, where high-efficiency gas combined-cycle power plants fueled with imported liquefied natural gas (LNG) could displace old, inefficient, and heavily polluting coal-fired plants, the theory goes, there could be considerable benefits both in terms of a reduction in greenhouse gas emissions—providing a global benefit—and in terms of reduction of local air pollution emissions in China, contributing to the health and well-being of China's citizens.

As attractive as the prospects of US gas exports to NEA might seem, it would be imprudent to consider them as a certainty for the future. First, in order to export gas to anywhere but Canada or Mexico, the US has to send gas out as LNG, which means building multi-billion dollar liquefaction "trains". Second, US gas supplies are large, but not infinite, and are constrained to some extent by pipeline capacity, therefore gas exports in quantity will have an effect on domestic US gas prices—which is good for gas producers, perhaps, but is certainly an issue that will be (and already is) of concern to US gas consumers[5]. Third, though gas is touted as a clean fuel relative to, for example, coal, but once produced, liquefied, and transported across the sea, its advantage over coal in terms of greenhouse gas emissions begins to wane. Fourth, the US natural gas industry in general, despite the recent boom, faces a somewhat uncertain future[6]. While it remains possible that gas exports from the US/North America to East Asia could play a role in helping to meet energy needs and help to reduce NEA dependence on Middle Eastern oil and gas, the day in which substantial flows start is likely sufficiently far in the future that deployment of other energy resources—such as energy efficiency and renewable energy sources—already gaining traction in places like China and Japan may be sufficiently well-underway on a large scale as to render the value of gas imports less than promised.

A full treatment of all of the above issues is beyond the scope of this Working Paper. An important unifying principle of the consideration of alternatives for fueling electricity generation in NEA, however, is that those alternatives should be considered on a full-energy cycle basis. That is, the full costs and impacts, across a spectrum of different criteria, of all of the elements that go into constructing generating facilities and supplying them with fuel, whether that fuel is produced locally or across the world, is needed in order to fully ascertain the relative energy security benefits or costs of different energy options.

In the remainder of this Working Paper, we first provide a general description of the elements of the full energy cycle that should be included in any comparison of different options for supplying electricity, followed by a description of the potential categories of "costs", broadly defined to include a wide range of costs and impacts, that may be incurred as a part of each element of the energy cycle. We then apply these fuel cycle elements and costs to qualitatively examine some of the key potential relative costs and impacts of three potential options for providing electricity in Northeast Asia—coal-fired, gas-fired, and nuclear power. Following this qualitative treatment, we present the assumptions and results of an initial quantitative analysis at two specific categories of costs/impacts for these generation options: direct costs and greenhouse gas emissions, focusing on coal- and gas-fired options in NEA fired with fuels imported from the United States (or North America more generally). A concluding section summarizes the findings of this Working Paper.

Before proceeding further with analysis of electricity generation options, it is necessary to underscore that this Working Paper does not purport to cover the full range of electricity supply options available to Northeast Asia. Renewable energy sources such as wind, solar, geothermal, and tidal and wave power must also be considered alongside fossil and nuclear generation alternatives, as must energy efficiency, which has in most cases and countries been shown to be the lowest-impact, least-cost means of, if not directly supplying electricity, stretching existing supplies and thus avoiding the use of generation fuels and the building of new generation capacity. The omission of consideration of these generation options in this Working Paper should not be seen in any way as a judgment on their viability for NEA, rather, the omission of consideration of these options is just a practical measure that allows us to focus on the costs and impacts of using fuels imported from America for electricity generation in Northeast Asia.

2. The Full Energy Cycle

In comparing electricity generation options it is sometimes tempting, for the sake of expediency, to focus solely on one element of the energy cycle, often the generation element. One argument for doing so is that the costs of other elements of the fuel cycle are already included in some of the costs considered in comparing generation costs. For example, one might consider fuel costs to be inclusive of all costs related to supplying that fuel to the generator. This may be true in cases where it is clear that all costs related to providing a fuel have been internalized in the fuel cost, but there are many types of impacts—most notably environmental impacts, but often others as well—where this internalization is manifestly not the case. As such, it is crucial that a full and fair comparison of the relative costs (broadly defined) of different sources of electricity generation span the full energy cycle. This is particularly true today, with new generation (and demand-side) technologies being implemented and on the horizon. The goal is to be able to be able to evaluate very different technologies, ranging, for example, from solar photovoltaic power to biomass-fueled systems to, as described below, gas, coal and power—using analytical techniques that are inclusive of all significant elements of the energy cycle. The goal of such analyses is that the final product of the energy system, be it electricity and/or another form of energy or energy service, comes at a "cost", broadly construed, both well-understood and acceptable to society.

A listing of the major categories of energy-cycle elements follows. Although there may be certain generation options for which this list may be incomplete, it provides a sense of the scope of what full energy-cycle analyses should include.

2.1 Resource or Fuel Provision

The first element of the energy cycle for electricity generation—which is actually in itself a set of sometimes many individual elements or steps, is providing the fuel (such as gas or coal) or resource (such as fissile material, wind, or water) to the site of generation in a form usable in the generator. At each step, important costs or impacts can accrue.

<u>Resource/site exploration</u>. A typical first step in providing fuel or resources for a generator is identifying, exploring, and evaluating sites where the resources used to generate power are found. Examples here are prospecting for petroleum or natural gas resources using, for example, remote geological methods or drilling of test boreholes, identifying and using drilling and other methods to map the extent of coal seams, and sampling to estimate coal quantity, installing anemometers to determine the variation of timing, direction, and strength of winds, or prospecting for uranium (U)

ore and assaying the U content of the ore body.

Resource extraction. Once resources have been identified and assessed, they must be extracted or otherwise made available for generation. Obvious examples here are coal mining, including underground mining and surface mining, drilling for and pumping out oil and gas (including "fracking", a process of in situ fracturing of gas-bearing rock by injecting fluids of various types under pressure, thus releasing the gas from the rock), and mining U ore, but building spillways or pipelines to move water to a hydro generator site is another example. For some resources—such as solar and wind power—resource extraction and generation happen effectively in the same step.

Fuel refining/treatment. Some fuels and resources, once extracted, must be refined or treated in different ways. Coal is often pulverized for transport and combustion, and is also frequently "cleaned" by various physical means to remove some of the ash (un-burnable) fraction and/or impurities such as sulfur. Natural gas is typically treated to remove natural gas liquids—mostly heavier hydrocarbons—as well as impurities such as hydrogen sulfide. Crude oil is refined into a slate of refined products ranging from gasoline, diesel fuel, and propane/butane to heavy fuel oil, lubricants, and waxes. Uranium must be processed through several steps before it is used in typical reactors. Uranium ore is treated and concentrated to yield "yellowcake", U_3O_8, then (when used in light water reactors) converted to uranium hexafluoride (UF_6), enriched to increase the ratio of the fissile isotope U_{235} to non-fissile U_{238}, converted to solid uranium oxide pellets, and assembled into fuel rods for reactors. Biomass fuels may be size-reduced and/or dried before combustion in a generator. Fuel refining and treatment often requires large, complex, and/or expensive facilities. In some cases fuels and resources are transported before being treated or refined.

Fuel transport and delivery. Once treated or refined (or, as noted, before treatment/refining), fuels and resources must often be transported to generation sites. For gas and oil, transport can be by pipeline, train, or truck. Coal is occasionally transported via slurry pipelines (pulverized coal mixed with water) for short distances, or by conveyor belts for "mine-mouth" coal-fired power plants, but often travels by a truck, rail, barge, or freighter ship (or a combination) to its power plant destination. Nuclear fuels typically travel either as yellowcake (by truck, rail, barge, or freighter) or as assembled fuel elements. Facilities that arguably span the categories of fuel refining/treatment and fuel transport and delivery are natural gas liquefaction plants. Here, natural gas is cooled and liquefied under pressure for shipment in LNG tankers. Transport facilities can be relatively inexpensive and generic, such as steel drums used to ship yellowcake and oil products, or bulk carrier barges, or can be highly specialized, such as trucks used to ship nuclear fuel assemblies and LNG tankers costing hundreds of millions of dollars.

