Table 2. Proven Oil Reserves, the end of 2003		
Country/Region	Share of Reserves (%)	Reserve/ Production ratio
USA	2.7	11.3
Canada	1.5	15.5
North America	5.5	12.2
South and Central America	8.9	41.5
Europe & Eurasia	9.2	17.1
Iran	11.4	92.9
Saudi Arabia	22.9	73.3
Middle East	63.3	88.1
Africa	8.9	33.2
Asia-Pacific	4.2	16.6
World	100	41

Source British Petroleum: Annual Statistical Review of World Energy, June 2004

Table 3. Natural Gas Reserves, the end of 2003		
Country/Region	Share of Total (%)	Reserve/ Production ratio
USA	3.0%	9.5
Canada	0.9%	9.2
North America	4.2%	9.5
South and Central America	4.1%	60.6
Europe & Eurasia	35.4%	60.8
Iran	15.2%	*
Saudi Arabia	3.8%	*
Middle East	40.8%	*
Africa	7.8%	97.5
Asia-Pacific	7.7%	43.4
World	100.0%	67.1

Source British Petroleum: Annual Statistical Review of World Energy, June 2004.

world oil proven reserves (14 per cent). There is a natural trade for both parties; the oil exporters have the reserves and the international companies have both the technology and financial capital. What can bring the two sides closer to boost capital investment in the upstream is a reduction in perceived financial risks.

The IEA study (2003) indicates that it is to the benefit of both the consuming and the producing nations if upstream oil and gas investments are channeled to the regions with more reserves, i.e. ME. If investment and output is restricted in ME, oil output will be lower, oil prices higher, the world economic growth lower, and ME producer's revenue lower.[3] Given the volume of investments needed to expand production capacity during the 2001-2030 period, the bulk of which has to come from ME producers, and the fact that such investments absorbs a large part of their oil revenues, leaving little to spend on their economic development, foreign capital inflow should fill the gap. It is expected that private foreign capital, in the form of finance, equity, or other arrangements, will grow significantly compared to the previous two decades to fund the required investment in the energy sector. Capital mobilization on such a large scale faces challenges and difficulties. One such challenge is the issue of mobility of international capital. World saving is expected to be sufficiently large enough to provide for investment in the energy sector and maintain the current world economic growth rate. However, due to international capital imperfections and institutional barriers, particularly in the developing countries, international capital may not be sufficiently mobile to be allocated in a timely manner to energy projects with above average rates of return.

Mobilization and allocation of capital in the upstream sector can also be influenced by price signals in commodity markets and the expected return signals from the equity markets. Until a few years ago price pessimism was the prevailing mood and expectations in the oil sector. Consequently, cap-ex in this industry significantly slowed-down. Moreover, during the 1990s the expected return on equity in the high-tech industries were quite high but because of relatively low crude prices prevailing during this period the rate of return on was relatively lower in upstream oil and gas. With a rebound in oil prices during the last few years, oil companies have had much better return on their equities than the high-tech and the dotcoms, consequently cap-ex is beginning to rise in the upstream activities. It is argued that while short-term prices have not sent the correct signals for investment in the upstream sector, long-term prices have in the recent years have sent the correct signals for investors (Horsnel 2004).

Two important notes are due at this point. Firstly, when prices and the rates of return are volatile and uncertain, as it has been the case in the oil industry during the last six years, a profit-maximizing investor might decide to postpone investment until additional information about prices and market conditions are obtained. The point implied by the theory of irreversible investment under conditions of uncertainty is that, it is better to make an error and under produce than err and over produce. A sustained period of firm oil prices should stimulate larger investments in the upstream sector. Secondly, an important recent development is shaping in the oil industry. While the prices of the marker crude oil, Brent and WPI, have risen very sharply over the last two years, the price in the physical market, in particular the price of OPEC crude has

3- Investment and output growth restriction by ME produces will increase world investment cost by 8 per cent and lowers demand by 8 per cent due to higher prices. See IEA (2003) for details.

cated. In fact these factors can induce postponement of capital investments by raising its option value. To complicate the matters even more, the big players in the oil field are the large international oil companies and the producing countries and they do not always have the same objective function. Some years ago, the difference in their behavior was perceived to be due to differences in their discount rates, implying that the former prefers to have more production hence investment sooner than later. In contrast to the producers who wish to smooth output flow over a longer time span. To put it in another way, profit maximization and share holder value is the dominant consideration for the companies while for the producers, in particular, the OPEC, market share and the security of oil supply are also important variables in their output and investing decisions.

In section 2 of this paper the projected oil demand in the world economy and the investment requirements consistent with these projections will be reviewed. Section 3 examines the trends in excess capacity, prices, and investment in the global oil industry. In section 4 we review the outlook for investment in the upstream sector.

