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Newsletter

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President's Message

Energy economics and politics co-exist in a delicate balance. For all that we think we know and understand in theory, empirical evidence is often confounding. In the bigger picture, of course, we all behave pretty much as we're supposed to with respect to our trade offs, so that, on balance, most of what we expect to see is realized. Higher prices do tend to depress demand and force substitution. Investors do tend to act so as to maximize returns. But when it comes to the details, like the policy and regulatory frameworks within which we make our decisions, what economists often recommend is not what is taken in practice. This is because markets are negotiated solutions, something that many economists find frustrating.

Energy economics is also challenged because of the intrinsic attributes of what it is we find interesting about "energy," and the highly integrated activities required to make energy available and useful for humankind. Take electricity, for instance. On the face of it, electric power is simple enough. Find an energy source, use the energy source to spin a turbine, use the turbine to drive a generator, attach some wires and send the energy source in the form of electrons off to everyone that needs them. But an enormous number of questions, with increasing complexity as one goes along, surrounds this apparently straightforward process. For example, who should provide electricity and to how many? How should these providers be organized? Who will supervise what they do, and how should that supervision be carried out? How much profit will they make? How much profit SHOULD they make? What should we pay for? Who will decide what we pay for, and how much we should pay? And so it goes.

On the face of it, it should be easy to propose, and implement, elegant solutions for the kinds of markets that could be imagined for electric power. If, that is, we did not need to worry about physics. Or, the engineering realities of building electric power systems. Or the investment realities of doing same. Much less the commercial requirements for operating electric power systems within complicated frameworks. You can see where I'm heading now, I'm sure. Ah yes, the August 14 blackout in the U.S., that apparent comeuppance for all of us who believe that at least some degree of competition can be introduced into the electric power system.

Regardless of one's perspective or position with respect to the August 14 events and the cascade of opinion and analysis that followed, they were illustrative. And, of course, there are lessons for all of us. For instance, the role of institutions is no less important today than it ever has been. The process of negotiating market solutions needs to involve many different kinds of stakeholders. Governance, so that costs and benefits can be properly defined and allocated, is critical. Standards are useful. Rules and laws can't be ambiguous, even though political actors (and some attorneys) may prefer them that way. Customers need to be informed and educated. And the process necessarily involves multiple disciplines. Economists need to understand the physical properties and engineering design of electric power systems. Engineers and policy makers need to understand economic principles.

(continued on page 2)

Editor's Notes

Tony Owen reviews life cycle analysis research into alternative automotive engine and fuel technologies in terms of both their private and societal costs. The economic viability of hydrogen-based technologies is shown to be heavily dependent upon the removal of subsidies to fossil fuel technologies and the appropriate pricing of fossil fuels to reflect the environmental damage of their use.

Lorna Greening and Erich Schneider note that Nuclear generation currently accounts for roughly 20% of annual electricity generation in the U.S. with relatively low emis-

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President's Message *(continued from page 1)*

One of the great things about IAEE is the tradition of combining business, government and academic members toward the common objective of "an interdisciplinary forum for the exchange of ideas, experience and issues among professionals interested in energy economics." If ever there was an example of why this is necessary, the August 14 blackout provides it, as do similar disruptions in other countries. It is our job, our responsibility, to look at all the angles, to pursue interdisciplinary inquiry and foster open, constructive debate on the kinds of questions that underlie the production and delivery of energy, and that flow from major events such as this. To do all of this, we need to work to maintain the business-government-academic balance in our organization, ensure that our conferences and networks are open and accessible and that our membership is constantly replenished with youth and vigor.

Michelle Michot Foss

Editor's Notes *(continued from page 1)*

sions of greenhouse gases. However, before increased nuclear generation becomes a viable option in the U.S., the disposal of spent nuclear fuel needs to be addressed. Several potential strategies that depend on evolving fuel processing technologies may lead to a sustainable nuclear future and mitigation of the spent nuclear fuel problem.

A group from CERI, led by Paul Mortensen, reports on a recent study of the long-term potential for Canadian Natural gas. They conclude that, assuming gas from unconventional sources and new basins can be brought on in a timely manner, gas production can be sustained at levels higher then now occurring, through at least 2025; possibly as high as 8 Tcf per year. Supply costs will be ever increasing, however.

Doug Reynolds continues his series of articles based on his book. This time he explains the two emerging LNG markets on the Atlantic Rim and the Pacific Rim. These two LNG markets look to have very different characteristics and future implications for Alaska and international LNG suppliers.

DLW

2004

"Energy, Environment and Economics in a New Era"

24th USAEE/IAEE North American Conference
July 8-10, 2004, Capital Hilton, Washington D.C.

Presented By

USAEE	IAEE	NCAC
United States Association for Energy Economics	International Association for Energy Economics	National Capital Area Chapter

Conference Objective

Explore commercial and policy strategies for an era that features energy resource challenges, higher environmental requirements, advanced technologies, renewed economic concerns and important changes in global politics.

Plenary Session Themes

A New Era in Oil Market Management, State & Regional Ascendancy in Energy Policy, Commercial Issues: Operating in Volatile Markets, The Price of Balancing the North American Gas Market, Impact of Climate (Non) Policy on the Energy Sector, Competition in the Electricity Industry?, International LNG, Electricity Reliability.

Conference Organizers

General Conference Chair: Mine Yucel
Program Co-Chairs: Louis Aboud, Alex Farrell, Kate Offringa
Arrangements Chair: David L. Williams
USAEE VP for Conferences: Shirley J. Neff

Possible Concurrent Sessions

Concurrent sessions will be developed from the papers selected for the program. The following is a non-exclusive list of possible topics: International energy markets, power markets, green markets, energy security, energy policy, energy and the global economy, regulation vs. competition, transportation, global economic outlook, role of paper markets, new technologies in the energy industry, energy environment nexus, natural gas supply, LNG, economic impacts of price volatility, role of sub-national governments, etc.

All topic ideas are welcome and anyone interested in organizing a session should propose the topic and possible speakers to: Wumi Iledare, Concurrent Session Chair (p) 225-578-4552 (f) 225-578-4541 (e) wumi@lsu.edu

Call For Papers (Submission Deadline February 3, 2004

Abstracts for papers should be between one to two paragraphs (no longer than one page), giving a concise overview of the topic to be covered. At least one author from an accepted paper must pay the registration fees and attend the conference to present the paper. The lead author submitting the abstract must provide complete contact details - mailing address, phone, fax, e-mail, etc. Authors will be notified by February 17, 2004 of their paper status. Authors whose abstracts are accepted will have until April 6, 2004, to return their papers for publication in the conference proceedings. While multiple submissions by individuals or groups of authors are welcome, the abstract selection process will seek to ensure as broad participation as possible: each speaker is to present only one paper in the conference. No author should submit more than one abstract as its single author. If multiple submissions are accepted, then a different co-author will be required to pay the reduced registration fee and present each paper. Otherwise, authors will be contacted and asked to drop one or more paper(s) for presentation. Abstracts should be submitted to:

David Williams, Executive Director USAEE.
28790 Chagrin Blvd., Suite 350 Cleveland, Ohio 44122, USA.
Ph) 216-464-2785 Fax) 216-464-2768 E-mail) usaee@usaee.org

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Externalities and Subsidies: the Economics of Hydrogen-based Transportation Technologies

*By Anthony D. Owen**

Introduction

This paper reviews life cycle analyses of alternative automotive engine technologies in terms of both their private and societal (that is, inclusive of externalities and net of taxes and subsidies) costs. The economic viability of hydrogen-based technologies is shown to be heavily dependent upon the removal of these market distortions. In other words, the removal of subsidies to oil-based technologies and the appropriate pricing of oil products to reflect the environmental damage (local, regional, and global) created by their combustion are essential policy strategies for stimulating the development of hydrogen-based renewable energy technologies in the transportation sector. However, a number of non-quantifiable policy objectives are also of significance in the planning of future technology options. Currently, the most important of these would appear to be security of oil supplies and associated transportation and distribution systems.

The Economics of Environmental Externalities

Externalities are defined as benefits or costs generated as an unintended by-product of an economic activity that do not accrue to the parties involved in the activity. Environmental externalities are benefits or costs that manifest themselves through changes in the biophysical environment. Pollution emitted by road vehicles is known to result in harm to both people and the environment. In addition upstream and downstream externalities, associated with securing fuel and waste disposal respectively, are generally not included in fuel costs. To the extent that the ultimate consumer of these products does not pay these environmental costs, or does not compensate people for harm done to them, they do not face the full cost of the services they purchase (i.e., implicitly their energy use is being subsidised). As a consequence, oil resources will not be allocated efficiently.

Environmental externalities of oil production/consumption can be divided into two broad (net) cost categories that distinguish emissions of pollutants with local and/or regional impacts from those with global impacts:

- costs of the damage caused to health and the environment by emissions of pollutants other than those associated with climate change; and
- costs resulting from the impact of climate change attributable to emissions of greenhouse gases.

The distinction is important, since the scale of damages arising from the former is highly dependent upon the geographic location of source and receptor points. The geographic source is irrelevant for damages arising from emissions of greenhouse gases (GHGs).

In the transport sector, externality costs are also incurred as a result of congestion, accidents and road damage. However, since this paper assesses differences between vehicles based upon alternative fuels and engines, these costs will be assumed to be common to all vehicles and consequently ignored.[1]

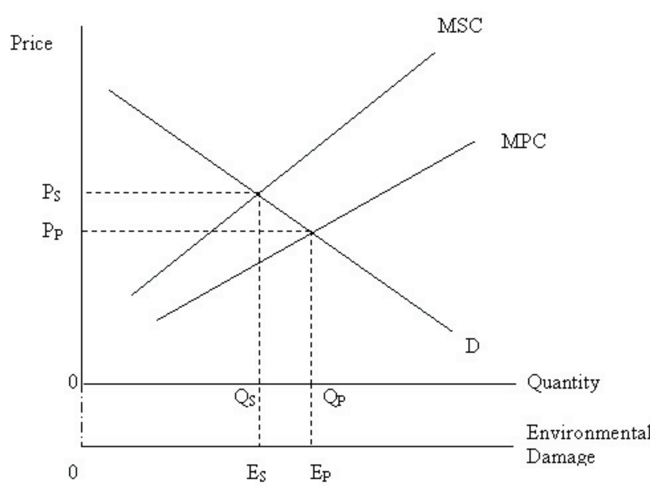
Costs borne by governments, including direct subsidies, tax concessions, indirect energy industry subsidies (e.g., the cost of oil supply security), and support of research and development costs are not externalities. They do, however, distort markets in a similar way to negative externalities, leading to increased consumption and hence increased environmental degradation.

In order to address effectively these environmental matters, together with energy supply security concerns, radical changes in automotive engine and fuel technologies will probably be required. Such changes must offer the potential for achieving "near zero" emissions of air pollutants and greenhouse gases (GHGs), and must diversify the transportation sector away from its present heavy reliance on gasoline. Only hydrogen currently appears to be a viable technical option.

Externalities in a Competitive Market[2]

The impact of a negative externality is illustrated in Figure 1, which shows the competitive market for a good whose production generates damaging emissions. The demand curve (D) represents marginal private benefits arising from consumption of the good. It is assumed that the production process gives rise to negative externalities, such that marginal damages increase as emissions rise, resulting in an increasing gap between marginal private costs (MPC) and marginal social costs (MSC) of production. The socially

Figure 1
Impact of an Externality



*Anthony D. Owen is Professor, School of Economics, The University of New South Wales, Sydney, NSW, Australia. He can be reached at a.owen@unsw.edu.au This is an edited version of his talk at the 23rd North American Conference of the IAEE/USAEE, October 19, 2003 in Mexico City. A more detailed paper is available from the author upon request.

[1] See footnotes at end of text.

optimal level of output is $0Q_S$ with a corresponding price $0P_S$. At this equilibrium position, the corresponding optimal level of environmental damage is $0E_S$. However, if the externalities of production are not "internalised", equilibrium price and output would be at $0P_P$ and $0Q_P$, respectively. Thus the lower price has encouraged increased demand and, as a result, increased levels of environmental damage amounting to E_SE_P above the optimal level.

The origin of an externality is typically the absence of fully defined and enforceable property rights. However, rectifying this situation through establishing such rights is not always easy to do. In such circumstances, at least in theory, the appropriate corrective device is a Pigouvian tax equal to marginal social damage levied on the generator of the externality (with no supplementary incentives for victims).

Externality Adders

An "externality adder" is simply the unit externality cost added to the standard resource cost of energy to reflect the social cost of its use. For the transport sector such units would be ¢/vkm (i.e. cents per vehicle kilometre) for passenger vehicles and ¢/tkm (i.e., cents per ton kilometre) for goods vehicles.

Pearce (2002) lists five uses for externality adders:

i. For public or quasi-public ownership of sources of electric power generation, the full social cost of alternative technologies could be used to plan future capacity with preference being given to that with the lowest social cost. Where electric power generation is privately owned, then regulators could use the full social cost to influence new investment, perhaps through an effective environmental tax.
ii. Environmental adders can be used to estimate the appropriate level of environmental taxes. Although estimates of environmental adders have been derived for a number of applications, examples of their actual implementation are few.
iii. Environmental adders could be used to adjust national accounts data to reflect depreciation of natural resources and damage to the environment arising from economic activity, yielding so-called "green" national accounts.
iv. Environmental adders could be used for "awareness raising"; i.e., to inform the public of the degree to which alternative energy sources have externalities that give rise to economically inefficient allocation of resources.
v. Environmental adders might assist in determining environmental policy priorities.

The task of estimating the value of an externality adder involves a substantial commitment of resources and expertise in order to ensure credible information for policy purposes. In the context of the energy sector, a life cycle approach must be adopted in order to identify and quantify environmental adders associated with energy use. The approach also provides a conceptual framework for a detailed and comprehensive comparative evaluation of energy supply options (based upon both conventional and renewable sources). The methodology employed is the subject of the next section.

Life-cycle Analysis

When comparing the environmental footprints of alternative energy technologies, it is important that the combustion stage of the technology not be isolated from other stages of the "cycle". For example, fuel cells emit virtually no GHG in their operation. However, production of their "fuel" (hydrogen) from fossil fuels may involve increases in GHG emissions in excess of those that would arise from using current commercial fossil fuel technologies. To avoid such distortions, the concept of life cycle analysis has been developed.

Life cycle analysis (LCA) is based upon a comprehensive accounting of all energy and material flows, from "cradle to grave",[3] associated with a system or process. The approach has typically been used to compare the environmental impacts associated with different products that perform similar functions, such as plastic and glass bottles. In the context of an energy product, process, or service, a LCA would analyse the site-specific environmental impact of fuel extraction, transportation and preparation of fuels and other inputs, plant construction, plant operation/fuel combustion, waste disposal, and plant decommissioning. Thus it encompasses all segments including upstream and downstream processes and consequently permits an overall comparison (in a cost benefit analysis framework) of short- and long-term environmental implications of alternative energy technologies. Central to this assessment is the valuation of environmental externalities of current and prospective fuel and energy technology cycles. It should be noted, however, that only material and energy flows are assessed in an LCA, thus ignoring some externalities (such as supply security) and technology reliability and flexibility.

For the purpose of this paper, life-cycle analysis will involve the following methodological steps:[4]

- Definition of the product cycle's geographical, temporal, and technical boundaries;
- Identification of the environmental emissions and their resulting physical impacts on receptor areas; and
- Quantifying these physical impacts in terms of monetary values.

Traditionally, LCA has omitted the third of these steps and the final analysis has, therefore, been expressed in terms of just the biophysical impacts that can be quantified. The extension to include costing of these impacts is generally known as the "impact pathway" methodology. Essentially, however, it can be considered as a specific application of LCA. This methodology formed the theoretical basis for the European Commission's ExternE (1997) study, which was the first comprehensive attempt to use a consistent "bottom-up" methodology to evaluate the external costs associated with a range of different fuel cycles.

