IA EE INTERNATIONAL ASSOCIATION FOR ENERGY ECONOMICS

Newsletter

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Editor: *David L. Williams* **Contributing Editors**: *Paul McArdle, Tony Scanlan and Marshall Thomas*

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President's Message

It has been a great privilege and honour to serve as president of the IAEE organization for the year 2001. I am particularly delighted that I have had the opportunity to serve during a very active period of the organization related to overall activities, planning for future international conferences and development of an excellent IAEE web-site (www.iaee.org).

The energy world is in the midst of fundamental changes in terms of markets and prices, deregulation and industrial structure, technology and energy and environmental policy. In addition we experienced a global economy in transition to a slowdown. This development has been accelerated by the terrible tragedy and disaster that struck September 11. We see the trends in many industries and observe the uncertainties among individuals and consumers. The end of year 2001 and beginning of 2002 is now characterized by turbulent times ahead both economically as well as politically. The aircraft transportation sector as an example consumes about 8 million bbl/day which represents 10% of the world oil consumption. When such an industry cuts their capacity and places a big share of the aircraft fleet on the ground, it influences the supply/demand equilibrium significantly.

Under such international circumstances it is even more important to communicate and discuss across borders, cultures and professions. IAEE is a relatively small international organization with a membership of about 3200 but with chapters in 24 countries and a membership presence in 65 countries. As such IAEE has a truly international network of energy professionals and individuals and may play an important role within a core sector for the global economy. Our international conferences serve as an excellent meeting point in this respect.

We now have a firm plan for future international conferences for the whole period 2002-2005 thanks to the excellent planning work from our VP for Conferences Michelle Foss together with the input both from David Williams at the HQ and the local organizers.

The 25th Annual IAEE International Conference will be in Aberdeen from 26-29 June, next year, at the Aberdeen Exhibition and Conference Centre and University of Aberdeen. The planning and preparation is taken well care of by Alex Kemp and Paul Tempest. You should mark this event in your schedule plan and prepare your papers for submittal. The next event in 2002 is the the 22nd USAEE/IAEE North American Conference that will take place in Vancouver, Canada 6-8 October, 2002.

The 2003 IAEE International Conference will be held in Prague, Czech Republic, 5-7 June. The 2004 IAEE International Conference will be arranged in Tehran, Iran at the Radio and TV Conference Centre in Tehran in May with the major hotel to be Azadi Grand Hotel; contact person, Seyed Alavi. The 2005 IAEE International Conference is then to be arranged at the Tapei International Convention Centre in Taiwan in June. The major hotel is the Hyatt Taipei Hotel and the contact person is Chyi-Gang Huang.

I would like to take this opportunity to thank the individual members of the IAEE Council for their cooperation, effort, work and time they have allocated into the development and operation of our organization for the year 2001. Also I would like to give tribute to the officers in all our local chapters for their contribution this year. Likewise I want to thank both

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Editor's Notes

Francisco García Hernández, Michelle Michot Foss, and Alberto Elizalde Baltierra describe the Mexican electricity market after several years in which private participation in electricity generation has been allowed. They provide an insight into the efficiency of Mexico's electricity system and suggest several proposals to advance the Mexican market.

Alexander Kemp and Linda Stephen note that the UK Continental Shelf is now a mature petroleum province, however, there are over 200 relatively small undeveloped

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

David Williams Sr. and Jr. for their efficient operation of our Headquarters and the tremendous effort they put into our organization. It is a pleasure for me to hand over the presidency for 2002 to Len Coburn. He is already member of the Council and has also served as a Council member in previous years.

Arild N. Nystad
President, IAEE

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

discoveries. Individual field developments on a stand-alone basis may not be viable. When a group of fields are developed on a cluster basis using a common infrastructure the reduction in development costs can greatly enhance their viability. Investment in a cluster of fields also produces very substantial risk-reduction benefits. To maximise these benefits there is a need to minimise conflicts of interest among different licensees. Unitisation of field interests helps to align investor incentives.

Petter Osmundsen and Ragnar Tveterås discuss the decommissioning of offshore oil installations, noting that the technical reports on the issue are generally not available to the public and that little attention has been paid to the economics involved. They provide an overview of the most important economics topics related to decommissioning and discuss Norway's policy on the matter.

Peter Hartley and Kenneth B. Medlock III write that prudence is justified when considering the appropriate policy with regard to global warming. Reducing fossil fuel combustion is a risky investment, which is justifiable only if the expected return is competitive with alternative investments of comparable risk. Substantially improved data gathered over the next decade will allow for a better assessment of the costs and benefits of controlling carbon dioxide emissions.

Douglas Reynolds writes about risk in the oil market. The majority of the world's oil resources are controlled by national oil companies, which tend to be very risk averse and expand oil supplies more slowly. The result will be much lower supplies than expected causing an oil price shock.

Hans Landsberg

Hans Landsberg, one of Resources for the Future's intellectual founders and a pioneer in energy and mineral economics, passed away on October 15th from complications of Parkinson's Disease. He was 88. He first gained national recognition for his groundbreaking 1963 work, *Resources in America's Future*, a blueprint for projecting long-term requirements and availability of energy, non-fuel minerals, land, water, crops and numerous other industrial materials, which he co-authored with Leonard Fischman and Joseph Fisher.

The work of Landsberg and his collaborators - including the landmark 1979 study, *Energy: The Next Twenty Years*, provided the impetus for what is now the routine and systematic collection and analysis of energy data by such entities as the U.S. Energy Information Administration.

Throughout his professional career, Landsberg served on a number of distinguished advisory panels for the National Academy of Sciences and the Congressional Office of Technology Assessment, among others. In 1972, he served as an advisor to Maurice Strong in his capacity as the Secretary General of the United States Conference on the Human Environment. In 1974, Landsberg was named a Fellow of the American Academy of Arts and Sciences; in 1982, he became a Fellow of the American Association for the Advancement of Science. The International Association of Energy Economists honored Landsberg in 1983 for his outstanding contributions to the field. That same year, he became a Senior Fellow Emeritus at RFF, where he continued to be professionally active, contributing to the literature on resource economics and advising other RFF scholars.

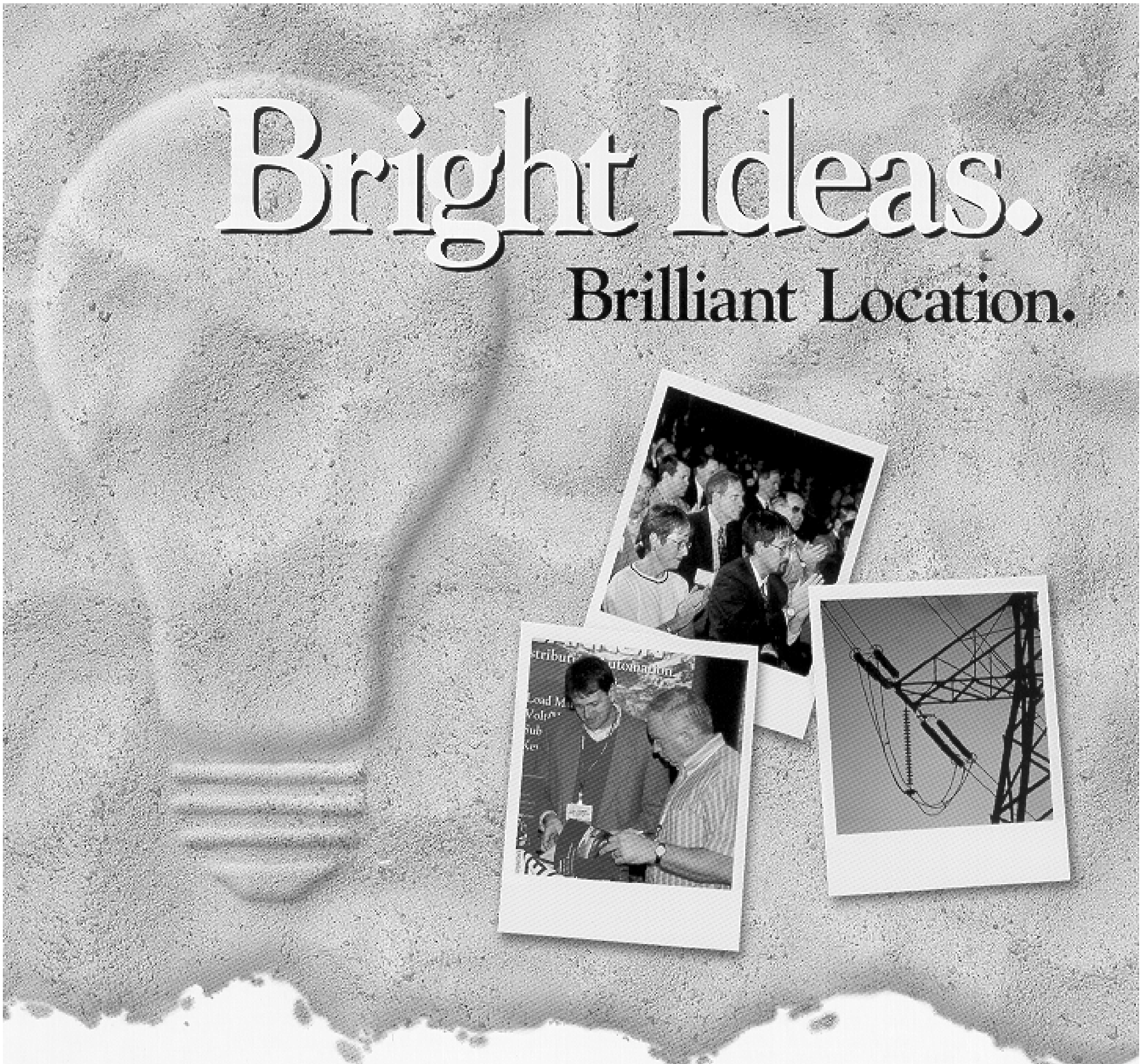
Landsberg is survived by his daughter Ann S. Landsberg, his sister Dr. Eva Landsberg-Lewin, and his two grandsons, James Truslow and Max Baehrd.

Future IAEE Events

June 26-29, 2002	25th IAEE International Conference Aberdeen, Scotland *Aberdeen Exhibition and Conference Centre*
October 6-8, 2002	22nd USAEE/IAEE North American Conference Vancouver, BC, Canada *Sheraton Wall Centre Hotel*
June 5-7, 2003	26th IAEE International Conference Prague, Czech Republic Dorint Prague Hotel

Special Offer to Academicians

Headquarters has a quantity of *The Energy Journal* Special Issue, **The Costs of the Kyoto Protocol: A Multi-Model Evaluation,** available for bulk purchase for academic use. Contact David Williams at 216-464-5365 or iaee@iaee.org for particulars.



Bright Ideas.
Brilliant Location.

British Institute for Energy Economics
International Association for Energy Economics

25th International Conference
Exhibition and Conference Centre, Aberdeen, Scotland
June 27th – 29th, 2002

Innovation and Maturity in Energy Markets: Experience and Prospects

***** Call for Papers – Program & Social Activities *****

On behalf of the British Institute for Energy Economics it is our pleasure to invite you to Scotland for the 25th International Conference of the IAEE. Please mark your calendar for this important event, the silver jubilee conference, and the first time that the IAEE has come to Scotland.

The conference will bring together a remarkable set of speakers for its plenary sessions. However, the centrepieces of the conference will be its concurrent paper sessions which will form the heart of the meeting. This is the first call for papers for these sessions. Submissions are welcome in all areas of energy economics, but those which lie within the main themes are particularly welcome. The conference has five main themes all of which are important globally:

Renewable Energy: The pace of development of all forms of renewables. Barriers to development. Technical progress, reduction of costs and government incentives.

The Role of Government: Government regulation in all stages of the energy industries. The impact of environmental policies on energy. Taxation of energy. The evolving geopolitics of energy.

Natural Gas: The problems of gas development at global and regional levels. The determination of prices. The reserve position. The place of natural gas within the power generation sector. Security of Supply.

The Oil Industry: Technology and the resource base. The development of the offshore industry. Taxation. New frontiers. The Future of the North Sea Industry. Oil price developments and market mechanisms.

IT and the Energy Sector: How has the impact of IT developed, or is the revolution over? The place of e-commerce. The provision of information by governments and its role. IT and market transparency. IT and its impact on costs.

Abstracts should be between 200 and 1000 words. Details should include the title of the paper, name(s) and address(es) of author(s), telephone, fax and email as well as a short CV. At least one author from an accepted paper must pay the registration fees and attend the conference to present the paper. All abstracts and inquiries should be submitted to: Professor Alex Kemp, University of Aberdeen, Department of Economics, Edward Wright Building, Dunbar Street, Old Aberdeen, AB24 3QY. Tel: 44 (0) 1224 272168, Fax: 44 (0) 1224 272181, email: a.g.kemp@abdn.ac.uk.

The deadline for submission of abstracts is January 31st 2002.

Visit the IAEE website at http://www.iaee.org for the latest information or visit the conference website at www.abdn.ac.uk/iaee

Important Notice: Young Energy Economists Session

One set of concurrent paper sessions will be given entirely to authors under the age of 35. In addition, a prize of $500 will be awarded for the best paper given in this session, plus the refund of the conference registration fees. Please indicate on the abstract if any author is under 35 years old.

Brief Program Overview

Session Topics Under Development Include:

Towards a New Global Energy Policy	The Perils of Forecasting
The North Sea in a Global Context	Privatisation
Middle East Energy Issues	25 Years of Energy Policy:
U.S. Regulation Matters	A Tour by Past IAEE Presidents

Preliminary List of Distinguished Speakers Include:

Malcolm Brinded, Chairman, Shell UK
Gerald Doucet, World Energy Council
Herman Franssen, Petroleum Economics Limited
Alex Kemp, University of Aberdeen
Paul Stevens, University of Dundee
Brian Wilson, UK Minister of Oil
Brett Polman, Texas PUC
Donald Santa, Troutman Sanders
Peter Davies, BP
Michelle Foss, University of Houston
Tony Hayward, BP
Lord Nigel Lawson
David Newberry, University of Cambridge
Shirley Neff, U.S. Senate
Vicky Bailey, US Department of Energy

Social Delights

The Conference will be held in Aberdeen, Scotland, the "Oil Capital of Europe" and operations centre for North Sea oil. Major and smaller oil companies and serve companies have prominent presences in the city. The timing of the conference ensures that attendees can enjoy daylight for nearly 24 hours per day. June is also generally the warmest month of the year. Aberdeen has many attractions including an ancient University. It is also the ready gateway to magnificent scenery, many castles, ancient and modern, malt whisky distilleries and golf courses.

The welcome reception on the evening of 26 June will be held in the Elphinstone Hall at the ancient University of Aberdeen. This will give delegates an opportunity to see the campus, including the unique King's College chapel.

On the evening of 27 June the gala dinner will be held at Ardoe House, a magnificent 19th century Baronial Mansion with modern ballroom facilities. It is located in beautiful surroundings beside the river Dee about 4 miles from the city.

On the evening of the 28th there will be a Scottish evening featuring a reception with Scottish food and entertainment.

Cultural Programme

A variety of cultural events will be available. Aberdeen itself has an art gallery and museums (including a Maritime Museum featuring the history of North Sea oil). Within easy travelling distance are many malt whisky distilleries. It is possible to go on a "whisky trail" involving several distilleries within a relatively short time period. The North-East of Scotland is also richly endowed with many castles, some of which date from the Middle Ages. Some are now ruined, but many are in use, including several run by the National Trust for Scotland. It is possible to visit more than one in a day, for example, Balmoral Castle, the Scottish home of the Royal Family, is within easy travelling distance. Aberdeen and the surrounding areas are also very well-endowed with golf courses, including several championship ones, generally open to visitors. The very long hours of daylight in June greatly increase the opportunities available to visitors.

Technical Tours

A variety of technical visits will be available. In Aberdeen itself, beside the Conference Centre, there is a drilling rig used for experimental work. Approximately 30 miles North of Aberdeen there is the recently expanded Peterhead Power Station with a capacity of around 1,500MW. A little further north is the large St. Fergus Gas Terminal. To the south of Edinburgh is the Torness nuclear power station.

Getting to Aberdeen

Aberdeen is served with 11 daily direct flights from London (Heathrow and Gatwick). There are also several direct flights from London Luton (Easyjet), London City airport, Manchester, Newcastle, Birmingham, Leeds/Bradford, Humberside, Norwich and Glasgow. There are direct international flights from Amsterdam and Stavanger. A special deal has been struck with KLM/Northwest for conference delegates. The airport is 20 minutes drive time to the City Centre or the Conference Centre. There are direct train links from London and many other cities in the UK to Aberdeen.

Queries:

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**** CONFERENCE SPONSORS TO-DATE**: Shell, BP Amoco, the UK Department of Trade and Industry and the Aberdeen City Council**

The Mexican Electricity Market: Regional Forecasting and Restructuring of the Power Industry

*By Francisco García Hernández, Michelle Michot Foss, and Alberto Elizalde Baltierra**

Abstract

Mexico, like many other emerging countries, is interested in restructuring its electricity industry. Mexico is moving from almost complete control of production, transmission and distribution of the electricity market by the government, to a situation in which private participation in electricity generation is allowed. This paper describes the Mexican electricity market after several years of operation of this new production arrangement and states some efficiency measures (technical and nontechnical losses and other criteria) of the actual electricity system. To understand the evolution of the Mexican electricity market, we have taken a regional approach. There has been a significant shift in the geographical location of production since NAFTA implementation. In our regional approach prices, supply and demand are analyzed for use in anticipating the electricity market situation going forward. Finally, in accordance with our analysis, several proposals are drawn to advance the restructuring of the Mexican electricity market.

Introduction

Mexico's electricity market, as in the case of the petroleum industry, works almost entirely through a single producing company, the *Comisión Federal de Electricidad* (CFE). Transmission is operated mainly by the CFE, but distribution and marketing are handled by the CFE and by *Luz y Fuerza del Centro* (LFC), which operates in Mexico City. The operating scopes of each entity are defined by regions and, from the point of view of their organizations, each public enterprise is independent of the other. The dominant power of the CFE in electric power generation, transmission and distribution is well known despite the 1992 reform to the Law of Public Service of Electricity. This reform sought to increase the participation of the private sector (both domestic and foreign companies) in the generation of electricity for the national market. According to an official document[1] the outcome has not been very encouraging. In 1999, CFE's participation in the capacity of generation of electricity was 90 percent, Petroleos Mexicanos or Pemex (Mexico's national oil company) 4.4 percent, LFC 2.3 percent and private companies 3.3 percent.

The private sector can participate in cogeneration, self-use production, in BLT projects (build, lease and transfer) and as independent power producers (IPPs). The main characteristics of each one of these categories can be described as follows:

- In the case of cogeneration and self-use production, any surplus production has to be sold to the CFE at a price fixed by the regulator.
- In the BLT projects, building and financing are the responsibility of the private investor. The CFE only supervises the project. When construction is complete, the plant is operated by the CFE. After two years of operation, the developer is paid as a financial leasing of the asset. The project's costs are registered as direct private investment (regardless of whether it is domestic or foreign), and after two years it is converted to public debt (again, regardless of whether the IPP is domestic or foreign).
- In the case of IPPs, the CFE guarantees the price and the market (total or partial) to private investors. They receive a concession for 30 years to operate the plants, after which the assets become CFE's property.