2.2 Technology Development

Another stage of the energy cycle at which cost and impacts can accrue is the development of technology. Technology development can apply to resource extraction, fuel treatment, generation, and/or waste management. Examples include development of nuclear generation technologies, solar photovoltaic technologies, or pollution control methods. In some cases, technology development costs and impacts are borne by the companies or other organizations who generate power, and thus are (in theory) internalized into electricity prices, and in others, some or most technology development costs have been carried by society in general.

2.3 Construction

Construction of generation facilities, and of the fuel refining and treatment and the fuel/resource transport that feed them, the electricity transmission and distribution (T&D) infrastructure that feeds it, and, if needed, facilities for treating/storage/disposal of wastes, is another step in the energy cycle where costs and impacts occur. A sub-category of these energy-cycle elements includes construction at power plant sites, including site preparation, creating access roads (or, for example, facilities for rail or water access), preparing foundations and buildings to house equipment, clearing right-of-ways for and building transmission and distribution facilities, and installing power plant infrastructure (turbines and generators, fueling facilities, pollution control equipment, offices, and other equipment/facilities) and or T&D infrastructure (power lines, transmission towers, substations, and distribution transformers, for example). Another category of construction costs and impacts can be associated with off-site manufacture and assembly of power plant elements, ranging from huge nuclear reactor vessels and large wind turbines, blades, and towers to T&D equipment to solar photovoltaic panels.

2.4 Generator Operations and Maintenance

At the generator, costs and impacts can be thought of as occurring in at least two different categories. First, generators require operation and maintenance not associated directly with fuel use, such as basic periodic maintenance and the administration of generator activities. The operation of generators associated directly with fuel and/or resource use is an element of all energy cycles associated with electricity generation, as is power transmission and distribution.

2.5 Pollution Control and Waste Management

Pollution control in power plants range from, for example, electrostatic precipitators, sulfur oxide scrubbers, and other pollution control facilities on coal-fired power plants, to selective catalytic reduction devices for gas-fired power plants. Waste management facilities span a range from simple landfills for coal ash and mine tailings to more sophisticated recycling and reuse facilities for waste products, to nuclear spent fuel treatment, storage, management (of which, arguably, reprocessing of spent fuel to enable the reuse plutonium and uranium is one of the more complex examples[7]) and disposal.

2.6 Decommissioning and Remediation

The final energy cycle category of considered here are decommissioning and remediation of energy cycle facilities, which can include demolition and disposal and/or recycling of power generation equipment and facilities, capping and plugging of depleted oil and gas wells, remediation of power plant sites for future re-use, reclamation of power line right-of-ways, contouring, remediation and reclamation of mine sites, and a host of other activities associated with rendering the sites and/or materials used in energy cycle elements stable, non- (or less-) hazardous, and in some cases, available for other uses.

3 Cost and Impact Categories for Energy Cycle Elements

Each of the energy cycle elements described above, as with almost any economic activity, has associated costs and impacts. Here, we define "costs" broadly to include both monetized and not monetized, quantifiable and not quantifiable costs and impacts. Some cost and impacts categories apply only to some technologies and energy cycle elements, and some are much more applicable and/or important for specific technologies. In evaluating costs and impacts of energy cycle elements, however, it is crucial to be inclusive of a wide range of different types of costs and impacts, whether quantifiable or not, as it is often the difficult-to-quantify or non-quantifiable costs and impacts that turn out to be the most policy-relevant in deciding between energy options. Key categories of costs and impacts of energy cycle elements frequently encountered in considering energy choices are described below[8].

3.1 Direct and Compensated Monetary Costs

The most straightforward category of costs and impacts are those monetary costs that are incurred directly by electricity producers, and are typically included in the pricing of the final energy product (electricity and any co-products, such as heat). Direct costs of this type include capital costs for purchase and installation of equipment, power plant sites, and a host of other types of capital goods and infrastructure. Operating costs, often divided into "fixed" operating (or O&M", standing for operating and maintenance) costs, which for the most part do not vary with the output of the plant, and variable operating costs, which do vary with output, are a second major cost category. Labor costs can be a component of either capital or O&M costs, or can be accounted for separately, as can costs for materials used in preparing, operating, and/or maintaining an energy cycle facility. Finally, finance costs are a key component of the direct costs that a producer pays, and that are (generally) passed on to the electricity consumer. Finance costs vary based on prevailing interest rates, the lifetime of the energy cycle facility, the perceived (by the financier) risk in investing in the facility, and the length of time that is required to build the facility, among other parameters.

3.2 Direct But Not Necessarily Compensated Monetary Costs

In some cases, direct costs are incurred in developing and/or providing electricity to society, but do not (or do not fully) find their way into the costing of the electrical energy provided to consumers. An example of such costs are the significant government outlays—tens of billions of dollars, at least—that have gone into basic nuclear power and related nuclear weapons technology development and other support for the nuclear energy industry[9]. In the United States, for example, the 1957 Price-Anderson Act, which has been revised and extended several times, provides insurance against nuclear accidents[10], and US federal loan guarantees for nuclear power under Title XVII[11]. Most other nations that have pursued or are pursing nuclear power including, the nations of NEA, provide a host of subsidies that have made nuclear energy development possible[12]. Additional examples of direct costs of electricity generation not necessarily included in the price of power include oil and gas depletion allowances and other favorable tax treatments that reduce the cost of fuels to generators, government-funded solar photovoltaic technology development, effectively subsidized costs for the cooling water requirements for thermal power plants (fossil-fueled or nuclear plants, for example, particularly those using fresh water for cooling), forest access road development costs for biomass-fueled generation, and many other types of costs, ranging from subsidized research and development costs to local property tax abatement to accelerated depreciation of power generation assets for some types of generation.

3.3 Indirect Economic Costs

In addition to the direct costs of energy cycle elements, whether or not they make their way into the prices that consumers pay for electricity, the direct costs of the elements of the electric energy cycle have an indirect effect on the economy as a whole. For example, higher costs for imported fuel for generation may, though an increase in electricity costs without a commensurate increase in local spending, reduce the amount that consumers have available to spend on other goods, thus reducing overall local economic activity and employment. Conversely, electricity options with a strong local component, to the extent that they displace those based on fuels from outside the economic system under study, can increase local economic activity. Estimates of the indirect economic impacts of energy policy (or, indeed, other policy) options are often greatly desired by policymakers, but are not particularly straightforward to estimate, requiring, typically, relatively complex models, a host of assumptions, and careful interpretation to avoid reading more into the results than is warranted.

3.4 Environmental Costs and Impacts

A wide range of environmental costs and impacts can occur through the elements of the energy cycle for electric power. A summary list of the major categories of these costs and impacts are presented below. In some cases—greenhouse gases and “criteria” pollutants are key examples—various techniques, ranging from adapting the market costs of emissions permits to estimating the costs of avoiding emissions through adoption pollution control technologies to attempting to capture damage costs—can be used to “monetize” these costs for side-by-side comparison with direct costs. Monetization of environmental costs, however, is an inexact process at best, because one ideally would like to express environmental costs in terms of the total value of their impact—on, for example, health, economic productivity, or environmental services—and implied valuations through markets, pollution control, or other methods are unlikely to yield more than an approximate (often incomplete) value.