Definition of the Product Cycle's Boundaries

The first task is to identify, both in terms of activities and geographic locations, the various stages of the fuel/technology cycle. Each energy form is viewed as a product, and impacts are included for the actual pathway. The precise list of stages is clearly dependent on the fuel chain in question, but would include both "upstream" and "downstream" activities in addition to the power generation or fuel combustion stage itself. "Upstream" activities would include stages such as exploration, extraction, refining and transportation of fuel. "Downstream" activities would include the treatment and disposal of wastes and by-products and, ultimately, refinery demolition and site restoration impacts.

The extent to which the boundaries must encompass indirect impacts is determined by the order of magnitude of their resulting emissions. In theory, externalities associated with the construction of plants to make the steel that is used in the construction of gasoline delivery trucks should be included. In reality, however, such externalities are likely to have a relatively insignificant impact.

The system boundary will also have spatial/geographical and temporal dimensions. These will have major implications for the analysis of the effects of air pollution in particular. For many air pollutants, such as ozone and SO_2, the analysis may need to focus on a regional, rather than local, scale in order to determine their total impact. For emissions of GHGs, the appropriate range is clearly global. Impacts must also be assessed over the full term of their impact, a period that may extend over many decades or even centuries in the case of emissions of GHGs and long-term storage of some nuclear waste products. This introduces a significant degree of uncertainty into the analysis, as it requires projections to be made of a number of variables that will form the basis of future society. Among these would be the size of the global population, the level of economic growth, technological developments, the sustainability of fossil fuel consumption, and the sensitivity of the climate system to anthropogenic emissions.

Identification of the Environmental Emissions and their Resulting Biophysical Impacts on Receptor Areas

Comparisons of alternative transport technologies utilising LCA are generally standardised as emissions per vehicle km in order to allow for different technologies and emission profiles. However, data used to quantify burdens are, to varying degrees, technology specific. For example, emission of CO_2 from cars depends only on the efficiency of the equipment and the carbon/hydrogen ratio of the fuel; uncertainty is negligible. Conversely, emissions of SO_2 can vary by an order of magnitude depending on the grade of oil and the extent to which emission abatement technologies have been incorporated in the vehicle. In general, one would adopt the best available technology currently in use in the country of implementation.

Quantifying the physical impacts of emissions of pollutants requires an environmental assessment that ranges over a vast area, extending over the entire planet in the case of CO_2 emissions. Thus the dispersion of pollutants emitted from fuel chains must be modelled and their resulting impact on the environment measured by means of dose-response functions. Ideally, in the context of damages to humans, such functions are derived from studies that are epidemiological, assessing the effects of pollutants on real populations of people. However, the relevance and reliability of current methodologies for putting financial estimates on human suffering in terms of increased levels of mortality and morbidity has been the subject of some debate.[5]

Total Societal Life Cycle Costs

The road transport sector emits (directly or indirectly) a similar range of pollutants to the electric power sector. However, the resulting impacts are not directly comparable. Power station emissions are generally from high stacks in rural areas. In contrast, road transport emission sources are more diverse, invariably closer to ground level and frequently in urban areas. In addition, alternative (non-oil-based) road transport fuels are not commercially available and, therefore, the large-scale use of "renewable" technologies is not currently a technologically feasible option. Nevertheless, consideration of environmental externalities of road transport fuels does provide an order of magnitude for calculation of environmental adders for the purpose of fuel taxation policy. Ultimately this may provide the financial incentive for development of "renewable" transport fuels, in conjunction with hydrogen and fuel cell technology.

Delucchi (2002a) has developed a Lifecycle Emissions Model (LEM) that estimates energy use, emissions of pollutants, and CO_2-equivalent GHG emissions from the complete lifecycles of fuels, materials, vehicles, and infrastructure arising from a variety of transportation technologies. Such models permit identification and calculation of the biophysical emissions, from which a total societal life cycle cost for each technology can be derived by calculating the present value of lifecycle costs (PVLC) associated with each stage; *viz*:

Total Societal Life Cycle Costs ($/vehicle)
=
Initial cost of vehicle (before tax)
+ PVLC (fuel + non-fuel operation and maintenance)
+ PVLC (full fuel cycle air pollutant damages + GHG emissions damage)
+ PVLC (full fuel cycle subsidies – full fuel cycle taxes).

Application of Fuel Cell Technology in the Road Transport Sector

Concerns over the health impacts of small particle air pollution, climate change, and oil supply insecurity, have combined to encourage radical changes in automotive engine and fuel technologies that offer the potential for achieving near zero emissions of air pollutants and GHG emissions, and diversification of the transport sector away from its present heavy reliance on gasoline. The hydrogen fuel cell vehicle is one technology that offers the potential to achieve all of these goals, if the hydrogen is derived from a renewable energy resource.

Fuel cells convert hydrogen and oxygen directly into electricity. They have three major advantages over current internal combustion engine technology in the transport sector:

- Gains in energy efficiency. "Well to wheels" efficiency for gasoline engines averages around 14 per cent, for diesel engines 18 per cent, for near-term hybrid engines 26 per cent, for fuel cell vehicles 29 per cent, and for the fuel cell hybrid vehicle 42 per cent.[6] Thus, up to a three-fold increase in efficiency is available relative to current vehicles.
- Near-zero emissions.
- Very low emissions of local air pollutants. Irrespective of the fuel, fuel cells largely eliminate oxides of sulphur and nitrogen, and particulates. All of these pollutants are associated with conventional engines.

In order to compare competing transport technologies on a basis that includes the cost of externalities as well as private costs, the societal life cycle cost of each technology must be calculated.

Fuel Cell Buses

Prototype fuel cell buses powered by liquid or compressed hydrogen are currently undergoing field trials in North America, while the European Commission is supporting the demonstration of 30 fuel cell buses in 10 cities over a two-year period commencing in 2003. In addition, the United Nations Development Program Global Environmental Facility is supporting a project to demonstrate the technology using 46 buses powered by fuel cells in the heavily polluted cities of Beijing, Cairo, Mexico City, New Delhi, Sao Paulo and Shanghai.

There are a number of reasons why hydrogen (in compressed form) would appear to be a likely option for large vehicles, such as buses:

- they return regularly to a depot thus minimising fuel infrastructure requirements;
- they are "large", thus minimising the need for compactness of the technology;
- in urban areas, low or zero emissions vehicle pollution regulations will assist their competitiveness as compared with diesel-powered buses;
- subsidies may be available from urban authorities in order to demonstrate urban pollution reduction commitments;
- they avoid pollution problems specifically related to diesel buses;
- They operate almost continually over long periods, thus making fuel-efficient technology more attractive.

Hörmandinger and Lucas (1997) have investigated the life cycle financial and economic cost of fuel cell buses utilising hydrogen as fuel. They assessed the costs that a private operator would face in running a fleet of fuel cell powered buses, inclusive of a new fuel supply infrastructure, compared to those of a fleet of conventional diesel powered buses of similar performance. Given the presence of economies of scale in the production of hydrogen, they concluded that the fuel cell bus would be marginally more competitive than its diesel counterpart. Extending the analysis to societal life cycle costs, the analysis favoured the diesel option. Adding in the cost of environmental externalities led to a significantly greater increase in the cost of the diesel, as opposed to the hydrogen, bus. However, this was more than offset by the removal of the excise duty on diesel.

The Hörmandinger and Lucas base-case model assumed a fleet of just 10 buses, operating over a 20-year time horizon and travelling 200 km a day, 7 days a week. The central hydrogen reformer plant, using natural gas feedstock, and the refuelling station were based upon currently available technology. Both were exclusively for the use of the bus fleet. The cost of the fuel cell stack was set at $300 per kilowatt, and it was assumed that it would be replaced every five years. Although this cost was rather low by 1997 standards, the authors speculated that it would be reasonable for their assumed time frame (5 to 10 years in the future). The fuel cell buses were assumed to be of the same weight (without the power train) as the diesel buses. The cost of the tank for on-board storage of compressed hydrogen represented one of the major uncertainties of the model, since the technology is still under development.

Sensitivity of Results: Private Costs

The annualised life cycle private costs, using a discount rate of 15 per cent, showed that the fuel cell bus was from 23 per cent (large bus) to 33 per cent (medium size bus) more expensive than the diesel bus. The difference was due to both the provision of fuel and the initial cost of the investment.

A sensitivity analysis indicated that the medium size fuel cell bus reacted to changes in the base case parameter values in a similar way to its larger counterpart. The most important parameter with regard to impact on life cycle costs was the discount rate. However, although variations in the discount rate had a major influence on the individual life cycle costs of both technologies, since their investment and running cost profiles were very similar, their relative costs remained fairly static. For large buses, a drop in the discount rate from 15 per cent to 8 per cent reduced the cost differential from 23 per cent to 19 per cent.

Fleet size was found to be an important parameter, since the on-site production of hydrogen was subject to significant economies of scale. Thus an increase in fleet size from 10 to 25 gave the fuel cell bus a marginal cost advantage over the diesel alternative.

Price variations of feedstock (gas) had a relatively minor impact on bus costs, since it was a relatively minor cost component of the hydrogen reformer plant investment and operating costs. However, the diesel bus was much more sensitive to fuel cost increases. In the base case, an increase of 80 per cent in the price of diesel would remove its cost advantage.

As might be expected, the size and cost of the fuel cell stack was critical, although not compared with the costs of the reformer. Note that if hydrogen could be "delivered" in the context of a hydrogen economy, then it is likely that reforming cost in the context of this example would be greatly reduced.

Sensitivity of Results: Societal Costs

The societal cost of life cycle emissions involved augmenting the private costs by the damage costs arising from the environmental externalities created by the two options, and removal of the excise duty (56 per cent of the price) from the diesel fuel in the calculations. A lower discount rate of 8 per cent was also imposed, to reflect societal rather than private expectations.[7]

Externality costs were based upon previous studies of estimated damages arising from comparable emissions from the electricity and transport sectors. This transfer of results may not be appropriate if the characteristics of the exposure-response relationship differ from those of the reference studies. This is because in urban areas exposure to emissions from fossil fuel combustion in vehicles involves higher concentrations of pollutants than in rural areas due to the close proximity of emission and receptor points. However, even taking social costs at the higher end of the range only gave fuel cell buses a marginal benefit over their diesel counterparts.

A number of other social benefits were not quantified. In the context of this particular application, their impact would have been extremely small. However, widespread adoption of fuel cell buses would have reduced other forms of local urban pollution from diesel buses (such as fuel spills and noise) and would have provided enhanced levels of security of domestic fuel supplies.

It is important to note that the GHG emission reduction benefits of hydrogen in the Hörmandinger and Lucas model were based upon the use of natural gas as feedstock, with no CO_2 sequestration. As a higher cost alternative, utilising electricity generated from renewable sources to produce the hydrogen or adopting CO_2 sequestration with natural gas as the feedstock would have produced near zero fuel-cycle GHG emissions and consequently significantly greater societal benefits for the fuel cell buses. In this context, however, it is important that energy from renewable resources is "additional" to that which was currently being generated. Simply utilising existing renewable resources and making up the shortfall elsewhere from fossil fuels would not have contributed towards a net reduction in global GHG emissions.[8]

Fuel Cell Cars

Ogden et al. (2004) has estimated the societal lifecycle costs of cars based upon alternative fuels and engines. Fifteen different vehicles were considered. These included current gasoline combustion engines and a variety of advanced lightweight vehicles: internal combustion engine vehicles fuelled with gasoline or hydrogen; internal combustion engine/hybrid electric vehicles fuelled with gasoline, compressed natural gas, diesel, Fischer-Tropsch liquids or hydrogen, and fuel cell vehicles fuelled with gasoline, methanol or hydrogen (from natural gas, coal or wind power). The analysis assumed a fully developed fuel infrastructure for all fuel options and mass production of each type of vehicle. This permitted all vehicles to be compared on the basis of their individual cost of construction, fuel costs, oil supply security costs and environmental externalities over the full fuel cycle. All costs were expressed net of direct taxes and subsidies, and all fuel costs were assumed to remain constant (in real terms) over the lifecycle of all vehicles.[9]

The present value of total societal lifecycle costs, excluding external costs, favoured current and advanced gasoline cars (Table 1), with fuel cell vehicles being upwards of 60 per cent more expensive. This imbalance was reversed when lifetime air pollutant and GHG emission damage costs were included (Table 2). Now, hybrid vehicles utilising traditional fossil fuels held a significant cost advantage over their fuel cell counterparts. It was only the introduction of an Oil Supply Insecurity (OSI) cost, that was intended to measure the cost of ensuring oil supply security from the Middle East, that those fuel cell vehicles based upon hydrogen (derived either from renewables or from fossil fuels with carbon sequestration) became competitive. However, the OSI was a rather arbitrary control-type cost and the fact that it was so critical to the viability of the hydrogen fuel cell car was unfortunate.

In a sensitivity analysis, higher values attached to the environmental externalities, as might be expected, favoured the fuel cell vehicles and particularly those fuelled by hydrogen derived from fossil fuels with CO_2 sequestration.

Cost of Energy Security of Supply[10]

The economic, environmental, and social objectives of sustainable development policies have, as an underpinning tenet, a major requirement of security of energy supplies. The economic and social implications of major breakdowns in the energy delivery system can be very severe. There is a marked asymmetry between the value of a unit of energy delivered to a consumer and the value of the same unit not delivered because of unwanted supply interruption. Further, interruptions, or threats of interruptions, can swiftly lead to widespread disruption given that it is difficult and expensive to store energy. The resilience of energy systems to extreme events is a major problem confronting industrialised society.

Energy "insecurity" is reflected in the level of risk of a physical, real or imagined, supply disruption. The market reaction to prospective disruptions would be a sudden price surge over the expected period of impact of the disruption. A prolonged period of high and unstable prices is, therefore, normally a symptom of high levels of insecurity. Interruptions to supply can also come from unexpected shocks to the energy system, such as deliberate acts of sabotage or unexpected generic faults in energy supply technology. There is also a time dimension to energy security, ranging from the immediate (e.g., refinery breakdown) to the distant future (e.g., the low carbon economy).

Estimation of Damage Costs for the Oil Market

The cost of supply disruption is generally assessed in terms of the potential decline in a country's Gross National Product (GNP) arising from interruption to the supply of crude oil in the international marketplace. It is then assumed that this disruption causes a sudden increase in the price of

Table 1
Projected Base Case Societal Lifecycle Costs for Automobiles with Alternative Fuel/engine Options

Technology	Present value: Lifetime Fuel costs	Retail cost: Drive train +fuel storage	Cost of aluminium frame	Present value: Total private lifecycle costs	Present value: Lifetime cost of externalities	Present value: Total societal lifecycle costs
Current gasoline SI ICEV	2828	2837	0	5665	6723	12388
Advanced lightweights ICEs						
Gasoline SI ICEV	1674	2837	936	5448	3579	9026
H_2 (NG) SI ICEV	3381	2837+2500	936	9654	1270	10924
Advanced lightweights ICE/HEVs						
Gasoline SIDI ICE/HEV	1316	2837+1342	936	6432	3015	9446
CNG SI ICE/HEV	1552	2837+1556	936	6881	1160	8040
H_2 (NG) SI ICE/HEV	2823	2837+2780	936	9376	1081	10457
Diesel CIDI ICE/HEV	996	2837+1863	936	6632	2809	9441
FT50 (NG) CIDI ICE/HEV	1058	2837+1863	936	6694	2253	8947
Lightweight fuel cell vehicles						
Gasoline FCV	2009	2837+5097	936	10879	3243	14122
Methanol (NG) FCV	2238	2837+3220	936	9231	916	10147
H_2 (NG) FCV	2169	2837+2459	936	8402	736	9138
H_2 (NG) FCV w/CO_2 seq.	2411	2837+2459	936	8644	225	8869
H_2 (coal) FCV	2200	2837+2459	936	8432	1247	9679
H_2 (coal) FCV w/CO_2 seq.	2435	2837+2459	936	8667	314	8981
H_2 (wind electrolytic) FCV	3394	2837+2459	936	9626	182	9808

Abbreviations:
AP: air pollutants; CIDI: compression-ignition direct-injection; CNG: compressed natural gas; CO_2: carbon dioxide; FCV: fuel cell vehicle; GHG: greenhouse gas emissions; H_2: hydrogen; HEV: hybrid electric vehicle; ICE: internal combustion engine; ICEV: internal combustion engine vehicle; NG: natural gas; OSI: oil supply insecurity; SI: spark-ignition; SIDI: spark-ignition direct-injection.
Source: Modified from Table 1 of Ogden et al. (2004)

oil, which in turn causes a corresponding reduction in GNP. The extent of the resulting "loss" will be positively related to the country's degree of dependence on imported oil and oil products. Estimation of the economic cost of supply disruption involves the following steps (Razavi (1997):

- Formulation of supply disruption scenarios. Each scenario relates to a probable political event and is reflected in reduction of oil supplies by a specific amount for a specific period of time.
- Assessment of the impact of each disruption on the oil price trajectory.
- Evaluation of the impact of the oil price increase on GNP. This requires an estimate of the elasticity of GNP with respect to the price of crude oil. It should

Table 2
Projected Base Case Lifecycle Costs for Externalities of Automobiles with Alternative Fuel/engine Options.