BLT and IPP projects are subject to public bidding, but once they are granted the market risk disappears for the investors. Financial risk does not exist either, given that the financial liabilities of the CFE become public debt.[2] It is interesting that from the increase in generation capacity carried out or to be carried out from the year 1998 to the year 2001, CFE resources will fund only 2 percent. The remainder will be BLT and IPP projects. This data clearly shows the dependency of the CFE on the federal government, and for the same token, it is a good indicator of the incipient development of the electric power market.

Restructuring Mexico's electricity industry was considered at the end of the previous public administration (from 1994-2000). The most important argument was that the federal government did not have the financial resources to maintain or increase the level of operations of the semi-official electric sector, and that reforms to the 1992 law did not give the expected results with respect to private sector participation.

Unfortunately, the proposal was unsuccessful because of the general opposition within political parties other than the Partido Revolucionario Institucional (PRI), in control of government at the time. The reasons, although obvious, are worth mentioning. Banks, highways and other state company privatizations were disastrous requiring massive public finance commitments to avoid bankruptcies. In addition, the proposed electricity restructuring plan was adopted from Argentina. The extensive dislocation of workers experienced in that country triggered strong opposition from Mexico's electric industry unions.

After the 2000 national elections and resulting change of government and political control, it was expected that there would be new proposals to restructure the electric industry. Instead, the original proposal developed in 1999 was slightly revised to include an emphasis on the possibility of establishing a bulk electricity market, a feature already contemplated in the original version. Political weakness of the present federal government may be a serious obstacle for its initiative to restructure the electric sector, especially if the opposition of "official trade unionism" is considered.

Historical Evolution of Electricity Consumption

In most "emerging market countries", electricity that is produced is electricity that is consumed. Prices are generally administrated and set more like political objectives than market signals. In the case of the CFE, an excessively high

* Francisco García Hernández is with the Instituto Tecnológico y de Estudios Superiores de Monterrey and Michelle Michot Foss and Alberto Elizalde Baltierra are with the Energy Institute, University of Houston. This is an edited version of their paper presented at the 24th Annual IAEE Conference in Houston, TX, April 25-27.

[1] See footnotes at end of text.

price can be justified given its status as a public monopoly, but a price excessively low can also be justified considering its dependency on the federal budget. The CFE's operating deficits become, eventually, current and capital transfers from the federal government.

Electricity Consumption by Region and by Consumer Category

The aggregate analysis of electricity consumption facilitates detection of the historical path of this variable, but hides the differential evolution of diverse sectors of the economy. Fortunately, there is information about electricity sales to six categories of final consumers: residential, commercial, services, agricultural and medium and large industry (Table 1). The information in Table 1 shows that electricity consumption in the industrial sector constitutes more than 50 percent of the total market, and that it has increased in recent years.

Levels of regional development in Mexico and economic activity in each region also define consumption paths and differential evolution of demand. Different regionalization criteria have been developed in accordance with different

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Table 1
Electricity Consumption by Region and by Consumer Category (GWh)

Border region

Year	**1988**	**%**	**1990**	**%**	**1995**	**%**	**1999**	**%**
Category								
Residential	5,444.4	22.3	6,440.9	23.2	8,615.0	23.9	10,785.3	22.6
Commercial	1,734.2	7.1	1,952.1	7.0	2,175.9	6.0	2,633.1	5.5
Services	756.5	3.1	784.1	2.8	765.1	2.1	794.6	1.7
Agricultural	2,584.2	10.6	2,693.0	9.7	2,687.8	7.5	3,081.2	6.5
Industry	13,910.2	56.9	15,935.1	57.3	21,743.1	60.5	30,438.4	63.6
Totals	**24,429.5**	**100.0**	**27,805.2**	**100.0**	**35,986.9**	**100.0**	**47,732.6**	**100.0**

Central Region

Year	**1988**	**%**	**1990**	**%**	**1995**	**%**	**1999**	**%**
Category								
Residential	4,427.1	18.7	5,305.9	20.5	7,469.6	24.6	7,761.3	20.9
Commercial	3,076.4	13.0	3,374.7	13.1	3,813.9	12.5	3,994.6	10.8
Services	1,774.4	7.5	1,698.9	6.6	2,009.3	6.6	2,108.0	5.7
Agricultural	328.3	1.4	343.8	1.3	360.5	1.2	424.8	1.1
Industry	14,054.5	59.4	15,105.5	58.5	16,756.4	55.1	22,890.7	61.5
Totals	**23,660.7**	**100.0**	**25,828.8**	**100.0**	**30,409.7**	**100.0**	**37,179.4**	**100.0**

Rest of the States Region

Year	**1988**	**%**	**1990**	**%**	**1995**	**%**	**1999**	**%**
Category								
Residential	6,953.4	20.6	8,642.3	22.5	12,377.0	26.4	14,823.9	24.7
Commercial	2,506.3	7.4	2,957.9	7.7	3,659.5	7.8	4,335.9	7.2
Services	1,910.4	5.7	2,045.9	5.3	2,509.9	5.3	2,529.1	4.2
Agricultural	3,496.3	10.3	3,670.6	9.5	3,641.5	7.8	4,490.5	7.5
Industry	18,928.1	56.0	21,172.4	55.0	24,780.5	52.7	33,905.0	56.4
Totals	**33,794.5**	**100.0**	**38,489.1**	**100.0**	**46,968.4**	**100.0**	**60,084.4**	**100.0**

Totals

Year	**1988**	**%**	**1990**	**%**	**1995**	**%**	**1999**	**%**
Category								
Residential	16824.9	20.5	20389.1	22.1	28461.6	25.1	33370.5	23.0
Commercial	7316.9	8.9	8284.7	9.0	9649.3	8.5	10963.6	7.6
Services	4441.3	5.4	4528.9	4.9	5284.3	4.7	5431.7	3.7
Agricultural	6408.8	7.8	6707.4	7.3	6689.8	5.9	7996.5	5.5
Industry	46892.8	57.3	52213.0	56.7	63280.0	55.8	87234.1	60.2
Totals	**81884.7**	**100.0**	**92123.1**	**100.0**	**113365.0**	**100.0**	**144996.4**	**100.0**

Source: Gerencia Comercial, CFE.

Mexican Electricity Market *(continued from page 7)*

study objectives. For example, the CFE has its own regional breakdowns while Secretaría de Energía or SE, Mexico's energy ministry, provides data on electricity consumption for nine regions.[3] In our paper, we consider that the dynamic northern tier economy, promoted mainly by the maquiladora industry, has established an electricity consumption pattern that has not been studied. To compare electric power patterns for the whole country, we define only three regions:

- The Border Region comprised by the states of Tamaulipas, Nuevo Leon, Coahuila, Chihuahua, Sonora and Baja California;
- The Center Region comprised by the states of Puebla, Morelos, Hidalgo, Estado de México and the Federal District served by (partial or totally) the LFC; and
- The remaining states.

The rationale for our regional structure is based on the following criteria:

- In the northern border region, demand for electricity can be satisfied by a company located in Mexico and/or by

Table 2

National and Regional Average Prices by Consumer Category (cents per KWh)

National and Regional

Year Region	1988	Difference	1990	Difference	1995	Difference	1999	Difference
Border	7.94	0.985	13.22	1.005	25.01	0.978	49.76	0.952
Central	8.85	1.098	14.27	1.084	27.83	1.089	57.02	1.091
Rest	7.60	0.943	12.37	0.940	25.14	0.984	51.33	0.982
National	8.06		13.16		25.66		52.27	

Border Region

Year Category	1988	Difference	1990	Difference	1995	Difference	1999	Difference
Residential	7.78	0.965	13.58	1.032	26.52	1.038	52.75	1.009
Commercial	15.36	1.906	26.88	2.043	63.74	2.494	118.58	2.269
Services	8.69	1.078	19.41	1.475	43.44	1.700	97.46	1.865
Agricultural	2.30	0.285	3.42	0.260	13.80	0.540	26.10	0.500
Medium Size	9.16	1.136	14.84	1.128	23.43	0.917	50.85	0.973
L. Industry	6.80	0.844	10.26	0.780	15.35	0.601	35.40	0.677

Central Region

Year Category	1988	Difference	1990	Difference	1995	Difference	1999	Difference
Residential	6.84	0.849	9.82	0.746	24.57	0.961	48.47	0.927
Commercial	14.99	1.860	25.34	1.926	58.08	2.272	115.21	2.204
Services	8.85	1.098	19.75	1.501	40.73	1.594	89.94	1.721
Agricultural	2.12	0.263	3.15	0.239	13.09	0.512	25.09	0.480
Medium Size	9.00	1.117	14.20	1.079	23.60	0.923	51.97	0.994
L. Industry	6.92	0.859	10.50	0.798	16.11	0.630	37.36	0.715

Rest of the States Region

Year Category	1988	Difference	1990	Difference	1995	Difference	1999	Difference
Residential	6.81	0.845	10.56	0.802	24.73	0.968	45.96	0.879
Commercial	14.74	1.829	26.06	1.980	60.33	2.360	121.02	2.315
Services	8.58	1.065	18.77	1.426	41.62	1.628	94.50	1.808
Agricultural	2.14	0.267	2.98	0.226	13.26	0.519	25.54	0.489
Medium Size	9.30	1.154	14.88	1.131	25.65	1.004	54.27	1.038
L. Industry	9.48	1.176	10.05	0.764	15.12	0.592	34.45	0.659

Source : CFE,Gerencia Comercial

companies located in the United Sates.

- The region served by LFC has a market that is important to analyze separately given that the company is managed with autonomous administrative criteria (quasi public).
- The region comprised by the rest of the states is currently served by the CFE and in the future could be served by private companies, all located within Mexico (i.e., no possibilities for cross-border trade).

The importance of each region to total consumption of electricity depends on historical factors and on more recent events such as the NAFTA treaty. Historical factors, such as regional concentration of population as a result of urbanization beginning in the 50´s and concentration of industrial activity, explain regional consumption of electricity. On the other hand, the NAFTA treaty partially altered the impact of some factors on industrial location, and because of that, produced a different pattern in electricity consumption that remains today. Table 1 shows the quantitative impact of these factors. As expected, the border region has increased its share of the Mexican electric market, increasing from 30% to 33%. This may seem like a very small change but it is important to consider that the consumption base is very high. Table 1 also identifies categories of consumers that are the source of changing market shares. Industrial and residential categories account for more than 80 percent of electricity consumption in each region with industrial consumption alone comprising almost the 60 percent, although industrial consumption in the border region takes up almost 64 percent of total regional use. Another relevant fact is that only in the border region does industrial consumption increase its share with respect to total regional demand, while in the central states and the rest of the country, the share of industrial use has remained constant. Finally, Table 1 also shows that residential consumption accounts for 20 percent or more of total consumption in our three regions. However, only in the border region has residential use remained constant during the period under consideration. In our other two regions residential share has increased. This is important, given that considerable emphasis has been placed on residential consumption as being subsidized by industry.

According to SE's most recent data (SE, 2000), it is expected that national electricity consumption will increase at a 5.9 percent average annual rate of growth from 2000 to 2009.

Evolution of Electricity Prices in Mexico

In countries like Mexico, with administered prices, it is known that the market is cleared by quantities and not by price. That is, the price is set and if the quantity demanded is greater than the quantity supplied, then some rationing mechanism is designed. If at that price the quantity demanded is lower than the quantity supplied, then production is reduced. If the market works this way for a long time, price is an adequate reference to evaluate the profitability of investment projects in the market, but it provides little information about the market's efficiency. It is necessary to mention this because the information about prices shown here reflects additional criteria, other than market interactions, given that price administration for electric power is part of the general economic policy of Mexico.

As shown in Table 2 (national and regional data), the price structure among regions has not changed much from 1988 to 1999. This indicates that with regard to price changes the federal administration has tried to keep the same structure, one in which the central region has an average price slightly higher than the other two regions. This statement is based on data in the columns labeled "differences," where difference is calculated as the ratio of the corresponding average regional price to the average national price for the same year. In these columns a number greater than one indicates an average regional price higher than the average national price, and any number smaller than one indicates an average price lower than the average national price.

Due to the fact that in the Mexican market there are substantial subsidies, mainly to the residential consumption of electricity (SE, 1999, pp. 22), it seems convenient to describe prices across our specified regions and across final consumer categories in order to deal with the issue of price subsidies.

The information in Table 2 (border, central and rest of the states regions) shows that price structure is very similar in each region since in all of them average prices for the commercial and services categories are highest. In contrast, prices in the large industry and agricultural categories are the lowest in each region. If prices are compared among the regions, we observe that, in 1999, the border region had the highest prices in the residential, commercial, services and agricultural categories. In the case of large industry, the differences are small, but it is important to take into account that this category is one of the largest in volume of electricity consumed, and that in all three regions its price is below the national average.

Comparison with the national average price may seem arbitrary, given that this comparison should be done with respect to the average total cost by region. This indicates that it would be necessary to have disintegrated data for generation, transmission and distribution costs by region. The availability of this information could allow us to understand subsidies by consumer category and by region. The information analyzed clearly reflects a price policy that hardly obeys a real structure of costs. Surely there are very different criteria to the costs that have been integrated in pricing policy, and they would have to be defined explicitly in any reorganization program for the industry. There is not enough published information about costs. In one of the few published papers, Bastarrachea (1994) shows data on the ratio of price to cost from 1955 to 1993, and on subsidies from 1975 to 1993. From this data the following observations were made.

- From 1970 to 1972, the ratio of price to cost was greater than one.
- From 1973 to 1993 (the last year of data included in the publication), the ratio of price to cost was less than one, reaching a minimum of 0.57 in 1983.
- Subsidies appear regularly from 1978 on and the percentage of sales that they represent has decreased considerably. For example, in 1982 subsidies were 72 percent of sales while for 1993 this percentage decreased to 16.0 percent.

The 1999 Annual Report of the CFE (CFE, 2000) reported the same data for 1998 and 1999. It shows that the

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Mexican Electricity Market *(continued from page 9)*

ratio of price to cost has been lowered (0.75 and 0.73, respectively) and the ratio of subsidies to sales has been increased (32.5 percent and 38.8 percent, respectively). *These values denote a non-acceptable financial practice with respect to efficiency criteria in a market economy, a practice that should also be reviewed in any reorganization program for the industry.*

The Supply of Electricity and its Components

Generation of Electricity

Since the electric industry was nationalized in Mexico, generation of electricity has been the responsibility of the government through the so-called "semi-official" sector (which includes the CFE, LFC and Pemex). Recently, there has been some participation by the private sector through cogeneration projects, self-use production and independent production. The number of private sector projects has increased, but they represent a small percentage of total generation capacity.

Table 3
Installed Capacity of the Semi-official Sector.

Year	Capacity (MW)	Variation (MW)	Gross Generation (GWh)	Plant Factor * %
1988	23,554	———	101,905	49.4
1989	24,439	885	110,101	51.4
1990	25,293	854	114,325	51.6
1991	26,797	1,504	118,412	50.4
1992	27,068	271	121,697	51.3
1993	29,204	2,136	126,566	49.5
1994	31,649	2,445	137,522	49.6
1995	33,037	1,388	142,344	49.2
1996	34,791	1,754	151,889	49.8
1997	34,815	24	161,385	52.9
1998	35,255	440	170,982	55.4
1999	35,675	420	181,988	58.2

Source: CFE and the Energy Ministry.
*Plant Factor = [(Gross generation)/(Installed capacity)x8.760]x100

As shown in Table 3, the installed capacity of electricity generation of the semi-official sector has grown in a continuous manner from 1988 to 1999, but annual variations have been very acute. Additionally, during the last three years there has been a reduction in installed capacity additions, which explains the attitude of energy sector officials regarding the urgency to invest in new increments.

Gross electricity generation, which has a high correlation with installed capacity, also has increased during the period analyzed but with variations that have little relationship to variations in installed capacity. It is important to mention that the upward tendency in "plant factor" in the last years is a reasonable indicator of the pressure that demand has exerted over supply. This has forced the system to a higher efficiency, integrating reserves with normal operations.

Plant factor captures technological, climatic and operational conditions. It is almost impossible to get a 100 percent efficiency factor due to the fact that electricity demand has daily, weekly and seasonal variations. Some generators only start up during peak demand, and for the same reason their capacity will remain idle much of the time. During drought periods, hydroelectric plants will not work at their maximum capacity, a fact that tends to decrease the plant factor estimate.

This issue leads to analysis of the evolution of generation capacity with respect to categories of plants that generate electricity. A quick review shows, as expected, that the installed capacity of electricity generation has evolved in such a manner that hydroelectric plants have become a smaller portion of total installed capacity. Table 4 shows the share of each type of generator within the installed capacity for Mexico.

Table 4
Participation of Each Type of Generator Within Installed Capacity (Semi-official Sector).

Year	1988		1999	
Category	Capacity (MW)	Participa-tion (%)	Capacity (MW)	Participa tion (%)
Thermoelectric	13,955	59.2	21,351.1	59.8
Hydroelectric	7,749	32.9	9,662.8	27.1
Coal-Fired	1,200	5.1	2,600.0	7.3
Nuclear	0	0	1,309.1	3.7
Geothermal	650	2.8	749.9	2.1
Aeolian	0	0	2.2	N.S.
Total	23,554		35,675.1	

Source: SE.

Besides the semi-official sector, the private sector also participates in the generation of electricity even though the proportion of privately generated power declined during the period 1988-1999. For example, in 1988 the private sector made up 7.2 percent of total electricity generation, while for 1999 its share reached only 5.2 percent. It is interesting to note this fact given that private generators have increased in absolute numbers, but with a lower total capacity than observed in the semi-official sector. (The relatively recent opportunities for private generation coupled with the restriction regarding sale of surplus power to CFE and pricing policies in Mexico explains the small contribution.) Additionally, these figures show that reforms in the electric sector have not had the desired impact, and that they must be deepened if the private sector is to participate more actively in electricity generation.

When comparing data on electricity generation within the private sector with installed capacity for 1997, the plant factor was almost 35 percent (INEGI, 1999), a percentage lower than that of the semi-official sector.

Regarding fuel consumption in power plants, in 1999 hydrocarbons accounted for 63 percent of energy transformed by the electric industry. Eighteen percent corresponded to hydroelectricity, 10 percent to coal, 6 percent to nuclear and 3 percent to geothermal and wind (SE, 2000).

Information on regional installed capacity may seem irrelevant due to the institutional arrangement of Mexico's electricity market. In this arrangement, regions and their distinctive characteristics are not the basis for defining regional markets but rather the geographic obligations of CFE, which must provide electricity in an efficient manner. Without market competition, the CFE's efficiency is only a function of its capacity to serve the national market given that traditionally its costs are not compared to international costs. The obvious conjecture is that there is a regionalization based on production, transmission and distribution costs of electricity which should be reflected in the prices that the CFE charges to consumers.