2. Future World Demand for Oil and Global Investment in the Oil Sector

Production follows demand and in the long-run higher levels of production requires more capital investment to increase output capacity. Based on modest growth projections, 1.6 per cent annual growth in demand for oil and gas and 1.7 per cent for all energy carriers over the 2001-2030 period, IEA projects a hefty 16 trillion US dollars investment requirement in the energy sector for the world economy. The world demand for oil will increase from 77 million barrels a day (mbd) to 120 mbd, therefore based on this projection 43 mbd additional capacity must be created. Projections from OPEC indicate similar, though a slightly higher, growth in the world oil demand until 2025 (table 1) and this implies a slightly higher cap-ex requirement.[2] It should be noted that much of the expected growth in oil demand will come from the developing countries, particularly from China and South Asia.

Nearly two-thirds of the projected total capital expenditures in the world energy sector are to be invested for modernizing old power plants and building of new ones. The amount of investment needed for the oil and gas sector is 3.1 trillion dollars, of which 2.2 trillion dollars is projected to be invested in the conventional oil exploration and development during the 2001-2030 period. The projected 16 trillion dollars energy investment will be a small fraction, 1.6 per cent, of the predicted world GDP, and the projected cap-ex

Table1. World Oil Demand Outlook in the OPEC Reference Case, in million barrels a day

	2005	2010	2015	2020	2025
North America	25	26.1	27.2	28.3	29.4
Western Europe	15.4	15.9	16.3	16.6	16.8
OECD	49.3	51.2	52.9	54.5	55.8
Developing countries	26.9	32.3	38.5	45.3	52.5
Transitional economies	4.8	5.3	5.7	6	6.3
World	81	88.7	97.1	105.8	114.6

Source: A. Shihab-Eldin, M. Hamel, and G. Brennand, OPEC REVIEW,Vol. XXVIII, No. 3, September 2004, p. 161.

requirement in the oil and gas sector will be an even smaller fraction of the world GDP, 0.3 percent, in the above period. However, the implied investment-GDP ratio will be much higher for the major oil exporting countries. Based on the projected geographical sources of world consumption and production of oil and gas, the Middle East, and especially the Persian Gulf oil producers, will deliver much of the additional expansion in the world oil and gas output.

The interesting observation, based on the past distribution of upstream cap-ex in the oil and gas sector as well as the above mentioned future investment projections is that, while much of the additional growth in output is expected to be delivered by the Middle Eastern producers, the bulk of cap-ex spending is projected to be allocated in other regions of the world. From a commercial point of view investments should be allocated to those regions and countries that have the rich reserves to sustain higher production. The Middle East, more specifically the Persian Gulf, region are the areas with abundant reserves (see tables 2 and 3) but historically have been under-invested. This indicates a geographical mismatch between the sources of reserves and uses of investment funds. This mismatch that has persisted over a relatively long time span and can be attributed to:

a)-incomplete international capital mobility

b)-perceived risks by oil consuming countries

C-difference in the discount rate between oil consumers and oil producers

d)-legal and institutional barriers

e)-incorrect price signals

The international oil companies have access to technology but have limited reserves. Their reserve/production ratio are much lower than the Persian Gulf oil exporters and control a much lower percentage of the

2- The projections made by the OPEC and IEA do not cover exactly the same period. For the former the period is 2000-2025 and for the latter is 2001-2030.

Investment, Prices, and Excess Capacity in Oil: A Global Outlook

The Text of Speech of Ahmad R. Jalali-Naini
Ninth International Conference of Institute for International Energy Studies December 2004

1. Introduction:

With the recent pickup in the world demand for oil, the dwindling OPEC excess capacity and rising oil prices the issue of adequacy of investment in new capacity has become topical. The major issues are: how much investment is needed, who is going to finance it, and the geographical location of future investments. The investment pattern in the oil industry during the last three decades prior to 2000 followed the price trends. During the high-price periods (1973-1984) capital expenditures were high resulting in large excess capacity in the industry. In the low price periods (1986-1999) new investments declined and excess capacity was shed. However, during the 1999-2004 period while the average crude price per barrel rose but the excess capacity declined further though at a much lower pace. Should we expect a new investment boom resulting in creation of a large capacity build up in the near future as a result of the recent surge in prices?