Technology	Externalities: original estimates Present value of lifetime costs			Present value: Lifetime cost of externalities
	AP	GHG	OSI	Original
Current gasoline SI ICEV	2640	1429	2654	6723
Advanced lightweights ICEs				
Gasoline SI ICEV	1162	846	1571	3579
H_2 (NG) SI ICEV	524	746	0	1270
Advanced lightweights ICE/HEVs				
Gasoline SIDI ICE/HEV	1097	683	1235	3015
CNG SI ICE/HEV	644	515	0	1160
H_2 (NG) SI ICE/HEV	458	623	0	1081
Diesel CIDI ICE/HEV	1150	590	1069	2809
FT50 (NG) CIDI ICE/HEV	1122	596	535	2253
Lightweight fuel cell vehicles				
Gasoline FCV	338	1019	1886	3243
Methanol (NG) FCV	248	668	0	916
H_2 (NG) FCV	257	479	0	736
H_2 (NG) FCV w/CO_2 seq.	119	106	0	225
H_2 (coal) FCV	366	881	0	1247
H_2 (coal) FCV w/CO_2 seq.	215	99	0	314
H_2 (wind electrolytic) FC	68	114	0	182

Abbreviations: see Table 1.
Source: Modified from Table 1 of Ogden et al. (2004)

be noted that this economic loss arises because of a sudden, rather than gradual, price increase. It arises because the economy cannot adjust immediately to higher oil prices. Instead, the oil disruption causes higher unemployment and lower GNP than would have been the case in the absence of a disruption. Estimation of the economic impact would require extensive analysis of macro and micro economic reactions to increases in oil and oil product prices. In the United States, which is dependent on imports for 40 per cent of its oil consumption and holds around 150 days of gasoline inventories, the elasticity of GNP to a sudden increase in oil prices is estimated at –0.25. Thus a 10 per cent increase in the price of oil would result in a 2.5 per cent decrease in GNP (ceterus parabus). In the case of Japan, where import dependency is almost 100 per cent and gasoline inventories also amount to around 150 days of consumption, the elasticity could be as high as –1.0.

Estimation of Control Costs

The actual amount of money spent by the U.S. on oil security is very difficult to estimate. U.S. defence expenditure is predicated on a number of varied regional objectives around the globe, and assigning a marginal cost to oil security activities in the Middle East (or, for that matter, elsewhere) involves a considerable element of subjective allocation. Further, the figure is likely to vary significantly over a period of years, depending on prevailing military actions both in the Middle East and elsewhere. Koplow and Martin (1998) have estimated that the total cost to the U.S. of stabilising foreign oil supplies ranges from $10.5 to $26.2 billion annually (in 1995 dollars). The difference in these estimated bounds is, to a large extent, due to the estimation techniques employed.

The U.S. oil industry has also benefited from a number of pieces of selective tax legislation. Those that are based solely on domestic considerations are accelerated depletion, percentage depletion, and expensing of oil exploration and development costs. Kaplow and Martin have provided an estimated range of from $1.16 to $2.32 billion as the subsidy arising from these three items.

Finally, established in 1975 in the wake of the 1973/74 OPEC-induced oil price hikes and embargoes, the strategic petroleum reserve (SPR) was intended to help cushion the U.S. from interruptions to imported oil supplies. The existing storage capacity in the SPR is 700 billion barrels. At year-end 2002, the SPR contained about 600 million barrels, or approximately 53 days of U.S. forward requirements. A further 100 days of inventories were estimated to be held by private oil companies. The major cost associated with the SPR is foregone interest on the capital invested in the scheme. Minor costs are incurred in its management and operation. Costs associated with oil purchases are not considered a "cost" since revenue arising from the occasional (or ultimate) sale of stocks can offset these. Only any loss, or gain, in such transactions should be attributed to SPR operating expenses. Kaplow and Martin have provided an estimated range of from $1.60 to $5.40 billion as the subsidy arising from the SPR.

Ogden et al. (2004) only considered the marginal external cost of maintaining a military capability for safeguarding access to Persian Gulf oil exports, which they labelled Oil Supply Insecurity (OSI) costs. All other U,S, oil industry subsidies were omitted from their analysis. Their estimated cost range was very broad, $20-$60 billion, which translated to an implied subsidy of $0.35-$1.05/gallon of gasoline equivalent,[11] and the mid-point of this range (i.e., $0.70/gallon) was used to derive the present value of OSI costs for all technologies using oil-based fuels. As noted previously, however, this is an estimated control cost not an estimated cost of the damage arising from specified supply disruption scenarios. As such, its credibility in a societal life cycle analysis is questionable. Nevertheless, if the methodology for deriving this value were deemed to be acceptable for reflecting a control cost, then logically it would represent the absolute minimum value that could be imputed for damage costs.

Concluding Comments

This paper has addressed the topic of environmental externalities and other market distorting influences in the context of hydrogen-based transportation technologies.[12] However, as noted earlier, since this paper assesses differences between vehicles based upon alternative fuels and engines, externality costs that are incurred as a result of congestion, accidents and road damage are assumed to be common to all vehicles and consequently ignored. In addition, the paper also ignores the important interaction between urban transport policy and near-zero emission transport technologies, which is beyond the scope of this particular study.

On the basis of two major studies concluded to date, it is evident that the societal benefits arising from the introduction of near zero emissions technologies based upon hydrogen rely heavily on their environmental and supply security benefits to offset their private cost disadvantages. Unfortunately, the precision of such benefits is questionable due a range of complex methodological issues and the absence of markets in environmental "goods". Nevertheless, the degree to which gasoline is either directly or indirectly subsidised is a significant factor in assessing the commercial viability of emerging alternative technologies.

Justification of energy subsidies to developing technologies may be based upon the desire of a government to achieve certain environmental goals (e.g., enhanced market penetration of low GHG emissions technology), to "level the playing field" by offsetting implicit and explicit fossil fuel subsidies, or for enhancing levels of domestic energy supply security. However, in general, case specific direct action is likely to give a more efficient outcome. Thus penalising high GHG emitting technologies not only creates incentives for "new" technologies, but it also encourages the adoption of energy efficiency measures with existing technologies and consequently lower GHG emissions per unit of output. In addition, if the existence of market failures is restricting the diffusion of renewable energy technologies, then (again) addressing those failures directly may provide an efficient outcome.

If sustainable development and energy security of supply can be regarded as public goods, then their level of provision through competitive market forces would be sub-optimal. This would justify market intervention designed to raise their supply to a level that is optimal to society. The hydrogen economy is one option available for addressing this situation.

However, in this context, renewable energy can be used directly to substitute for fossil fuel-based technologies. In addition, a range of alternative fuels and technologies are currently available that offer significant emission reduction potential per unit of energy output using established technologies. Thus opportunities for the widespread adoption of hydrogen-based technologies are currently very limited. Perhaps the greatest potential for growth is in the distributed generation market but, again, competing technologies are available.

Footnotes

[1] Delucchi (2002b) has provided estimated damage costs arising from an extensive range of transportation externalities.

[2] Consult Baumol and Oates (1988) for a comprehensive coverage of environmental externalities.

[3] Often referred to as "well to wheels" in the context of applications in the transport sector.

[4] These steps describe a "bottom up", as distinct from a "top down", methodology for life cycle analysis. Top-down studies use highly aggregated data to estimate the external costs of emissions. They are typically undertaken at the national or regional level using estimates of total quantities of emissions and estimates of resulting total damage. The proportion of such damage attributable to certain activities (e.g., the transport sector) is then determined, and a resulting monetary cost derived. The exercise is generic in character, and does not take into account impacts that are site specific. However, its data requirements are relatively minor compared with the "bottom up" approach. The latter involves analysis of the impact of emissions from a single source along an impact pathway. Thus all technology data are project specific. When this is combined with emission dispersion models, receptor point data, and dose-response functions, monetised values of the impacts of specific externalities can be derived. Data requirements are relatively large compared with the "top down" methodology, and, therefore, omissions may be significant.

[5] Pearce (2002) has raised concerns with the methodology used to derive monetary estimates of health impacts.

[6] Fuel cells can more than double the efficiency of an ICE, but energy used in making and storing hydrogen offsets these gains to the benefit of fuel cell hybrid vehicles.

[7] In the context of climate change damages arising from emissions of GHG this discount rate would still be regarded as unreasonably large (ref: Pearce (2002).

[8] In fact, such a practice could actually increase net emissions of CO_2. This is because 1 GWh of electricity provided from renewable resources avoids 972 tonnes of CO_2 if it replaces coal-fired generation. If the same 1 GWh was used to produce hydrogen by electrolysis for use in a fuel cell vehicle to replace a gasoline hybrid vehicle the avoided CO_2 emissions would amount to 390 tonnes. Although this comparison ignores the intermittent nature of some renewable energy technologies, which could lead to significant levels of power "spillage", the gap is nevertheless considerable.

[9] This implies that fuel price volatility is also irrelevant in the analysis. Yet hydrogen derived from renewable resources that have no fuel costs (e.g. wind or solar power) is likely to exhibit considerably less price volatility than (direct use of) gasoline, natural gas or diesel fuels.

[10] Adapted from Owen (2004).

[11] These values were calculated by dividing the total cost of maintaining U.S. military activity by 20 per cent of Persian Gulf exports to reflect the fact that the U.S. accounts for 20 per cent of gross oil imports at the global level.

[12] In principle, the same approach can be adopted for hydrogen and fuel cell technologies in the stationary power sector.

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The U.S. Spent Nuclear Fuel Legacy and the Sustainability of Nuclear Power

*By Lorna A. Greening and Erich A. Schneider**

Abstract. *Nuclear generation capacity currently accounts for roughly 20% of annual electricity generation in the United States. Following recent operating successes (>90% plant availability, and lower production costs), license extensions for existing nuclear generation capacity as well as addition of new capacity are being pursued as responses to increases in emissions of greenhouse gases and other pollutants while maintaining reliability and security of supply. However, before increased nuclear generation becomes a viable option in the U.S., the disposal of spent nuclear fuel (existing and future accumulations) needs to be addressed. Options under discussion include long term above ground storage, geologic disposal in engineered repositories or boreholes, and subsequent recycling of recovered unused nuclear fuel. Our work with advanced nuclear fuel cycle technologies suggests several potential strategies that may lead to a sustainable nuclear future and mitigation of the spent nuclear fuel problem.*

Spent Nuclear Fuel: The History and the Future Dilemma

Currently, nuclear power plants provide roughly 20% of electricity generated on an annual basis in the United States.[1] When compared on a full fuel-cycle basis, a kilowatt-hour of electricity generated by nuclear technologies avoids approximately 95% of the greenhouse gas emissions from the use of coal (DeLuchi, 1991). Further, nuclear generation has been demonstrated to be an effective means of compliance with the air quality regulation (South, 1999). However, for every kilogram of nuclear fuel used, roughly 10 grams of plutonium and one gram of actinide elements are produced. Both are considered to be hazardous to health[2] and, if in the wrong hands, national security. But both, if recovered, can be re-cycled as fuel for future use. Although the average U.S. household can be supplied with all of its annual electricity needs with ten grams of uranium, a resulting equivalent amount of spent fuel is also produced. That spent fuel must be either stored under special shielded protective conditions for centuries before it reverts to a relatively harmless state -- federal guidelines call for its essentially complete sequestration for 10,000 years[3] -- or re-processed with the active elements (plutonium and the actinides) recovered (Blowers, 1995).

The economics of nuclear energy in the U.S. are exhibiting the effects of use of a "mature technology" and market forces such as de-regulation. These have combined over the last ten years to decrease operating costs and increase availability factors (Cohn, 1997; Rogner and Langlois, 2001). The economics of nuclear generation in the U.S. have largely improved as a result of increases in operating efficiencies. Much of this improvement can be attributed to an integration of such functions as maintenance, engineering, and operations. Decreases for staff for these functions have averaged approximately 3% per year since 1995 and produced a corresponding decrease in fixed labor costs, a significant cost for nuclear generation facilities.

In addition to operating efficiencies, the economics of nuclear generation have benefited from technological improvements, increases in capacity factors largely due to increased fueling cycle lengths and greater burn-ups, falling fuel costs, and increased thermal efficiency (Kazimi and Todreas, 1999). These technological improvements along with enhanced economics and the improved safety record as a result of the same factors that have reduced forced outages would lead to the assumption that new nuclear capacity will be built and that existing capacity will undergo life-extension through license renewal. Interest has been expressed in license renewal by owners of approximately half of the existing nuclear capacity (Schneider, 2003). This is a particularly attractive proposition at costs ranging from $10 to $50 per kW. However, license applications for renewals and new facilities have not been made at the expressed rate of interest. The lack of construction of new plants can easily be explained by the experience with the previous generation of reactors which were characterized by high capital costs with substantial contingency, and the long lead times. The final units of the previous generation of nuclear power plants, coming online in the late 1980s, had overnight construction costs of $3133 per kW ($1988) and construction times of 12.2 years (National Academy of Sciences, 1992). The "next generation" of reactor technologies available for short-term deployment promise lowered capital costs, shorter construction times, and extended life times (up to 60 years). Limited experience already with this class of reactor has proven this with overnight construction costs of approximately $1522 per kW and construction times of 36.5 months (Taylor, 2001).

When compared on the basis of avoided emissions, increased energy security through reduced dependency on imported fuels, and the relatively low (and declining) costs

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*Lorna A. Greening is an Independent Consultant and Erich A. Schneider is with the Los Alamos National Laboratory. She may be reached at lgdoone@aol.com and he at eschneider@lanl.gov The conclusions and opinions presented in this article are those of the authors and do no necessarily reflect those of Los Alamos National Laboratory, U.S. DOE, or any agency of the U.S. Federal Government. All errors of commission or omission are ours, and the usual caveats apply. We wish to thank the Office of Air Programs (U.S. EPA) for initial funding during the early stages of model development. More important than funding, we owe a tremendous debt of gratitude to over 200 individuals who provided data and expertise in specialized areas over a two year period. Of special mention, the entire staff (without fail) of the Energy Information Administration provided technology data underlying NEMS, energy consumption data, and some significant suggestions on incorporating that data into LA-US MARKAL. Various individuals and organizations in the national laboratory system and the industrial community also were instrumental in model development. Without this "grass roots" community contribution, effort and support, we would not have been able to complete this work.