- Greenhouse gas (GHG) emissions: Emissions of carbon dioxide (CO_2), methane (CH_4), Nitrous oxide (N_2O), chlorofluorocarbons, black carbon[13], and other natural and man-made compounds have effects on the global climate through their impacts on the earth’s radiation balance. Greenhouse gas emissions are sometimes monetized using assumed values per kg CO_2 equivalent, or ascribed values based on market-clearing prices on the various carbon exchanges operating in a number of different nations and regions around the world.
- Acid gas and other pollutant emissions of regional importance—including, for example, sulfur oxides, and nitrogen oxides (SO_x and NO_x) but also potentially extending to particulate matter that is transported across oceans by prevailing winds—are a second class of often-monetized environmental emissions. As Sox and NOx emissions from power generation can be significantly reduced by the application of emissions control devices, the net cost of applying these devices is sometimes used to estimate the monetary value of these pollutants, though other approaches are also used.
- Air pollutant emissions with impacts in local areas and sometimes beyond, including SOx, NOx, particulate matter, hydrocarbons, heavy metals, and toxic air pollutants, can be emitted at many different steps of the energy cycle. Like regional air pollutants, monetized values of emissions of some local air pollutants have been derived, using a variety of methods.
- Some steps in the energy cycle of some types of electricity generation produce water pollution, that is, emissions of substances to bodies of water. These can range from drainage of acids from working and abandoned coal mines into watersheds, leakage of drilling chemicals for oil and gas wells into groundwater, to emissions of materials from cleaning of generation equipment (such as “blowdown” emissions from steam tubes) and runoff of dissolved and suspended materials from ash piles.
- Many thermal power plants discharge heat to bodies of water as a part of power plant cooling. These emissions raise the ambient temperature of the receiving body of water, potentially affecting its ecology and the ecology of the areas around it.
- A number of energy cycles for electricity generation generate solid wastes, ranging from mine wastes to coal fly and bottom ash, which if not properly disposed of can have their own impacts, through a variety of pathways, on health and the environment.
- Nuclear power generation produces radioactive wastes, including routine emissions to the air, low-level wastes from maintenance activities, spent fuel containing a variety of radioactive products and, if spent fuel is reprocessed, concentrated high-level liquid or “vitrified” (in a glass-like material) wastes. The steps in the nuclear fuel cycle produce radioactive emissions of varying extent and concentration. In addition, accidental emissions of radioactive substances have occurred frequently over the period that nuclear power has been in use, with a few incidents (most notably, in Chernobyl, Ukraine, in 1987) severe enough to cause substantial loss of life. Human (or

animal) exposure to radioactive substances in high enough doses can cause a variety of health impacts.

3.5 Social and Cultural Costs

In addition to direct, indirect, and environmental costs, elements of any given electricity generation energy cycle can have significant social and cultural costs that may be difficult or impossible to monetize, but should be taken into account in any comparison of candidate electricity sources. Examples of social and cultural impacts include displacement of populations from traditional homelands due to mining activities or the inundation of areas by hydroelectric reservoirs, often with loss of access to cultural resources such as artifacts or burial grounds, as well as impacts related to uprooting of populations. Social and cultural impacts can also occur in communities that become hosts to large energy facilities, as the economy and social structure of the area changes as the plant is built and begins operation, as well as when it reaches the end of its life and is shuttered[14].

3.6 Technological Risks

A category of potential costs/impacts that should be considered when weighing choices between electricity options and their associated energy cycles is that of technological risk. This set of costs, though difficult to quantify, relate to the degree to which dependence on a particular technology exposes its users, and the society around them, to the risk that the technology will fail in various ways. Failure of technology could happen through simple failure of the technology to produce the desired outcome or to reach cost targets, or if the technology has consequences for the environment or society unforeseen at the time it was adopted.

3.7 Military and International Security Costs

Finally, each energy cycle, for each potential user of an electricity generating option, can come with its own set of military and international security costs associated with retaining or obtaining access to resources or technologies. A clear example particularly germane to Northeast Asia include securing sea lanes for imports of oil and gas, and the geopolitical issues associated with those maritime security arrangements. Another example relates to access to (and agreements related to the use of) nuclear fuel cycle technologies, which is (for example) a key point of discussion between the United States and the Republic of Korea as the two nations look toward renewal of their Peaceful Nuclear Cooperation Agreement, set to expire in early 2014[15]. Another type of cost in this category relate to the impact that retaining access to fuels from abroad has on a consumer nation's relationship with supplier countries. The United States' relations with Persian Gulf countries are frequently cited as cases in point here, are China's more recent relationships with fuel supplier nations such as Sudan.

4 Key Costs for Energy-Cycle Elements: Coal-fired, Gas-fired, and Nuclear Power

The above discussions help to define the rows (energy cycle elements) and columns (costs/impacts) of a matrix for a systematic side-by-side comparison of any two or more electricity generation options. Although an exploration of each possible energy cycle element and each potential cost and impact of coal-fired, gas-fired, and nuclear power generation fuel cycles is beyond the scope of this Working Paper, Table 1, below, summarizes key generic costs/impacts by energy cycle elements for each of the three generation types, as a prelude to the more specific discussion of selected costs and impacts of NEA generation options using imported fuel presented in Section 5 of this Paper. Note that Table 1 does not purport to provide an exhaustive list of the possible costs and impacts for each energy cycle element, rather generic and indicative costs and impacts for each of the three types of generation.

Table 1: Examples of Elements of Full Energy-Cycle Analysis for Coal-fired, Gas-fired, and Nuclear Power

	Examples of Key "Costs"		
Energy Cycle Element	Coal-fired Power	Gas-fired Power	Nuclear Power
Technology Development	Most, not all (example, IGCC[16]) development costs privately funded	Most, not all (example, potential cross-subsidies between gas turbines developed for power and aircraft use) development costs privately funded	Development significantly historically underwritten by public sector, both for nuclear energy and for nuclear technologies shared with weapons programs; these costs are not directly reflected in nuclear electricity prices
Fuel Extraction	Significant environmental, social costs, large volumes of materials removed/left behind, leaching hazards, methane emissions from operating and abandoned mines	Environmental, social costs, arguably lower than coal because gas extraction has had a smaller "footprint", but the environmental and other impacts of newer production technologies (e.g. "fracking"[17]), including methane emissions, are still being documented	Volumes of material removed/left behind potentially also large (at average U concentration of ~0.2%), but still low per kWh vs. coal, and overall direct "fuel" costs for nuclear power, even including refining and treatment, are typically less than coal or gas
Fuel Refining/ Treatment	Coal pulverization/washing direct costs relatively low, but produce significant solid wastes	Natural gas is treated in large facilities to remove co-product natural gas liquids and impurities, with some resulting air and water pollutant emissions	Ore processing and concentration leaves significant solid wastes, LWRs[18] require fuel enrichment, leaving depleted uranium for disposal or re-use; fuel fabrication

Examples of Key "Costs"

Energy Cycle Element	Coal-fired Power	Gas-fired Power	Nuclear Power
Fuel Transport	Costs, potential environmental/economic impacts significant for rail or truck transport	Pipeline gas transport requires compressors using gas or electricity; methane emissions from gas pipelines vary significantly, hard to estimate; significant investments, infrastructure needed to produce, transport LNG	Costs relatively insignificant due to low volume of "fuel" per kWh
Generator, T&D Site Development, Construction	Significant space required for coal, ash storage and handling, and to isolate neighbors from dust; construction period one or several years longer than gas	Typically relatively compact power plant sites; gas storage, cooling equipment required; construction relatively rapid	More space required around plant, construction period often years longer than coal
Generation and Pollution Control	Higher GHG emissions/kWh than other fuels, significant "criteria", heavy metals emissions, large volumes of scrubber sludge/ash	Lower GHG emissions than other fossil fuels, and significantly lower emissions of most criteria air pollutants and other than coal-fired power; emissions controls primarily required to reduce NO_x emissions, some of which (e.g. SCR[19]) require significant inputs of reagents and catalysts	Little GHG, air pollutant emissions; low-level rad wastes, spent fuel is low in volume, but handling requires very special facilities, transport vehicles
Waste Management and Disposal	Coal ash/scrubber sludge requires special handling, can be reused in building industries (but not without controversy)	Waste management includes management of spent SCR catalysts	Ultimate disposal of spent fuel/high level wastes not yet decided, requires long-term attention; mine remediation

