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.

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

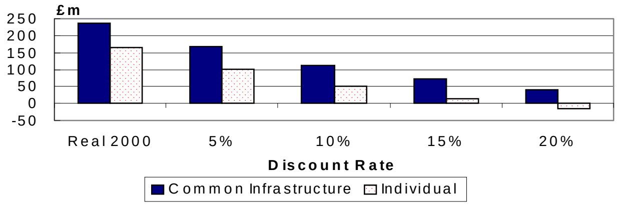
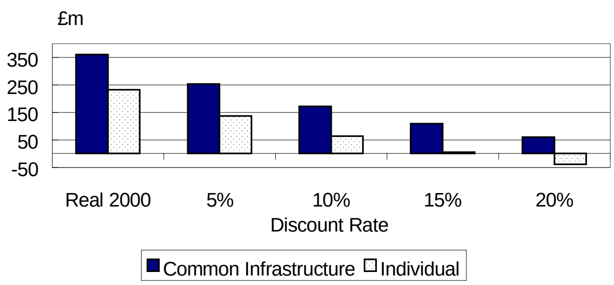


Figure 5
Post-Tax NPVs for 5 Field Cluster Oil price $18/bbl



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-

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[1] See footnotes at end of text.

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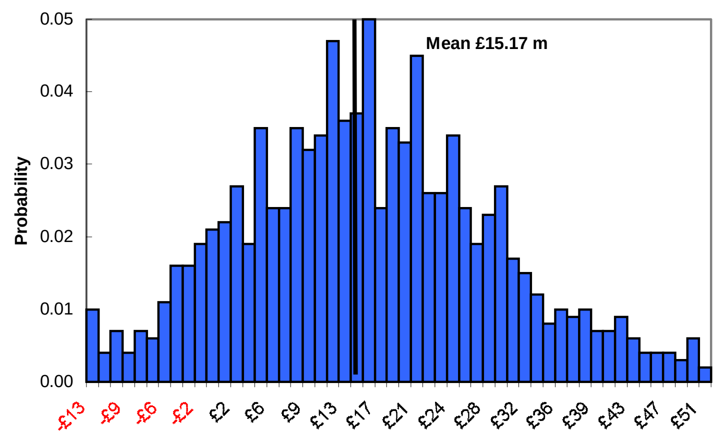
lating the probabilities of the internal rate of return (IRR) in real terms exceeding specified values. In Figure 9 the results are shown for IRRs of 20%, 25%, 40% and 50%. For the 10 mmbbl field the respective probabilities are 67.4%, 55.8%, 23.6% and 11.2%. For the 20 mmbbl field the probabilities 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

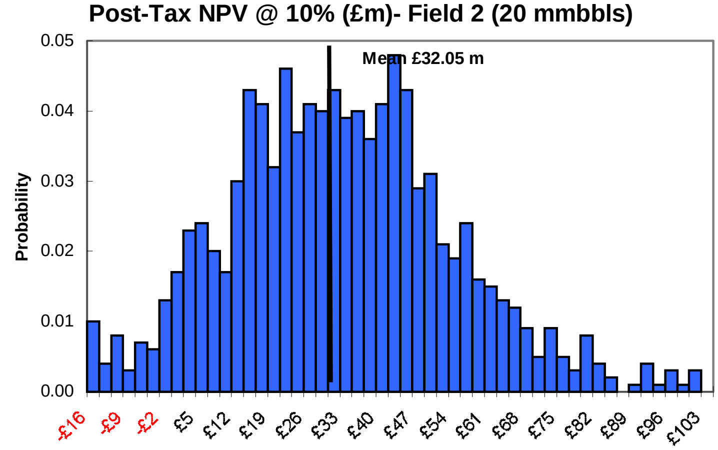
Post-Tax NPV@10% Statistics £m		
Trials		1000
Mean		£15.17
Median (approx)		14.44
Mode (approx)		15.56
Standard Deviation		13.71
Variance		187.95678
Skewness		0.31
Kurtosis		0.16
Coefficient of Variability		0.90
Minimum		-26.33
Maximum		67.34
Range		93.67
Mean Standard Error		0.43
Trimmed Mean (98%)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

Post-Tax NPV @ 10% (£m)- Field 1 (10 mmbbls)



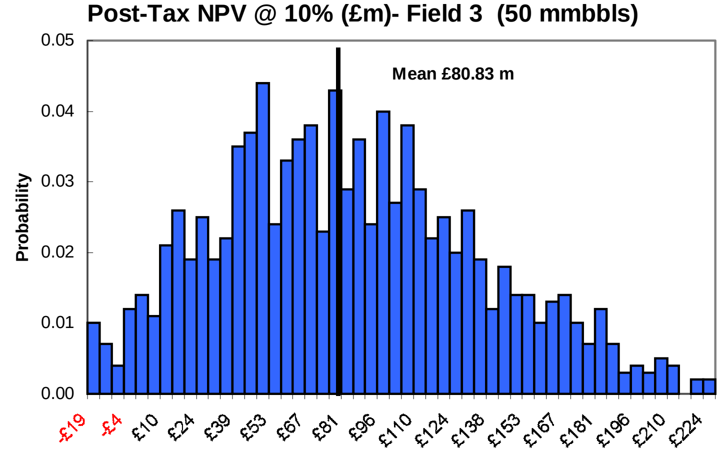
Post-Tax NPV@10% Statistics £m		
Trials		1000
Mean		£32.05
Median		30.88
Mode		42.66
Standard Deviation		23.25
Variance		540.75139
Skewness		0.64
Kurtosis		1.51
Coefficient of Variability		0.73
Minimum		-35.20
Maximum		147.73
Range		182.93
Mean Standard Error		0.74
Trimmed Mean (98%)		31.75
Negative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