With rational, natural regional markets, the location of electricity generation plants would depend on the existence of natural resources (water in the case of the hydroelectric plants), the availability of fossil fuels (as in the case of thermoelectric plants) and price levels and market conditions (demand). Proximity to big consumer centers could be another important variable, but that advantage is partially offset by environmental and congestion costs that tend to be reflected in high location costs.

The available information about electric generation capacity using the regional criteria established in this paper is shown in Table 5.

Table 5
Electric Generation Capacity (MW)

Region	1993	1998	2000*
Border	8,097	9,395	11,415
Central	4,143	4,111	4,111
Rest of States	16,964	21,750	22,287

Sources: INEGI and CRE.
* Estimate on base of authorized projects.

Installed capacity in the Border Region is not interconnected given topographical constraints. In the case of the state of Baja California Norte, its connection is mainly with the state of California and the U.S. The states of Sonora and Chihuahua have small connections with the main Mexican transmission system and also with U.S. border states. Finally, the states of Coahuila, Nuevo Leon and Tamaulipas have large connections with the Mexican transmission grid and with the state of Texas. The central and rest of the states regions operate, as expected, only within the Mexican system. Thus, four regional markets can be distinguished: Baja California Norte, Sonora, Chihuahua and the so called northern zone comprised by the states of Coahuila, Nuevo León and Tamaulipas.

According to most recent data from SE (2000), about 26,281 MW of power capacity should be installed in Mexico between 2000 and 2009. Of this, 12,054 MW are already under construction or planned through BLT or IPP projects. More than 14,000 MW of planned new capacity remains unfinanced and represents an excellent opportunity for private investment.

Transmission and Distribution Infrastructure

The transmission and distribution infrastructure has to be planned and executed jointly with the generation of electricity. The National Electric System (NES) consists of transmission and distribution lines, distribution substations and distribution transformers that are used to move the electricity from the generation plants to final consumers adjusting voltage and current according to their needs.

With respect to transmission lines, SE (2000) mentions that high-tension lines of 230 to 400 KV are used to transmit electricity long distances. These lines feed sub transmission nets, which have a narrower scope and range from 69 to 161 KV. In a similar manner, sub transmission nets feed medium tension lines that range from 2.4 to 60 KV and are used for small geographical areas. Finally, low-tension lines that range from 220 to 240 volts are used to transmit electricity to low consumption consumers. Information about length of the lines of each type of tension varies according to the information source, and because of that we decided to use data provided by SE because of larger coverage over time (Table 6).

Table 6
Length of the Transmission, Sub Transmission and Distribution Lines (Kms).

Year	Transmission	Sub Transmission	Distribution	Total
1980	18,021.3	26,000.7	160,693.9	204,715.9
1985	22,035.0	34,219.0	344,208.0	400,462.0
1990	27,433.0	38,616.0	426,838.0	489,887.0
1995	30,791.0	39,469.5	494,399.1	564,599.6
2000	35,921.3	43,395.7	567,115.5	646,423.5
AARG (%)	3.5	2.6	6.5	5.9

AARG = Average annual rate of growth
Source: The Energy Ministry and own calculations.

Mexico's grid is complemented with transmission and distribution substations, and distribution transformers. According to CFE data, in 1998 it had the following infrastructure:

- 300 transmission substations with 96,679 MVA belonging to the CFE and 38 private substations;
- 1,239 distribution substations with 28,241 MVA belonging to the CFE and 389 private substations; and
- 678,575 distribution transformers with 22,870 MVA belonging to the CFE and 169,481 private transformers.

This complex system has as a main objective to provide quality service to each one of the consumer categories at minimum operation cost. The CFE's experience in operating the National Electric System is not in doubt, and it is known to have utilized simulation and optimization models for many years. However, information regarding system losses exists, but does not have any explicit explanation in official documents. *It is possible to consider how much the country could save if system losses could be reduced by a certain percentage.* According to the CFE, system losses are calculated in the following way.

Net generation = gross generation – self-use
Available energy = net generation + imports + purchases
Losses = available energy – sales

Available energy is transmitted to final consumers using the transmission and distribution (T&D) system, and during this process some of the system losses occur. These losses are attributed, in part, to the lack of adequate T&D capacity. System losses also occur in the distribution of energy to small consumers, since it is known that many of them have illegal connections to the distribution system (residential and small commercial and manufacturing companies). In a World Bank paper on the Russian electricity system (1999), there is a clear distinction between transmission and the distribution losses. In the latter case it was estimated that non-technical losses

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comprised a little more than two thirds of all distribution losses. In the case of the Mexican electric system, the losses of the system are reported in aggregate, without any distinction between technical and the non-technical losses. This differentiation would be very useful to detect the areas for improvement. An estimation of system losses is shown in the Table 7.

Table 7
Electricity Losses (TWh)

Years / Concept	1985	1990	1995	1998
Gross generation	85.3	114.3	142.3	171.0
Self-uses	2.9	5.7	6.3	8.5
Net generation	82.4	108.6	136.0	162.5
Purchases	0.1	0.6	1.4	2.5
Available energy	82.5	109.2	137.4	165.0
Total sales	71.1	94.3	115.6	139.7
System losses	11.4	14.9	21.8	25.9
Losses (%)*	13.8	13.6	15.9	15.7

Source: CFE and INEGI.
* Losses as a percentage of available energy.

Conclusions

We conclude with the following observations drawn from our analysis.

- Based on information shown in this paper, the Mexican electric industry has a long way to go towards efficiency, and this is one of the first problems that must be solved. One the one hand, the plant factor data indicates the possibility of increasing the efficiency of the generation system. One way to do this is improved maintenance for power plants and establishing demand side management (DSM) programs that can modify the pattern of demand over time. DSM programs can improve plant factor by means of reducing daily and seasonal demand fluctuations. This sort of program is already being used in the Mexican electricity market, such as establishment of summer daylight savings time and Mexican official norms for energy efficiency. DSM programs that encourage reduction of daily demand fluctuations could be used more extensively. Customer participation remains extremely important for success. However, if losses in the transmission and distribution system could be reduced, it is possible to infer that efficiency of the Mexican electric system could be augmented in a considerable manner without increasing the electricity generation capacity. Finally, though, no strategy is superior to the use of price information to ration demand. Removal of price subsidies, institution of real time pricing and other mechanisms would go a long way toward improving electric power market efficiency and ensuring that capacity additions are sensibly undertaken relative to demand and supply conditions. This is likely to be a long and contentious process.[4]
- As mentioned by Hartley (1998), electricity asset privatization with the sole objective of obtaining financial resources, whether to pay off debt or to finance government expenditures, is an inadequate decision. It is important to think seriously about the development of an electricity market that has been dominated by the operation of a state monopoly. Hartley recommends increasing the efficiency of the industry through price setting, eliminating subsidies to social groups (for example, electric power industry workers do not pay for their energy), rationalizing labor and establishing competitive regional companies. This last issue is possible given that the administrative regions established by the CFE could be the basis for the creation of regional companies, a strategy that has been discussed off and on over the years (Foss, et al., 1997). If operating efficiency of regional companies is increased, CFE's market value will increase and eventual privatization will generate more resources for Mexico than what could be obtained at the present time.

Acknowledgements

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Footnotes

[1] *A Proposal for the Structural Change of the Electric Industry in Mexico* Secretaría de Energía (SE), 1999.

[2] *Prospective of the Electric Sector 2000-2009*, SE, 2000.

[3] *Prospective of the Electric Sector 2000-2009.*

[4] It has been mentioned several times in our paper that CFE financial losses become public debt. The costs associated with price subsidies and system losses have been such that CFE's deficit was estimated to be as much as 50 percent of Mexico's total energy sector (Foss, et al., 1998). This means that income elsewhere in the sector, for example from sales generated by crude oil exports by Pemex, is effectively reduced leaving little for reinvestment and thus creating the constraints on infrastructure improvements and expansion that we see today.

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The Economics of Field Cluster Developments in the UK Continental Shelf

*By Alexander G. Kemp and Linda Stephen**

Introduction

The UK North Sea is now in its mature years. Oil production is peaking. Gas production will continue to grow for another few years on the basis of fields under development, but thereafter decline is very likely. The average size of discovery has been falling for many years, and over the last few years the exploration success rate and the exploration effort have been lower than in earlier periods.

There is, however, a substantial inventory of undeveloped discoveries. The industry is currently seriously examining for development over 50 "probable" fields as well as over 70 incremental investment projects in mature fields. A further 278 discoveries containing information on their possible size, type (oil, gas, condensate), and location by block number are in a database constructed by the present authors.

Most of these undeveloped discoveries are quite small. On a stand-alone basis many are not economically viable. This leads to the notion that joint development of a group of fields might be viable where individual projects remain unattractive. Joint development could involve benefits from (a) economies of infrastructure cost-sharing and (b) risk-sharing. These subjects are investigated in this paper.

Potential Economies of Scale from Cluster Developments

It is clear that the employment of a common infrastructure (manifold plus pipeline) produces an economy of scale. The question which is now investigated is whether the economy of scale is worthwhile and what difference it makes to the prospective returns compared to independent field investments.

The procedure adopted was to examine the returns from a set of fields typical of those available for development when developed (a) individually and (b) as a cluster. Five model fields were selected for analysis. When developed separately (but still linked to major infrastructure) their investment, operating, and decommissioning costs were estimated as shown in Figure 1.

Figure 1
Deterministic Assumptions for Individual Development

MMBBLS	5	10	20	35	50
Devex $/bbl	10	8	7.5	6.5	5
Annual Opex as % Devex	8	9	9	7	7
Abandonment as % Devex	10	10	10	10	10
First Production	t 0	t 1	t 1	t 1	t 1
Tariff (£/bbl)	1.5	1.5	1.5	1.5	1.5

The specific development, operating and decommissioning costs of these fields when developed as part of a cluster were then estimated. The data are shown in Figure 2. The common infrastructure costs for 3 field and 5 field clusters were then estimated. The results are shown in Figure 3. In obtaining these estimates use was made of data on the cost structures of existing cluster developments.

When these common infrastructure costs had to be apportioned to fields, they were done so in relation to the total reserves of the fields.

Deterministic financial modelling was employed to calculate the returns to the fields when developed individually and as clusters. The results for 3 field and 5 field clusters are shown. Comparisons are made with the sum of the returns to the fields in question when developed individually. The base price is $18 per barrel in real terms with sensitivities of $24 and $12. The results are shown in terms of net present values (NPVs) at various discount rates.

Figure 2
Deterministic Assumptions for Cluster Type Development

MMBBLS	5	10	20	35	50
Devex $/bbl	8	4.5	4.5	4.5	4
Annual Opex as % Devex	8	9	9	7	7
Abandonment as % Devex	8	8	8	7	7
First Production	t 0	t 1	t 1	t 1	t 1
Tariff (£/bbl)	1.5	1.5	1.5	1.5	1.5

Figure 3
Common Infrastructure of Cluster

	Fields	Common Infrastrucgture			
		Capacity	Devex	Annual Opex	Decommissioning
3 Field Cluster	10, 20, 50 mmbbls	80	$1/bbl	2.5% of devex	17% of devex
5 Field Cluster	5, 10, 20, 35, 50 mmbbls	120	$0.8/bbl	2% of devex	18% of devex

Costs shared on a percentage of total reserves basis

Results

In Figure 4 the comparative returns to the 10, 15, and 50 mmbbl fields are shown when developed individually and as a cluster under the $18 price. At 10% discount rate the NPV for the cluster is over £100 million. With individual developments the combined return is less than £50 million. At 15% discount rate the NPV for the cluster development is around £60 million, but only around £7 million for the sum of individual developments. At 20% discount the NPV is plus £30 million for the cluster development, but minus £30 million for the individual developments. At the $12 price the returns to the investments are generally negative irrespective of whether the fields are developed individually or as a cluster. The returns are much worse with individual development. At the $24 price the returns are substantially positive under both investment situations. The returns are significantly higher with the cluster developments.

In Figure 5 the results are shown for the 5, 10, 25, 35 and 50 mmbbl fields at the $18 price. At the 10% discount rate the NPV with the cluster development exceeds £150 million. For the 5 separate developments the NPVs run to £50 million. At the 15% discount rate the NPV for the cluster development is around plus £100 million. The individual developments produce a negative NPV. The returns under the $12 price are seen to be generally negative. The returns under the $24 price are substantially positive and are significantly higher with the cluster development.

* Alexander G. Kemp and Linda Stephen are with the University of Aberdeen, Aberdeen, Scotland. This is an edited version of their paper presented at the 24th Annual IAEE Conference in Houston, TX, April 25-27.

Figure 4
Post-Tax NPVs for 3 Field Cluster Oil price $18/bbl

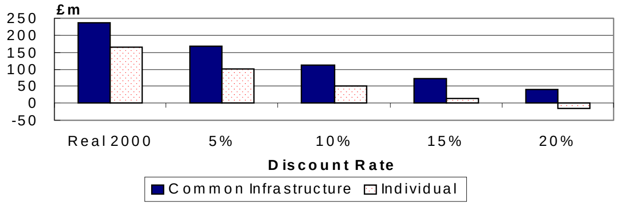
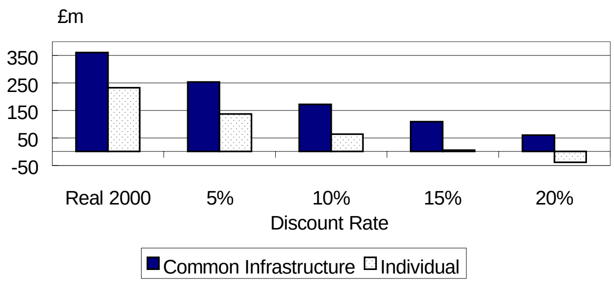


Figure 5
Post-Tax NPVs for 5 Field Cluster Oil price $18/bbl



The main conclusions which can be drawn from the financial modelling are that under likely field development conditions in the UK North Sea, significant scale economies can be obtained from cluster developments compared to individual field developments. In some cases these benefits could be sufficient to produce positive returns where individual field developments produce negative returns.

Risk Sharing with Cluster Developments

Methodology and Data

A different possible benefit relates to the risk sharing which results from investment in a cluster rather than individual fields. These benefits are conceptually the same as those obtained from holding a portfolio of shares compared to an individual one. The issue requiring detailed investigation is whether in the realistic conditions of the North Sea these benefits of risk diversification are substantial or not. Diversification reduces unique, unsystematic, or specific risks, but not systematic risk. In principle, diversification reduces risk rapidly at first and then more slowly as the size of the portfolio is enlarged.[1] In the present study the oil price risk cannot be diversified.

The approach adopted has been to conduct a comparative risk analysis of the investments using the Monte Carlo technique. The key assumptions are set out in Figure 6. There are 4 stochastic variables, namely field reserves, development costs, operating costs and oil price. The distribution of field size is taken to be normal with a standard deviation (SD) of 30% of the mean. In addition minimum and maximum values are stipulated. For field development costs the distribution is also taken to be normal with the SD equal to 20% of the mean. Again, maximum and minimum values are specified. The distribution of field operating costs is also taken to be normal with the SD equal to 20% of the mean. Minimum and maximum values are also specified. The oil price is taken to be mean reverting. The mean value is set at $18 (real terms) and the SD at 40% of the mean. Minimum and maximum values are also specified.

Figure 6
Assumptions for Monte Carlo Analysis

Mean Reserves MMBBLS)	**5**	**10**	**20**	**35**	**50**
SD 30%					
Minimum	0.5	1	2	3.5	5
Maximum	9.5	19	38	66.5	95
Mean Devex ($/bbl)	8	4.5	4.5	4.5	4
SD 20%					
Minimum	3.2	1.8	1.8	1.8	1.6
Maximum	12.8	7.2	7.2	7.2	6.4
Annual Opex					
(% of Accum.Devex)	8	0.09	0.09	0.07	0.07
SD 20%					
Minimum (%)	3	4	4	3	3
Maximum (%)	13	14	14	11	11
Mean Oil Price (Real)	$18				
SD 40%					
Minimum	$8				
Maximum	$39.6				

To make meaningful comparisons of the risk position the distributions of the expected returns from cluster developments were compared with those from the individual fields. To the specific costs of the latter were added a share of the common infrastructure costs. This was related to the particular field's share of the total reserves of the member fields of the cluster. Emphasis was put on the distribution of NPVs. Risk in the statistical sense is often measured by the SD of the distribution. Because the mean values of the distributions of the NPV for the cluster will be much higher than those for the individual fields meaningful comparisons cannot be made using this measure. Coefficients of variation can be used for this purpose and emphasis is given to these.

Results

In Figure 7 the distributions of NPVs at 10% discount rate for the 10, 20 and 50 mmbbl fields are shown. The coefficients of variation are respectively 90%, 73% and 66%. In Figure 8 the distributions of NPVs for the 3-field cluster are shown. The coefficient of variation at 10% discount rate is 50% and at 15% it is 61%. The reductions in overall project risk as indicated by this measure are quite dramatic.

Risk is often considered in relation to the chance of making a loss. In the present context this is measured as the probability of the NPV being negative. The results of this calculation for the 3 individual fields and the cluster are also shown in Figures 7 and 8. At 10% discount rates for the 10, 20 and 50 mmbbl fields respectively, the probabilities are 13.5%, 6.5% and 4.5%. The probability of the cluster having a negative NPV is 1.5%. At 15% discount rate the probabilities of negative NPVs for the 3 fields are 22.5%, 14.5% and 12.5%. The probability of the cluster having a negative NPV is 3.5%. The reduction in risk from the cluster development is quite noticeable.

Investors are also interested in upside potential. The Monte Carlo modelling obtained measures of this by calcu-

(continued on page 16)

[1] See footnotes at end of text.