Examples of Key "Costs"

Energy Cycle Element	Coal-fired Power	Gas-fired Power	Nuclear Power
Decommissioning and Remediation	Mine remediation needed; site decommissioning relativelystraightforward, ongoing CH_4 emissions from decommissioned mines possible	Site decommissioning less than coal due to limited size of equipment per unit capacity; decommissioning of wells historically less demanding than for coal mines; impact of new technology unclear	Mine remediation needed; reactor site decommissioning very expensive (hundreds of millions of dollars per unit or more), involved, and time-consuming due to need to manage irradiated/radioactive infrastructure

5 Direct Costs and GHG Emissions Comparison of Power Plant Alternatives for NEA Based on Fuel Imported from North America

Exporting fuels—particularly coal and gas—from North America (particularly the United States) to Northeast Asia is not unprecedented, but has by no means been the norm in recent years. Slowly declining coal demand in the United States, as older coal-fired power plants are retired and environmental regulations become more stringent, plus burgeoning supplies of natural gas in the United States as new supplies come on line, have caused US energy producers to look to Asian markets as potential export destinations for their goods. Conversely, higher coal and especially natural gas prices at home, coupled with low prices in North America, have attracted potential importers in China, the ROK, and Japan. Apart from direct cost considerations, and the desire on the part of NEA nations to increase the diversity of their sources of fuel supply, one of the arguments for importing natural gas is that it can offer lower GHG and local air pollutant emissions than the fuel it would likely replace, which, in China at least, is probably domestic coal. Even if the infrastructure already exists (or is being built) to import coal and gas to NEA, the infrastructure does not yet exist to export large quantities of coal and gas from the US to NEA. As a result, communities in the US Pacific Northwest are being asked to consider coal export terminals and related rail facilities, and ports in the Pacific Northwest and other US coastal states are being asked to review proposals for LNG export terminals.

Below, we ask, and undertake a preliminary investigation to answer, two questions related to these proposals. When viewed from a full energy-cycle perspective, first what are the relative direct costs of NEA power plants fueled with North American coal or LNG, and second, what are the GHG emissions associated with such plants. In both cases, we compare the cost and GHG emissions performance with nuclear power, which is also, certainly in the case of Japan and Korea, though possibly not in case of China, fueled with imported resources.

5.1 Key Assumptions for Comparison

In comparing the cost and emissions performance of NEA power plants fueled with imported resources, the following assumptions are made for all types of power plants:

1. The power plants, and the systems that fuel them, go on line in approximately 2018. We view this as the earliest that LNG from new United States export terminals could reasonably be assumed to

reach NEA in significant quantities, due to the likely time required to build such terminals. Given probable delays in decisions to host rail terminals for exports of coal sourced in the interior west of the US, and the time required to build nuclear reactors, the non-LNG alternatives may be unlikely to be on-line before 2018 either.

2. Generation costs in general are based on costs adopted by the US Department of Energy in its 2012 Annual Energy Outlook for plants going on line in approximately 2017[20]. These power plants costs, particularly for coal-fired and possibly nuclear power, may be somewhat high for those likely to be encountered in China, and possibly for the ROK as well, but are likely not far off Japanese costs.
3. Costs are expressed in 2010 US dollars, as in the USDOE 2012 Annual Energy Outlook.
4. Coal and LNG receiving terminal costs in NEA were not included in the comparison, as these facilities were assumed to be already existing or under construction in NEA, and thus not incremental in new cross-Pacific energy trading.

5.2 Cost Assumptions: Coal-fired Power Plants

The following assumptions were used in evaluating the costs of coal-fired power plants fueled with coal imported to NEA from the United States:

- Capital costs for coal-fired power plants with SO_x scrubbers were assumed to be at the US levels adopted by USDOE for the reference case "conventional coal" plant: $2,844 per kW in 2010 US dollars, including a 7 percent "project contingency" factor. Recognizing that this cost is likely high for today's Chinese coal-fired plants[21], a sensitivity case was prepared in which capital costs were reduced by 50 percent ("Conventional Coal, Lower Capital Costs"). Cost of labor and other inputs to power plant construction have, however, been rising significantly in recent years, so it is likely that by 2017 capital costs in China will have risen close to US levels.
- A heat rate of 8800 Btus (British Thermal Units) per kWh, or 9280 kJ/kWh, was assumed, consistent with a relatively efficient new unit. A capacity factor of 85 percent was assumed for all coal-fired plants.
- Fixed and non-fuel variable operating and maintenance (O&M) costs were taken from USDOE figures at $4.0 and $4.3 per MWh generated, respectively.
- Coal was assumed to be sourced from the Interior West (for example, the Powder River Basin) of the United States, and was thus assumed to be shipped by rail to the US Pacific Northwest, and from there by ocean freighter to NEA, with the example destination chosen as Shanghai. By far the largest component of the costs of coal delivered to NEA is shipment by rail from mines in the US to coastal ports. Even assuming bulk freighter lease rates of $30,000 per day, about twice today's rates for five-year leases[22], trans-ocean shipping only represents about 20 percent of the cost of moving coal from US mines to China.
- Not yet included in the costs of exporting coal (or gas—see below) are profits for US energy exporters. Coal prices in China, by one estimate[23], were expected to be about $4.80 per MMBtu in 2014, which would appear to be about 30 percent more than the landed cost of US Powder River Basin coal in China. The implication is that US producers may be able to charge a significant mark-up on coal shipped to the Far East, though it is difficult to estimate exactly what mark-up might be possible, given the large differences in coal prices and competition from other nations exporting coal to NEA.
- In addition to Conventional Coal plants, costs were estimated, again based on USDOE assumptions for "Advanced Coal Plants with Carbon Capture and Storage". Capital costs for these plants were

assumed to be $5,348 per kW, including contingency factors. Heat rates for plants with CCS are lower due to the energy requirements of carbon capture, at 10,700 Btu/kWh[24]. Given that advanced coal with CCS is a relatively new technology, a lower-capital cost variant was evaluated.

- Decommissioning costs for coal-fired power plants appear to vary substantially with the size, age, and location of the plant to be decommissioned, but are much less than decommissioning costs for nuclear reactors, largely because decommissioning of coal-fired plants does not involve handling of power plant components that have been exposed to radiation, and are radioactive themselves. An average decommissioning cost for coal-fired power plants of $40 million per GW of capacity was assumed for this comparison[25].