Post-Tax NPV @ 10% (£m)- Field 2 (20 mmbbls)



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

Post-Tax NPV @ 10% (£m)- Field 3 (50 mmbbls)



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

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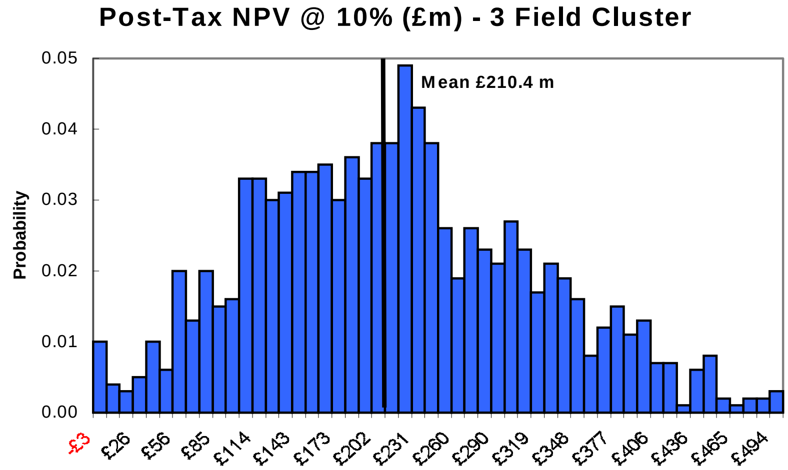
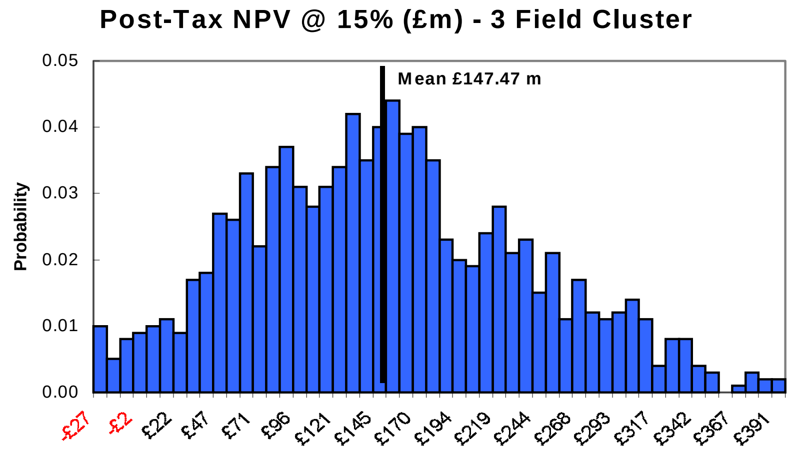
Figure 8

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

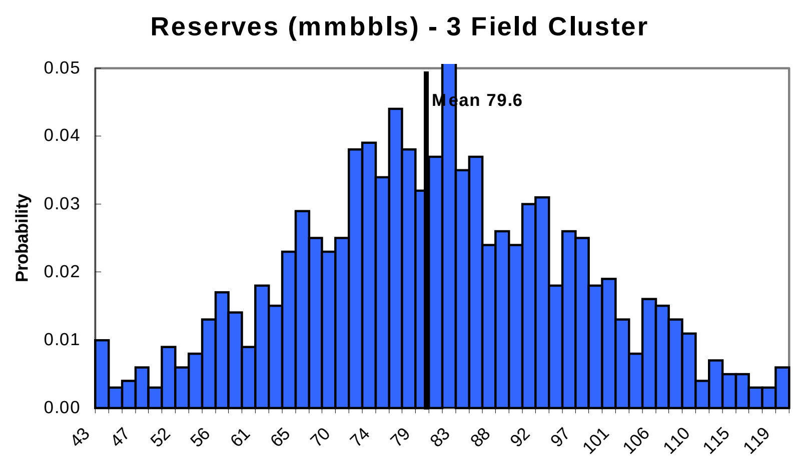
Post-Tax NPV@10% Statistics £m		
Trials		1000
Mean		£210.40
Median (approx)		204.28
Mode (approx)		221.36
Standard Deviation		105.49
Variance		11127.83
Skewness		0.39
Kurtosis		0.04
Coefficient of Variability		0.50
Minimum		-60.68
Maximum		566.74
Range		627.42
Mean Standard Error		3.34
Trimmed Mean (98%)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