[1] See footnotes at end of text.

of electricity generation from nuclear sources, the issue of spent nuclear fuel does not appear to be a deciding factor for future implementation. However, approximately 40,000 metric tons of spent nuclear fuel (SNF), arising from nearly 30 years of commercial nuclear generation, currently reside at nuclear generation facilities. Estimates indicate that by the end of the lifetimes of the existing 103 licensed, operating reactors, over 80,000 metric tonnes of SNF will require permanent disposal (Macfarlane, 2001). Given the current pace of operating license extensions, this figure could, in fact, exceed 100,000 metric tonnes. The long-term geologic repository at Yucca Mountain, Nevada is slated to begin accepting waste in 2010 with this date subject to change to a later point in time. Congress has, however, legislated the capacity of this repository to be 63,000 tonnes of SNF (Nuclear Waste Policy Act, 1982).

Much of the hesitancy to either re-license and the lack of new construction of nuclear generation can be explained by past and current U.S. policies toward the disposal of spent nuclear fuel. Under the Nuclear Waste Policy Act (NWPA) of 1982, the U.S. Federal government was to take title to all spent fuel, and begin to move it to a geologic repository by January 31, 1998 (Montange, 1987). Under the Amendments to the NWPA in 1987, Yucca Mountain, located partially within the boundaries of the Nevada Test Site, was designated as the location of the permanent geologic repository for U.S. high-level waste (Macfarlane, 2001). For the accumulation of SNF to be limited to the legislated capacity of Yucca Mountain, the approximately 100 giga-watts of current nuclear generation capacity would need to be replaced with other sources of electricity generation capacity. To further compound the problem, this replacement process must occur in the time-frame of 2005 to 2020 as licensed ceilings for on-site SNF storage are met. Therefore, not only is the waste problem still unresolved, but also the issues of potential short-falls of electricity or steep increases in the price of electricity to the consumer or both must be faced.

Although the legislative groundwork had been laid, early in the decade it became quite apparent that the U.S. DOE would be unable to meet the 1998 deadline for opening Yucca Mountain (Macfarlane, 2001). Currently, the repository is not estimated to open until 2010 or later. DOE's own total system life cycle cost estimates, conducted every five years, have shown that the anticipated cost of building and operating Yucca Mountain has almost doubled, in constant dollars, since 1980 (Schneider, 2003). Further, although applications have been made for the construction of interim-storage facilities, none have been approved. Finally, many existing nuclear facility operators have and are experiencing problems on receiving licensing approval for at the reactor on-site dry-cask storage. Without the appropriate avenues for the disposal of waste, the future of current nuclear generation facilities and the construction of new generation facilities is highly uncertain. As a result, even with the improving economics of nuclear power, few private firms are willing to undertake the politically induced risks associated with ownership of a nuclear facility (Rosenbaum, 1999). Utilities have claimed that the unplanned additions of storage capacity associated with this delay have cost $56 billion (Nuclear Energy Institute, 1998) – roughly $1400/kg or 2.8 mills/kWh for the affected SNF.

In other countries, such as Japan, the United Kingdom, and France, where firm commitments have been made to waste disposal strategies, construction of new nuclear generation is occurring. While the U.S. produces approximately 20.5% of its electricity with nuclear generation, France produces 76%, Japan 32%, and the UK 28% (International Energy Agency, 2001). All of these countries to one extent or another have struggled with the issue of SNF disposal (Blowers, 1995; Kondo, 1998; Delmas and Heiman, 2001; Pickett, 2002). And, these three countries have adopted SNF disposal strategies that include reprocessing and the fabrication of mixed-oxide fuels. Considering that only 5% of the energy content of nuclear fuel is released when it is burned in a light water reactor, not only are these countries reducing the decay heat and radiotoxicity of the waste for permanent geologic disposal, but also are recovering a valuable energy source (Banks, 2000). The limited economic analyses that are available of the reprocessing in these countries do indicate that reprocessing is economic particularly if compared with interim- or permanent storage options for SNF (Jones and Pearson, 1981; International Energy Agency, 2001). However, in the U.S., policy decisions in response to proliferation concerns currently remove reprocessing as an option (Beck, 1999).

With the growing concerns over the volumes of legacy SNF, and the very strong potential of exceeding the statutory limits of Yucca Mountain with the associated political and social risks of building a second such repository, a closed nuclear fuel cycle is necessary for sustaining nuclear generation in the U.S. (Rosenbaum, 1999). A closed nuclear fuel cycle would of necessity require reprocessing. During reprocessing one metric tonne of SNF can be reduced to 930 kg of relatively harmless uranium,[4] 10 kg of plutonium, and 60 kg of high level waste (Schneider, 2003). This strategy would result in a 10-fold increase in the 'effective' capacity of Yucca Mountain. Although, plutonium is separated from the fuel–this is considered to pose a proliferation risk–new advances in nuclear fuel cycle technologies (e.g., transmutation[5]) avoid complete separation of plutonium (Schneider, Bathke et al., 2003). Combined with new nuclear generation technologies such as high-temperature gas cooled or fast spectrum reactors, the nuclear fuel cycle becomes completely closed and sustainable (Lake, Bennett et al., 2002).

In this analysis, several different strategies are evaluated for resolving the conundrum of spent nuclear fuel, expiration of nuclear capacity licenses, and meeting the growing demand for electricity in the U.S. We have implemented expanded detail for the nuclear fuel cycle, including short-term storage, long-term disposal options, reprocessing of spent fuel, and technologies associated with "next-generation" reactors in a widely used energy system model. Use of an energy system model allows the comparison of various strategies to resolve the "nuclear" conundrum, including a phase-out of nuclear generation, permanent disposal of nuclear fuel in a geologic repository, and replacement with other types of electricity generation such as natural gas-fired combined cycle, "clean coal," or renewables. Alternatively, potential strategies include the reprocessing of SNF to reduce the volume of materials requiring permanent disposal and to recover fuel components for future use.

The remainder of this paper is organized as follows. In Section 2, an energy system model used in the development of the analysis, and the underlying structure and data for the U.S. energy system are discussed. Results of the analysis are presented in Section 3. Finally, in Section 4 the policy implications are discussed, and some conclusions are drawn. Our work indicates that a strategy utilizing a "closed nuclear fuel cycle" starting in the time frame of 2015 to 2030 will lead to a reduction in volumes of spent nuclear fuel in various stages of storage. This will allow the continued implementation and use of an electricity generation source that is relatively low in other types of emissions, dispatchable, resource conserving, and economic. However, strategies involving reprocessing would be necessary to reduce the volumes of spent nuclear fuel. These results are sensitive to the economic costs associated with technological development, market conditions, and the political process. Since these factors are changeable, we are continuing to evaluate the sensitivity of results to each of these parameters and the range over which our conclusions are robust.

Method of Analysis and Description of LA-US MARKAL

Within the framework of a widely-used energy system model (MARKAL), a detailed depiction for the nuclear fuel cycle, including short-term storage, long-term disposal options, reprocessing of spent fuel, and technologies associated with next–generation reactors has been implemented. Embedding such a detailed depiction in an energy system model allows the evaluation of the life-cycle (through spent nuclear fuel disposal) costs of nuclear generated electricity in comparison with other sources including fossil–and renewable–centrally dispatched generation sources and distributed generation. Further, use of a general energy system model allows the inclusion of the effects of end-use energy efficiency gains, the demand response to electricity price increases, and fuel substitution for all energy types on future levels of electricity demand, and the required generation mix to meet that demand.

Method of Analysis

MARKAL (MARKet ALlocation model) is a technology-oriented energy system model, which utilizes a dynamic linear programming framework and where all energy supplies and demands for energy services are depicted (Goldstein, Greening et al., 1999). Technologies within the modeling framework are described by initial investment and operating and maintenance (fixed and variable) costs, capacity utilization for demand technologies and availability for process and conversion (i.e., electrical generation technologies), and the efficiency (or heat rate in the case of electricity generation) of fuel use. As is typical of energy system models, energy flows are conserved, all demands are satisfied, previous investments in technologies are preserved, peak-load electricity requirements are honored, and capacity limits are observed along with similar traits of an energy system. Technologies are selected for inclusion in the solution based on comparison of life-cycle costs of alternative investments. Using linear programming, MARKAL minimizes energy system (capital, operating, and fuel) costs over the entire planning horizon.[6] In addition, MARKAL provides an accounting mechanism for emissions by either the application of emissions coefficients on fuel consumption and/or on the per unit output of a conversion, processing, or demand technology. Emissions constraints or "caps" may be defined on a per period basis (e.g., limits on SO_2 under the U.S. Clean Air Act) or cumulatively. Alternatively, emissions taxes or estimates of environmental damages and benefits may be depicted in this modeling framework. Further, emissions can be depicted on an economy-wide basis or on a more disaggregate basis (e.g., mercury emissions from fossil fuels used in the electrical sector).

The MARKAL family of models consists of a number of variants (Goldstein, Greening et al., 1999). For the work presented here, MARKAL_Elastic Demand (MED) (see Loulou and Lavigne, 1996, for additional details), a linear programming formulation with demand response to price changes, was used. As a result of addition of a price response to the standard linear programming formulation, a key factor, energy price demand response, in the consideration of any energy policy can be incorporated into the analysis. Without a demand response, costs of the implementation of a policy resulting in increases in energy prices could be overestimated, i.e., any reduction in energy consumption or emissions must be made totally through investment in new equipment. Further, this MARKAL variant does allow for the asymmetry of price response. As often demonstrated, energy demand exhibits a lag in response to downward movement of prices (Gately, 1993). This asymmetric demand response is the result of rates of capital turnover and technological innovation, and as a result energy demand may not return to previous levels.

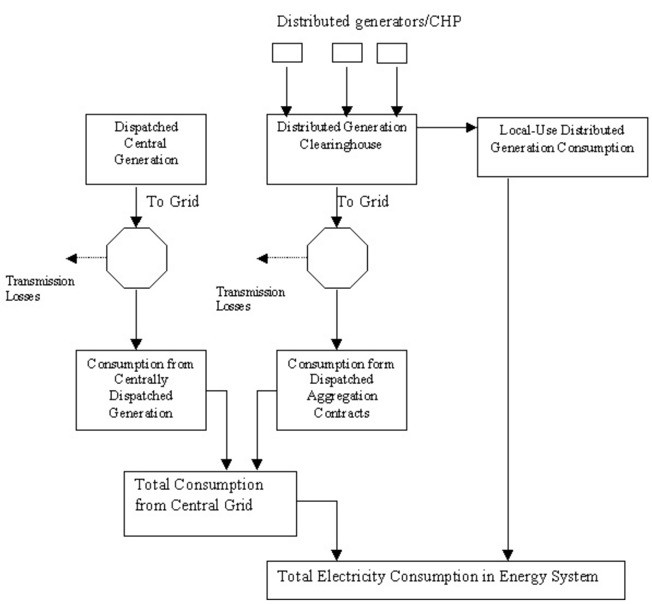
However, this variant of MARKAL does not capture the macro-economic feedbacks depicted in MARKAL-MACRO, another widely implemented variant of the MARKAL family. But, comparison of the two variants indicates that a GDP response (or feedback) accounts for less than 5% of demand response (Loulou and Lavigne, 1996). To capture the expanded detail of the nuclear fuel cycle, and other details of the U.S. energy system, a trade-off must be made between expanded detail, and the tractibility of solution of the non-linear component of MARKAL-MACRO.

Description of LA-US MARKAL[7]

The data used in this analysis depicts the energy system of the U.S. and is from a number of publicly available sources (Greening, 2003). This version of US MARKAL depicts over 3000 energy using technologies in the industrial, commercial, residential, and transportation sectors, 90 centrally dispatched and over 300 distributed electricity generation technologies, both conventional (e.g., coal, petroleum, nuclear) and non-conventional (e.g., geothermal, biomass, solar) fuels, and approximately 100 categories of energy service demands. Table 1 provides a comparison of the technology characterization underlying US MARKAL with that underlying NEMS (National Energy Modeling System) which is used by the U.S. Energy Information Administration to produce the Annual Energy Outlook (see NEMS documentation for complete details, EIA, 2000). As demonstrated by this comparison, the two modeling frameworks are similar in detail. The base year for this analysis was 1995 (i.e., all costs are in \$1995) while energy service demands and other parameters are consistent with AEO 2002 (EIA, 2001).). Although similar in detail, NEMS does have a number of forecasting capabilities resulting from its modular structure that MARKAL does not have.[8] Therefore, MARKAL should not be viewed as a forecasting model, but rather as a tool to evaluate different potential views of the future. Further, MARKAL, because it is a linear optimization framework depicting the entire energy-system, can be more difficult to develop, calibrate and achieve "sensible" results.

Electricity generation in this version of US MARKAL is depicted as centrally dispatched and distributed generation (Figure 1). For centrally dispatched generation, over 90 generation technologies are characterized. The generation types characterized include fossil (i.e., oil, natural gas, and coal) steam, combined cycle, and conventional and advanced turbines. As part of this technology choice set, nine 'clean coal' technologies including integrated coal gasification combined cycle, atmospheric and pressurized fluidized bed, and advanced turbines are depicted. Renewable technologies including solar (power tower, central thermal, thermal dish Stirling, and photovoltaic concentrator), wind (three classes), biomass (combined cycle and direct fired), hydroelectric, geothermal (binary cycle and flashed steam) and municipal solid waste (mass burn, modular, RDF, and methane) are also included.

Figure 1
Distributed Electricity Generation (DG) versus Central Electricity Generation (CG)
LA-US MARKAL



A detailed summarization of the data for electricity generation technologies depicted in US MARKAL is quite lengthy and available from the author on request.

For nuclear generation, this framework incorporates one of the most complete models of the nuclear fuel cycle, nuclear generation, and nuclear spent fuel currently in existence, and exceeds the detail found in earlier efforts (e.g., Joskow and Baughman, 1976). The nuclear fuel cycle represented in this version of US MARKAL includes uranium enrichment by diffusion and centrifuge techniques, fuel fabrication processes for oxide and metal fuels, and aqueous and pyro-metallurgical SNF reprocessing. These facilities support a variety of current, evolutionary and next generation reactor types: advanced light water reactors, high temperature gas cooled reactors, fast-spectrum ("breeder") reactors, and several systems (accelerator-driven systems) dedicated to efficient burning of actinide materials. These facilities are modeled upon those being considered in three Department of Energy programs: Nuclear Power 2010 (U.S. DOE, 2001), the Advanced Fuel Cycle Initiative (U.S. DOE, 2003), and the Generation-IV Program (U.S. DOE, 2002b). Unique to this framework is the inclusion of advanced reprocessing and the implementation of several types of storage including cooling, interim dry storage, and permanent storage with the characterizations (i.e., costs) based on decay heat and radiotoxicity. As part of this depiction, we are able to track heavy metal tonnage throughout the system, and can estimate amounts of different materials (such as transuranics) in stockpiles, reprocessing, reactors, cooling and interim dry storage, and permanent geologic depositories. This approach allows the evaluation of limitations on different types of storage, technological innovations in fabrication and reprocessing, strategies involving the use of the Nuclear Trust Fund for subsidizing different disposal strategies, and the impacts of market conditions including the availability and price of competing energy sources.