5.3 Cost Assumptions: Gas-fired Power Plants

The following assumptions were made in analyzing the potential costs of NEA gas-fired power plants fueled with LNG sourced from the United States:

- Capital costs for gas-fired combined-cycle (GCC) power plants were assumed to be at the US levels adopted by USDOE: $977 per kW in 2010 US dollars (with contingency factors). No lower-cost variant was explored for NEA, because capital costs for GCC plants generally include a much higher fraction of equipment, often imported equipment, costs than do coal plants, which require more on-site infrastructure development.
- A heat rate of 7050 Btus per kWh, or 7440 kJ/kWh, was assumed for gas combined-cycle generation. A capacity factor of 87 percent was assumed for all gas-fired plants.
- Fixed and non-fuel variable operating and maintenance (O&M) costs were taken from USDOE figures at $1.9 and $3.4 per MWh generated, respectively.
- Natural gas was assumed to be sourced from the United States, and distributed to a US Pacific Northwest coastal location via pipeline. It is assumed that, at least at first (and for the purposes of this analysis), the volumes of gas exported will not require significant new pipeline builds, but this situation will not last forever if LNG exports boom, and the costs of transporting gas within the US will go up as a result as the industry is obliged to add pipeline capacity. Pipeline gas is assumed to be converted to LNG in a newly-built liquefaction facility on the Pacific Northwest coast, and exported from there to NEA by LNG tanker. Costs to move natural gas from producers to a Pacific Northwest port were assumed to be approximately equal to the difference between average US gas spot prices and State of Washington, which in 2012 were about $1.8 per MMBtu[26]. The multi-billion dollar capital costs of LNG liquefaction terminals, when amortized over the annual LNG output of those terminals assuming a 20-year lifetime and a 95 percent capacity factor, adds about $2.50 per MMBtu per fuel cost, and transport costs from the wellhead to the liquefaction terminal and from the US terminal to a receiving terminal in NEA adds a similar amount to the cost of delivered gas.
- Before adding any profit for producers, the delivered cost of gas to NEA would be about $11 per MMBtu, considerably lower than the approximately $15 per MMBtu estimated delivered cost of LNG in Japan, Korea, and China as of early 2013. The implication, if the prices in both the US and NEA hold, is that US gas producers may be able to charge a significant mark-up on LNG shipped to the Far East. It is, however, difficult to estimate exactly what mark-up might be possible by the time that US West Coast liquefaction facilities come on line, given the volatility of gas markets, LNG shipping markets, and uncertainty as to the actions of gas producers worldwide in response to changing market conditions.
- In addition to conventional gas plants, costs were estimated, again based on USDOE assumptions for “Advanced Gas Combined Cycle with Carbon Capture and Storage”. Capital costs for these

plants were assumed to be $2,060 per kW, including contingency factors. Heat rates for GCC plants with CCS are somewhat lower due to the energy requirements of carbon capture, at 7,525 Btu/kWh[27].

- Decommissioning costs for natural gas plants were assumed to be half of decommissioning costs for coal-fired plants. This is a very rough assumption, and costs net of salvage value for these plants could be lower, particularly if prices for salvaged metals continue to rise.

5.4 Cost Assumptions: Nuclear Power

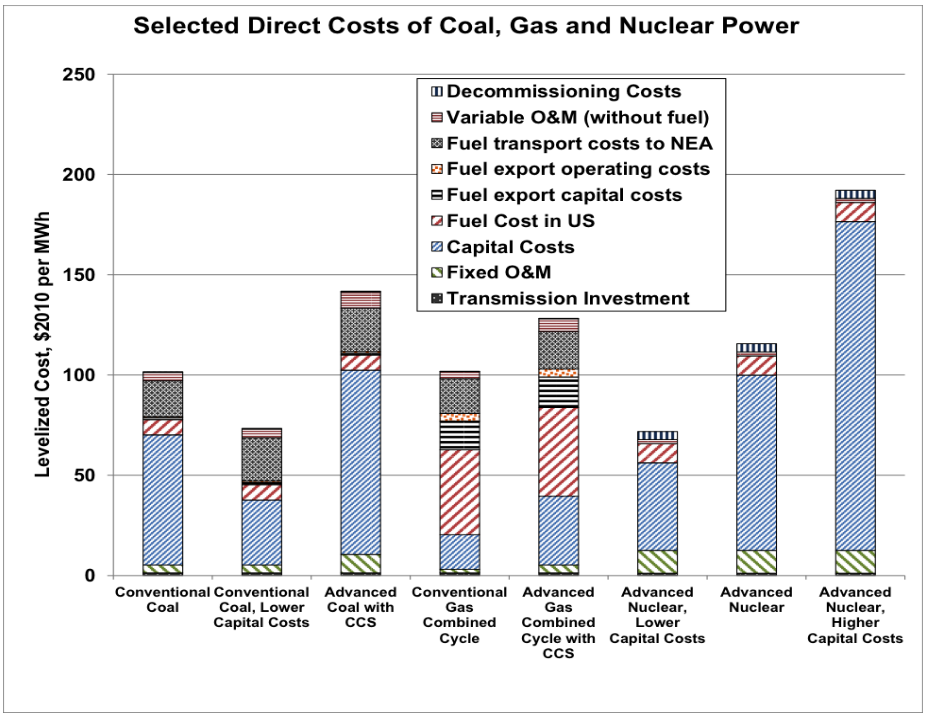
As a point of comparison with coal- and gas-fired power, levelized costs for advanced new nuclear power plants were calculated. Key assumptions in these calculations were as follows.

- As a reference comparison, the capital cost for advanced nuclear power plants was adopted from the estimated used in the USDOE's AEO2012, at $5,335 per kW. Nuclear power plant costs, however, have in recent year been highly variable from nation to nation and plant to plant. As a consequence, two alternative cost cases are presented, one with a higher capital cost of $10,000 per kW, consistent with recent estimates for nuclear power costs for two proposed plants in the US Southeast[28]. These higher costs may be more in line with what capital costs for new nuclear plants in Japan could be if Japan choses to resume its nuclear power program. The second alternative cost case reduces the USDOE nuclear costs by 50 percent, bringing nuclear reactor costs more in line with estimates of costs of new nuclear plants in China and the ROK[29]. As noted above, however, quoted nuclear power costs may include public subsidies or industrial cross-subsidies that make comparisons with other technologies difficult.
- Nuclear fuel costs in NEA were assumed to be similar to those in the US, at $9.5 per MWh of output. Non-fuel fixed and variable O&M costs are estimated at a total of $13.3 per MWh. As is typical for nuclear power costs, capital costs dominate fuel and O&M costs.
- Nuclear reactor decommissioning costs were assumed for the purposes of this comparison to be $400 million per GW of capacity, and to be treated essentially as an up-front capital cost[30].

5.5 Power Plant Cost Comparison

Figure 1 presents estimates of total levelized electricity cost for the coal-fired, gas-fired, and nuclear generation options described above. The levelized costs of conventional coal-fired power and gas combined-cycle plants fueled with coal and gas from the United States are similar, although power costs from coal-fired plants with lower capital costs remain substantially less than gas-fired power costs. Cost for advanced nuclear plants, assuming on the order of $5000 per kW capital costs, are estimated at about 20 percent higher, overall, than costs for conventional gas or coal-fired plants. When lower nuclear capital costs are assumed, overall levelized nuclear electricity costs are similar to those costs for coal-fired plants when lower capital costs are assumed for the latter as well. Higher capital costs for nuclear plants brings the levelized costs of electricity from nuclear to nearly $200 per MWh. Carbon capture and storage adds $30/MWh and $40/MWh to the costs of generation for gas- and coal-fired power, respectively.

Figure 1:



6 Greenhouse Gas Emissions from Coal-fired, Gas-fired, and Nuclear Power Plants

Given its lower carbon content per unit energy content, and that natural gas combined-cycle power plants are typically the most efficient thermal power plants available, natural gas, among the fossil fuels, offers the lowest GHG emissions per unit of electricity produced. A natural gas-fired power plant located in NEA and fueled with gas derived from LNG imported from the US would have these low-CO2 and high-efficiency properties when consumed in a power plants in Asia, but emissions from additional fuel cycle elements, including those related to producing, transporting, and liquefying natural gas (along with corresponding parts of the coal energy cycle) must be counted as well in order to provide a complete comparison. Key assumptions in evaluating the emissions from each fuel (nuclear power is provided as a comparison) are provided below, along with summaries of reference-case and sensitivity-case results.

