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Inside Geopolitics of Energy

- **Engineered Geothermal Systems: Economic Viability and Future Prospects**
  By Michal C. Moore

  While ample uncertainty surrounds the prospects of reaching global consensus during the upcoming UN Climate Change Conference in Copenhagen, one thing is clear: work will continue to establish new, globally-binding carbon emission standards even if a climate treaty is not forged right away. In his paper on "Engineered Geothermal Systems: Economic Viability and Future Prospects" Professor Michal Moore of the University of Calgary's Institute for Sustainable Energy, Environment, and Economy (ISEEE) reviews the current status and assesses the potential of Engineered Geothermal Systems (EGS). The inquiry has important implications for the policy agenda and future needs of both developed and developing economies that strive to meet rapidly expanding baseload power needs cleanly. Professor Moore contends that EGS is not yet economically competitive with other forms of electricity generation, but it is quickly closing the gap. With the aid of modest boosts in R&D funding, EGS holds potential as a viable and cost-competitive means to provide clean power in our carbon-constrained future.

- **The Future of Arab Economy Against the Backdrop of the Global Financial Crisis and Risks of New and Emerging Energy Technology**
  By Sulayman S. Al-Qudsi

  In the second paper on "The Future of Arab Economy in the Backdrop of Global Financial Crisis and Risks of New and Emerging Energy Technology" Professor Sulayman Al-Qudsi reviews the recent developments in the Arab economies in the backdrop of the global financial crisis and resultant global economic recession. He reviews how the global crisis has caused significant oil demand destructions which induced setbacks to the growth momentum in the oil-based Arab economies. Evidence is rampant from trade, real estate, capital flows, and regional and international FDI which all sharply declined. With depreciating greenback, the Arab currency peg to the dollar is again in focus which might renew strong inflows of speculative investor money. New risks are also emerging in the areas of new and renewable energy technologies which made substantial inroads over the past few years. These risks, in tandem with the financial risks that the global crisis exemplified, have important implications for the very long-term strategic vision of sustainable development in the Arab, especially GCC, economies.

Engineered Geothermal Systems: Economic Viability and Future Prospects

*by Michal C. Moore**

Overview

This paper introduces Engineered Geothermal Systems (EGS), which are processes that artificially engineer deep geothermal resources – exchanging heat from transmissible fluids for baseload power. Geothermal power is relatively environmentally benign, widely distributed and available, and once installed can provide economic support for developed as well as developing nations. Environmental offsets are endemic to this technology, and it also promises lower delivered prices, diminished reliance on fuel imports, and fewer possibilities of fuel delivery disruption. EGS technology relies on well established drilling and extraction techniques pioneered by the oil and gas industry; it presents a low surface impact for communities while providing employment benefits and power generation for industry needed to maintain viable economic activity and expansion.

Introduction

Energy in all its forms is the underpinning of the economy and quality of life we all enjoy. In recent years it has become apparent that electricity, an energy carrier, is dominating the delivery of energy at every level from production to comfort and primary subsistence.

However, most electricity production (by percent share of total energy generated whether in terms of joules or kW) results in a direct or indirect contribution of heat or other undesirable by-products. Recent research identifies direct links between energy generation and increases of CO_2 and CH_4 in the atmosphere which is correlated strongly with regional changes in weather patterns, water and air quality, and resultant shifts in agricultural productivity world-wide.

Since electricity is the core of the non-transportation delivery of energy, resiliency of the delivery structure is of critical interest in developed and less-developed countries alike. We can describe this resiliency in three critical areas: physical, financial and external (i.e., linked to other social enterprises such as environmental quality).

Physical integrity of the electric system is traditionally associated with redundant systems, backup and interconnection of transmission lines, with spinning or available reserves to deal with spikes or system outages. Financial integrity of the system is ensured by a widely interwoven and overlapping set of contracts and settlements that reflect the nature of processing, transformation, and delivery of a continuous stream of energy to match load. Environmental quality is an exogenously measured phenomenon that is affected both by the generation and delivery of electricity, but also by the ultimate use of that energy in consumption.

In recognition of this dynamic tension of demand and supply constraints, both developed and developing nations are seeking ways to diversify electricity production in such a way that a wider range of affordable, dependable, and environmentally-friendly energy production is supported within the economy. Various means of achieving these ends are in use in non-exclusive and often overlapping schemes including cleaner fuels for fossil energy generation, post combustion capture and neutralization of exhaust, achieving higher efficiency in use, pricing schemes to alter time of use (and corresponding generation), substitution of energy production technologies, and the integration of renewable – often indigenous – energy sources into the generation mix.

The perceived value of *renewable energy resources* has gained widespread inclusion in policy and regulatory prescriptions in recent years. In spite of that acceptance, however, renewable energy resources are often discounted in value, citing intermittency, high cost per unit of output, reliability and remote geographic location (or if not remote, then not in proximity to existing transmission and substation facilities). This perception notwithstanding, the role and use of renewable resources in electricity grid management has a great deal to offer not only in terms of power delivery, but in the diminishment of externalities, in increased resiliency of the overall power delivery system, and by analogy, in the stability of the underlying economy at issue.