Distributed generation (DG) and combined heat and power (CHP) are depicted with an end-use sectoral-specific (e.g., commercial or each industrial sector) electricity and steam or heat grid. The sector-specific electricity grids are also connected to the main electricity grid through a broker or "aggregation" function, and as a result the option exists for inter-sectoral trades of electricity from distributed sources. Where appropriate, it is assumed that technologies can produce either heat or power (based on the technical constraint of a minimum production of electricity), and that the heat to power ratio is flexible changing in response to the demand for each. In any event, DG and CHP are treated as the "marginal" producer to central generation sources. This configuration defines a limited, but expandable, market niche for DG and CHP. DG and CHP generation types include turbines (fossil-

Table 1. Comparison Between NEMS and US MARKAL

End-Use Sector	NEMS	US MARKAL
Residential Demand	14 end-use services	13 end-use services
	3 housing types	2 housing types
	34 end-use technologies	150 end-use technologies and building conservation measures
	No distributed generation	36 distributed generation technologies (fuel cells and photovoltaics)
Commercial Demand	10 end-use services	9 end-use services
	11 building types	1 building type
	10 distributed generation technologies	36 distributed generation technologies (fuel cells, reciprocating engines, microturbines, photovoltaics, conventional coal, oil, natural gas, biomass, MSW)
	64 end-use technologies	325 end-use technologies and building conservation measures
Industrial Demand	15 industrial sectors including 7 energy intensive industries	10 industrial sectors including 8 energy intensive industries
	End-use demands defined as annual sectoral output in real dollars	Demands for each sector based on end-use service demand (e.g., lighting or HVAC) or physical unit demand (i.e., tons of product) or annual output in real dollars
	Use of production possibility frontier for each sector	Over 2400 technologies in a process train formulation using materials flows
	cogeneration	Up to 34 CHP/distributed generation per sector
Transportation Demand	6 automobile sizes	3 automobile sizes (sub-compact, small to medium, and full size).
	6 light truck sizes	3 light truck sizes (SUV, minivans, pickups and large vans)
	59 fuel saving technologies for light-duty vehicles	Fuel saving devices are combined with vehicle types (68 LDVs including up to 8 time dependent improvements in fuel efficiency for conventional combustion, fuel cells, SIDI, hybrids); each vehicle type has its own emissions characterization 8 emissions dependent upon type of combustion and fuel (e.g., reformulated gasoline)
	15 fuels for light-duty vehicles	7 fuels types (gasoline, diesel, hydrogen, electric, flex alcohol, biofuels, and CNG)
	20 vintages for light-duty vehicles	Aggregate existing stock (with average characteristics for each vehicle type)
	8 types of aircraft	4 types of aircraft
	12 types of freight trucks	30 types of trucks (Classes 3-6, 7-8), 10 types of buses, 3 types of rail, and 4 ship types
Electricity Generation	29 capacity types (10 renewable) Regional disaggregation with vintaging of existing coal technologies Generic DG/CHP	90 generation technologies (see text) Existing generation represented on a national aggregate basis Sector specific DG/CHP
Conventional Resources	Coal by region, rank, and sulfur content Petroleum discovery sub-module simulating exploration and finding of oil, natural gas, and natural gas liquids	Coal by region, rank, and sulfur content Oil, natural gas, and natural gas liquids by region, proven versus potential resource (USGS) for conventional and unconventional reservoirs
Alternative fuels	Biomass supply curves MSW and cap. CH_4 cost per BTU Wind Solar	Biomass supply curves MSW and cap. CH_4 supply curves Wind supply curves on basis of costs to reach main grid and congestion, and wind class Solar supply curves on basis of grid connection costs and congestion Biofuels including ethanol and biodiesel
Hydrogen	Cost per BTU	Centrally produced hydrogen from natural gas, coal, electrolysis of water, biomass, petroleum coke, and advanced nuclear. Decentralized production from natural gas, electricity, methanol, and gasoline.
Nuclear Fuel Cycle	Cost per BTU, 2 nuclear generation technologies, no disposal of spent nuclear fuel	Full nuclear fuel cycle represented with advanced nuclear technologies (see discussion in text)
Emissions	For electricity generation: mercury, SO_2, NOx On an economy-wide and by end-use sectors: CO_2	On an economy-wide, and an end-use sector or energy resource produced basis: mercury, particulates, CH_4, CO, CO_2, N_2O, NOx, SO_2, VOCs

fueled and biomass for example in the paper and pulp industrial sector), microturbines, fuel cells, reciprocating engines, and photovoltaic sources.

Results

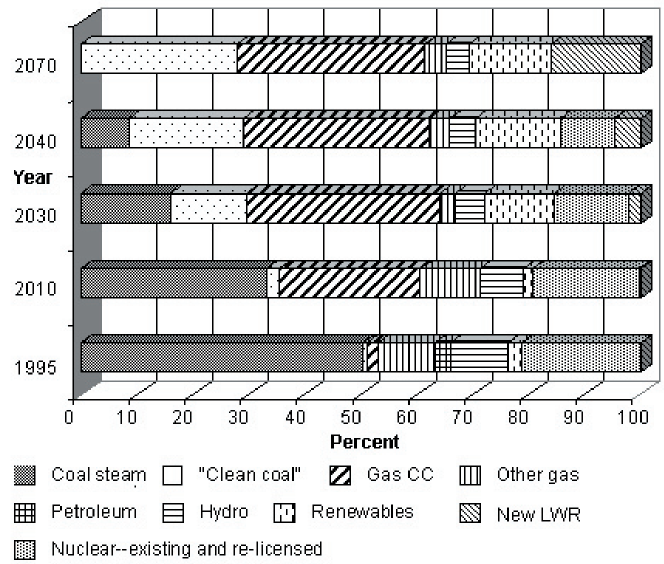
For this analysis, we analyzed three cases: (1) a reference case assuming current nuclear capacity factors with no added capacity and that spent nuclear fuel is not a problem; (2) a case where gradual 'extinction' of nuclear generating capacity occurs, no re-licensing or reprocessing are assumed, and no additional repositories are built beyond those necessary to dispose of spent nuclear fuel generated with the current stock; and (3) a case with reprocessing or a closed nuclear fuel cycle is implemented. The assumptions of the first case parallel the Annual Energy Outlook (AEO) 2002 reference case between 1995 and 2020 in terms of fuel prices, other costs and investment. Those assumptions have been projected for the remainder of the forecast horizon. The AEO also assumes that SNF disposal is not an issue. The second case represents the extreme end-point where existing nuclear generation is replaced by other generation sources, and all existing SNF is disposed of in a permanent geologic repository (e.g., Yucca Mountain). The third case represents an optimistic view of nuclear generation. In this case the spent nuclear fuel issue is at least temporarily ameliorated through the use of reprocessing to reduce the volumes sent to a permanent geologic depository. Further, separated components are recycled into mixed-oxide fuels and advanced nuclear fuels.

Comparison of these cases indicates the value of reprocessing and the 'closed nuclear fuel cycle' in terms of maintaining the sustainability of the nuclear option for electricity generation. Nuclear generation in the reference case grows at a rate of approximately 2.5% per year with 125 giga-watts of advanced light water reactor capacity installed by 2070 while existing licensed nuclear capacity has expired. Figure 2 illustrates the mix of electricity generated over the forecast horizon for the reference case. In addition to nuclear generation, renewable generation increases to slightly over 12% of total generation, while the shares of coal and natural gas become nearly equivalent. However, facilities for repository disposal approaching the equivalent of five to six Yucca Mountains will be required.

Without reprocessing and specifically in the case where nuclear generation is phased out of the generation mix, as illustrated in Figure 3, renewable technologies are the primary substitutes for the replacement of nuclear generation capacity. Renewables increase to nearly 24% of the total electricity generated, and the shares of coal and natural gas increase by slightly over the reference. However, even with the termination of nuclear generation in the U.S., facilities for repository disposal on the order of between 1.5 and two Yucca Mountains will be required. The on-going costs for disposal of this waste burden must be included in the overall costs of supplying the U.S. with electricity.

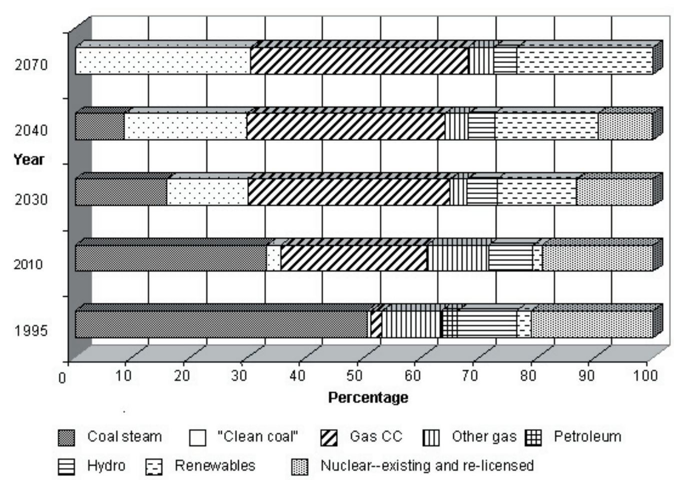
With a nuclear strategy, however, that includes reprocessing and transmutation, a fission technology where the undesirable elements of SNF are consumed, an entirely different

Figure 2
Reference Case
Centrally Generated Electricity by Fuel



picture unfolds. With the implementation of these technologies, once again nuclear generation grows to approximately 100 giga-watts by 2070 or very similar to the reference case. However, these technologies are not widely available until

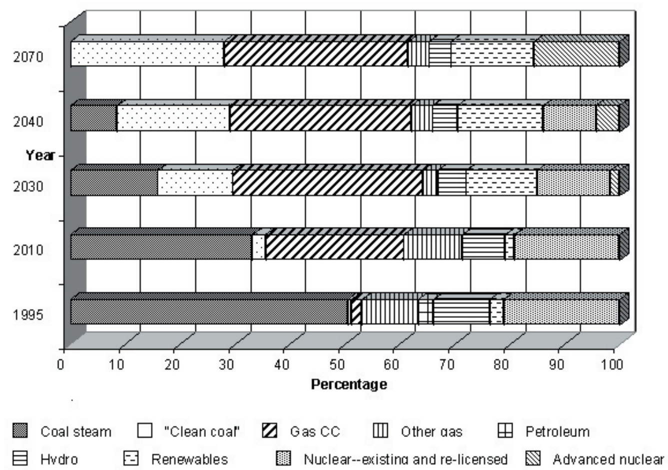
Figure 3
Phase-out of Nuclear Generation
Centrally Generated Electricity by Fuel



approximately 2030. The overall generation mix appears once again to be similar to the reference case with the exception of renewables. During the period of time that the share of nuclear generation is declining while new technologies are commercialized, renewables are the preferential technology. As a result, emissions do not increase substantially over the reference case. However, geologic disposal requirements exceed the capacity of Yucca Mountain only slightly in the near term (2015 to 2030). This extra capacity is provided by interim dry-storage, which is a temporary holding facility. As fast-spectrum transmutation facilities come on line and increase in share of the generation mix, the total volumes of 'legacy' and freshly generated nuclear requiring permanent geologic disposal fall well below the statutory limits of Yucca Mountain. Further, required volumes of temporary interim-dry storage contract and eventually disappear.

These results should be viewed as preliminary, and representative of first-order estimates of the impacts of advanced nuclear technologies. As such, these results are subject to both economic and technological uncertainty. The economic conditions including potential subsidies from the Nuclear Waste Trust Fund for development of flexible disposal strategies, changes in the regulatory climate and institutional setting, and the sensitivity of our results to declines in technology costs are all subjects of research by the authors. These initial results, however, do suggest that our energy future may very well include a nuclear component which can continue to support the U.S. style of life at relatively low levels of emissions and contribute to the development of a "hydrogen economy."

Figure 4
Advanced Nuclear Case
Centrally Generated Electricity by Fuel



Conclusions

The nuclear "conundrum" poses an interesting problem to policy makers, and the energy industry. If on one hand, nuclear generation is phased out in this country, other sources of electricity generation must be developed, and many of those sources emit greater levels of several critical air pollutants and greenhouse gases. Some of those sources are dependent upon decreasing domestic resources of non-renewable resources such as oil and natural gas. Other replacement sources such as certain types of renewable generation (e.g., wind) sources do not currently have attributes such as dispatchability and the high availability factors that characterize other more conventional sources of electricity. Many of the alternative conventional and unconventional electricity generation sources currently have higher costs than the nuclear generation that they would replace.

Efficiency improvements for various end-use technologies do hold potential for reducing the amount of energy we consume. However, eventually, diminishing returns from that source result from thermodynamics, economics, and utility or acceptability (e.g., comfort and convenience). And, we can avoid some energy consumption through price increases. However, energy demand in the short-run is inelastic, and in the long-run highly dependent upon the choices available for energy-using capital. As recent events have so aptly demonstrated, "going without" or energy at high prices will probably not gain widespread political acceptance.

If on the other hand, nuclear electricity generation is part of our energy future, then we will need to find a way to deal with the resulting spent nuclear fuel. Our work does, as does the work of many others, indicate that there are options available to the expanded development of permanent, geologic depositories. However, before we can reach the goal of a "closed nuclear fuel cycle" interim strategies involving reprocessing will be necessary. As a result, much thought will need to be given to the political, social, and security ramifications of strategies that include reprocessing as an interim and long-term solution.

We have only touched on some of the economic aspects of the "nuclear conundrum." Our results are highly dependent upon the sensitivity of the economics to technological innovation, the relative prices of competing electricity generation sources, and changes in the political and regulatory arenas. Nuclear energy has both positive and negative aspects as does any source of energy. Trade-offs among those aspects must be considered by all participants in the policy arena, and weighed in terms of the over all implications for long-term economic and social wellbeing. Our concentration in this analysis has been very limited, focusing on only nuclear electricity generation. A more complete analysis in which factors directly affecting other types of generation might lead to an entirely different set of conclusions. As a result, the future of nuclear generation remains an open, unresolved question.

<u>Footnotes</u>

[1] The Energy Information Administration reports that the 103 nuclear power plants in this country generated over 768.8 billion kWh of electricity in 2001, and operated at an 89% capacity factor (EIA, 2002).

[2] Health hazards result from the ionizing radiation that is emitted from both substances. Short-term effects of exposure to ionizing radiation include radiation sickness with symptoms akin to an acute case of the flu. Long-term effects of chronic exposure include cancer, reproductive failure, birth defects, genetic defects, and death (Blowers, Lowry et al., 1991).

[3] The dose to the maximally reasonably exposed individual at the site boundary of a repository is not to exceed 15 millirem (mrem) per year for 10,000 years following waste emplacement. An average individual in the United States receives a dose of 360 mrem/year from background radiation (U.S. DOE, 2002a).

[4] The resulting uranium with an enrichment of less than 0.72% is considered to be Class C waste and requires less restrictive disposal measures (Montange, 1987).

[5] Transmutation closes the nuclear fuel cycle by recycling actinides (of which plutonium is but one of several heavy elements created when uranium is irradiated) until they are fissioned. In so doing, energy is extracted from these elements that otherwise would have gone unutilized. This is also the only way—short of natural

decay over millions of years—to permanently dispose of these materials.

[6] Linear programming has a set of embedded economic assumptions that have implications for the modeling of energy markets (Dantzig, 1963). Those assumptions include: (1) all cost functions are homogeneous and linear; (2) perfect competition is assumed with a large number of participants in the market and all are 'price takers'; (3) all economic agents operate at the minimum of their total cost curve; (4) ease of exit and entry is assumed; (5) all markets are in equilibrium; and (6) perfect foresight exists. These assumptions are particularly idealized for energy markets which are very rarely in equilibrium, very often can be characterized by economies of scale, and rarely have a market structure that includes a large number of participants.

[7] LA-US MARKAL is one of four US MARKAL models currently in existence or under development. Each model has a different level of detail, a different forecasting horizon, and is designed to evaluate a different set of problems. If the reader has a particular interest in determining which model is the "best," direct contact with the developers is recommended. Of course, the reader should be forewarned that each set of developers would claim "superiority."

[8] The modules in NEMS forecast the mix of technologies and resources available based on non-energy related characteristics. For example, in the transport module, NEMS can produce the mix between vehicle sizes based on characteristics such as number of passengers carried, interior compartment size, acceleration, and similar passenger amenities. The parameters for this sub-module are from the econometric analysis of survey data. To produce a similar result in MARKAL requires the conversion by the analyst of output from a discrete choice model into a system of linear proportionality constraints. These constraints are not endogenously responsive to price, and must be updated by the user to changed economic or demographic conditions.

Bibliography

A detailed bibliography is available from the authors on request.