Investment behavior in the oil industry and its responsiveness to prices and market conditions are more complex than described by the standard competitive models of the optimal capital stock[1] or the simple Hotelling valuation models. In the simple Hotelling models a fixed quantity of discovered reserves are assumed; the finding costs are sunk costs and there is no development cost. The insitu value of the reserves depends on the discounted net profit such a reserve can generate. More sophisticated versions of the model allows for development cost of the reserves. In a competitive market the price of an insitu reserve is equal to the per barrel marginal development cost plus per barrel marginal user cost (Watkins and Streifel 1996). For those who do not subscribe to the idea of exhaustibility of oil, there is no fixed stock of oil and a stream of investment adds to proven reserve inventory from a larger under ground inventory (Adelman 1990). In this view the oil industry's supply problem is one of inventory renewal. The simple industry-wide rule calls for holding about 15 years' supply under the ground as proven reserves. Proven reserves are defined as those recoverable at today's prices given today's technology. The cost of reserves is closely related to the capital investments required to find them, that is, to drill, complete the wells, and connect it to a pipeline. The discounted net cash flows determine the value of investments in the upstream project.

Uncertainty over prices (or costs) is a complicating issue. Without price uncertainty, the Hotelling Valuation Principal implies that investors should be willing to pay more for reserves when oil prices net of extraction cost go up (Miller and Upton 1985). However, with the presence of price uncertainty over the future course of prices the investment decision process becomes more compli-

The basic result in the theory of business investment is that, the optimal stock of capital is a function of the rental or the real cost of capital. In the simplest version, we assume a representative competitive firm maximizes the present value of its profits (II), with a discount rate equal to r (Romer 1996).

$$\Pi = \int_{t=0}^{\infty} e^{-rt}\left[\pi(K(t)\kappa(t) - I(t) - C(I(t))\right]dt.$$

Where K is the industry-wide capital stock, ?, is the firms' own capital stock, and $\pi(K(t)) = rq(t) - \dot{q}(t)$. ,and C(I) $K_{t+1}=K_t+I_t$ is investment adjusted cost. It is possible to form a Hamiltonian,

$$H(\kappa(t), I(t)) = \pi(K(t))\kappa(t) - I(t) - C(I(t))q(t)\left[I(t) - \dot{\kappa}(t)\right].$$

The first order conditions of interest is This implies that demand for capital will rise until the marginal revenue product of capital (with p=1 here) is equal to its marginal cost. In the above qt is equal to the purchase price of capital (assumed here to be 1) plus the marginal adjustment cost, and r is the interest rate.

Figure 2: The Analysis of The Net profit based on Thermal power plant alternative for The Saydoun HEPP project					
Economic efficiency B/C (percent)	NPV (million rials)	Total Profit (million rials)	Annual Costs (million rials)	Energy Profits (million rials)	Depreciation rate
1.32	110425	58994	182556	241557	3 %
1.25	87029	44553	171674	216228	4 %
1.2	72565	32945	163356	196301	5 %
1.14	39626	23480	157075	180556	6 %
1.1	27380	15643	152401	168045	7 %
1.23	16706	10564	148987	159551	8 %
1.02	10806	9828	146564	156392	9 %
0.98	2649	5425	144921	150346	10 %
0.95	334	2327	143894	146221	11%
0.93	-1425	-664	124359	123645	12%

the project, thus making small HEPP very economically viable projects in which few other projects are capable of paralleling them (due to fact that the ratios of benefits, costs, etc. of small HEPPs are homogeneous.)

Summary

1) In small hydro electric power plants, due to the excessive primary investment, which is about 90% of the total investment and the income obtained from power sales, based on the guaranteed price rates and defined increase in costs, when we incorporate the effects of time in the Benefit/cost calculations (for NPV and IRR indexes) we find that the internal rate of return for these projects is 11-20 percent, which is an acceptable rate, yet it does not define the economic effects of these projects. The results of this study show that if we utilize the "most optimal thermal power plant alternative" method in order to determine the benefits of the Saydoun project, the Internal rate of return will be equal to 11%. This differs greatly from the IRR obtained in the first method and also decrease the sensitivity of the project towards variations in MARR to a great extent (about 50%). In other words with the increase in the governments expectations from these types of projects, and an increase in the social depreciation rate, the project will retain its benefits and economic return to a great extent.

2) The most important financial and economic benefit of these types of projects is the minimum amount of ongoing costs. This in itself brings about positive cash flows after a few years of operations (four to seven years). Using the DPP factor, this financial benefit is best determined. In the Saydoun chain of dams, with a normal rate of return (8%), the return rate for the original investment will equal zero, and with an equivalent rate of return, along with an internal rate of return of 23% for the protect, the return rate for the original investment will take 10 years. This is a very significant result and shows the importance of using other indexes (other than the standard ones.)