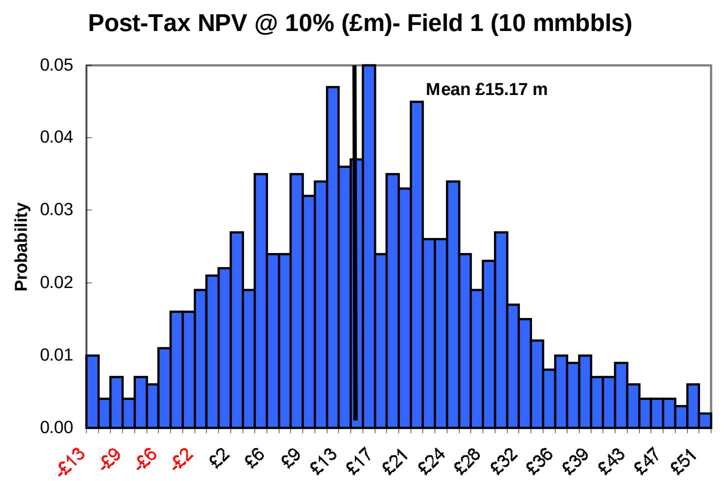
Economics of Field Cluster *(continued from page 15)*

lating the probabilities of the internal rate of return (IRR) in real terms exceeding specified values. In Figure 9 the results are shown for IRRs of 20%, 25%, 40% and 50%. For the 10 mmbbl field the respective probabilities are 67.4%, 55.8%, 23.6% and 11.2%. For the 20 mmbbl field the probabilities are respectively, 70.7%, 56.6%, 17.2% and 7.6%, and for the 50 mmbbl field they are 74.6%, 58.4%, 19.4% and 7.9%. For the cluster development the corresponding probabilities of reaching the specified threshold

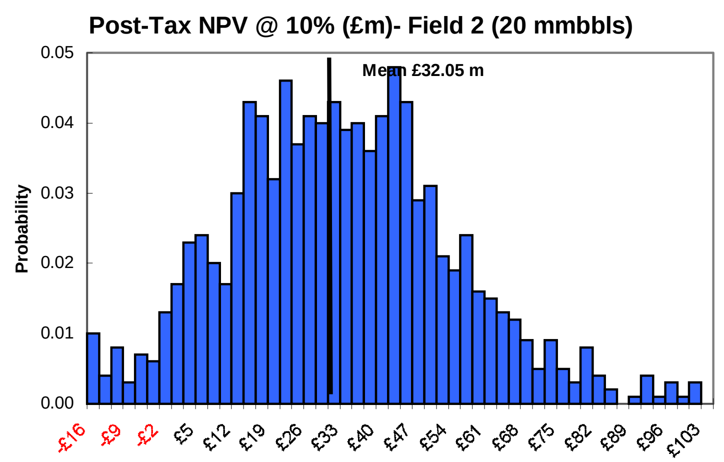
Figure 7

3 Field Cluster Fields @ 10% (£m) : Mean Oil Price $18 p/b

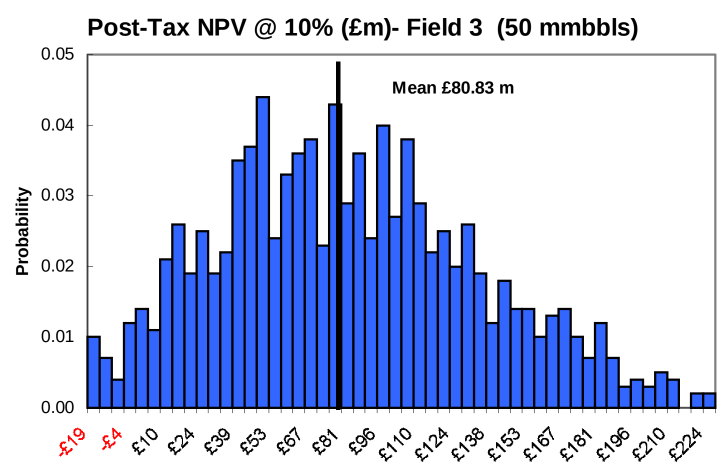
Post-Tax NPV@10% Statistics £m	
Trials	1000
Mean	£15.17
Median (approx)	14.44
Mode (approx)	15.56
Standard Deviation	13.71
Variance	187.95678
Skewness	0.31
Kurtosis	0.16
Coefficient of Variability	0.90
Minimum	-26.33
Maximum	67.34
Range	93.67
Mean Standard Error	0.43
Trimmed Mean (98%)	15.10
Negative Probability	13.50%
68% of Distribution	
£1.22	£28.37



Post-Tax NPV@10% Statistics £m	
Trials	1000
Mean	£32.05
Median	30.88
Mode	42.66
Standard Deviation	23.25
Variance	540.75139
Skewness	0.64
Kurtosis	1.51
Coefficient of Variability	0.73
Minimum	-35.20
Maximum	147.73
Range	182.93
Mean Standard Error	0.74
Trimmed Mean (98%)	31.75
Negative Probability	6.50%
68% of Distribution	
£10.49	£52.91



Post-Tax NPV@10% Statistics £m	
Trials	1,000
Mean	£80.83
Median	76.02
Mode	48.04
Standard Deviation	53.33
Variance	2,843.63
Skewness	0.44
Kurtosis	0.02
Coefficient of Variability	0.66
Minimum	-66.11
Maximum	291.39
Range	357.50
Mean Standard Error	1.69
Trimmed Mean (98%)	80.35
Negative Probability	4.50%
68% of Distribution	
£26.67	£134.06



returns are 76.6%, 59.4%, 14.6%, and 4%.

These results indicate that the chances of the IRR exceeding 20% and 25% are greater with the cluster development. For threshold IRRs of 40% and 50% the probabilities are higher with the individual fields.

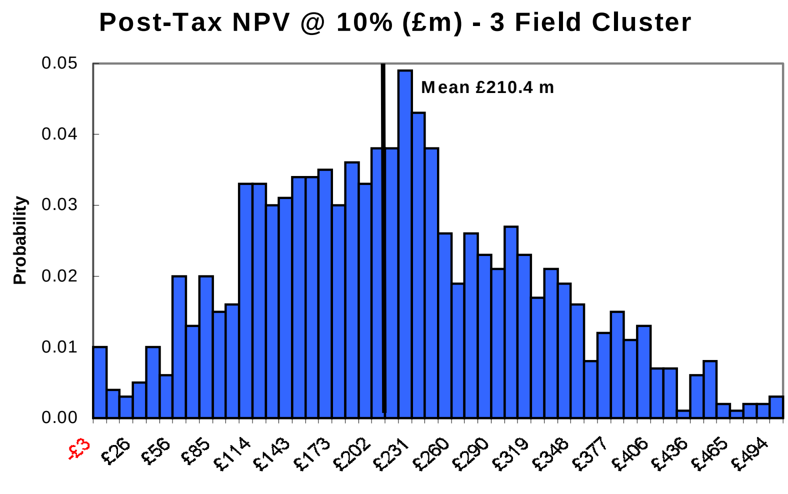
The analysis was repeated for the 5-field cluster and its constituent fields. The results for the NPVs at 10% discount rate produce coefficients of variations for the 10, 20, 50, 35, and 5 mmbbl fields respective of 84%, 68%, 61%, 75% and 201%. For the 5-field cluster the coefficient of variation is

(continued on page 18)

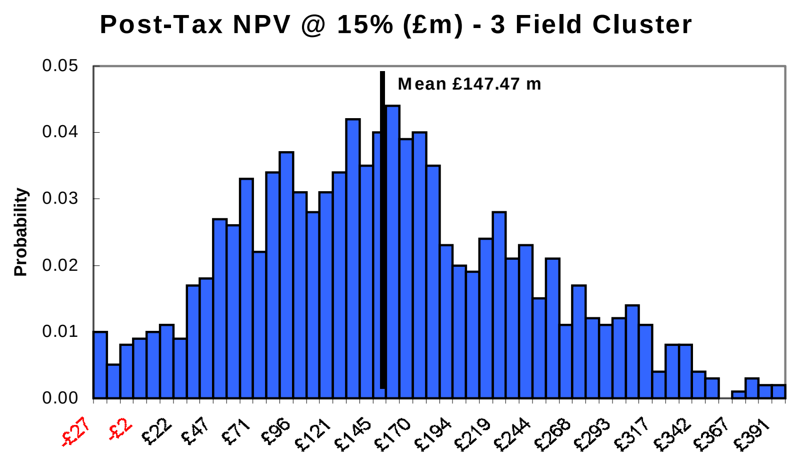
Figure 8

3 Field Cluster Development : Mean Oil Price $18 p/b

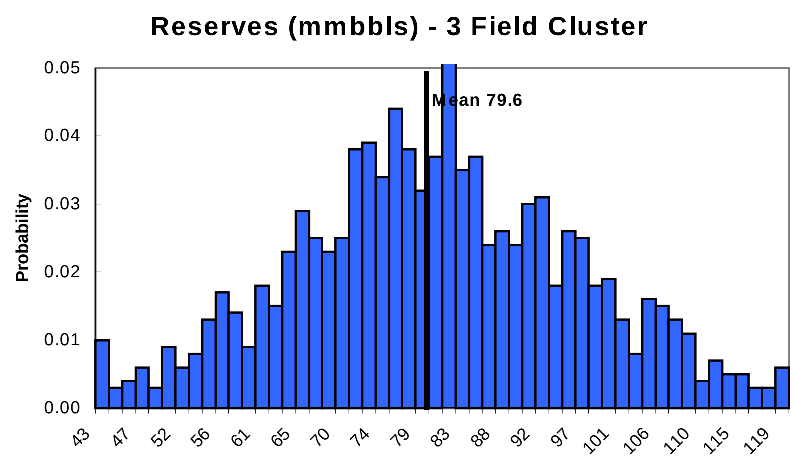
Post-Tax NPV@10% Statistics £m		
Trials		1000
Mean		£210.40
Median (approx)		204.28
Mode (approx)		221.36
Standard Deviation		105.49
Variance		11127.83
Skewness		0.39
Kurtosis		0.04
Coefficient of Variability		0.50
Minimum		-60.68
Maximum		566.74
Range		627.42
Mean Standard Error		3.34
Trimmed Mean (98%)		209.60
Negative Probability		1.50%
68% of Distribution	£105.95	£319.06
95% of Distribution	£29.76	£432.05



Post-Tax NPV@15% Statistics £m		
Trials		1000
Mean		£147.47
Median		142.47
Mode		153.40
Standard Deviation		90.06
Variance		8110.15
Skewness		0.38
Kurtosis		0.06
Coefficient of Variability		0.61
Minimum		-110.22
Maximum		459.37
Range		569.59
Mean Standard Error		2.85
Trimmed Mean (98%)		146.84
Negative Probability		3.50%
68% of Distribution	£57.73	£240.76
95% of Distribution	-£9.54	£330.18



Cluster Reserves MMBBLS	
Trials	1,000
Mean	79.60
Median	79.36
Mode	81.70
Standard Deviation	16.27
Variance	264.69
Skewness	0.03
Kurtosis	-0.11
Coefficient of Variability	0.20
Minimum	28.13
Maximum	124.62
Range	96.49
Mean Standard Error	0.51
Trimmed Mean (98%)	79.62



Economics of Field Cluster *(continued from page 17)*

47% at 10% discount rate. At 15% discount the coefficients of variation relating to the 5 constituent fields are respectively 113%, 92%, 81%, 100% and 348%. The corresponding coefficient of variation for the cluster is 57%. The results confirm the major reduction in risk as indicated by this measure.

The probabilities of the NPVs being negative were then examined. At 10% discount rate the chances of the 10, 20, 50, 35 and 5 mmbbl fields having negative NPVs are respectively 11.5%, 4.5%, 2.5%, 4.5%, and 31.5%. The probability of the cluster having a negative return is 0.5%. At 15% discount rate the chances of the 5 fields having negative returns are respectively 19.5%, 12.5%, 8.5%, 13.5%, and 39.5%. The probability of the cluster having a negative return is 2.5%. There is clearly a large reduction in the downside risk from the cluster developments as a combined investment.

Figure 9
Probability of IRR Greater than

	20%	**25%**	**40%**	**50%**
3 Field Cluster	76.6%	59.5%	14.6%	4.0%
Field 1 (10 mmbbls)	67.4%	55.8%	23.6%	11.2%
Field 2 (20 mmbbls)	70.7%	56.6%	17.2%	7.6%
Field 3 (50 mmbbls)	74.6%	58.4%	19.4%	7.9%

	20%	**25%**	**40%**	**50%**
5 Field Cluster	80.4%	63.5%	16.5%	4.9%
Field 1 (10 mmbbls)	70.7%	59.2%	26.5%	13.8%
Field 2 (20 mmbbls)	74.6%	61.3%	21.6%	9.5%
Field 3 (50 mmbbls)	79.7%	64.4%	23.8%	10.4%
Field 4 (35 mmbbls)	72.5%	57.5%	20.0%	8.7%
Field 5 (5 mmbbls)	51.2%	41.9%	21.8%	14.8%

Possible Schemes for Sharing Common Infrastructure Costs and their Problems

To obtain the benefits of shared infrastructure costs and risk sharing it is necessary to devise a scheme to execute the sharing among the licensees in the various fields. It is most likely that there will be separate licensees in the different fields. Even where the same licensees have interests in the different fields, it is most unlikely that the interests of any one company would be the same in the different fields. These factors create complications in the determination of efficiently-functioning contractual arrangements among the various licensees. Some possible schemes are outlined in this section, their problems examined, and some solutions proposed.[2]

The first scheme is where the licensees in each field pay a share of the common infrastructure investment costs equal to their respective share of the capacity. In practice this will equate to the corresponding share of reserves. The common infrastructure operating costs are paid for in relation to each field's share of capacity actually used.

This type of scheme has some appeal in terms of equity. In practice there are some problems. The common infrastructure has to be financed before reserves of the respective fields are fully known. Where there are different ownership interests involved conflicts of interest with respect to initial reserves determination can emerge. Of course, re-determinations of reserves can be made through time, and consequential modifications made to ownership interests in fields and thus in the common infrastructure ownership. But such modifications may be costly, and, where recalculation of the cost contributions made in the past is required, difficult problems of compensation arise for parties who had in the event overpaid their cost share.

With respect to the common infrastructure costs, problems arise regarding their equitable sharing in the (very likely) circumstances when different fields in the cluster cease production at different times.

A second scheme involves a modification to the first one with respect to common operating costs. These are shared on throughput (per barrel) basis. Some of the problems referred to above clearly apply to this scheme as well.

A third possible scheme is where one company finances all the common infrastructure costs. All the other investors then pay tariffs to the asset owner. These tariffs would cover the development and operating costs. There are problems of appropriate tariff determination. The asset owner may feel that he, having incurred the investment costs and risks, should levy tariffs reflecting these risks. He might try to levy tariffs which would in effect collect a share of any expected economic rents from the fields. Other licensees may feel that the appropriate tariff should cover the costs with only a utility rate of return. There is plenty scope for differences of view on this matter, and clearly there is a potential conflict of interest among the parties involved.

Under a fourth scheme all licensees would pay a share of the common infrastructure investment costs based on capacity or reserves. Tariffs based on throughput, would then be payable by all parties. The revenues would initially be used to cover the common infrastructure operating costs. The remainder of the tariff revenues would be distributed among the different owners of the common infrastructure. The level of tariff would be set such that, at a minimum, they covered all the investment and operating costs. The scheme is designed to reflect the comparative contributions which each participant makes to the infrastructure.

A principal problem of this scheme relates to tariff determination, especially in the (likely) case where there are different interest shares in the cluster fields. The issues raised with respect to the first and second schemes also arise.

In practice a cluster development could take place where all the fields are developed simultaneously, but it is more likely that field developments will be sequential. The phasing of the fields could vary by several years. The four schemes with their associated problems discussed above can apply to both simultaneous and sequential developments. With the latter, further issues arise which require resolution. Possible solutions are now discussed.

Under a fifth scheme all investors pay a share of the infrastructure investment and operating costs as in the second scheme discussed above. Additional provisions would then be made such that the "early" field owners compensate "late" field owners by sharing production from the "early" fields with them. The amount of the compensation would be related to the relative timing of the "early" and "late" field developments.

The problems requiring solution include all those of the second scheme discussed above. In addition there are others relating to the terms of the compensation for the "late" field owner. Such compensation could be in oil or cash. The amount would depend on what discount rate is appropriate to reflect equitable compensation. There is plenty scope for differing views on this matter. A technical tax problem could arise for the "early" producer. He may be faced with a tax burden on the production which is in effect transferred to the "late" producer.

This suggests a tax modification which would in essence introduce tax changes similar to those which were granted in the 1980's for gas banking schemes. This would become a sixth possible scheme. The other problem areas discussed above remain.

A seventh scheme would be the same as the second one except that the investors in the "late" fields are given a discount on their contribution to the common infrastructure costs. As well as the problem areas discussed in relation to the second scheme, the determination of the appropriate discount requires solution. The question of the rate of discount which should reflect the difference in timing of the field developments is a key issue.

An eighth scheme would base the common infrastructure costs on the present value of the reserves. Common infrastructure operating costs would be shared in accordance with each investor's share of the capacity employed. The problems here lie in the determination of the respective reserves before they are developed. Additionally, the discount rate to reflect the differences in timing has to be determined.

The problems discussed above can be solved. But their resolution may well be very time consuming and project executions thereby delayed. Solution of the problems is clearly easier if the potential conflicts of interest are eliminated or at least reduced. This can be achieved by asset transactions among the investors in the various fields to bring about unitisation of interests in the cluster. This means that any one investor would have the same interest in each of the fields. (An extreme case would be where that share was 100%). Unitisation of interests would produce a much better alignment of incentives and greatly reduce any potential conflicts of interest.

There are several requirements for the achievement of unitised interests. Firstly, investors mush be willing to trade assets to the extent necessary. Different investors may well have diverging views about the prospects relating to the different fields. While this creates scope for asset transactions it is not necessarily in the direction of producing interest unitisation. Pre-emption rights of existing licensees may hinder transactions. A further requirement is the ability of the respective parties to trade assets to the extent required. Thus investors who should increase their share will have to fund the required investment and may have capital constraints which restrict their ability to execute the deal. Until recently there was a capital gains tax problem inhibiting asset transactions. The rollover relief enacted in 1999 for capital gains tax has significantly reduced the net cost of asset transactions. Other government/industry initiatives particularly LIFT and DEAL also help to facilitate asset transactions.

Unitisation of field interests will not only reduce conflicts of interest and thus facilitate infrastructure cost sharing, but ensure that the risk-sharing benefits are also secured. These are separate advantages.

Footnotes

[1] For a discussion of the principle see R.A. Brealey and S.C. Myers, (1991), Principles of Corporate Finance, McGraw-Hill, chapter 7.

[2] For a full discussion of the schemes including financial modelling of their operation see A.G. Kemp and L. Stephen (1995), The Economics of Infrastructure Cost Sharing with Cluster Type Developments in the UKCS, University of Aberdeen, Department of Economics, North Sea Study Paper No. 53.

Student Conferences

Two student conferences on energy economics have been held recently, the first on September 20 in Mexico City at the National Autonomous University of Mexico and the second on October 5 in Paris at the University of Paris IX-Dauphine-CGEMP.

At the Mexican conference with the general title of **The Energy in Mexico: A Student Approach** in a session on *The Petroleum Industry in Mexico*, Elizabeth Mar Juarez, Ph.D. Student in Energy Engineering and Armando Maldonado Susano, Master Degree Student in Mechanics presented a paper on "The Mexican Experience in Saving Fuel Policies – The CAFE in Mexico". The was followed by a paper by Marbella Herrera Loza, Bachelor Degree Student in Economics, on "The Fiscal Regimes for PEMEX in Case of Opening Upstream Activities"

At the second session on *The Natural Gas Industry in Mexico,* Lavinia Salinas Díaz, Master Degree Student in Energy Engineering, presented a paper on "Energy Integration in North America in the Context of the NAFTA. Some Implications for Mexico's Natural Gas Industry" and Alberto Elizalde Baltierra, Ph.D. Student in Economics, discussed "Deregulation in the Natural Gas Industry: Characteristics in North America."