IAEE Student Activities – Paving the Way to Becoming Acquainted With the Energy Economic Community

One of the major benefits of conferences and work shops is that they offer in a relaxed and friendly manner the opportunity to get in contact with colleagues (or students) of your profession from around the world. IAEE activities, like the annual International Conference, offer this possibility in an excellent and very pleasant way, as I had the chance to experience at the Prague International Conference. The conference proceedings (as well as the other IAEE publications) are valuable resource for papers on energy related matters. In short, the IAEE activities not only provide an excellent starting point for students to become acquainted with the international energy economic community but also offer resources to further build up this initial stepping stone. Thus, encouraging students to attend IAEE conferences by offering reduced conference fees or even scholarships as well as special students program activities is one important way the IAEE could address new students, who might not have attended any conference before.

Surely a lot of students do not have the opportunity to attend an IAEE International Conference due to, amongst other reasons, limited financial resources. Local (or national) activities on the other hand, are much easier to attend and less of a cost burden. As the IAEE started appointing student council members three years ago to help supporting student matters on an international level, affiliates are also encouraged to do this (or something similar) within their organization. This, along with other means to enhance student involvement on the affiliate level, would also improve IAEE's chance to reach out to new students: Due to their better knowledge of national universities, affiliate student council members could directly address relevant faculties or departments concerning IAEE activities.

To offer students the chance for international networking on energy related matters (beside international conferences), the student section on iaee.org was started by the preceding Student Council members. After some reorganization and improvements its main features are now the IAEE Student Directory and the IAEE Student Newsgroup. Students interested in energy economics from around the world, who don't necessarily have to be members of the IAEE, are encouraged to send in their student information to be displayed on the Student Directory page and are then subscribed to the IAEE Student Newsgroup. The student information contains country of studies, university, study subject, current research project, energy interests etc. Students are also encouraged to send in an abstract of their current research project, which is then made available on the Student Directory page and could be the starting point for discussions within the newsgroup. The newsgroup is open to postings on current energy related matters, student research projects, or IAEE student activity proposals. Subscribers also receive the IAEE Student Newsletter, which contains listings of special events and programs for students, and IAEE members in general, as well as abstracts of student research projects.

Future initiatives for the student section of iaee.org will address additional student's needs, for example the mediation of internship opportunities; a service which especially will need the support of the IAEE's membership. I would like to take this opportunity to ask for the continuing excellent support from the membership for the IAEE student activities to help students to become acquainted with the energy economic community.

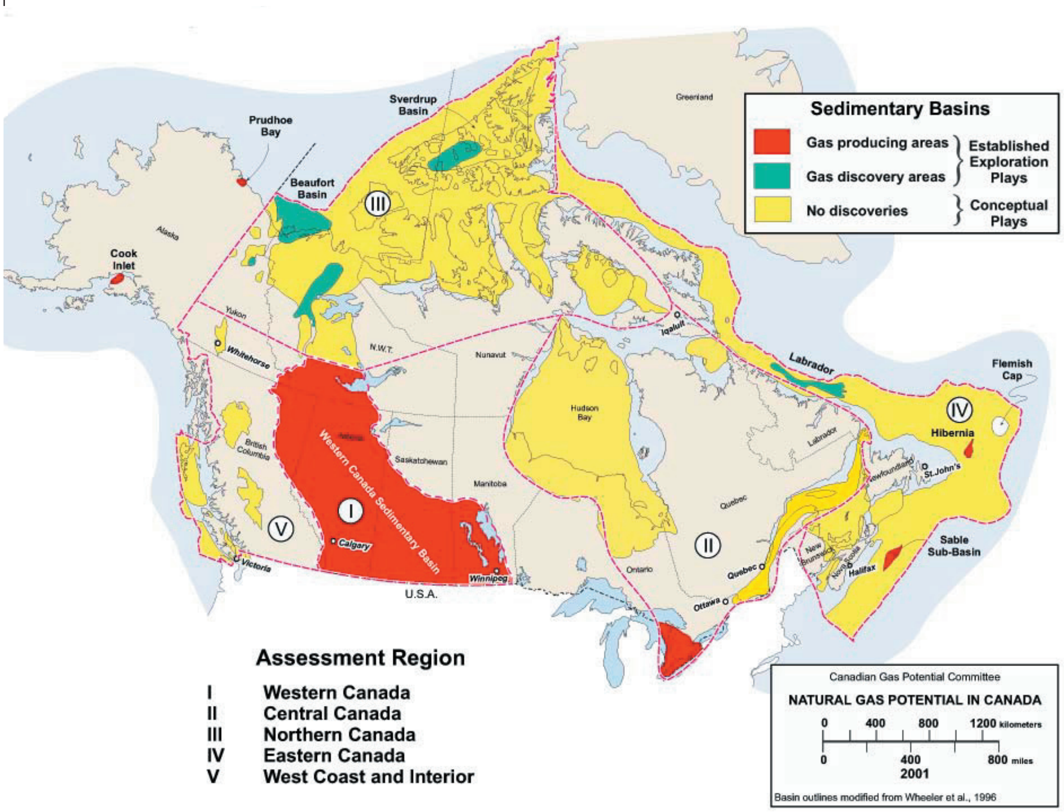
Stefen Sacharowitz

Potential Supply and Costs of Natural Gas in Canada

By Paul Mortensen, Matthew Foss, Brian Bowers and Peter Miles*

Canada's annual natural gas production increased almost 20 percent between 1995 and 2001. During that time Canadian gas satisfied continuing growth in domestic markets while increasing exports to the U.S. by almost a third. In 2002, the record of growth came to an end as gas well completions fell by 17 percent and overall production began to drop. Despite higher prices and substantial increases in drilling in 2003, supply growth remains elusive. Does this mean the limit has been reached for conventional gas production from Western Canada, and what does the future hold for alternative sources of Canadian natural gas?

Figure 1
Natual Gas Potential in Canada - 2001
A Report by the Canadian Gas Potential Committee



According to Natural Resources Canada, the Canadian share of the North American market is projected to grow from about 6.2 Tcf in the year 2001 to 8.1 Tcf or greater by 2010[1]. The U.S. Energy Information Administration projects Canadian exports to the U.S. to grow from 3.6 Tcf in 2001 to 4.1 Tcf by 2010 and 5.1 Tcf by 2020[2]. Continued growth in Canadian production would be required to support these projections. But the projections have been made without a detailed assessment of the potential sources and costs of gas in Canada.

A geologic assessment of Canada's natural gas resources was published in September 2001 when the Canadian Gas Potential Committee (CGPC) released its second assessment of Canadian natural gas potential[3]. The CGPC assessment provides estimates for the total volume of potentially recoverable gas, by geological play, for all of Canada's sedimentary basins. It concludes that there is approximately 590 Tcf of discovered and undiscovered natural gas in place in Canada.

The CGPC work is a geologic assessment and, though critical, is only part of the analysis needed to understand the prospects for Canada's gas supply. The other part relates to the costs of finding, developing and producing the gas - 'supply costs'. Without this latter analysis, the likely size of Canada's prospective gas production cannot be determined.

The Canadian Energy Research Institute (CERI) recently released a report[4] containing an assessment of the costs and related potential supply of natural gas in Canada. The study represents the most comprehensive public analysis ever undertaken into the potential and costs of Canadian natural gas supply. For the first time, a detailed pool-based analysis of the Western Canada Sedimentary Basin is supplemented by analysis of Canadian coalbed methane, and of frontier regions in the North and off the East and West Coasts. The report estimates the size of the economically recoverable natural gas resource base and provides a 20-year projection for Canadian gas production.

This article reports the study's principal findings beginning with a summary of the geological estimates that underlie the analysis.

The Canadian natural gas resource base consists of resources in the currently producing supply regions – Western Canada and offshore Nova Scotia – and in the frontier regions that are currently unconnected to the pipeline infrastructure of North America. The major frontier regions are the Mackenzie Valley and Delta (onshore and offshore), the Arctic islands, offshore Newfoundland and Labrador, offshore Brit-

*The authors are with the Canadian Energy Research Institute, www.ceri.ca. The lead author, Paul Mortensen, can be contacted at pmortensen@ceri.ca. See footnotes at end of text.

ish Columbia (BC) and the unconnected geological basins of offshore Nova Scotia (Figure 1).

Currently, an estimated 304 Tcf of gas in place has been discovered in the Western Canada Sedimentary Basin (WCSB), of which about 181 Tcf are expected to be recovered as marketable gas. To the end of 2001, about 127 Tcf has been produced and about 54 Tcf remains to be produced. In the frontier regions and central Canada, about 63 Tcf of gas in place has already been discovered, of which about 42 Tcf are expected to be marketable. Apart from a small amount of production in Ontario and from the Sable project off Nova Scotia (about 1 Tcf in total), there has been no production to date from frontier resources.

For the whole of Canada, 367 Tcf (304+63) of gas in place has been discovered to date, of which 223 Tcf (181+42) are expected to be marketable. Subtracting the 127 Tcf of production to date leaves remaining discovered marketable resources of about 96 Tcf for the whole of Canada.

The size of Canada's natural gas resource base is uncertain, notwithstanding the large number of discoveries and the significant analysis performed to date. In this study uncertainty about the geology is taken into account through the use of two scenarios – the "CGPC" and "Alternate" cases respectively. The CGPC estimates that conventional gas, originally in place totals 593 Tcf. Of this, 367 Tcf has already been discovered and 226 Tcf remains to be discovered. Gas originally in place in the WCSB, amounts to 423 Tcf of which 304 Tcf has already been discovered and 119 Tcf remains to be discovered. Gas originally in place in the Canadian frontiers and eastern Canada, amounts to 170 Tcf of which 63 Tcf has already been discovered and 107 Tcf remains to be discovered (Table 1).

Table 1
Distribution of Discovered and Undiscovered Conventional Gas Resources In Canada – Year End 2001
(original gas in place in Bcf)

	CGPC Estimates			Alternate Estimates		
Assessment Region	DISC.	UNDISC.	TOTAL	DISC.	UNDISC.	TOTAL
Total WCSB And Yukon	304060	118985	423045	304060	173442	477502
Total Central Canada	1959	3060	5019	1959	3126	5085
Total Northern Canada	34343	50553	84896	34343	172287	206630
Total Eastern Canada	26602	39174	65776	26602	147435	174037
Total West Coast And Interior	0	13724	13724	0	30803	30803
All Canada	366964	225496	592460	366964	527093	894057

SOURCES: (1) Natural Gas Potential in Canada - 2001, A Report by the Canadian Gas Potential Committee, 2001; and (2) Canada's Ultimate Natural Gas Potential – Defining a Credible Upper Board, Drummond Consulting, March 2002.

Because the CGPC resource estimate excludes volumes for a number of areas thought to have reasonable prospects for natural gas discoveries, CERI commissioned a study to define an alternate, more comprehensive, estimate of Canada's natural gas resources. The study uses estimates of the Geological Survey of Canada and others, that include assessments of gas in place for conceptual plays, to provide an alternate – more complete – estimate of total resources.

For the Alternate case, the estimated total conventional gas, originally in place in Canada, amounts to 894 Tcf, with 527 Tcf remaining to be discovered. Gas originally in place in the WCSB, amounts to 478 Tcf, and 174 Tcf remains to be discovered. Gas originally in place in the Canadian frontiers and eastern Canada amounts to 416 Tcf, and 353 Tcf remain to be discovered (Table 1).

Unconventional sources of natural gas include coalbed methane (CBM), gas hydrates, tight gas and shale gas. All of these are known to have very large volumes of gas in place. However, little is known about the amount that may be available for commercial production in Canada.

In Canada commercial production of CBM is just commencing. There is currently no identified production from tight reservoirs or shale formations, although some production from these sources occurs along with production from conventional gas reservoirs. With respect to gas hydrates, the technology to extract the methane gas from the hydrates does not currently exist.

A key feature of the analysis is adjustment of the resource estimates to reflect access restrictions. Off-limits to drilling are areas such as national parks, municipalities and large lakes. Other environmentally sensitive areas may not preclude drilling but instead introduce additional costs and delays to satisfy more stringent conditions. The issue is especially critical in the Foothills of Western Canada where some of the highest potential for new gas finds is in areas with moderate to high degrees of access restrictions. Access restrictions were found to remove roughly 7 percent of the remaining resource base in Western Canada and 12 percent in the North.

CERI undertook detailed pool by pool supply cost analysis of the majority of the remaining gas in Western Canada and all of the gas in the frontiers. Producing pools were analyzed to determine the extent of additional development and gas recovery that could be achieved at higher price levels. Analysis of unconnected pools provided the cost points where this additional gas could begin production. Supply costs for undiscovered gas incorporate the full costs of exploration in addition to pool development. Separate techniques were used for onshore, offshore and coalbed methane resources to capture the unique attributes of each. The results of the analysis provide the volume of gas available at one dollar supply cost increments up to \$10/Mcf[5] for all regions and all categories of gas in Canada.

The supply cost analysis provides the material to construct some illustrative profiles of what the evolution of Canadian production and related supply costs might look like over the next two decades.

For the WCSB, annual productive capacity will be related to the pace of drilling. Three time profiles for drilling activity illustrate a plausible range as a basis for assessing the possible evolution of productive capacity:

- a low case, depicted by a constant rate of drilling at 8000 gas wells per year;
- a high case in which drilling occurs at a rate of 15000 gas wells per year; and
- a middle scenario in which drilling increases from 8000 wells per year in 2002 to 15000 wells in 2008 and 2009 and then declines to about 10,000 wells per year in 2025.

As a point of reference, approximately 9000 gas wells were drilled in Western Canada in 2002.

For the two higher drilling scenarios in the CGPC case, WCSB productive capacity remains at or above 2002 levels until about 2010 and subsequently declines steadily. For the low drilling case, productive capacity begins a steady decline in 2005. In the Alternate case, WCSB production increases in the near term in both high and middle scenarios and remains above present levels until about 2015.

For the unconnected frontier regions, potential future supplies are illustrated by two scenarios–"constrained" and "unconstrained".

The unconstrained case (Figure 2) is intended to characterize the potential productive capacity of the available resources without regard to timing. Annual volumes are estimated on the assumption that each field is produced over a twenty-year period. No assessment is made as to the time by which the gas could be connected to markets.

Figure 2
Potential Productive Capacity of Unconnected Frontier Resources

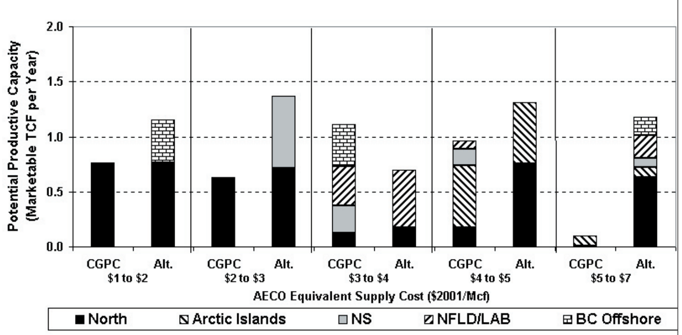
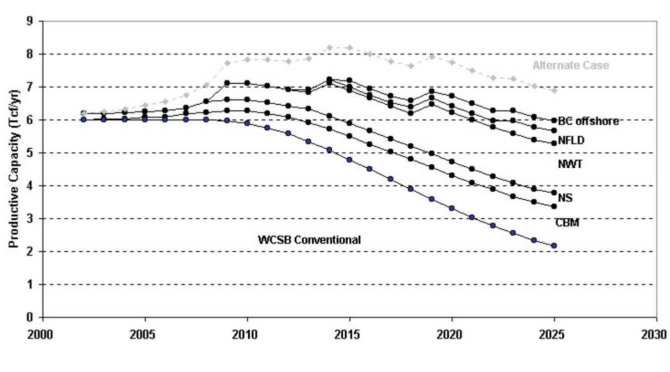


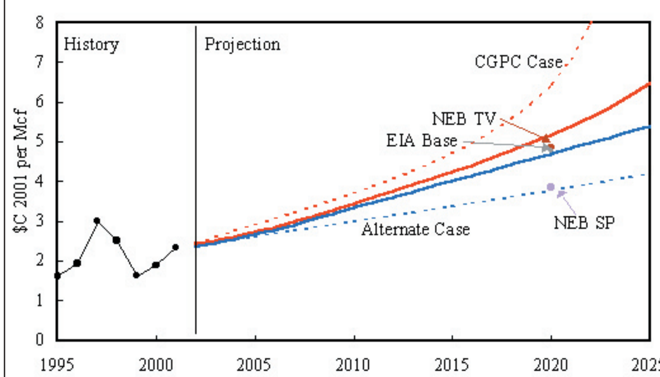
Figure 3
Gas Productive Capacity
CGPC Case (Tcf/year))



Prospective frontier volumes are substantial; the amounts potentially producible for up to $4/Mcf (2001 Canadian dollars) are estimated to total between 2.6 and 3.2 Tcf/year in the CGPC and Alternate cases respectively, close to half of Canada's production in 2002.