3) The sensitivity analysis of the operations and maintenance costs(O&M costs) show that in comparison to other indexes, the project shows a slighter sensitivity to O&M costs and the changes in NPV rate will be equivalent to the range of other indexes i.e a decrease between 10th 20 times normal. This is largely due to the fact that small hydroelectric power plants do not have any specific fuel requirements and are therefore immune from inflation, making it easier to repay the original investment costs.

In the end, we would like to express our appreciation of your closed corperation with KWPA, water standard and research department, Dams and HEPP development division.

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6.Worldwide Hydropower Development And Capacity Magazin 2001-2002

Figure 1: The Calculations for the Duration of Profit Return

Year	Annual rate of return	Costs	Income	Net Cash Flow
1	12234.75	133779.75	9255.60	-124527.15
2	12234.75	13472.36	9996.05	-3476.31
3	12234.75	13571.37	10795.74	-2775.63
4	12234.75	13678.30	11659.40	-2018.90
5	12234.75	13793.79	12592.15	-1201.64
6	12234.75	13918.51	13599.52	-318.99
7	12234.75	14053.21	14687.48	634.27
8	12234.75	14198.69	15862.48	1663.79
9	12234.75	14355.80	16425.38	2069.58
10	12234.75	14525.49	17131.48	2605.99

The Cost Rating Method of the optimal Thermal Power Plant Alternative

This method is the most common method used for the evaluation of Hydroelectric power plants and is actually the costs for Hydroelectric power plant options. The basis of this method is the careful determining of the existing conditions with and without the implementation of the project. The primary assumption is that should the need arise for an increase in the load factor, the thermal power plant alternative will provide the excess required, whether the HEPP is constructed or not; therefore if the project is implemented, it will show how the system will operate in order provide the required load using the available sources. These sources are deemed as the new hydroelectric power plant projects or other generating facilities. If the project is not implemented, it will show how the system will operate in order to provide the same power demand using the available sources and a combination of new generating sources which would replace the non-existing HEPP generating facility. In this case the most optimal thermal power plant alternative must be determined, yet since in most cases Hydropower plants operate differently than Thermal power plants in a grid system and taking the HEPP Unit factor and Thermal Power plant Unit factor into consideration, the capacity and produced energy are regulated using standard formulas. In addition all related costs of Thermal power plants must be determined and will be considered as constant costs (installation costs) and variant costs (energy costs). These costs are then transformed to the amount of energy produced per hydroelectric power unit and by deducting the amount of annual costs for the HEPP project, one can estimate the relative annual Net profit of the HEPP and the NPV can be estimated using the formula below:

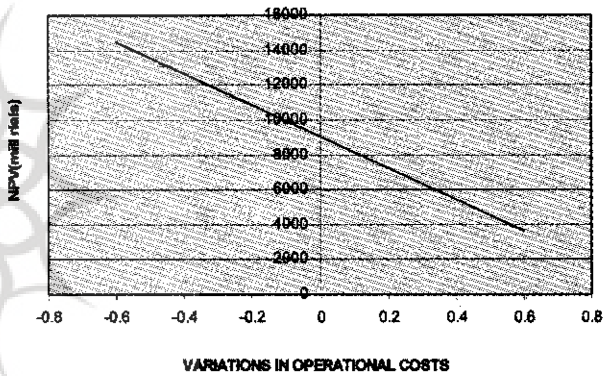
$$NPV = A \left(P/A \;,\; i\% \;,\; n \right)$$

Regarding small HEPPs, due to their small capacity, the only suitable thermal power plant alternative is a Diesel powered thermal power plant and therefore they are completely equivalent to HEPPs in this specific condition. In addition due to their small scale as pointed out earlier we use general economic indexes for the determining of engineering and energy costs; therefore, it is not necessary to regulate the capacity and produced energy elements.

The results of the calculations using the aforementioned method are summarized in figure 2.

The Sensitivity Analysis

The sensitivity analysis for the construction costs, based on the Thermal power plant alternative method is as follows:



Comparing the methods of calculating the Return Rate.

1) A review of the sensitivity Analysis graphs in both methods show that in the " Thermal power plant alternatives method" with a±20% change in the MARR, the NPV rate for the project will fluctuate on a range of 3000 to 130,000 and a cost of 60000 million rials, whereas byusing guaranteed price rates, using the same range of variance for the aforementioned index, the NPV rate for the project will fluctuate on a range of 3,000 to 15,000 and a cost of 11500 million rials, In other words, by utilizing the most optimal thermal power plant alternative in the estimating of the projects resources, the higher the government's expectations of the project (to the extent of MARR= IRR) the more economical the project will be. 2) The IRR of the project in the first method is approximately 20% and in the "Thermal power plant Alternative" method it is approximately 11% and by comparing it with the constant MARR, it greatly effects the decision making factor for