At the third session on *The Electricity Industry in Mexico,* Ubaldo Jerónimo Carrera, Ph.D. Student in Energy Engineering, discussed "Distributed Generation in Electric Power Systems: a First Analysis"; Leonardo Zepeda Gutiérrez, Bachelor Degree Student in Economics, presented a paper on "Economic Regulation of Electricity Transmission in Mexico" and Paloma Macías Guzmán, Master Degree Student in Energy Engineering, discussed "The Mexican Power System and Emissions of SO_2: Regulatory, Economic and Institutional Aspects."

At the final session on *Energy and Environment*, Stine Grenaa Jensen, Ph.D. Student in Economics, discussed "Green Certificates and Emission Permits in Combination with a Liberalized Electricity Market", while Tanya Moreno Coronado, Bachelor Degree Student in Energy Engineering, discussed "The Role of Energy Saving in the Energy Future of Mexico" and Joel Hernández Santoyo, Master Degree Student in Energy Engineering, presented a paper on "The Energy Analysis for a Sustainable Development."

At the Paris conference with the title **Restructuring in Energy Industries** in the opening session on *The Natural Gas Sector* Alexandra Bonanni, Ph.D. Student in Economics, discussed "Strategies of Multiutilities in England," while Alberto Elizalde Baltierra, Ph.D. Student in Econom-

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!!! MARK YOUR CALENDARS — PLAN TO ATTEND !!!

Energy Markets in Turmoil: Making Sense Of It All

22nd USAEE/IAEE Annual North American Conference – October 6-8, 2002
Vancouver, British Columbia, Canada – Sheraton Wall Centre Hotel

We are pleased to announce the 22nd Annual North American Conference of the USAEE/IAEE, ***Energy Markets in Turmoil: Making Sense Of It All***, scheduled for October 6-8, 2002, in Vancouver, British Columbia at the Sheraton Wall Centre Hotel.

Please mark your calendar for this crucial conference. Some of the key selected themes and sessions for the conference are listed below. The plenary sessions will be interspersed with concurrent sessions designed to focus attention on major sub-themes. Ample time has been reserved for more in-depth discussion of the papers and their implications.

California Fallout: What Useful Lessons Can Be Learned?
Session Chair: Perry Sioshansi, Menlo Energy Economics
- What Went Wrong?
- Resolving the Situation
- Lessons for Other Jurisdictions

Offshore Petroleum Industry: Reflections on Moving Forward
Session Chair: Merete Heggelund, Norsk Hydro
- Economics of Offshore Projects
- Local Procurement for a Global Industry
- Environmental Issues

Fossil Fuels and Sustainability: Like Oil and Water?
Session Chair: Mark Jaccard, Simon Fraser University
- Decarbonating Fossil Fuels
- Sequestering Carbon
- Technology Synergies

Energy Regulation Trends and Prospects in North America
Session Chair: Michelle Foss, University of Houston

Continental Energy Policy Prospects
Session Chair: Arnold Baker, Sandia National Laboratories

Energy Security in the 21st Century
Session Chair: To be confirmed

Canada – U.S. Natural Gas Trade Prospects
Session Chair: Campbell Watkins
- Resource prospects
- Market considerations
- Transmission expansion

There are 24 planned concurrent sessions (note the enclosed information on Call for Papers for this meeting – the abstract cut-off date is May 1, 2002. Conference organizers are open to setting aside some concurrent sessions to cover joint submissions by a group of authors (maximum 4 per concurrent session). Given the location of the meeting in Vancouver, we anticipate an even larger draw to our concurrent sessions. The conference organizers STRONGLY SUGGEST that you get your abstract in extra early so that prompt follow-up can be given.

Vancouver, British Columbia is a wonderful and scenic/tourist place to meet. Single nights at the Sheraton Wall Centre Hotel are $224.00 Cdn. (approximately $150.00 U.S. dollars – a phenomenal rate) per night. Contact the Sheraton Wall Centre Hotel at 604-893-7120, to make your reservations). Conference registration fees are $500.00 for USAEE/IAEE members and $600.00 for non-members. Your registration fee includes two lunches, a dinner, three receptions and numerous coffee breaks, all designed to increase your opportunity for networking. Special airfares have been arranged through Air Canada. Please contact Air Canada by calling 800-361-7585 (or 514-393-9494) and reference our group #CV625181. These prices make it affordable for you to attend a conference that will keep you abreast of the issues that are now being addressed on the energy frontier.

There are many ways you and your organization may become involved with this important conference. You may wish to attend for your own professional benefit, your company may wish to become a sponsor or exhibitor at the meeting whereby it would receive broad recognition or you may wish to submit a paper to be considered as a presenter at the meeting. For further information on these opportunities, please fill out the form below and return to USAEE/IAEE Headquarters.

Energy Markets in Turmoil: Making Sense Of It All

22nd Annual North American Conference of the USAEE/IAEE

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Issues of Decommissioning

*By Petter Osmundsen and Ragnar Tveterås**

Introduction

In the process of developing a decommissioning plan, the oil companies use independent consultants and contractors to carry out environmental assessments, safety studies and cost analyses.[1] These are predominantly technical reports, undertaken by engineers, and they are generally not available to the public. In spite of the interesting policy issues and the large sums involved, decommissioning of petroleum installations seems to have been given scant attention by researchers of economics. We give an overview of the most important economic topics related to decommissioning and disposal, illustrated by recent Norwegian decommissioning policy.

International Decommissioning Issues

There are more than 6500 offshore installations world wide, with an estimated overall removal cost of 20 billion USD. There is a great variety of installations, each designed for a particular set of conditions; ranging from fixed shallow-water structures in 30 metres of water to tension leg platforms in 900 metres of water. Some 490 installations (excluding subsea facilities) are located in the North Sea and the North East Atlantic. The majority of platforms, around two-thirds, standing in less than 75 metres of water or weighing less than 4000 tonnes, are referred to as small structures, although they can still be the size of the Houses of Parliament. The remaining platforms, mainly in Norway and the UK, comprise 112 large steel structures - which may be as high as the Eiffel Tower and have a footprint the size of a football field - and 28 concrete gravity base structures. In addition there are some 26 floating installations. Over the next 10-20 years, an average of 15-25 installations are expected to be abandoned annually in Europe. This represents, amongst other materials, 150,000-200,000 tonnes of steel per year. The continental shelf bordering the states of the European Community and Norway counts some 600 offshore oil and gas platforms, 400 subsea structures and 600 subsea wellheads.

A typical platform consists of the *topsides*, which contain the drilling, processing, utilities and accommodation facilities, and the supporting *substructure* or *jacket*. Steel jackets can weigh up to 40,000 tonnes and are fixed to the seabed by steel piles. The topsides themselves can weigh up to 40,000 tonnes. Concrete gravity base structures are even larger, for example, Troll on the Norwegian continental shelf weighs some 700,000 tonnes, and sit on the seabed, stabilised by their own weight and penetration of the *skirt* into the seabed. In the absence of storing facilities, only the topsides of the platform are in contact with hydrocarbons and may contain limited amounts of potentially hazardous substances, whereas the substructure or jacket is generally clean steel or concrete.

Cost-benefit calculations are in this context needed for two types of decisions: (a) the choice of method of removal and disposal of installations, and (b) timing issues. As for (a), after production is closed down, topsides are in most cases taken to shore for recycling. Interesting policy issues, therefore, mostly pertain to the various solutions for the substructure. The basic decommissioning options are as follows:

i Leave in place.
ii Partial removal, with alternatives (a) emplacement/toppling on site, (b) carry to shore for recycling or disposal as waste, (c) deep water disposal, (e) artificial reefs, (f) re-use/other uses.
iii Total removal, with alternatives (a) carry to shore for recycling or disposal as waste, (b) deep water disposal, (c) artificial reefs, (d) re-use/other uses.

Artificial reefs mean using cleaned offshore platforms to create reefs for marine life. Early evidence indicates that such reefs enhance and protect existing marine habitats and create new habitats for marine animals and plants.[2] Artificial reefs have been developed in the United States, Brunei, Japan, Cuba, Mexico, Australia, Malaysia and the Philippines.

The choice of decommissioning procedure is subject to stringent and extensive international regulations. Still, considerable discretion is left to national governments. In 1958, the Geneva Conference adopted a Convention on the continental shelf, requiring that an offshore installation being abandoned must be entirely removed. The 1982 UN Conference of the Law of the Sea introduced some exceptions, allowing some installations to be left in place as long as requirements linked to navigational safety, fisheries and environmental impact were met. The 1989 UN International Maritime Organisation (IMO) Guidelines for the Removal of Offshore Installations required that abandoned structures standing in less than 75 metres of water and weighing less than 4,000 tonnes in air, excluding the topsides, must be entirely removed.[3] Platforms exceeding those limits need to be cut off to allow 55 metres of clearance between their highest point and the surface. The water depth limit will increase to 100 metres for new platforms installed after 1 January 1998. Disposal at sea of offshore installations in the North Sea or North East Atlantic is regulated by the Oslo and Paris Conventions. These two conventions were merged into one (OSPAR) in 1997. Following the Brent Spar controversy, the OSPAR countries reached a unanimous agreement in 1998 for the future rules for disposal of petroleum installations.[4] The vast majority of existing offshore installations will be re-used or returned to shore for recycling or disposal. Exceptions are made for certain installations or parts of installations in the event that an overall judgment in each case gives good reasons for sea disposal. For those installations where there is no generic solution, one should take a case-by-case approach, and considerable discretion rests with local

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* Petter Osmundsen and Ragnar Tveterås are with Stavanger University College, and are affiliated with Foundation for Research in Economics and Business Administration in Bergen. We are grateful to Frank Asche, Håkan Eggert, Ove Tobias Gudmestad, Rögnvaldur Hannesson, and participants at seminars at the Norwegian Petroleum Directorate, the University of Tromsø, and the Norwegian School of Economics and Business Administration for useful comments and suggestions. We thank The Norwegian Research Council for funding. The paper is an abridged version. The full text can be obtained from the authors at the email address below. Address of correspondence: Petter Osmundsen, Stavanger University College, Section of Petroleum Economics, PO Box 2557 Ullandhaug, 4091 Stavanger, Norway Tel. +47 51 831568. Fax +47 51831550. Email: Petter.Osmundsen@tn.his.no. Internet: http://www.snf.no/Ansatt/Osmundsen.htm

[1] See footnotes at end of text.

Issues of Decommissioning *(continued from page 21)*

governments.

The negative existence value in the population of obsolete offshore oil installations may be one of the elements influencing the reputation costs associated with decommissioning. Reputation is often viewed as a strategic resource for the individual holder, as a positive reputation may provide the holder with goodwill capital. If a country's - or company's - decommissioning policies lead to a reduction in goodwill, other countries' public opinion, special interest groups and governments may become less tolerant of its actions in other areas, and may even introduce direct reprisal actions in the form of public protests, boycotts or court actions. The Brent Spar and Exxon Valdez incidents are two cases where the oil companies involved seem to have perceived the reputation costs to be considerable and have been willing to incur extra costs to reduce these (SNF, 1998, chapter 4).

Norwegian Decommissioning Policies

The Norwegian Parliament sanctioned the OSPAR Convention. However, there is a number of large installations on the Norwegian continental shelf for which decommissioning is not regulated directly by the Convention. Concrete installations and steel jackets with weight above 10,000 tonnes are exempt from the OSPAR ban on sea disposal. For concrete installations, the Norwegian government has full discretion, i.e., they may be fully or partly removed, left in place, toppled on site for use as artificial reef, or dumped elsewhere.[5] The Norwegian government also has partial discretion with respect to decommissioning of the six largest permanent steel installations on the Norwegian continental shelf[6], i.e., the jacket may be left on the seabed but not dumped elsewhere.[7] After February 9, 1999, however, all new steel installations must be designed so that total removal is feasible.

Characteristic features of the Norwegian continental shelf are great deeps and large reservoirs, developed by large installations. Thus, the cost of decommissioning in the Norwegian sector is on average considerably greater than in the rest of the world. There are approximately 6,500 offshore oil and gas installations in the world, with an estimated overall removal cost of 20 billion USD. Decommissioning all of the Norwegian installations was in 1993 estimated to cost 7.5 billion USD, i.e., as much as 37.5 per cent of the estimated global costs.[8] Such estimates are highly uncertain, though. There is not much experience in this field; the first Norwegian decommissioning plan was issued in 1994. New technology and the development of a decommissioning industry are likely to bring down removal costs. Thus, an estimate from 1995 was 5.4 billion USD for a total removal of all installations, and 1.8 billion for a partial removal.[9] The total investments on the Norwegian continental shelf at that time, in comparison, were 100 billion USD. Nevertheless, adding the fact that the Norwegian government will carry most of the costs, and that the major part of these costs will come in a period when petroleum revenues are declining and the number of retirees is increasing, decommissioning will be a considerable fiscal burden for Norway. By establishing a considerable petroleum fund, however, the Norwegian authorities should have the means to smooth out this effect.

The procedures for decommissioning decisions are as follows. The license owners, represented by the operator, develop a detailed decommissioning plan. The plan is to examine and evaluate different decommissioning options. It has a conclusion, which can be perceived as an application for the licensees' preferred decommissioning option. Thereafter, the plan is submitted to the government and at the same time circulated to a number of environmental and fisheries organisations for comments. The plan is then reviewed by the Ministry of Petroleum and Energy, which considers environmental, technical, economic and resource aspects. Furthermore, the ministry considers international obligations and the consequences for fisheries and shipping, and the comments of environmental and fisheries organisations. Typically, the recommendation from the Ministry to *Stortinget* (the Norwegian parliament), lies somewhere between the recommendations from the licensees and the environmental and fisheries organisations. The latter typically advocate a complete removal of all installations, whereas the former would often prefer some of the facilities to remain on the field or to be dumped. The Ministry would recommend only special facilities, such as pipelines, to remain ashore. In these recommendations to Stortinget it is emphasised that each field is unique and that the recommendations are not intended to form precedent. Existing Norwegian offshore petroleum installations are very heterogeneous with respect to factors influencing decommissioning, such as external effects and removal costs, calling for a separate evaluation of each case.

Tax Treatment of Decommissioning

Decommissioning raises some interesting tax questions. As a background for this discussion we first present the general features of the Norwegian petroleum tax regime. The Norwegian petroleum tax system is based on the Norwegian rules for ordinary corporate tax, charged at 28 per cent of corporate profit. Owing to resource rents a special tax of 50 per cent has been added to this industry, implying a marginal corporate income tax of 78 per cent.[10] Licences are allocated by a discretionary licensing system, with no up front payments by the companies. Statoil, a 100 per cent state-owned company, operates on the Norwegian continental shelf on a commercial basis. Through the State's Direct Financial Interest (SDFI), the Norwegian government is a passive stake-holder in many licences.[11] In addition, the Norwegian state owns 40 per cent of Norsk Hydro, a central actor on the Norwegian continental shelf.

As for tax treatment of decommissioning expenses, should (a) the oil companies be allowed appropriations in the tax accounts for future removal costs, or (b) should the actual removal costs be tax deductible? Neither is the case in the Norwegian Petroleum Tax Code. Instead, the state's share of the removal costs is paid directly to the oil companies at the time of removal. These levies are individually sanctioned by the Norwegian Parliament. The main rule for the state's share, estimated in each separate case, is the average effective corporate income tax rate the company has faced on the net incomes from the field. The cost-sharing rule is thus mimicking the tax effect of scheme (a). If the oil company has been in a tax paying position in the entire period of operation, the state's share is approximately 78 per cent. For the decommissioning of 15 platforms at the Ekofisk field, starting in 2003, the state is to pay about two thirds of the removal costs.[12] There are, however, exceptions to this cost sharing rule. In cases where the estimated state share is unreasonably low, the state's share can be increased, after application by the operator. For the Nordøst-Frigg field the state's share was increased from 39.7 to 50 per cent after application. Exxon applied for increasing the state's share to 68 per cent, up from 38.2 per cent according to scheme (a), and was granted 50 per cent.[13] In calculating the revised cost share, the government has taken into account the company's *future* tax position in Norway[14], i.e., scheme (b) is applied. Thus, while the main rule is (a), rule (b) may be applied if the main rule is unreasonable. Although the tax treatment of decommissioning costs does not convey advantageous tax credits, it does seem to provide the oil companies with a higher probability of obtaining a tax deduction than is the case for other costs.

According to a proposition bill from the Norwegian government (Ot.prp. no. 33, 1985-86), there are several reasons why removal costs are given a special tax treatment. One objective is to avoid discrimination. With a traditional tax treatment, a number of firms would not have had a full tax deduction, since at the time of removal they may not have had sufficient income generated in Norway to cover the costs. Another important objective is to avoid distortions in the companies' decisions, in particular distortions that reduce the recovery rate. Traditional tax treatment of removal costs might tempt the firms to close down production early, while they have sufficient revenue, and refrain from building out adjacent reservoirs (satellite fields).

Another reason why the oil companies were not allowed appropriations in the tax accounts for future removal costs, was perhaps the fact that this approach might imply large tax advantages for the oil companies: because neither the timing nor the extent or costs of future removal could be established with a reasonable degree of certainty at the time of appropriations, these would be arbitrary. Implicit in this argument is the belief that the companies would have an incentive to exaggerate future removal costs, e.g., by underestimating the expected cost reductions due to advances in technology, and thereby obtain undue tax credits.

In addition to refunding parts of the companies' share of the removal costs, the Norwegian state would also have to carry the costs that accrue to the state equity share in the various licences. Assuming that the private oil companies in a given licence have been in a tax paying position for the entire period of operation, and that the SDFI holds 30 per cent of the licence, Statoil 20 per cent, and Norsk Hydro 15 per cent, the Norwegian state is to pay 90 per cent of the removal costs.[15] If Statoil and SDFI together held 80 per cent of the equity (which is the case for some licences), the state would be accountable for 97 per cent of the removal costs.[16]

Externalities to Fisheries from Oil Installations.

In several areas around the globe, such as off the Norwegian coast, the most important externalities from offshore petroleum installations are to the fishing industry. Offshore oil activities have made considerable fishing areas inaccessible for fishing vessels. Hence, the disposal choice for obsolete installations may have significant economic consequences to fisheries. This section analyses the nature of externalities to fisheries, and provides estimates from a case study of the Ekofisk field on the Norwegian continental shelf.

Offshore petroleum installations and pipelines occupy considerable areas in the Norwegian sector that were previously used as fishing grounds or represent potential fishing grounds. Most oil installations have a safety zone that is closed to fishing vessels. Pipelines on the seabed have a reputation for damaging demersal trawl gear (Soldal *et al.*, 1997). In addition, a large number of objects have been dumped on the seabed in conjunction with oil activities, leading to damage or loss of fishing gear.