Much of the production potential at relatively low costs is in the North along the Mackenzie Valley and in shallow waters of the Beaufort Sea. But the analysis also suggests that there is reasonably low cost potential production offshore British Columbia, Nova Scotia, and Newfoundland. Realization of much of this potential is, however, contingent on the construction of lengthy pipelines and related infrastructure. These facilities, involving large capital expenditures and long lead times, are inherently risky.

Figure 4
Average Marginal Supply Costs at AECO



SOURCES: (1) Canadian Energy Research Institute (2003); (2) NEB: National Energy Board, Canada's Energy Future- Scenarios for Supply and Demand to 2025 (draft for public consultation), - TV = Techno-Vert, SP=Supply Push Scenario; and (3) EIA Base: Reference case from Energy Information Administration, Annual Energy Outlook, 2003.

For the constrained case (Figure 3) judgments are made, based on available information about the likely timing of production startup for frontier basins. Such timing must take into account a number of factors including time taken to negotiate with stakeholders, to obtain regulatory approvals and to undertake construction.

The constrained case yields a time profile in which, for the CGPC case—relatively low geological potential total Canadian production (assuming the middle drilling scenario for the WCSB) increases to some 7 Tcf/year by 2010 from its 2002 level of about 6 Tcf. Production is maintained at about 7 Tcf/year until 2015, following which it declines at a modest rate to about 6 Tcf in 2025. In the Alternate case, productive capacity remains well above 2003 levels throughout the projection horizon, so that it is still about 7 Tcf/year in 2025.

These projections indicate that, so long as supplies of gas from unconventional sources, such as CBM, and from new basins can be brought on stream in a timely manner, natural gas production in Canada can be sustained at levels higher than now exist through at least 2025. Indeed, if the geological estimates of the Alternate case are correct, production could be as high as 8 Tcf per year over much of the projection horizon.

The analysis concludes, however, that such levels of production are likely to come at ever-increasing supply costs (Figure 4). Compared to its level of some $2.50/Mcf in 2002, the supply costs of Canadian gas – in 2001 Canadian dollars – are likely to be at least $4.00 by 2020. Supply costs associated with the mid-point of the supply projections are about $5.00/Mcf by 2020. This cost range appears to be generally consistent with price projections from other agencies.[6]

This, in turn, implies that the North American gas price would have to continue to trend upwards from its annual average in 2002. However, it also raises questions as to whether the prices observed in the early months of 2003 (which have ranged from $5.42/Mcf to $13.64/Mcf – Canadian dollars – at AECO, the principal hub for the Western Canada basin) are likely to be sustainable in the long run.

Finally, it is important to emphasize that this analysis relates to the long-term potential for Canadian natural gas. The actual path of development of that potential takes time and is influenced by a number of factors, including producers' price expectations and the availability of capital and other resources. The production profile that actually emerges will be much less smooth than that portrayed above.

Footnotes

[1] *Canadian Natural Gas Outlook, 2001 Market Review and Outlook*, Natural Resources Canada, Natural Gas Division, Ottawa, Ontario, June 2002.

[2] *Annual Energy Outlook 2003 With Projections to 2025*, DOE/EAI 0383 (2003), Energy Information Administration, Washington, DC, January 2003.

[3] *Natural Gas Potential in Canada - 2001*, A Report by the Canadian Gas Potential Committee, 2001.

[4] Paul Mortensen, Matthew Foss, Brian Bowers and Peter Miles, *Potential Supply and Costs of Natural Gas in Canada*, CERI Study 107, Canadian Energy Research Institute, Calgary, Alberta, June 2003.

[5] All costs and prices are expressed in 2001 Canadian dollars. The exchange rate at the time of writing was approximately $1 Canadian = $0.74 U.S.

[6] The fact that the price projections are similar to CERI cost estimates does not imply similar consistency of EIA and NEB supply projections with those of this analysis. The price/cost comparison is made simply to illustrate that the broad cost/price trends are similar.

Hong Kong Energy Studies Centre Holds International Conference on Energy Market Reform

The Hong Kong Energy Studies Centre, together with the Department of Geography of Hong Kong Baptist University held an international conference on "Energy Market Reform: Issues and Problems," (Second Asian Energy Conference) on August 25-26, 2003 at the University. Scholars and experts from 15 countries presented 27 papers, 17 of which dealt with energy market reform; practically all focusing on reform of the electricity market. Approximately 100 people attended the conference. Attendees included the paper presenters, senior executives and other personnel of local energy firms –power companies, towngas company and oil firms–government officials, academics, consultants and individuals.

At present, the power industry in Hong Kong, consisting of two investor-owned, vertically integrated utilities, is governed by a Scheme of Control, a rate of return type of regulatory framework. The Scheme will expire in 2008, and the Hong Kong SAR government is in the process of working out a new market structure, with the possibility of opening up the market. Consequently, relevant government officials, senior executives of local energy firms, politicians, environmental groups, consultants and academics are all intensely interested in the topic. They would like to know how energy market reform is working or not working in the other countries, and what lessons Hong Kong could learn from foreign experiences.

Stemming from this, the papers on energy market reform were organized along country lines, with 8 papers dealing with reform in Asian countries, including China, Hong Kong, Taiwan, Japan, Thailand, Singapore and India (2 papers). Seven papers covered western countries, including the EU, Sweden, Canada, the U.S. (2 papers) and Australia, and one dealt with Israel. While all focusing on electricity market reform, some of the papers discussed broad issues such as the steps taken to introduce reform and the problems encountered, while others dealt with more specific issues relating to reform. Both types of papers were useful and informative. Certainly the Hong Kong audience learned a great deal about foreign experiences in reform, as reflected in the conversation with local participants during and after the conference.

The other 10 papers covered a variety of themes, including the application of renewable energy in Hong Kong and China, the relationship between fuel quality on the one hand and taxation and the economy on the other, and papers on Chinese energy. Overall, the quality of most of the papers was quite good.

Following the practice of the First Asian Energy Conference held in August 2001 at the University, "Asian Energy in the New Century: Issues and Policies," the Hong Kong Energy Studies Centre has made arrangements with *Energy Policy* to publish a special issue containing selected papers from the conference. An international editorial committee consisting of Dr. Larry Chow, Director of the Centre and serving as chairman, Dr. Hiroshi Asano, Prof. Fred Banks, Prof. Leslie Dienes, Prof. David Green and Dr. C.K Woo, was formed to select the papers. The committee met on August 27, 2003 to make the selection, based upon a ranking of the papers according to their quality and suitability for

(continued on page 26)

Atlantic and Pacific Rim LNG Markets

By Douglas B. Reynolds*

Most gas supplies currently are transported to market via pipelines, which physically link each supplier with each customer. That is why the world's natural gas market consists of a number of regional markets with regional suppliers. However, soon the world will see a fundamental transformation where an ever larger percent of natural gas will be transported as liquefied natural gas (LNG) over the oceans. This will interlace regional markets so that they are more connected creating an emergent world LNG market.

However even though the cost of transportation for LNG is declining, those costs are still high enough that there may continue to be some regionalization of gas markets. In particular two main regional LNG markets look to emerge in the future: the Pacific Rim LNG market and the Atlantic Rim LNG market. In my new book, *Alaska and North Slope Natural Gas: Development Issues and U.S. and Canadian Concerns* (2003), I explain how the two markets will develop and be quite different from each other.

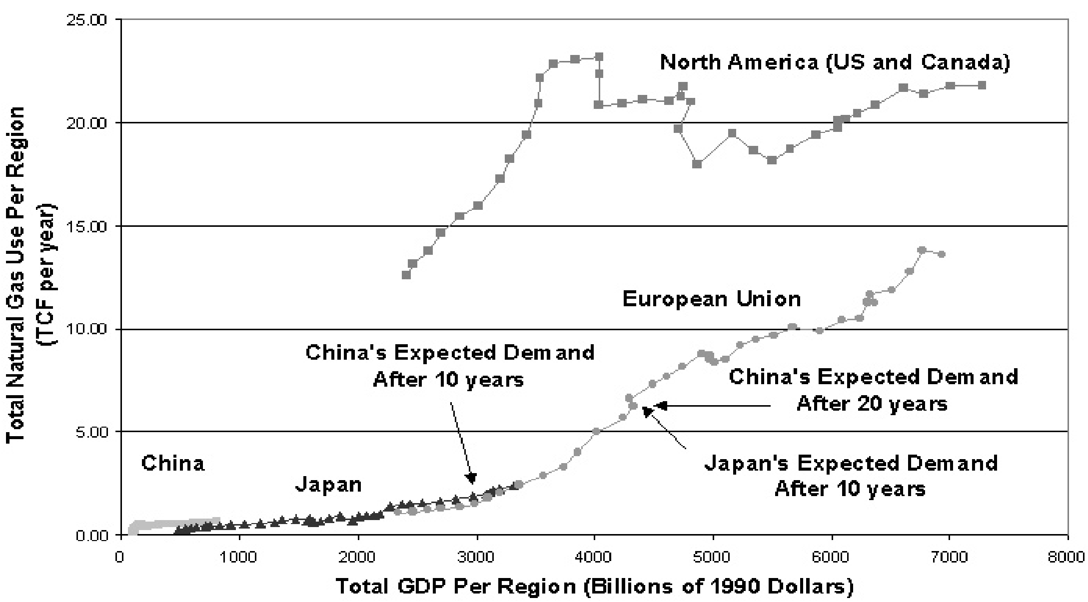
These two LNG markets are actually quite distinct with unique characteristics. Because of the distances involved, the Pacific Rim and the Atlantic Rim can be considered separate market neighborhoods each with their own major supply and demand players. Therefore, it is interesting to look at how the two market neighborhoods are shaping up and to analyze what the advantages and disadvantages are for Alaska and LNG suppliers such as Russia and the Middle East in these two neighborhood markets.

First let's look at the Pacific Rim. On the demand side, the Pacific Rim has four main customers: China, Japan, California and the rest of East Asia. Japan's economy with ten years of sluggish growth is slow moving with structural problems. China's economy is moving slower than expected also due to a lack of internal market deregulation. Therefore, energy demand in both countries and indeed for all of East Asia is increasing at a much slower pace than expected.

Figure 1 shows the demand for natural gas as a function of GDP for China, Japan, North America (not including Mexico), and the European Union (E.U.). Notice how China and Japan are following an E.U. type of pattern of slower growth in demand. This is probably due to high cost supplies but also due to differently regulated markets. On top of this slow growth in gas demand compared to GDP, East Asia has also begun to experience slower GDP growth itself, particularly in Japan. This will make the yearly overall growth in LNG demand even slower.

California may start to buy LNG supplies on the Pacific Rim, but probably at a slow pace since California already has access to gas from New Mexico and is a mature market with a slower demand growth rate. Therefore, for the Pacific Rim the demand side looks to be sluggish and slow moving.

Figure 1
Natural Gas Use as a Function of GDP



On the supply side in the Pacific Rim, there are a number of nearby suppliers with substantial supply capacity, particularly Indonesia, Australia, and the Sakhalin Islands off of Russia's East Coast. All three of these suppliers have natural gas wells right on the shore line with gas that is ready to be converted to LNG and shipped. Unfortunately for Alaska a long and expensive 800 mile pipeline is required before its gas can even get to a shoreline let along get to market in the Pacific Rim. That makes Alaskan gas very uncompetitive on the Pacific Rim. Other supply players on the Pacific Rim will be Middle East countries like Qatar and possibly Bangladesh. Therefore, on the Pacific Rim there are more than adequate supplies and a slow moving demand side that should make small new projects easy to plan and get on line. The way the market is shaping up there will be slow growth, very competitive supplies and therefore a stable, relatively low price.

The Atlantic Rim however looks quite different. While

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*Douglas B. Reynolds is Associate Professor of Oil and Energy Economics, School of Management, University of Alaska Fairbanks. This is the second of a series of articles based on his new book at first glance there appears to be plenty of Atlantic natural gas suppliers (including Algeria, Nigeria, Norway, Venezuela, Trinidad and Tobago, Russia's western regions, and even the Middle East) the demand side may still outpace supply growth. Thus the difference between the Atlantic Rim and the Pacific Rim is not really the size and potential capacity of the supply side, but rather it is the difference in the speed with which the demand side will increase. This is where the U.S. East Coast comes into play. But before we can understand how the eastern United States and eastern Canada will change the Atlantic Rim LNG market so profoundly, we need to look at how U.S. natural gas supplies will soon peak and decline (or indeed may have already peaked and started to decline) creating a huge supply gap within North America.

Right now North America is almost a de-facto closed market for natural gas. But the supply within the region is subject to M. King Hubbert's supply curve. To see the implication of this let us step back in time and see what happened in the United States oil market back in the 1970s and 1980s. A lot of energy professionals may recall the U.S. oil situation in the 1970s. At that time M. King Hubbert was one of the few energy professionals touting an imminent peak and decline in U.S. oil production. One criticism of Hubbert was that even if he were right about U.S. supplies, there would be plenty of oil supplies to satiate U.S. oil demand from the Middle East, and at reasonable or even cheaper prices. What actually did happen was quite unexpected. OPEC emerged as a powerful oil broker willing to reduce output in order to maximize its own value of the oil. And incidentally OPEC also managed to conserve the world's most important non-renewable natural resource for future generations, which very few people give them credit for doing. See Reynolds (2000). We should all be saying, "Thank you" to OPEC.

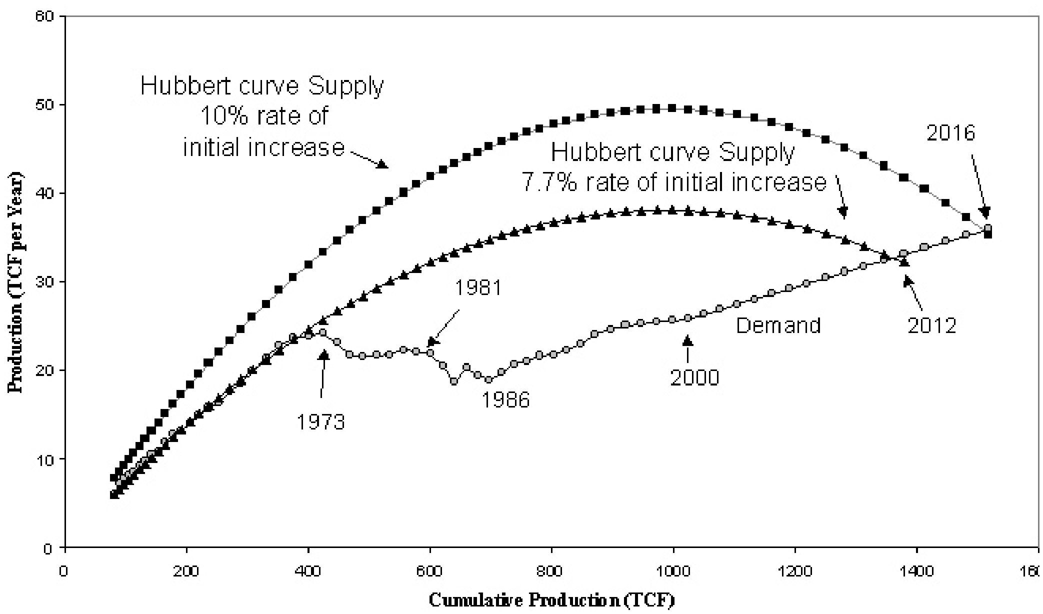
However, there is one other important lesson from the 1970s and 1980s. The actions at that time of individual OPEC members, and even non-OPEC oil producers who control their own oil production such as Mexico, show that supply does not quickly increase in the face of high energy prices. One reason for this is something that energy professionals have not considered much. Oil and gas producing countries that own and control all their own energy output tend to have very high reserve to production ratios. This is in part due to the risk averse nature of these countries. See Reynolds (2002). Oil producing countries are so concerned about making mistakes in investment and making mistakes in production agreements with major oil companies that they tend to expand oil and gas development very slowly.