6.1 Emissions Assumptions—Coal-fired Power Plants

Key assumptions and data used in estimating overall GHG emissions associated with providing power in NEA using coal sourced from the United States include the following:

- Estimates of CO_2-equivalent emissions per kWh of generation for the energy cycle elements of coal-fired generation corresponding to fuel extraction and preparation, power plant construction, operations and maintenance (other than generation), power generation, waste management, and power plant decommissioning were taken or derived from a summary prepared by Fripp[31].
- Estimates of rail transport-related emissions assumed coal is shipped from the Powder River Basin of the US Interior West to a coal terminal in the Pacific Northwest, a distance assumed to be 1200 miles (1920 km). Coal train diesel use was assumed to average 486 ton-mile of coal transport per gallon of diesel fuel[32], or the equivalent of about 1.93 kg of CO_2e per GJ of fuel moved to shipping terminals, including an assumed 50 percent additional fuel use to move empty coal cars back to the mining area.
- Transportation of coal across the Pacific, about 5000 miles (8000 km), was assumed to produce 3.65 g of CO_2 per ton-mile[33], or about 37 kg of CO_2 per metric ton of coal transported.

6.2 Emissions Assumptions—Gas-fired Power Plants

Key assumptions and data used in estimating overall GHG emissions associated with providing power in NEA using coal sourced from the United States include the following:

- Estimates of CO_2-equivalent emissions per kWh of generation for the energy cycle elements of gas-fired generation corresponding to fuel extraction and preparation, transportation via pipeline, power plant construction, operations and maintenance (other than generation), power generation, waste management, and power plant decommissioning were taken or derived from a summary prepared by Fripp[34].
- Liquefaction of gas from interior-US sources at a Pacific Northwest liquefaction terminal were taken to yield 7.4 g CO_2e/MJ of gas produced[35]. This implies that the energy requirements of liquefaction are over 10 percent of the energy value of the LNG output.
- LNG transport costs were estimated at about 0.95 g CO_2e/MJ for the transit to NEA from the US Pacific Northwest, again based on California Air Resources Board figures.

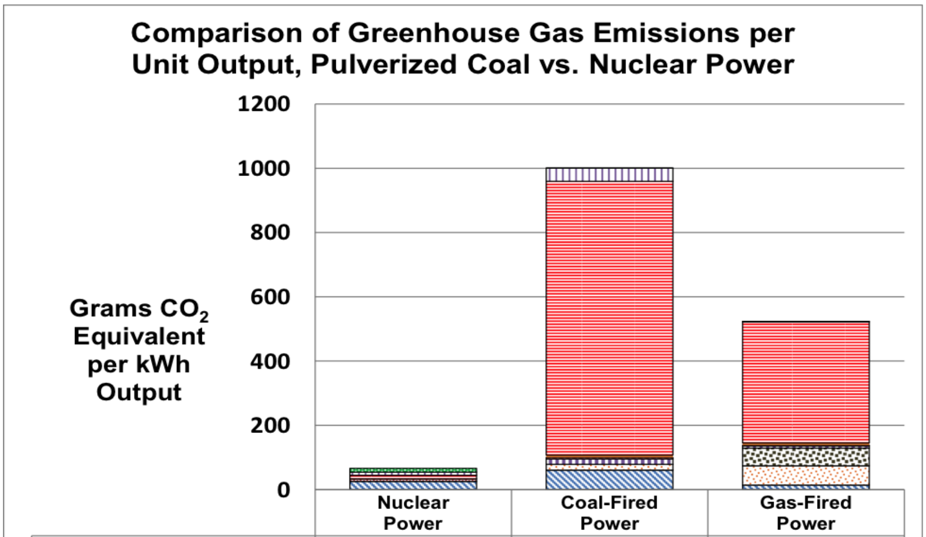
6.3 Emissions Assumptions—Nuclear Power Plants

Although the use of nuclear fuel to generate power produces no (or little) GHG emissions in and of itself, the nuclear energy cycle includes a number of energy-intensive steps. The estimates of nuclear fuel cycle emissions cited below were taken from a comprehensive survey of many assessments of GHG emissions from nuclear power by Sovacool[36]. The average cited here, however, is just one point in a large range of estimates of total GHG emissions from the nuclear energy cycle; Sovacool's survey included studies estimating total emissions ranging from near zero to near 200 g CO_2e per kWh of electricity generated.

6.4 Reference Case Results

Figure 2, below, shows an overall comparison of estimated GHG emissions in NEA power plants, including coal- and gas-fired plants fueled with energy imports from the United States. Emissions from coal-fired power plants, taking into account all major elements of the energy cycle, remain about twice those of gas-fired power plants, though consideration of full energy-cycle emissions shows that non-generation emissions from the natural gas energy cycle are larger, both in absolute terms and relative to generation emissions, than for the coal energy cycle. By contrast, nuclear energy cycle GHG emissions are substantially lower than either of the fossil-fueled alternatives considered, and, in fact, also lower than emissions from at least the first generation of coal- or gas-fired plants using carbon capture and storage technologies[37].

Figure 2:

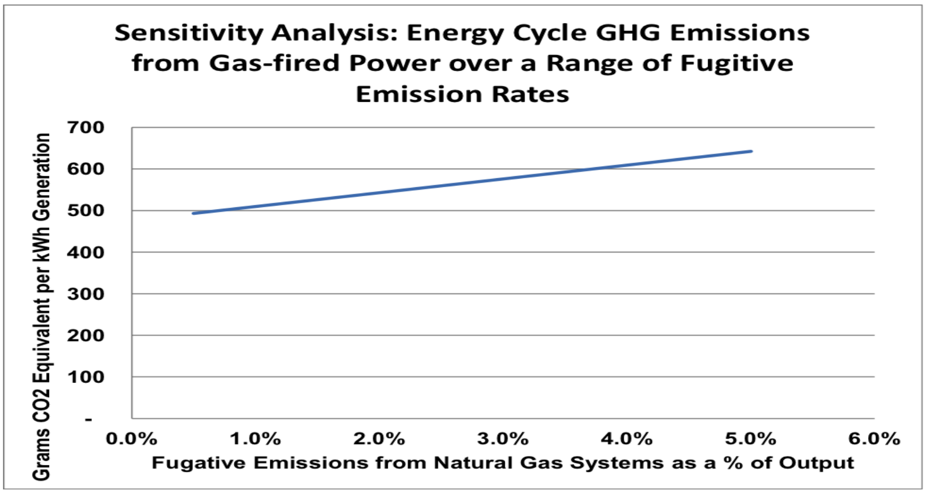


	Nuclear Power	Coal-Fired Power	Gas-Fired Power
Decommissioning	12.0	0.1	0.1
Waste Management	9.2	40.7	0.4
Generation	11.6	852.6	377.3
Operation and Maintenance	-	6.9	6.9
Construction	8.2	4.5	2.0
Fuel Transport to NEA	-	17.0	7.1
LNG Liquefaction	-	-	55.0
Fuel Transport in US	-	17.9	60.3
Fuel Extraction/Preparation	25.1	60.7	13.9

6.5 Sensitivity Analysis: Methane Leakage During Gas Production

The calculation of overall GHG energy-cycle emissions from gas-fired power implicitly adopts Fripp's assumption, based on US Environmental Protection Agency data, that 1.4 percent of natural gas is emitted to the atmosphere before reaching consumers. With the advent of fracking as a key production technique in the United States (with interest in the technology also becoming keen worldwide), more attention has been focused on how emissions from fracking might be different, and higher, than those related to more conventional gas production techniques. Recent tests have found gas emissions from specific wells as high as 9 percent of gas output[38], though other studies, including a survey of producers from the American Petroleum Institute and America's Natural Gas Alliance[39] have estimated total emissions at well under one percent of output. At present, the Environmental Defense Fund, working with partners in academia and industry, are undertaking a comprehensive estimate of fugitive emissions from natural gas production, with results expected in 2014[40]. Pending those results, Figure 3 provides a sensitivity analysis showing the variation in overall GHG emissions from natural gas-fired power for a range of fugitive methane emissions from 0.5 to 5 percent of overall gas output. Figure 3 shows that if emissions from gas extraction/transport systems, at least for the US gas producers on the margin (those that would fuel exports to NEA), are ultimately found to be closer to 5 percent than 1 percent, some of the advantage gas has over coal (at about 1000 g CO_2e/kWh) is eroded somewhat, but gas still enjoys a substantial GHG emissions advantage. Moreover, it is more than likely that if current average fracking-related fugitive emissions turn out to be on the high-end of the range of recently-measured samples, producers would (in response to a combination of economic and regulatory pressures, for example), adopt control measures to minimize emissions. To some extent, the adoption of measures to capture more fugitive emissions from fracking gas wells in the US is already beginning.