For both the fisheries and petroleum sector most of the production is exported. In 2000 exports of products from the seafood sector totalled US$ 3.4bn. This is much less than the export revenues of US$ 28.8bn from the petroleum sector. But unlike the latter sector, fisheries should be able to maintain income streams around the current levels into an indefinite future. The Norwegian fishing industry employed 22,900 fishermen in 1997, while 16,000 were employed offshore and onshore in petroleum extraction. However, the greater short-term magnitude of petroleum revenues may have lead to a favourable treatment of the petroleum sector in areas where the two sectors have had conflicting economic interests.

There exist no estimates of the total costs to fisheries due to loss of access, damages to equipment and pollution in the Norwegian sector. A government report from 1986 analyses losses to fisheries for some selected areas (NOU, 1986:6). It estimates the reduction in annual catch revenues due to petroleum activities to represent 23% of the catch potential in these areas, or nominal 1986 US$ 3.3 million. The estimated losses are of minor significance, both in absolute terms or when compared to total revenues from the Norwegian fishing sector. However, with a gradual shift in petroleum activities from the southern waters of the Norwegian sector to the northern waters, where fish resources are much larger, the trend is that new petroleum installations are located closer to the more important fisheries.

Until recently, the focus has been on the effects of new production facilities on fish stocks and fisheries. However, as some oil fields now approach their terminal phase the focus is shifting towards disposal options for installations. An important topic is the potential externalities associated with different disposal options. Although petroleum activities are generally being regarded as a source of negative externalities to the fisheries sector, it is recognized by some that there may be benefits from installations that have reached their cold phase. There are several issues that need to be considered in an analysis of externalities to fisheries from abandoned installations:

- *Stock pollution*: are there any toxic emissions from abandoned installations that can lead to increased mortality and/or reduction in the market value of the fish?
- *Stock enhancement effect*: does the physical presence of oil installations increase the reproductive ability of fish stocks (fishing reefs), thus leading to an increase in fish biomass and harvesting potential?
- *Stock concentration effect*: will the fish stocks gravitate towards the feedstock that tends to gather around offshore installations?
- *Fishing access*: to what extent does the physical presence of obsolete installations and pipelines limit the accessibility of different types of fishing vessels and different gear types?

(continued on page 24)

Issues of Decommissioning *(continued from page 23)*

There is no general answer to the question whether abandoned oil installations will pollute the surrounding fish population. However, it is anticipated that for the installations in the Norwegian sector the costs associated with cleaning up after termination of production should be relatively small. The most visible pollution is usually pile cuttings on the seabed (Anon., 1999). The environmental impact has not been such that it has affected the prices of fish caught in the area.

Summary and Conclusions

This paper has examined major policy issues associated with decommissioning of petroleum installations, using the Norwegian continental shelf as a case study. Decommissioning is becoming an increasingly important issue, as many offshore petroleum fields around the world are approaching the time when their reservoirs are exhausted. The Brent Spar incident suggests that this is also a politically potent issue extending across national boundaries. International conventions, most notably the OSPAR agreement, still allow for a large degree of discretion on the part of national governments in the case of pipelines and large installations.

By signing international agreements such as the OSPAR, governments have constrained themselves to choosing decommissioning options with limited adverse environmental effects. The costs of decommissioning programs depend on the choice of strategy. However, the decommissioning strategy not only influences costs but also which parties are going to carry the costs. Potential winners and losers are oil companies, taxpayers, and different groups of fishing vessels. Hence, decommissioning is a cost-benefit problem involving important distributional considerations, with binding political constraints represented by the national and international environmental opinion, as well as taxpayers' willingness to pay for a clean seabed.

Disposal of petroleum installations raises a number of interesting questions. Examples are timing issues, tax treatment, and liability for installations that are permanently left at the seabed. New technology and discovery of new reserves in adjacent areas may make it optimal once again to use the facilities for extraction purposes. Thus, it may be optimal to postpone the disposal of platforms.

Petroleum installations may function as artificial reefs that may provide positive fish stock concentration and enhancement effects, generating possible gains to specialized artificial reef fisheries but losses to demersal trawlers that will not be able to access the area. Calculations from the Ekofisk field at the Norwegian continental shelf show that leaving the installations as artificial reefs and establishing a marine reserve around the abandoned installation, is the option that generates the highest net present value to the fisheries. However, the future discounted net revenues for fisheries are small, less than one per cent of the disposal costs.

The most influential Norwegian fisheries organization opposes artificial reefs. Adding the fact that environmental organizations strongly oppose reef programs, as well as the fact that the Norwegian government previously has not approved such applications, it is perhaps not surprising that the Ekofisk field operator, Phillips Petroleum, proposes to take the steel substructures on the Ekofisk field ashore. This disposal solution is estimated to cost 460 million USD, compared to 100 million USD for artificial reefs. For this decommissioning decision to be in correspondence with society's cost-benefit calculations, the population's willingness to pay for a clean seabed in this particular area must exceed the net loss to fisheries of removing the installations and the cost difference of removing installations, e.g., it must exceed 363.9 million USD in the case of Ekofisk. It is worth noting that Norway has a small population (5 million) and a large number of offshore platforms. In the area surrounding the Ekofisk field there is a low fish density and a small share of the fish biomass is high value species. Thus, other areas on the Norwegian shelf have a considerably larger potential for increase in fish biomass and economic rent through an artificial reef program.

Footnotes

[1] Shell UK requested the international certification, classification and advisory body *Det Norske Veritas* (DNV), to perform a comparative assessment of the proposed options for disposal of Brent Spar (DNV Report No. 970911-0007). The scope of work covered technical feasibility, safety assessment, environmental assessment and price verification.

[2] See section four for a further discussion and references.

[3] In addition, there are national regulations, which reflect the circumstances of the different countries. Since the UK and Norway are the only countries to have installations in waters deeper than 75 metres, only these two countries have developed detailed procedures and guidelines for offshore disposal. Abandonment plans have to be approved by government and the necessary licences obtained.

[4] OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations.

[5] See proposition from the Norwegian government, St. prp no 8, 1998-99.

[6] Two installations on the Ekofisk Field, two on the Oseberg field, and one on the Brage and Heimdal fields.

[7] Provided that there are 55 metres of clear water over the remains to ensure safety of navigation.

[8] See report to the Norwegian government, NOU 1993:25.

[9] See proposition from the Norwegian government, St. prp. no 36, 1994-95.

[10] Although Norwegian petroleum taxation is mainly a profits tax, royalty is payable on oil production from fields approved for development before 1986, and recently a carbon tax has been imposed on petroleum that is burnt and on gas that is directly released. It has been decided, however, that the royalties will be phased out over a three-year period. Also, the CO_2-tax is likely to be reduced.

[11] For more details on the Norwegian petroleum tax system, see MPE (1998).

[12] *Stavanger Aftenblad*, October 22, 1999.

[13] See proposition from the Norwegian government, St. prp. no. 50, 1995-96.

[14] See St. prp. no. 36, 1994-95

[15] Note that if the companies have partly been out of a tax paying position, e.g., with an average tax rate of 30 per cent, the state's share would be considerably lower.

[16] The state's equity share, however, has been reduced in recent licensing rounds.

References

For references contact the authors.

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Controlling Carbon Dioxide: An Analysis of Competing Marginal Effects

*By Peter Hartley and Kenneth B. Medlock III**

Introduction

When considering the control of carbon dioxide (CO_2) emissions, policy-makers are faced with a difficult decision. On the one hand, actions can be taken today to restrict the flow of emissions into the atmosphere, which by most accounts would result in a considerable economic loss. On the other hand, action can be delayed, which may or may not result in considerable social and economic loss at some point in the future. In principle, action should only be taken when the marginal costs of that action exactly offsets the marginal benefits (for the moment we are disregarding the effects of discounting in a dynamic setting). Therein lies the difficulty. There is considerable uncertainty about the potential costs and benefits of the problem at hand.

There exists a corollary to the problem of deciding when and if to enact CO_2 abatement measures in economic theory. The decision to abate CO_2 can be viewed as a problem of investment under uncertainty because it demonstrates some key characteristics of such a problem. First, once we decide to take abatement measures, the cost borne in the form of lost economic growth cannot be recovered, and is thus at least partially irreversible. Second, there is uncertainty over the future rewards of undertaking this investment project. And third, we have to make a decision about the timing of the investment. Thus, when analyzing the decision to abate CO_2, we must consider costs and benefits, and how costs and benefits change as time progresses.

Some scientists claim that the accumulation of CO_2 in the atmosphere will harm future generations by raising atmospheric temperatures. A number of factors, however, lend to a persistence of uncertainty concerning not only the possible effects of CO_2 on climates, but also concerning the natural forces that have produced substantial fluctuations in past climates. Delaying control of CO_2 emissions allows us to take advantage of future research. Evidence may show that CO_2 emissions are relatively harmless or even beneficial on net, and that people need not reduce their use of fossil fuels. Given our current understanding of the effects of CO_2, fear of global climate change does not justify an increase in the taxes on fossil fuel combustion and the concomitant adverse effects on economic growth and prosperity. Economic progress directly increases the welfare of future generations and provides resources necessary to developing new technologies and improving the environment. Technological change eventually will reverse the accumulation of CO_2 in the atmosphere without constraining energy demand or lowering economic growth.

Delaying action to abate CO_2 allows us to determine whether structural and technological changes that accompany economic growth will abate CO_2 emissions in amounts sufficient to alleviate concerns. As economies grow, consumption and output shift away from more energy-intensive industrial goods to less energy-intensive services. Moreover, current rates of technological advance in using alternative energy resources suggest that, within decades, fossil fuels are likely to provide a much smaller proportion of total energy requirements than they do now. By the middle of this century, innovations in solar and fuel-cell technologies could largely eliminate the use of coal, oil or natural gas to generate electricity. In addition, advances in the efficiency of fossil fuel combustion can reduce CO_2 emissions, even as such advances allow fossil fuels to remain price competitive. For example, gas-electric hybrid motor vehicles could increase private transportation efficiency by up to a factor of three, which, for a fixed number of miles driven, would reduce demand for gasoline by 67%. Such a development would greatly reduce fossil fuel consumption in industrialized countries, where energy demand for transport is currently a large proportion of total energy demand.

Delaying control also permits a more gradual adjustment to higher energy prices. There has been extensive research investigating the effects of oil prices on the macroeconomy. Rapid oil price increases are highly correlated with reductions in real GDP growth.[1] A large permanent rise in energy prices would make substantial amounts of otherwise usable capital obsolete. A gradual rise in energy prices would allow existing capital to continue providing productive services as it is phased out and replaced by more energy-efficient alternatives. Since only the gradual accumulation of CO_2 matters, future control at lower cost is an attractive alternative to current control at high cost.

Controlling CO_2 emissions can be viewed as an investment project. Up-front costs are incurred in order to deliver possible future benefits. We develop a simple framework in order to illustrate some of the important features of fossil fuel price increases brought about in order to reduce CO_2 emissions. Taxes on fossil fuels constrain economic growth by reducing the consumption of energy. A possible offsetting benefit, however, is that CO_2 emissions would be reduced. In weighing the costs and benefits of adopting a carbon reduction policy, one must sufficiently account for the marginal contributions of various beneficial and detrimental factors. For example, the modeling framework that we present indicates that if the net marginal effects of CO_2 on the biosphere and of fossil fuels as an energy source are positive at the optimal level of CO_2, then the marginal effects of additional CO_2 on the climate must be negative. Contrary to popular impressions, therefore, it would not be optimal to reduce CO_2 to a level where it has negligible harmful effects on the climate.

Some Sources of Uncertainty

Over the past 100 years, industrial activity, the demand for electricity, and the demand for transportation services have increased exponentially. The degree to which humans rely on fossil fuels to provide energy for these things is indicated by the fact that in 1997 fossil fuels provided about

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[1] See footnotes at end of text.

86% of primary energy requirements globally. Since carbon dioxide (CO_2) emissions are an unavoidable by-product of fossil fuel combustion, modern economic activity has resulted in an increase in the concentration of CO_2 in the atmosphere. From 1958 to present, the concentration of CO_2 in the atmosphere has risen about 14% and is now about 30% above pre-industrial levels. Furthermore, the Intergovernmental Panel on Climate Change (IPCC) currently estimates that future economic activity will cause CO_2 concentrations to rise during the next century to a level 90% above pre-industrial levels.

The accumulation of carbon dioxide (CO_2) in the atmosphere is purported by some scientists to cause a warming of the Earth's surface. Since about 1970, there has been a positive correlation between the atmospheric concentration of CO_2 and average global temperatures, which has led many to suggest that the relationship is causal. The hypothesis, referred to as the "greenhouse effect", is plausible because CO_2, as well as other greenhouse gases[2], absorb some of the infrared radiation that is emitted from the earth's surface after the sun warms it. This, in turn, warms the atmosphere thereby increasing the amount of water vapor. Increased water vapor can then amplify the effect of CO_2 to produce noticeable temperature increases.

Due to the extreme complexity of the Earth's climate, complicated computer models are necessary to predict the impact of future CO_2 accumulations. The global climate models (GCM's) vary considerably in their predictions. Not only does the global average temperature increase predicted by different models vary, but the regional predictions for rainfall and temperature also vary considerably. This variability in prediction only serves as a testament to the degree of uncertainty that exists in climate science. A general tendency, however, does emerge. Specifically, the coldest winter air masses in Siberia, North America and Antarctica are predicted to warm the most.[3] Therein lies a potentially major global problem. The melting of land-based polar ice, combined with thermal expansion of the world's oceans, could raise sea levels, flooding low-lying, coastal areas. Moreover, adjusting to rising sea levels could be difficult because the change could occur abruptly. Initially, warming may cause a gradual melting of ice, but if large chunks of land-based ice fall into the ocean, they will melt more rapidly. The resulting influx of fresh water into the oceans could also affect the circulation of ocean currents producing further changes in climates.

Many factors complicate the modeling of global climates. For example, the net effects of the initial increase in temperature produced by CO_2 are complicated by interactions between the atmosphere and the oceans. It is well known that the oceans serve to regulate climate, but the extent to which they act in such a manner is largely unknown. There is also much to learn about the effects of upper atmospheric disturbances, such as ozone depletion and changes in stratospheric winds. To complicate matters further, there is geological evidence that suggests the world's climate can change rapidly, but the amount of CO_2 that must accumulate before a catastrophic event would occur is unknown.

Other factors complicate the assessment of any damages that may result from warming. For example, increased CO_2 can stimulate plant growth and, more generally, biosphere productivity. Since carbon compounds form a large part of living organisms, an expansion of the biosphere would tend to reduce CO_2 concentrations in the atmosphere. When coupled with the uncertainty in climate modeling, this type of competing factor contributes to making the timing and severity of any potential damage very difficult to predict.

When the Intergovernmental Panel on Climate Change (IPCC) was established in 1988, the GCM's that formed the basis for that report were predicting a median temperature increase of 8 degrees Celsius by the year 2100. However, as the scientific understanding of climate mechanisms has grown, additional climate feedbacks have been incorporated into the GCM's, and subsequent predicted temperature increases have been reduced. For example, in 1990, the median predicted increase for 2100 was reduced to 3.2 degrees Celsius, and by 1995 the IPCC's median projection had fallen to 2 degrees Celsius. Just as with any other discipline, advances in climate science extend both our understanding of the climate system and our ability to predict future climate outcomes.

Despite the uncertainties surrounding the causes and ramifications of global warming, the severity of the purported damages of global warming has raised public awareness and governments are being urged to act. The Kyoto Protocol, an international agreement signed in 1997 but yet to be ratified by any of its signatories, calls for the reduction of greenhouse gas emissions. The protocol specifies a greenhouse gas emissions target of between 5% and 8% below 1990 levels by 2008-2012 for a group of industrialized nations (referred to as Annex I countries). Carbon taxes or direct controls could be used to achieve these targets, but they are likely to be very costly. Costs will also be higher the faster controls are enforced since reducing emissions in the short term generally requires reducing production causing some degree of capital obsolescence. Relatively low cost methods of control, such as land-use changes, the clean-development mechanism (CDM), and emissions permit trading, have been proposed, but methods of implementation have yet to be worked out.

Modeling the economic cost of taking CO_2 abatement measures is just as difficult as modeling the climate. Uncertainty pervades the exercise due a number of problems. The lack of clearly defined guidelines for reducing CO_2 emissions, an inadequate understanding of the potential of new technologies, and more conventional problems of projecting economic growth, the composition of fossil fuel use, and projecting energy prices each contributes to this uncertainty. Therefore, while we cannot be certain whether or not global warming is an immediate and serious threat, we also cannot be certain about the economic costs of taking steps to eliminate an uncertain threat.

Technology is another major source of uncertainty that affects the prediction of future climate and the estimation of the economic costs of CO_2 abatement. Contrary to the predictions of many analysts, and despite continuing growth in energy demand, the price of energy has not risen significantly in real terms in recent decades. The real price of oil at the end of 1999 was about equal to the real price at the beginning of the 1970's. Significant advances in fossil fuel (oil, coal, and natural gas) recovery technology have extended the life of previously mined reserves and allowed new

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Controlling Carbon Dioxide *(continued from page 27)*

resources, such as deep water oil reservoirs, to be exploited. In addition, technological change in energy-using industries has reduced the amount of energy needed per unit of output produced. Finally, alternative energy sources, such as nuclear power, hydro-electricity, solar power, and fuel cells promise to provide alternatives to fossil fuels for meeting new energy demands. For example, while fossil fuels accounted for 96% of total energy requirements in the United States in 1970, by 1995 they provided only 84%. This process is likely to accelerate as alternative sources of power are developed. Solar power ultimately may supply much of the electricity to the interconnected grid. While solar power currently can compete with fossil fuels only in specialized and remote applications, future innovation and development may make solar generated power competitive with conventional forms of power, such as coal-fired electricity, in urban areas.

Controlling CO_2 as an Investment

Controlling CO_2 emissions can be viewed as an investment project. Up-front costs are incurred in order to deliver future benefits. The primary up-front cost of CO_2 abatement is forgone economic growth. For example, taxes on fossil fuels constrain economic growth by raising the cost of capital services, which reduces the utilization of capital and, hence, the consumption of energy. A possible offsetting benefit of fossil fuel taxes is that CO_2 emissions would be reduced. There is, however, substantial uncertainty about the consequences of changes in the atmospheric concentration of CO_2. Discounting is also important because the significant costs of global warming, should they occur, will be experienced decades into the future. Thus, the discounted present value of the net benefits of CO_2 abatement must be large enough to warrant the up-front costs.