Thus even though oil prices were very high in the 1970s and 1980s, and even though there were no OPEC agreements on output reductions until 1982, many OPEC countries could not expand their output and lower their reserve production ratios by much. This same problem is likely to inhibit growth in Atlantic Rim LNG supplies.

Now move from the 1970s back to the early 21st century. What happened with oil supplies in the United States is also about to happen with natural gas supplies. Soon if not already, North America's natural gas supplies will reach a peak, the same way that oil production peaked and declined for the United States in 1970. See Figure 2 for one (possibly optimistic) scenario based on one analysis of natural gas discoveries within the currently accessible U.S. and southern Canada natural gas supply region. Once the natural gas production peak occurs, the United States and even Canada, will need substantial quantities of natural gas much of it coming from international LNG producers.

Figure 2

U.S. Lower 48 and Southern Canadian Natural Gas Production and Forecast Maximum Production and Demand as a Function of Cumulative Production Base on Multi-cycle Hubbert Model Forecast



This shortage scenario will happen quickly. First a severe gap in U.S. supply and demand will emerge that Canada and Mexico will no be able to fill. Even with Alaskan and Northern Canadian gas on line there will still be a gap, so LNG imports will start up. But the demand gap for gas is likely to open up fast just like the U.S. oil supply gap enlarged very rapidly after U.S. oil production peaked. Most of this U.S. gap in natural gas supply will be on the east coast such that mostly Atlantic Rim supplies will be needed.

Unfortunately because of the speed with which the gap in supplies will hit and the large volumes of supply that will be needed, the Atlantic Rim suppliers will not be ready in time with new supplies. Atlantic Rim suppliers will have a hard time reacting quickly enough and the price may spin out of control. Indeed this is already happening. Certainly demand will also be forced down with the higher prices, but still a price shock will ensue. And prices can easily stay high for ten or more years while the major LNG suppliers only slowly increase their facilities. One reason that supplies will not rapidly increase as might be expected is because all of the major LNG suppliers will be risk averse to investing in new LNG capacity. This is exactly what happened with OPEC members in the 1970s. Oil production capacity just could not increase very quickly and it was actually demand reductions rather than supply increases that finally brought oil prices down. Plus bottlenecks and cartel behavior may only add to the long lead time needed.

Some might recall that when the U.S. deregulated natural gas that the market started reacting relatively fast to price signals such as the 2000/2001 natural gas price shock. Others might recall that the oil price shocks of the 1970s pushed oil prices above normal for over ten years. So both quick and slow responses are possible in energy markets. Plenty of anecdotal evidence can be had for both situations. Short run elasticities of supply and demand are not easily attained until an actual situation arises where they can be measured. As yet there has never been a natural gas crisis under a deregulated market other than possibly California's 2000/2001 experience to determine short run elasticities. But even in California, there was no LNG involved, no new gas pipelines created, and hydro power was restored.

One thing is clear no matter how fast or how slow LNG suppliers can ramp up and start producing significant new supplies of gas, the gas will be in much greater demand on the Atlantic than on the Pacific Rim side. This is the one reason that Alaska will obtain better value for its natural gas by selling it to the Atlantic Rim side via a long natural gas pipeline to Chicago than by selling it on the Pacific Rim side as LNG.

On the other hand, all energy players whether producers or consumers of energy should understand that there will be a significant difference in the Atlantic Rim LNG market compared to the Pacific Rim LNG market and should start planning for that difference. Maybe there will not be prolonged high LNG price on the Atlantic Rim side, but don't count on it.

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Hong Kong Energy Studies Centre Holds International Conference *(continued from page 23)*

publication. Fourteen papers were selected, with 11 of them dealing with energy market reform; consequently, the special issue will have the theme "Energy Market Reform." The Hong Kong Energy Studies Centre has invited Prof. Dienes from the University of Kansas to serve as a visiting research fellow during August to October, 2003 to help edit the special issue. The selected papers have been refereed by members of the editorial committee; the authors will carry out the necessary revisions, and the final polishing work by Dr. Chow and Prof. Dienes will be completed by mid-November for final submission to *Energy Policy.*

The Asian Energy Conference is a bi-annual international event presented by the Hong Kong Energy Studies Centre focusing on energy issues of particular relevance to Hong Kong and the region. Given the small number of energy specialists in Hong Kong, but its strategic location within Asia, the Centre believes that it can play a useful coordinating role in linking local specialists and energy firms with international experts to tackle current energy problems. Results of such activities culminated in some high quality publications, e.g., the First Asian Energy Conference yielded the Special Issue "Themes in Current Asian Energy" *Energy Policy,* No.11, Vol. 31. The past two conferences have been financially supported by the Hong Kong Baptist University, and local energy firms like Hong Kong & China Gas Co. Ltd., CLP Power HK Ltd., ExxonMobil and Caltex Oil HK Ltd. It is anticipated that some future conferences might be jointly organized with Asian universities located in other countries. The network of energy specialists built up in the past two conferences will be very useful in developing future events with an international dimension.

Larry Chow

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6TH IAEE EUROPEAN CONFERENCE 2004

Hosted by:
Swiss Association for Energy Economics (SAEE) and Centre for Energy Policy and Economics (CEPE)

Modelling in Energy Economics and Policy

Swiss Federal Institute of Technology Zurich (ETH) – Zurich – Switzerland
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General equilibrium modelling and energy policy analysis (Top-down)
Input-Output models
Integrated energy system models (Bottom-up)
New modelling concepts
Strategic modelling challenges for energy companies
Modelling policy-induced technical progress
Modelling of environmental impacts of energy production

**** CALL FOR PAPERS ****

Abstract Submission Deadline: January 31, 2004
(Submission opening November 1, 2003)

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Derek Bunn, London Business School, UK
Michael A. Crew, Rutgers University, USA
William Hogan, Harvard University, USA
Lester Hunt, University of Surrey, UK
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- Fuel Cell and Hydrogen Technology
- Distributive Energy Systems
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3. Sustainability:
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- Global Warming and Energy
- Energy and Pollution Control
- Nuclear Safety and Waste Disposal
- Rationality and Energy Selections
- Policy Options and Strategies

Keynote Plenary Session Theme:
- The Future of Energy

4. Individual Energy Sectors:
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- Oil
- Natural Gas (including LNG)
- Electricity
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5. Energy Efficiency and Energy Modeling:
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Publications

Norwegian Natural Gas – Liberalization of the European Gas Market. Ole Gunnar Austvik (2003). 272 pages. Price: Euro 45. Contact: Europa-programmet, PO Box 6877 St. Olavsplass, N-0130 Oslo, Norway. Phone: 47-22-99-28-00. Fax: 47-22-99-28-01. Email: bestilling@europaprogrammet.no URL: www.europaprogrammet.no

Getting Bigger By Growing Smaller. Joel Shulman (2003). 224 pages. Price: $24.95. Contact: Gardi Ipema Wilks, FT Prentice Hall. Phone: 708-366-8389. Email: giwilks@aol.com

Calendar

3-6 November 2003, Hydro 2003 at Cavtat, Croatia. Contact: Helen Green, Project Manager, NetWork Events Ltd, Old Manor House, Compton, West Sussex, PO18 9EX, United Kingdom. Phone: 44-23-9263-1331. Fax: 44-23-9263-1797 Email: hydro@networkevents.ltd.uk URL: www.networkevents.ltd.uk/events/hydro2003

3-4 November 2003, North American Gas Strategies Conference at Calgary. Contact: Paula Arnold, Manager, Corporate Communications & Conference, Ziff Energy Group, 1117 Macleod Trail SE, Calgary, AB, T2G 5M8, Canada. Phone: (403) 234-4279. Fax: (403) 237-8489 Email: paula.arnold@ziffenergy.com URL: http://www.ziffenergyconferences.com

6-7 November 2003, National Oil Companies 2003 at Le Meridien Piccadilly, London, UK. Contact: Babette Van Gessel, Global Pacific & Partners. Phone: 27-11-778-4360. Fax: 27-11-880-3391 Email: info@glopac.com URL: www.petro21.com/events

12-13 November 2003, Indian Petrochem - 2003 at Mumbai, India. Contact: Jayesh Sampat, Elite Conferences Pvt Ltd, India. Phone: 91-22-2385-1430. Fax: 91-22-2385-1431 Email: eliteconf@vsnl.com URL: www.eliteconferences.com

12-13 November 2003, US Coal Imports at Baltimore, USA. Contact: Justine Clark, Marketing Manager, The McCloskey Group, 2 Pages Court, St.Peters Road, Petersfield, Hampshire, GU32 3HX, UK. Phone: +44 1730 265095. Fax: +44 1730 269032 Email: justine.clark@mccloskeycoal.com URL: http://www.globalcoal.com/mcis/news/searchnews.cfm?task=2&pubnameid=13&ShowMenu=11

13-14 November 2003, North American Transmission Grid Reliability at Marriott Bloor Yorkville, Toronto, Ontario, Canada. Contact: Graham Christison, Marketing Coordinator, The Canadian Institute, 1329 Bay Street, Toronto, Ontario, M5R 2C4, Canada. Phone: 877-927-7936 x404. Fax: 877-927-1563 Email: graham@canadianinstitute.com URL: http://www.canadianinstitute.com/contentframes.cfm?ID=2377

17-19 November 2003, World Energy Engineering Congress at Georgia World Congress Center, Atlanta, GA. Contact: Patricia Munoz, Conference Coordinator, AEE, 4025 Pleasantdale Rd Ste 420, Atlanta, GA, 30340, USA. Phone: 770-447-5083. Fax: 770-446-3969 URL: www.aeecenter.org

17-21 November 2003, World Fiscal Systems for Oil and Gas - Training Seminar at Nassau, Bahamas. Contact: Norrie Hernon, Sales Executive, CWC Associates, 3 Tyers Gate, London, SE1 3HX, UK. Phone: +44 207 089 4181. Fax: +44 207 089 4201 Email: nhernon@thecwcgroup.com URL: www.thecwcgroup.com/conferences

17-18 November 2003, 2nd Annual Conference GEPetrol & Oil and Gas in Equatorial Guinea 2003 - USA at Houston, USA. Contact: Kate McHugh, Miss, CWC Associates Ltd, 3 Tyers Gate, London, SE1 3HX, UK. Phone: +44 20 7089 4200. Fax: +44 20 7089 4201 Email: kmchugh@thecwcgroup.com URL: http://thecwcgroup.com/conferences

17-21 November 2003, Export & International Project Finance in the Energy Sectors at New York. Contact: Jeff Kaminski, Euromoney Training - Americas, 225 Park Avenue South, New York, NY, 10003, United States. Phone: 212-843-5225. Fax: 212-361-3499 Email: jkaminski@euromoneyny.com URL: http://www.euromoneytraining.com/databasedriven/coursedetail.asp?busareaid=3&CourseID=160

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19-20 November 2003, International Petroleum Agreements at Houston, TX. Contact: Conference Division, The University of Tulsa - CESE, 600 S College Ave, Tulsa, OK, 74104, USA. Phone: 918-631-3088. Fax: 918-631-2154 Email: cese@utulsa.edu URL: www.cese.utulsa.edu:8080/coursedetail.jsp?id=126

27-28 November 2003, 3rd Annual Anglo-Norwegian Energy Conference at Oslo, Norway. Contact: Conference Coordinator, The CWC Group, Norwegian Petroleum Society, PO Box 175, Stavanger, 4001, Norway. Phone: 47-51-84-90-43/44. Fax: 47-51-84-90-41 Email: annette.aalmo@npf.no URL: www.npf.no/cwc2003/

1-5 December 2003, World Legal Systems and Contracts for Oil & Gas - Training Seminar at London, UK. Contact: Norrie Hernon, CWC Associates, 3 Tyers Gate, London, SE1 3HX, UK. Phone: +44 207 089 4181. Fax: +44 207 089 4201 Email: nhernon@thecwcgroup.com URL: www.thecwcgroup.com

10-11 December 2003, Produced Water Management Europe at Aberdeen. Contact: Customer Services, Oil & Gas IQ (IQPC), Anchor House, 15-19 Britten St, London, SW3 3QL, UK. Phone: +44(0)20 7368 9300 URL: www.oilandgasIQ.com/GB-2062/ediary

12-23 January 2004, PURC/World Bank 15th International Training Program on Utility Regulation and Strategy at Gainesville, Florida, USA. Contact: Virginia Hessels, Program Manager, Public Utility Research Center, University of Florida, PO Box 117142, Matherly Hall, University of Florida, Gainesville, Florida, 32611, USA. Phone: +1-352-392-3655. Fax: +1-352-392-5090 Email: purcecon@cba.ufl.edu URL: http://bear.cba.ufl.edu/centers/purc/international/fifteen.htm

14-16 January 2004, Electricity Supply Industry in Transition at Thailand. Contact: Mr. Olivier Le Sang, Energy Field of Study, Asian Institute of Technology, PO Box 4, Klong Luang, Pathumthani, 12120, Thailand Email: olivier@ait.ac.th URL: www.serd.ait.ac.th/ep/esi

20-21 January 2004, Distributed Energy Resources at San Diego, CA. Contact: Frank Kester, Conference Coordinator, Energy West. Phone: 949-492-1340 Email: energywestnews@cs.com

20-22 January 2004, Distributech at Orlando, FL. Contact: Jennifer Lindsey, Conference Manager, PennWell Global Energy Group, 1421 S. Sheridan Rd, Tulsa, OK, 74112, USA. Phone: 918-832-9313 Email: dtechconference@pennwell.com URL: www.distributech.com

11-14 February 2004, Oceantex 2004 at Mumbai, India. Contact: Deepak Mukhi, Chemtech Secretariat, 3rd Flr, 210, Taj Building, Fort, Mumbai, 400001, India. Phone: 91-22-56310515. Fax: 91-22-56310525 Email: deepak_mukhi@jasubhai.com URL: www.chemtech-online.com

18-19 February 2004, Wind Energy and Rural Development in North Dakota V Conference at Fargo, ND. Contact: Derek Walters, Communications Director, EERC, Univ of North Dakota, PO Box 9018, Grand Forks, ND, 58202, USA. Phone: 701-777-5000. Fax: 701-777-5181 Email: dwalters@undeerc.org URL: www.undeerc.org

20-22 February 2004, Eastern Economic Association 2004 Annual Conference at Washington, DC. Contact: Dr. Mary Lesser, EEA, c/o Iona College, 715 North Avenue, New Rochelle, NY, 10801, USA. Phone: 914-633-2088. Fax: 914-633-2549

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Contributing Editors: *Paul McArdle* (North America), Economist, US Department of Energy, Office of Policy, Planning and Analysis, PE-50, Washington, DC 20585, USA. *Tel*: 202-586-4445; *Fax* 202-586-4447. *Tony Scanlan* (Eastern Europe), 37 Woodville Gardens, London W5 2LL, UK. *Tel* 44-81 997 3707; *Fax* 44-81 566 7674. *Marshall Thomas* (Industry) 3 Ortley Avenue, Lavallette, NJ 08735, USA *Tel* 908-793-1122; *Fax:* 908-793-3103.

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Energy Economics Education Foundation, Inc.
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