Figure 3:



7 Conclusion

In sections 5 and 6, above, the results of a comparison of the levelized cost of electricity found that costs of generation are not significantly different, taking into account the native variability in such estimates, for coal or gas-fired (or nuclear) power in NEA, fueled by energy imports from the United States. Further, gas-fired power, even when elements required to liquefy gas and move it across the ocean are considered, and even if fugitive emissions are higher than reference estimates, continues to have a significant edge over coal-fired power when overall energy-cycle GHG emissions are considered.

Having considerer two of the "countable" full energy-cycle parameters associated with providing electricity in NEA based on coal and gas fuels imported from the United States, we come full circle to the concepts presented earlier in this Working Paper, and are obliged to ask after some of the full energy-cycle impacts that may, in the long run, be those that end up "counting" in terms of influence on energy exports policy in the United States, and energy imports policy in Asia.

For example, how will the fears of environmental impacts from fracking be resolved[41]? Will local communities in US coastal locations be willing to host LNG and coal export facilities, and at what cost, and over what time frame? How will exports affect prices of coal and gas in the US, and the US economy as a whole[42], as well as prices of coal and gas (including LNG from other suppliers) in Asia? Will the objections of US consumers (for example, large industries, which have already expressed reservations about exports) to sending gas abroad significantly slow or stop exports in their tracks? Will avoided local pollution from substituting gas for coal in Asia prove a sufficient inducement to overcome other issues? Will gas and coal exports, by the time export infrastructure has been developed in the US, prove less than expected due to changes in national or global markets, or due to the implementation of "game changing" renewable and/or efficiency technologies? These and other questions, lamentably beyond the scope of this Working Paper, remain to be more fully explored, though a number of authors have made an excellent start on the discussion[43].

III. References

[1] Derived from data in British Petroleum (2012) "Statistical Review of World Energy 2012" workbook, available as
http://www.bp.com/assets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statist

ical_energy_review_2011/STAGING/local_assets/spreadsheets/statistical_review_of_world_energy_full_report_2012.xlsx.

[2] As of early 2013, only two of the 54 reactors Japan in service as of early 2011 had been placed back on line.

[3] See Junko Edahiro (2013), "Japan's Energy Situation after the Great East Japan Earthquake", JFS Newsletter #126, dated 2/28/2013. Edahiro compares the pre-Fukushima (February 2011) energy output of fossil-fueled power plants, at 63.1 percent of national generation, with early 2013 fossil generation at 90.6 percent of the Japan's electricity output.

[4] See, for example, Goho, Shaun (2013), "In U.S., the Lure of Export May Further Fuel Natural Gas Boom", Yale Environment 360, available as http://e360.yale.edu/feature/in_us_the_lure_of_export_may_further_fuel_natural_gas_boom/2605/, and Mufson, Steven (2012), "As shale gas booms, U.S. considers LNG exports", The Willits News (byline, The Washington Post), dated December 10, 2012, available as http://www.willitsnews.com/ci_22163548/natural-gas-boom-fracking-lng-export. See also Associated Press (2013),"Japan's TEPCO gears up for US shale gas imports", dated February 7, 2013, and available as http://fuelfix.com/blog/2013/02/07/japans-tepco-gears-up-for-us-shale-gas-imports/.

[5] See, for example, Bastasch, Michael (2013), "Fight over LNG exports pits energy industry against manufacturers, chemical industry", The Daily Caller News Foundation, available as http://dailycaller.com/2013/01/12/fight-over-lng-exports-pits-energy-industry-against-manufacturers-chemical-industry/.

[6] Krauss, Clifford (2013), "Exports of American Natural Gas May Fall Short of High Hopes", The New York Times, January 4, 2013, available as http://www.nytimes.com/2013/01/05/business/energy-environment/exports-of-us-gas-may-fall-short-of-high-hopes.html?pagewanted=all&_r=0.

[7] See, for example, World Nuclear Organization (2012), "Processing of Used Nuclear Fuel", dated May, 2012, and available as http://www.world-nuclear.org/info/inf69.html.

[8] The costs and impact categories offered below echo, to a degree, the various aspects of broadly-defined "energy security" as presented in, for example, David von Hippel, Tatsujiro Suzuki, James H. Williams, Timothy Savage, and Peter Hayes (2011), "Energy Security and Sustainability in Northeast Asia", *Energy Policy*, Energy Policy, volume 39, pp. 6719-6730, available as http://dx.doi.org/10.1016/j.enpol.2009.07.001; David von Hippel, Tatsujiro Suzuki, James H. Williams, Timothy Savage, and Peter Hayes (2011), "EVALUATING THE ENERGY SECURITY IMPACTS OF ENERGY POLICIES", Chapter 3 in *The Routledge Handbook of Energy Security*, edited by Benjamin K. Sovacool, Routledge Publishers; and David F. von Hippel, James H. Williams, Fritz Kahrl, and Peter Hayes (2012), "Energy Security—East Asia", in Volume 7 of *Berkshire Encyclopedia of Sustainability: China, India, and East and Southeast Asia: Assessing Sustainability*, Berkshire Publishing Group. An updated treatment of these energy security concepts is planned for later in this Working Paper series.

[9] See, for example, Doug Koplow (2011), Nuclear Power: Still Not Viable without Subsidies, prepared for the Union of Concerned Scientists, dated February, 2011, and available as http://www.ucsusa.org/assets/documents/nuclear_power/nuclear_subsidies_report.pdf.

[10] See, for example, American Nuclear Society (2005), The Price-Anderson Act: Background Information, dated November 2005, and available as http://www.ans.org/pi/ps/docs/ps54-bi.pdf.

[11] See, for example, Congressional Budget Office (2011), Federal Loan Guarantees for the Construction of Nuclear Power Plants, dated August, 2011, and available as http://www.cbo.gov/sites/default/files/cbofiles/ftpdocs/122xx/doc12238/08-03-nuclearloans.pdf.

[12] For a discussion of subsidies related to nuclear power facility siting in Japan, see, for example, Hiroshi Onitsuka (2011), "Hooked on Nuclear Power: Japanese State-Local Relations and the Vicious Cycle of Nuclear Dependence", The Asia-Pacific Journal: Japan Focus, available as http://www.japanfocus.org/-Hiroshi-Onitsuka/3676.

[13] Black carbon is a class of particulate matter derived from the incomplete combustion of fuels, most commonly coal and wood, with an impact on climate about which scientific understanding is still evolving. Black carbon particle in the atmosphere affect climate through its absorbance of solar radiation, influence on cloud processes, and its alteration of the melting of snow and ice cover by rendering snow and ice darker, and thus better able to absorb heat from the sun. See, for example, T. C. Bond et al, "Bounding the role of black carbon in the climate system: A scientific assessment", Journal of Geophysical Research: Atmospheres, accepted for publication January 15, 2013, and available as http://onlinelibrary.wiley.com/doi/10.1002/jgrd.50171/pdf.