Figure 1
Cost of Taxes on the Use of Fossil Fuel

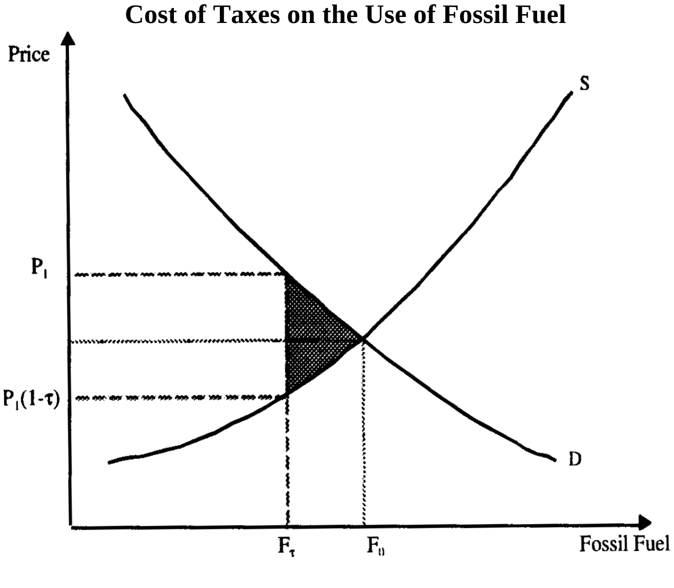

Figure 1 illustrates the effect of a tax on energy use, ignoring any beneficial effects such a tax might have on emissions of CO_2. The latter benefits are examined separately in Figure 2. In Figure 1, the curve labeled *S* represents the supply of fossil fuel, or the marginal costs of supplying fossil fuel energy, ignoring potential externalities from CO_2 emissions.[4] The curve labeled *D* represents the demand for fossil fuel, or the marginal benefits of fossil fuel energy consumption (the marginal value of transport services, electricity consumption and so forth). Equilibrium fossil fuel energy use in the absence of taxes is labeled F_0, while F_t represents energy consumption under an energy tax at rate t. The tax imposes efficiency losses by artificially discouraging the consumption of fossil fuel energy. The reduced production of fossil fuel energy saves costs equal to the area under the marginal cost curve between F_0 and F_t. The lost benefits equal the area under the marginal benefit curve between F_0 and F_t. The efficiency losses, therefore, equal the loss in benefits minus the cost savings, which is the shaded area in Figure 1. This area is proportional to the square of the reduction in fossil fuel consumption $(F_0 - F_t)^2$.

Figure 2
Losses from an Excessive Level of CO_2 Accumulation

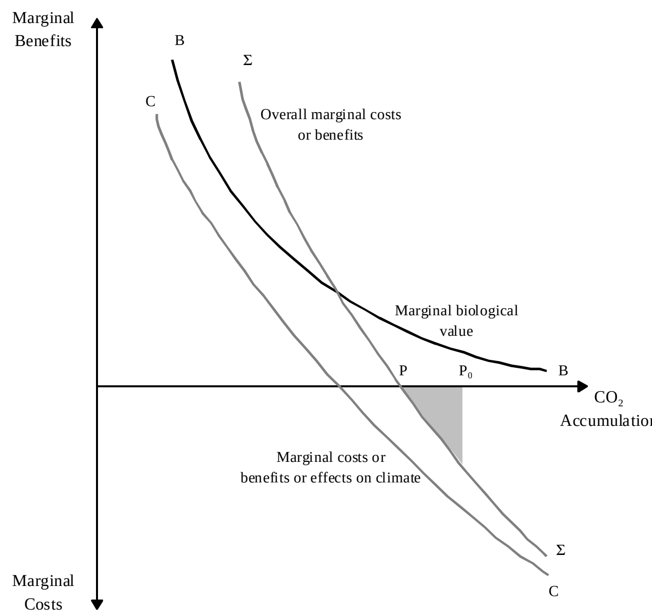

Figure 2 presents the efficiency losses accompanying an excessive, or insufficient, amount of CO_2, if we ignore the value of fossil fuels as an energy source. The latter was presented in Figure 1. Figure 2 contains two downward sloping curves labeled *B-B* and *C-C* and a third curve, labeled Σ-Σ, which represents the vertical sum of the other two curves. The curve labeled *B-B* in Figure 2 represents the marginal value of CO_2 to the biosphere, ignoring the effects of CO_2 on climate. These benefits arise as a result of the beneficial effects of CO_2 on plant growth. Plants (including plankton in the oceans) absorb CO_2 as part of the process of photosynthesis. Increased CO_2 has been shown to make most plants grow faster and bigger, make them more resistant to stresses such as drought or disease, allow them to photosynthesize with less nitrogen and water and at lower levels of light, and increase the production of fruits and grains.[5] Most life on earth is based on the production of carbohydrates by plants using CO_2, water and sunlight as inputs. Making plants more productive also allows the animal kingdom to expand on that food base. The productivity of agriculture and forestry (and perhaps also fishing) is likely to rise substantially as more CO_2 is added to the atmosphere (and oceans). Throughout the range represented in Figure 2, the "fertilizer" effect of CO_2 is positive, but the curve slopes down because the marginal benefits decline as the CO_2 level increases. With a relatively large amount of CO_2 already present in the atmosphere, a given increase has less of a stimulatory effect on plants.

The curve labeled *C-C* in Figure 2 represents the marginal effects of atmospheric CO_2 on the climate. At very low levels of CO_2, the climate models imply that additional CO_2 would be beneficial because it helps prevent the earth from being too cold.[6] The models imply, however, that as the CO_2 level increases, the average global temperature rises. Eventually, climates become undesirable for humans. Most of the models imply that the effect of CO_2 on the average global temperature is approximately linear. The curve *C-C* in Figure 2 need not be linear, however, because it represents the marginal cost of the temperature change and that need not be a linear function of the average temperature.

If we ignore the direct benefits obtained from fossil fuel consumption, the overall marginal benefits or costs of CO_2 are represented by the sum of the biological effects and the effects on climates. This is the curve labeled Σ-Σ in Figure 2. The efficient level of CO_2, labeled *P*, would be where the marginal climate costs of CO_2 just balance the marginal biological benefits. There is no presumption that P corresponds to either the current or the "pre-industrial" level of CO_2 in the atmosphere. If the biological benefits of CO_2 were large, and the effects on climates were small, CO_2 levels far above the current level would be optimal, even if we ignored the benefits from fossil fuel combustion.

An interesting implication of Figure 2 is that if the marginal biological effects of CO_2 are positive at the optimal level of CO_2 (ignoring the benefits of fossil fuels as an energy source), the marginal effects of additional CO_2 on the climate ought to be negative. Contrary to popular impressions, it would not be optimal to reduce CO_2 to a level where it has negligible harmful effects on the climate. At the CO_2 accumulation level labeled P_0 in Figure 2, there is too much CO_2. The total cost of the increase in the CO_2 level from *P* to P_0 are given by the area under the overall marginal cost curve Σ, or the shaded "triangle" in Figure 2. This area is proportional to the squared difference $(P_0 - P)^2$.

Suppose that the level of CO_2 initially exceeds *P* as illustrated in Figure 2. A tax on the use of fossil fuel will produce a triangle of efficiency losses in the fossil fuel energy market, but the resulting fall in the rate of accumulation of CO_2 in the atmosphere will reduce the efficiency losses illustrated in Figure 2. In principle, the tax rate should be chosen so that the losses in Figure 1 just balance the reduced losses in Figure 2. An implicit assumption underlying this analysis is that we can calculate the optimal CO_2 level *P*. In reality, we do not know enough about the likely effects of additional CO_2 in the atmosphere to enable us to do this. The extent of uncertainty about *P* should fall over time as we learn more about the effects of additional CO_2 on climate and the biosphere. Hence, any decision made in the future regarding optimal tax rates to reduce CO_2 emissions should be better informed.

The point here is worth reiterating. Efforts to reduce CO_2 emissions should only be taken when $P_0 > P$ by an amount in excess of the benefit to society from consuming fossil fuel. Then, and only then, are the costs of imposing a tax on fossil fuels justified. The difficulty in measuring these costs, however, presents a significant problem. We do not have a clear picture of where the curves *B-B* or *C-C* lie. Thus, with no knowledge of the optimal value of CO_2, we must somehow deal with the uncertainty. A typical firm, when faced with significant uncertainty, will delay an investment until more information can be obtained regarding potential returns. One can argue, therefore, that action should be delayed until some of the uncertainty can be eliminated. The cost of imprudent action is simply too high to be ignored.

Concluding Remarks

In order to stabilize greenhouse gas concentrations, anthropogenic global emissions cannot exceed 40% of their 1996 levels (6.518 billion tons of carbon), which amounts to 2.6 billion tons of carbon. An emissions reduction on the order of ten times the level proposed in the Kyoto agreement would be required. Calculations using the climate models suggest that full implementation of the Kyoto Protocol will decrease the predicted increase of average world temperatures in 2100 by only 0.07 degrees Celsius. This difference is so small that it could not be detected reliably by ground-based thermometers. Moreover, if controls are imposed sooner rather than later, technology will be less advanced, the life of more capital equipment will be prematurely shortened, and fewer resources will be available to compensate for losses. Cost estimates of fully implementing the provisions of the Kyoto Protocol range from $US5-180 billion annually in the United States alone.[7] To justify spending such large amounts to reduce CO_2 emissions, reliable evidence of significant and dangerous global warming is imperative.

Processes affecting climates are not well understood. While the costs of delaying action on CO_2 emissions may be small, the benefits could be large. The determinants of global climates are not fully understood. Uncertainty persists not only concerning the possible effects of CO_2 on climates, but also concerning the natural forces that have produced substantial fluctuations in past climates. Delaying control of CO_2 emissions allows us to take advantage of future research. Evidence may show that CO_2 emissions are relatively harmless or even beneficial, and that we need not compel people to reduce their use of fossil fuels.

Ten more years of research and observations are likely to tell us a great deal about the accuracy of predictions from computer simulations of the earth's atmosphere. The most sensible approach, therefore, is to wait and see how our understanding of the effects of CO_2 emissions develops over the next decade. In fact, most of the anticipated costs of CO_2 accumulation are predicted to occur decades in the future. The incremental costs of delaying control, therefore, would also be incurred in the distant future, making them quite small in present value terms. In addition, economic growth will raise the living standards of future generations, and make the sacrifice needed to adjust to a climate change easier to bear in the future than in the present.

Footnotes

[1] See, to name a few, Bohi (1991), Hamilton (1983), Lee, Ni, and Ratti (1995), and Mork, Olsen, and Mysen (1994).

(Continued on page 33)

THE COSTS OF THE KYOTO PROTOCOL: A MULTI-MODEL EVALUATION

Edited by John P. Weyant
(Energy Modeling Forum, Stanford University)

This Special Issue represents the first comprehensive report on a comparative set of modeling analyses of the economic and energy sector impacts of the Kyoto Protocol on climate change. Organized by the Stanford Energy Modeling Forum (EMF), the study identifies policy-relevant insights and analyses that are robust across a wide range of models, and provides explanations for differences in results from different models. In addtion, high priority areas for future research are identified. The study produced a rich set of results. The 448-page volume consists of an introduction by John Weyant and a paper by each of the thirteen international modeling teams. More than forty authors provide richly illustrated descriptions and of what was done and concluded from the model runs that were undertaken.

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ABOUT THE EDITOR: John P. Weyant is a professor of engineering-economic systems and Director of the Energy Modeling Forum (EMF) at Stanford University. His current research focuses on analysis of global climate change policy options and models for strategic planning.

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Risk and the Reserve/Production Ratio

*By Douglas B. Reynolds**

Risk is a factor in oil exploration and development that has not been fully incorporated into our analysis of OPEC and world oil market. Robin and Thaler (2001) show that an individual's marginal utility for wealth-gains decreases exponentially and that for wealth-losses increases exponentially. In other words, people are normally highly risk averse. But if an individual person, who is an economic agent, is highly risk averse, then an economic entity such as an oil company can also be risk averse. Each OPEC country has a National Oil Company (NOC) or a national bureaucracy, which controls all oil exploration and development. Since an NOC is an economic entity and could be highly risk averse, then we might see not only high reserve to production ratios for that country, but also very little new exploration or development.

Adelman (1986) shows that Saudi Arabia has less exploration and development than the United States even though oil reserves and potential oil production are greater in Saudi Arabia than in the United States. Reynolds (2000) suggests that the reason oil exploration and development investments are lower for some oil producer countries than for the United States is due to risk aversion. NOCs are risk averse to oil investment and, therefore, have lower oil production and in turn higher reserve to production ratios. Investments tend to be less aggressive and the pace of oil exploration and development is much slower than under a competitive environment. This, however, should not be interpreted as a bad thing. It is to the world's advantage that oil be conserved for the future. Oil is the most valuable energy commodity on earth and always will be. Therefore, any market environment that conserves oil should be applauded.

In contrast to OPEC producers, the United States has a well adjudicated property rights system and a competitive market, with many wildcat drillers. These wildcat drillers tend to have little to lose and are extremely risk loving. They push oil exploration to the limits of marginal cost. Oil supply models that compare a competitive U.S. market environment, with greater risk taking, to a risk averse market environment, such as OPEC countries operate in, can lead to the wrong oil supply forecast. It is important to incorporate the idea of risk loving and risk averse behavior into a model of oil supply. I will do that by using a modified Hubbert curve model, which is one of the most important models for oil supply.

In 1962 M. King Hubbert created a mathematical logistics curve, often called the Hubbert curve, which could be used to project future trends in oil discovery and production. Cleveland (1991), Reynolds (1999), Slade (1982), and Uhler (1976) give theoretical reasons for why the Hubbert curve works. Cleveland and Kaufmann (1991), Moroney and Berg (1999), and Kaufmann (1991), incorporate economic principles into Hubbert's equations. Pesaran and Samiei (1995), Campbell and Leherrere (1998), Edwards (1997), Campbell (1997), and Cleveland and Kaufmann (2001) use Hubbert's equations to forecast oil supplies for the United States and the world. On the other hand, Wiorkowski (1979), Ryan (1965), and Lynch (1994) have criticized Hubbert for not accounting for economic, technological and political changes in the oil market. The claim that in many instances it is not possible to forecast oil supplies using the Hubbert curve. Nevertheless, even with as much criticism as Hubbert received, his 1962 forecast for the peak in oil production for the U.S. lower 48 was only off by one year. Hubbert also theorized that his curve does take into account technological trends.

Since Hubbert's work has been resurrected as a viable forecast model, forecasters are starting to use it more. For example Campbell and Leherrere (1998) predicted a world oil shortage in the near future. The U.S. Energy Information Administration (EIA) also uses what looks to be a Hubbert curve analysis for their world oil supply forecast. The EIA, (EIA 2000), forecasts that oil production will not peak until at least 2030 and maybe into the 22nd century. I will also use a Hubbert curve to forecast world oil supplies and add a risk factor to take into account OPEC countries risk averse behavior. However, in order to better use the Hubbert curve it needs to be made into a cumulative production model rather than a time dependent logistics curve.

One of the problems with Hubbert's oil discovery and production logistics curve has been that it is time dependent. Because of this, if the demand for oil goes down or even increases more slowly, then the time path of production changes substantially from Hubbert's logistics curve. Once oil production goes below Hubbert's logistics curve it becomes difficult to track where the production limit is. An alternative Hubbert curve uses a simpler quadratic equation. This equation is derived by using the Hubbert time dependent oil production logistics curve and the time dependent cumulative oil production logistics curve and subsuming the time variable. The quadratic Hubbert curve is no longer time dependent but cumulative production dependent. The equation for the curve is:

$$QP = a \times CQP - (a/URR) \times CQP^2$$

where

QP = Quantity of Oil Produced during each year, i.e. the rate of oil production.
CQP = Cumulative Quantity of Oil Produced up to each year.
URR = Ultimately Recoverable Reserves.
a = a size parameter, which determines the height and width of the Hubbert curve.

Note, that QP is statistically independent of CQP because they have different units of measurement, one is a rate and the other is a quantity. The independence of QP from CQP, similar to the independence of QP from time, allows a statistical analysis using the quadratic Hubbert curve similar to his logistics curve. The new quadratic Hubbert curve has characteristics that make it easier to use. For example, if actual oil production is below the quadratic Hubbert curve, it is easier to see where consumption falls relative to the limits of supply. Plus it is easier to see how far demand can increase before it reaches the Hubbert limit. Therefore, this new Hubbert curve is the supply limit. Putting both supply and

(continued on page 32)

* Douglas B. Reynolds is an Assistant Professor at the University of Alaska Fairbanks, his new book *Scarcity and Growth Considering Oil and Energy: An Alternative Neo-Classical View* should be out in April 2002. This is an edited version of his paper presented at the 24th Annual IAEE Conference in Houston, TX, April 25-27.

Risk and the Reserve/Production Ratio *(continued from page 31)*

consumption (demand) on the same graph will allow us to see how far away the Hubbert curve supply limit is from demand.

Campbell and Laherrere use a Hubbert curve to estimate total world oil supplies at 1.8 trillion barrels and a peak in oil production before 2005. If they are right, in less than five years oil prices will increase to spectacular heights. An oil crisis of immense magnitude will ensue. However, even if the URR is much larger than what Campbell and Laherrere predict, we may still reach a Hubbert curve limit sooner than expected due to OPEC countries' risk averse natures. When risk aversion is included into a Hubbert analysis then Campbell and Laherrere's prediction may turn out to be much truer than expected. First consider an alternative Hubbert analysis using the EIA's world oil supply forecast. The EIA estimates a medium URR using geological data and scientific methods at 3 trillion barrels. The EIA's medium estimate for increases in oil demand is 2% per year. Putting together supply and demand, the EIA's best estimate is that world oil supply will peak in 2037. An alternative estimate forecasts the peak in 2030. If the EIA's estimated URR is correct and the world follows a U.S.-type Hubbert curve, then we can see where supply and demand were relative to each other in the past. Figure 1 shows the EIA model in terms of a quadratic Hubbert curve. The assumption is that reserve to production ratios will be at 10 to 1 as it has been in the United States for many decades.

The problem with using a U.S.-type Hubbert curve or assuming a low reserve to production ratio is that the United States has a competitive market with a large number of risk loving agents. As explained above, the United States is unique in its competitive marketplace. In many of the largest world oil producing regions, only one NOC is allowed to look for oil, or to determine who will and who will not explore for and develop oil within the country, and at what profit. Having a single economic entity in charge of all oil activities will normally reduce risk taking and create a very risk averse environment. Clearly with a single entity in charge, the Hubbert curve model, or any model, must take into consideration that risk averse behavior, which will radically reduce oil exploration, development, and production for any given region.

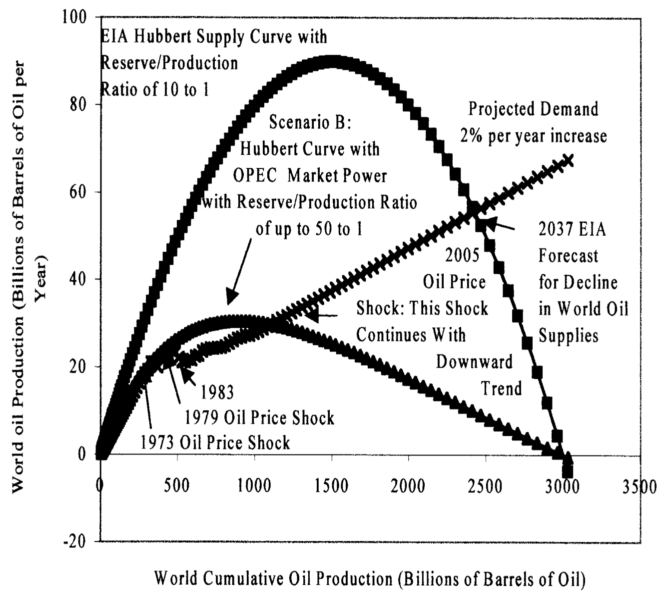
If a normal U.S.-type Hubbert curve cannot be used to analyze world oil supplies because actual supplies will be much lower than a 10 to 1 reserve to production ratio would allow, then how can world oil supplies be modeled? The best model for world oil supplies may simply be to track the maximum supply points in the past and forecast that path to the estimated URR. Looking at 1973 and 1979, we see extremely sudden declines in demand. The changes occurred because oil prices suddenly shocked upward. However, was it the price changes that caused the demand trend to change, or was it a supply limit that forced prices to increase and demand to fall. It is surprising to find oil prices rising so suddenly when oil consumption was well below the EIA modeled Hubbert curve limit. Indeed, the very fact that oil prices suddenly skyrocketed and stayed high suggests that the Hubbert curve at a 10 to 1 reserve production ratio is not in fact the limit of oil production, but that the Hubbert curve limit is much lower. Remember, many oil producing countries in the world produce oil at a 50 to 1 or even a 100 to 1 reserve/production ratio. This is a level of oil production 80% lower than for a 10 to 1 ratio. This means that a standard Hubbert curve should not be used to forecast world oil supply potential.

Figure 1 shows an alternative Hubbert curve called Scenario B. The Scenario B curve is created by finding a formula that fits the 1973 high point of oil production, the 1979 high point of oil production, and the currently estimated URR. The equation used for this curve is

$$QP = [a \times CQP - (a/URR) \times CQP]^2 \times 0.78[(CQP/URR) + 1]^{-ex}$$

Where $ex = 2.5$

Figure 1
Forecast OPEC Supply and World Oil Demand As a Function of Cumulative Production



Other exponents for *ex* less than or greater than 2.5 do not fit the 1973 and 1979 high points as well. Scenario B assumes that the maximum world oil production is lower than what a 10 to 1 ratio would give. One way to look at Scenario B is to assume that political or other economic factors have caused it. I believe it is OPEC countries risk averse environment that caused NOC's to have lower exploration and development efforts that caused Scenario B. Therefore, it is the Scenario B Hubbert curve that caused the 1973 and 1979 oil price shocks rather than the oil price shocks causing Scenario B. Note that although the second price shock was slightly lower than Scenario B suggests, this was due to Iran's slight reduction in production and Saudi Arabia's reductions thereafter. The most striking thing about Scenario B is that demand will reach and exceed supply in the next five years creating an oil price shock, even with URR at three trillion barrels. If URR is even higher at say six trillion barrels, Scenario B can be redrawn and the price shock is only delayed by another five years. Therefore, we should not expect higher URR estimates to delay for long the inevitable world oil price shock.

The reason the Scenario B curve is so much lower than a regular Hubbert curve is because of the inherent risk averse nature of NOCs. No matter how much an NOC is cajoled, reorganized or provided with internal incentives, it will still be a single entity making oil exploration and development decisions one project at a time. The company will by nature be risk averse because each individual oil project it decides on will be judged a gamble in isolation from all other considerations. In other words, the NOC does not judge individual project decisions by comparing it to other risks in the economy or by comparing it to the countries overall wealth. Rather the entity judges each risk in isolation and becomes very risk averse to make any move. This makes the oil entity, just like many individuals, very hesitant to expand its activities and investment.

What Scenario B suggests is that the world is in danger of an upcoming oil supply shock of epic proportions. What is more, there will be confusion over why such an oil shock will happen. Oil price shocks in the past occurred during or around significant political evens such as a war. However, I must stress that in no way could a one month Arab/Israeli war or a six month Iranian revolution cause an oil price increase of such a sustained magnitude as what happened in 1973 and 1979. The price increases were caused by fundamental economics. They were caused independently of political events and were due to the risk averse nature of OPEC's NOC's. However, political events do tend to push markets into chaos a little faster than they normally would. In today's highly charged political and terroristic environment, there will no doubt be future significant events as great as the World Trade Center horror. These events will not be the cause of future oil price increases but they will exacerbate them. Political and economic events that happen simultaneously will be interpreted as being cause and effect. Political events will be judged the cause rather than the underlying economic reality. Plus political events will exacerbate the economic events. What we can assume, though, is that there will be a huge oil price adjustment within five years. Oil prices of upwards of \$200 to \$300 per barrel are not out of the question. We need to prepare now for that event.

References

For references contact the author.

Student Conferences *(continued from page19)*

ics, presented a paper on "Deregulation in the North American Natural Gas Industry: what lessons for Mexico?"

At the second and final session on *The Electricity Sector,* Virginie Pignon, Ph.D. Student in Economics discussed "Electricity Transmission Tariffs in the Nordic Countries: An Assessment of Pricing Rules," Marie Laure Guillerminet, Ph.D. Student in Economics, discussed "Investment and Financing in an Institutional Environment in Mutation: the Case of an Electronuclear Equipment," Pierre Taillant, Ph.D. Student in Economics, discussed "Technological Competition and Lock-in in the Photovoltaic Solar Electricity Production" and Stine Grenaa Jensen, Ph.D. Student in Economics discussed "A Simple Integrated Power Market Model Including Tradable Green Certificates and Tradable Emission Permits."

The abstracts of the presentations from the Mexican student conference will be in the next issue of the newsletter of the Mexican Association for Energy Economics. In order to obtain free proceedings of either one of the student conferences please contact Alberto Elizalde Baltierra (elizaalb@hotmail.com) or Stine Grenaa Jensen (stine.grenaa@risoe.dk).

Controlling Carbon Dioxide *(continued from page 29)*

[2] Greenhouse gases, as defined by the United Nations Framework Convention on Climate Change (UNFCCC), are "those gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and re-emit infrared radiation." These are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC's), perfluorocarbons (PFC's), and sulfur hexafluoride (SF_6). Each gas is assigned a "global warming potential," which is a value that allows for comparison in terms of carbon units. The most important constituent of global warming models, in terms of its impact, is water vapor.

[3] Since water is far more effective at absorbing outgoing infrared radiation than is CO_2, most of the temperature increase predicted by the models arises from increased water vapor in the atmosphere triggered by CO_2 rather than the CO_2 itself. A slight warming of the coldest air masses allows them to hold substantially more water vapor and greatly increases their insulating effect. By contrast, more water vapor at tropical latitudes, and in the summer months, increases cloud cover. Clouds reflect incoming solar radiation, however, and this tends to have a cooling effect. Another factor making CO_2 more potent at warming higher latitudes is that CO_2 absorbs a greater proportion of the longer wavelength radiation emitted from colder surfaces.

[4] Figure 1 simplifies the analysis by ignoring the role of the OPEC cartel in the world fossil fuel energy market. The Appendix (to the companion paper) shows how the discussion in this section can be extended to allow for the actions of OPEC in setting the price of oil and thus indirectly of coal and other energy resources. The analysis of this section applies to the case where the supply chosen by OPEC is independent of the tax rate on fossil fuel. More generally, the analysis in this section under-states the efficiency costs of taxing the use of fossil fuel. Monopoly pricing by OPEC would already reduce the consumption of fossil fuel below the efficient level. Additional taxes on fossil fuel consumption would only exacerbate the efficiency losses resulting from monopoly pricing.

[5] If average temperatures do increase, laboratory experiments have shown that the stimulatory effect of CO_2 on photosynthesis is likely to be enhanced.

[6] Sir Fred Hoyle (1996) has noted the difficulties this creates for people concerned about current projected levels of global warming (K stands for degrees Kelvin, or degrees above absolute zero):

"Given the choice, I imagine nobody would opt for a world without any greenhouse, that is a world with a mean temperature of about 259K. And probably few would opt for an ice-age world with a mean temperature of 275K to 280K. To this point, the greenhouse is seen as good. Further still, a clear majority continues to see the greenhouse as good up to the present-day mean of about 290K. But, at the next 1.5K a drastic change of opinion sets in: the greenhouse suddenly becomes the sworn enemy of environmental groups, worldwide, to the extent that they rush off to Rio and elsewhere and make a great deal of noise about it. I find it difficult to understand why. If I am told that computer calculations show immensely deleterious consequences would ensure, then I have a good laugh about it. In private, of course, since I am always careful to be polite in public." (p. 185)

[7] These cost estimates derive from the survey of a number of models presented in a special issue of *The Energy Journal* (Weyant, (1999)).

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Publications

Thermal Use of the Underground – Ground Source Heat Pump Systems, VDI Verein Deutscher Ingenieure, VDI Gesellschaft Energietechnik, (September 01). Price: 123,00 DM. Contact: Beuth Verlag GmbH, D-10772 Berlin, Germany. Phone: 44-30-2601-2759. Fax: 49-30-2601-1263. Email: postmaster@beuth.de

European Energy Industry Business Strategies – Deregulation and the Furture of the Electricity Supply Industry in Europe, Professor A. Midttun, Editor (2001). Price: NLG240(euro 108.91)/US$125.50. Contact: Elsevier Science, PO Box 945, New York, NY 10159 USA. Phone: 212-633-3730. Fax: 212-633-3680. Email: usinfo-f@elsevier.com

World Energy Assessment: Energy and the Challenge of Sustainability. 516 pages. Price: $65.00. Contact: United Nations Publications, Room DC2-0853, Dept. D150, New York, NY 10017. Phone: 800-253-9646. Fax: 212-963-3489. Email: publications@un.org

Commercialization of Renewable Energy Technologies for Stustable Development. 200 pages. Price: $35.00. Contact: United Nations Publications, Room DC2-0853, Dept. D150, New York, NY 10017. Phone: 800-253-9646. Fax: 212-963-3489. Email: publications@un.org

Reform and Restructuring of the Gas Industry in Economies in Transition. 120 pages. Price $25.00. Contact: United Nations Publications, Room DC2-0853, Dept. D150, New York, NY 10017. Phone: 800-253-9646. Fax: 212-963-3489. Email: publications@un.org

Environmental Management in Oil and Gas Exploration Production: An Overview of Issues and Management Approaches. 72 pages. Price: $40.00. Contact: United Nations Publications, Room DC2-0853, Dept. D150, New York, NY 10017. Phone: 800-253-9646. Fax: 212-963-3489. Email: publications@un.org

First Europe-Latin American Dialogue on Promotion of Energy Efficiency. 84 pages. Price: $10.00. Contact: United Nations Publications, Room DC2-0853, Dept. D150, New York, NY 10017. Phone: 800-253-9646. Fax: 212-963-3489. Email: publications@un.org

Prospects for Caspian Gas. Price: £1250. Contact: Centre for Global Energy Studies, Jenni Wilson. Phone: 0044-0-20-7309-3610. Email: marketing@cges.co.uk

Arab Oil & Gas Directory 2001. 656 pages. Price: £620. Contact: Petromedia s.a.l., Suite 251, 28 Old Brompton Road, London SW7 3SS, UK. Phone: 44-20-7644-4979. Fax: 44-20-7644-4861. Email: petromedia@mail.com

Calendar

3-5 December 2001, LNG at Cavalieri Hilton, Rome. Contact: Victoria Watt, Head of Marketing, CWC Associates Ltd, 3 Tyers Gate, Bermondsey, London, SE1 3HX, England. Phone: +44 (0)20 70894150. Fax: +44 (0)20 7704 8440 Email: vwatt@thecwcgroup.com URL: www.thecwcgroup.com

3-4 December 2001, Oil & Gas in Angola 2001 at Meridien Presidente, Luanda. Contact: Naheed Islam, Marketing Manager, CWC Associates Ltd, 3 Tyers Gate, Bermondsey, London, SE1 3HX, England. Phone: +44 (0)20 70894150. Fax: +44 (0)20 7704 8440 Email: nislam@thecwcgroup.com URL: www.thecwcgroup.com

3-5 December 2001, Gambling with the Future Outsourcing the Utility Enterprise at Houston, Texas, US. Contact: Kim Good, T&D World Outsourcing Conference, 9800 Metcalf Ave, Overland Park, KS, 66212, USA. Phone: 913-967-1865. Fax: 913-967-1898 Email: kgood@intertec.com

4-7 December 2001, 17th International Exhibition for Environmental Equipment, Technology and Services - 2001 Pollutec Industry at Paris, France. Contact: Pollutec/Reed Expositions France, 70 rue Rivay, 92532 Levallois-Perret cedex, France. Fax: 33-0-1-47-56-21-10 URL: www.pollutec.com

5-6 December 2001, Mergers & Acquisitions in the Oil & Gas Industry Conference at One Whitehall Place, London. Contact: Myah McAlpine. Phone: 44-20-7291-1030 Email: mcalpine@gbnuk.com

6-7 December 2001, Asphalt: Future World Market and Technologies at Rome. Contact: Patricia Besa, Marketing Manager, CWC Associates Ltd, 3 Tyers Gate, Bermondsey, London, SE1 3HX, England. Phone: +44 (0)20 70894150. Fax: +44 (0)20 7704 8440 Email: pbesa@thecwcgroup.com URL: www.thecwcgroup.com

7-7 December 2001, Third Annual Russian Energy Summit at Moscow. Contact: Patricia Besa, Marketing Manager, CWC Associates Ltd, 3 Tyers Gate, Bermondsey, London, SE1 3HX, England. Phone: +44 (0)20 70894150. Fax: +44 (0)20 7704 8440 Email: pbesa@thecwcgroup.com URL: www.thecwcgroup.com

14-25 January 2002, 11th International Training Program on Utility Regulation and Strategy at Gainesville, FL. Contact: Pascale Parker, Program Manager, PURC, University of Florida, 205 Matherly Hall, Gainesville, FL, 32611, USA. Phone: 352-392-3655. Fax: 352-392-5090 Email: purcecon@dale.cba.ufl.edu URL: www.purc.org

14-16 January 2002, Indian Oil and Gas Conference at Taj Palace Hotel, New Delhi, India. Contact: IOGC 2002 Secretariat, 212 A Telok Ayer Street, Singapore, 068645, Singapore. Phone: 65-226-5280. Fax: 65-226-4117 Email: iogc@cconnection.org

21-23 January 2002, Gulf E-Business Conference for Gas and Oil Industry at Dubai, United Arab Emirates. Contact: Abderrahim Merzak, General Manager, GulfNet Conferences &

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Exhibitions. Phone: 971-4-3430481. Fax: 971-4-3431489 Email: info@gulfnetce.com URL: www.gulfnetce.com/ecomgo

24-25 January 2002, Emissions Trading and Kyoto Mechanisms in the Euro-Mediterranean Area at Rome, Italy. Contact: Stefan-Marc Keidel, Institute for Economy and the Enviroment, University of St. Gallen (HSG), Switzerland Email: kyoto@unisg.ch URL: www.iwoe.unisg.ch/IMKYM-CONFIN

28-29 January 2002, The Spanish Energy Summit, 2 at Westin Palace, Madrid. Contact: Victoria Watt, Head of Marketing, CWC Associates Ltd, 3 Tyers Gate, Bermondsey, London, SE1 3HX, England. Phone: +44 (0)20 70894150. Fax: +44 (0)20 7704 8440 Email: vwatt@thecwcgroup.com URL: www.thecwcgroup.com

30-31 January 2002, West Africa Reservoir Management at International Convention Centre, Accra. Contact: Victoria Watt, Head of Marketing, CWC Associates Ltd, 3 Tyers Gate, Bermondsey, London, SE1 3HX, England. Phone: +44 (0)20 70894150. Fax: +44 (0)20 7704 8440 Email: vwatt@thecwcgroup.com URL: www.thecwcgroup.com

27-28 February 2002, 2nd Annual African Insiders Strategic Briefing 2002 at Rosebank Hotel, Johannesburg, South Africa. Contact: Babette van Gessel, Group Managing Director, Global Pacific & Partners, 2nd Flr, Regent Place, Cradock Ave, Rosebank, Johannesburg, 2196, South Africa. Phone: 27 11 778 4360. Fax: 27 11 880 3391 Email: info@glopac.com URL: www.petro21.com

February 27, 2002 - March 1, 2002, DistributTECH 2002 at Miami Beach, Florida. Contact: Jennifer Lindsey, Conference Manager, PennWell. Phone: 918-832-9313 Email: jenniferL@pennwell.com URL: www.penwell.com

6-8 March 2002, World Sustainable Energy Day 2002 at Stadthalle Wels, Austria. Contact: O.O.Energiesparverband, Landstrabe 45, A-4020 Linz, Austria. Phone: 43-732-6584-4380. Fax: 43-732-6584-4383 Email: office@esv.or.at URL: www.esv.or.at

18-19 March 2002, 2nd Annual Latin Gas 2002 at Sheraton Rio Hotel, Rio de Janeiro, Brazil. Contact: Babette van Gessel, Group Managing Director, Global Pacific & Partners, 2nd Flr, Regent Place, Cradock Ave, Rosebank, Johannesburg, 2196, South Africa. Phone: 27 11 778 4360. Fax: 27 11 880 3391 Email: info@glopac.com URL: www.petro21.com

19-21 March 2002, Electric Power 2002, St. Louis, MO, USA at America's Center. Contact: The TradeFair Group Inc, 1220 Blalock Road, Suite 310, Houston, Texas, 77055, USA. Fax: 713-463-9997 URL: www.electricpowerexpo.com

7-9 April 2002, 10th Middle East Petroleum & Gas Conference at Doha, Qatar. Contact: The Conference Connection Inc, PO Box 1736, Raffles City, 911758, Singapore. Phone: 65-226-5280. Fax: 65-226-4117 Email: info@cconnection.org

8-9 April 2002, 6th Annual Asia Upstream 2002 at Holiday Inn, Park View, Singapore. Contact: Babette van Gessel, Ms, Global Pacific & Partners, Private Bag X61, Saxonwold, Gauteng, 2131, South Africa. Phone: 27 11 7784360. Fax: 27 11 8803391 Email: info@glopac.com URL: www.petro21.com

15-16 April 2002, 2nd Fujairah Fuel Oil and Bunkering Forum (Fujcon 2002) at Fujairah, United Arab Emirates. Contact: The Conference Connection Inc, PO Box 1736, Raffles City, 911758, Singapore. Phone: 65-226-5280. Fax: 65-226-4117 Email: info@cconnection.org

7-8 October 2002, 6th Annual Africa Downstream 2002 at Crowne Plaza, Sandton, Johannesburg, South Africa. Contact: Babette van Gessel, Group Managing Director, Global Pacific & Partners, 2nd Flr, Regent Place, Cradock Ave, Rosebank, Johannesburg, 2196, South Africa. Phone: 27 11 778 4360. Fax: 27 11 880 3391 Email: info@glopac.com URL: www.petro21.com

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