[14] For a discussion of methods of assessing the social impacts of energy facilities, see, for example, Ravi Jain, Lloyd Urban, Harold Balbach, and M. Diana Webb (2012), Handbook of Environmental Engineering Assessment, Strategy, Planning, and Management, Butterworth-Heinemann.

[15] See, for example, Sharon Squassoni (2013), "U.S.-South Korean Peaceful Nuclear Cooperation Agreement", Center for Strategic and International Studies, dated February 19, 2013, and available as http://csis.org/publication/us-south-korean-peaceful-nuclear-cooperation-agreement.

[16] IGCC is integrated gasification combined-cycle coal-fired generation technology, the development of which, particularly in the United States, has been underwritten significantly by the public sector, in part because it IGCC technology is considered a key to being able to apply carbon capture and storage (CCS) to coal-fired power plants.

[17] "Fracking" is a process whereby the fracturing of gas-bearing rock formations by injecting water, sand, and chemicals from the wellhead in order to stimulate the production of gas. This process has been in use for many years, but its widespread use has more recently been coupled with new horizontal drilling techniques to open up new gas fields, particularly in the United States. See, for example, United States Geological Survey (USGS, 2012), "USGS Frequently Asked Questions, Energy » Hydraulic Fracturing ("Fracking")", available as

http://www.usgs.gov/faq/index.php?sid=54684&lang=en&action=show&cat=229.

[18] LWRs are light water reactors, encompassing “PWRs” (pressurized water reactors) and “BWRs”, boiling water reactors. LWRs are the most common reactors used for electricity generation worldwide. LWRs require uranium enriched to 3 to 5 percent U_{235} from natural uranium, which is 0.7 percent U_{235}. In contrast, heavy water reactors, which are found in many nations, including Japan and the ROK, do not require enriched fuel, but as a consequence use a greater volume of fuel (as U) per unit of output, and produce a greater volume of spent fuel per unit of output.

[19] “SCR” is selective catalytic reduction, used to remove nitrogen oxides from boiler or turbine exhaust gas streams. See, for example, United States Environmental Protection Agency (USEPA, 2003), “Air Pollution Control Fact Sheet [SCR]”, available as http://www.epa.gov/ttn/catc/dir1/fscr.pdf.

[20] US Department of Energy (USDOE, 2012), Electricity Market Module, part of the U.S. Energy Information Administration | Assumptions to the Annual Energy Outlook 2012, and available as http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf.

[21] See, for example, Fang Rong and David G. Victor (2012), What Does It Cost to Build a Power Plant?,Laboratory on International Law and Regular Working Paper #17, dated September, 2012.

[22] See, for example, Dryships Inc (2013), “Daily Market: This page contains the latest Dry Bulk Shipping News”, available as http://www.dryships.com/pages/report.asp.

[23] http://www.bloomberg.com/news/2013-01-14/china-coal-imports-to-fall-with-domestic-prices-bernstein-says.html

[24] USDOE’s projections are that plants with CCS will have substantially improved performance as the technology matures; the heat rate shown here is for an early example of a commercial integrated gasification combined-cycle (IGCC) plant, as is consistent with approximately year-2017 deployment.

[25] For example, Jeff Clock Sr (2009), in “Guidelines for Coal Plant Decommissioning", by Jeff Clock Sr, EPRI (the US-based Electric Power Research Institute), Plant Closure Workshop, November 12, 2009, cites decommissioning costs for three smaller (160 – 340 MW) coal-fired power plants in the on the order of $100 million per GW, while John G. Edwards (2009), in "Laughlin coal-fired power plant going away", Las Vegas Review-Journal (Posted June 11, 2009, updated: April 9, 2012, and available as http://www.lvrj.com/business/47761602.html), cites an estimated decommissioning cost for a larger (~1500 MW) coal-fired plant in the US Southwest at about $20 million per GW, less the value of salvaged scrap metal. In "Brownfield IGCCs as an Option in the National Energy Modeling System (NEMS)", Report number DOE/NETL-2008/1311, dated February 2007, and available as http://www.netl.doe.gov/energy-analyses/pubs/Brownfield_IGCCs.pdf, decommissioning costs for coal plants are assumed to be in a range of $40 to $60 million per GW, though it is not clear what size of coal-fired units this cost applies to.

[26] US DOE Energy Information Administration (2013), “Table 3. Selected national average natural gas prices, 2007-2012”, available as http://www.eia.gov/naturalgas/monthly/pdf/table_03.pdf, and “Table 19. Average citygate price, by state, 2010-2012, available as” http://www.eia.gov/naturalgas/monthly/pdf/table_19.pdf

[27] USDOE’s projections are that plants with CCS will have substantially improved performance as the technology matures; the heat rate shown here is for an early example of a commercial integrated gasification combined-cycle (IGCC) plant, as is consistent with approximately year-2017 deployment.

[28] Max Chang, David White, Ezra Hausman, Nicole Hughes, and Bruce Biewald (2011), Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S. Synapse Energy Economics, dated October 6, 2011, available as http://www.synapse-energy.com/Downloads/SynapseReport.2011-10.UCS.Big-Risks-Better-Alternatives.10-037.pdf.

[29] Fang Rong and David G. Victor (2012), What Does It Cost to Build a Power Plant?,Laboratory on International Law and Regular Working Paper #17, dated September, 2012.

[30] Nuclear decommissioning costs (and cost estimates) vary widely. The $400 million figure used is adopted from from the US Nuclear Regulatory Commission (2011), “Fact Sheet on Decommissioning Nuclear Power Plants”, dated April, 2011, and available as http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/decommissioning.html. The treatment of decommissioning costs as, effectively, up-front capital expenses is consistent with the treatment of such costs for non-utility reactor owners in the US.

[31] Matthias Fripp (2009), Lifecycle Greenhouse Gas Emissions from Clean Coal, Clean Gas and Wind Generators, Environmental Change Institute, University of Oxford, dated April 30, 2009. Note that adoption of Fripp’s estimate of emissions associated with coal mining may somewhat overestimate emissions related to mining of coal from the Powder River Basin, because methane emissions from surface mining of coal (the dominant extraction method in that area) are typically less, per unit mined, then for underground mines, and Fripp’s figures present a weighted average of surface and underground mining.

[32] See, for example, http://www.csx.com/index.cfm/about-csx/projects-and-partnerships/fuel-efficiency/.

[33] Derived from Table 13 “IMO Emission Factors” for large bulk carriers, in http://www.epa.gov/smartway/documents/partnership/shipper/partnership/420b12005.pdf.

[34] Matthias Fripp (2009), Lifecycle Greenhouse Gas Emissions from Clean Coal, Clean Gas and Wind Generators, Environmental Change Institute, University of Oxford, dated April 30, 2009.

[35] California Air Resources Board (2009), http://www.arb.ca.gov/regact/2009/lcfs09/nangremote.pdf. This figure is very close to the rate of 0.4 million tons CO2e per million tonnes LNG produced cited in

http://www.igu.org/html/wgc2009/papers/docs/wgcFinal00845.pdf.

[36] Benjamin K. Sovacool (2008), "Valuing the greenhouse gas emissions from nuclear power: A critical survey", Energy Policy, volume 36 (2008), pp. 2940– 2953.

[37] See, for example, Figure 2 of Matthias Fripp (2009), Lifecycle Greenhouse Gas Emissions from Clean Coal, Clean Gas and Wind Generators, Environmental Change Institute, University of Oxford, dated April 30, 2009.

[38] Jeff Tollefson (2013), "Methane leaks erode green credentials of natural gas", Nature News [NEED TO COMPLETE REFERENCE], dated January 2, 2013, and available as http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123.

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IV. NAUTILUS INVITES YOUR RESPONSES

The Nautilus Peace and Security Network invites your responses to this report. Please leave a comment below or send your response to: nautilus@nautilus.org. Comments will only be posted if they include the author's name and affiliation.

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