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Characteristics

Renewable energy resources are by definition based on indigenous and often dispersed geographic or temporal characteristics. Wind blows intermittently, solar resources are not available at night, and there are ebbs and flows of water in streams and rivers. However, these characteristics, when combined with the inherent fuel cost of the resource can be strengths when seen in light of the system and load that is placed on it. Thus, wind power may offset fossil generation during evening peaks, while solar energy may be well matched to high load demands during peak daylight hours. In this context, geothermal power has unique properties that make it valuable for systems that are searching for baseload power generation either to match increasing load or to replace less desirable thermal generation such as coal or nuclear power. In addition, this power resource can be adapted easily to remote or distributed generation opportunities where extension of transmission facilities is either impractical because of terrain, or because the market cannot support the debt on capital facilities.

Geothermal heat is accessible in several different ways ranging from soil or rock temperature differentials (geothermal heat exchange) and low depth hot water to deeper hydrothermal resources found near fault-based fractures and deep plutonic intrusions or volcanic formations. Beyond heat exchanges widely available at very low depths, the geothermal industry has depended on natural formations of hydrothermal resources which are regionally concentrated and as a consequence available only on a limited scale. When geothermal heat is available, though, it provides high reliability and availability and can be dispatched as baseload power with extremely competitive costs for delivered power.

In an effort to access deeper, hotter rock mass that is available in virtually all regions, researchers have turned to the potential of EGS where hot, but relatively dry, rock formations can be reached through very deep drilling. The formations can be artificially stimulated or hydraulically cracked and flooded with a heat transfer fluid (water or CO2) which can then be used to transfer the heat energy to the surface where it can spin traditional electricity turbines. The spent system still has heat value, which can be used in agricultural operations or combined for heat and power (CHP) when located near population centers.

Background

Geothermal resources have been utilized as a source of energy since the discovery of the first hydro-thermal vent (Armstead and Tester, 1987). The obvious and ultimate source of that heat has been sought, at deeper and deeper depths, since the advent of modern drilling techniques. As a consequence, the quest to access a deeper and hotter resource has been tied closely to technology advances in the oil and gas industry and new techniques in seismic refraction.

Pioneering research at Los Alamos National Laboratory confirmed the potential of so-called HDR “hot dry rock” (referred to from this point as EGS), but ultimately was unsuccessful in penetrating, fracturing, and establishing productive fluid circulation at depth.

Diminished public research support from the US Department of Energy, roughly 1980-2000, reduced interest and field exploration of EGS. This period coincided with increased reliance on coal and natural gas-fired electric generation. There has been a renewal of interest and research support in EGS in recent months. For instance, the United States Department of Energy support for deep drilling a test EGS well in the Geysers in California, is illustrative of a new and long-term interest in discovering the potential of expanding the reach of a proven system like hydrothermal generation. This recent interest in EGS can be attributed to four interrelated forces: the forecast loss of significant electric baseload capacity in North America and Europe,[1] advances in drilling techniques, new identification of areas likely to have high heat potential, and improvements in power conversion technologies.

Like any other power generation technology, developing EGS facilities will involve costs which must be seen in context of the power *delivery* and the characteristics of the power technology itself. In other words, the cost effectiveness of the entire system must be deemed competitive, not only by the market, but by those public and quasi-public agencies who deliver power, or it will simply languish.

Thus, in order to consider a source like EGS, we must view the relative economic costs in the context of overall power system operations as well as policy prescriptions including “green” power and carbon offsets.

EGS Systems Defined

Development of Engineered Geothermal Systems or EGS, for economic purposes represents an extension of existing technology for extracting heat from hydrothermal reservoirs. There are two distinctions that create the business case for EGS. In the first distinction, EGS extends the vertical range of existing hydrothermal complexes by reaching hot resources at successively greater depths than those currently circulating naturally hot water. In the second, we consider the case of hot resources available where fluid must be introduced and artificially circulated after penetrating and fracturing the surrounding rock.

A common definition shows Hot Dry Rock or HDR as having conduction energy potential worldwide as greater than 30 TW or about 900 quads per year with net stored energy in the earth.

Most current North American geothermal power is generated from hydrothermal reservoirs, limited in areal extent and confined to limited geographic areas such as the western United States, Canada and Mexico, generally associated with volcanic intrusions or fault fractured zones. In current locations, and in spite of the limited amount already developed, hydrothermally-originated electric power represents a significant and important source of baseload support.

The real role of EGS, then, is to create new, artificially stimulated reservoirs to supplement and, in some cases, replace baseload power supplies, either at greater depth in existing reservoirs or in areas where no hydrothermal potential exists. Creation of enhanced, or engineered reservoirs requires drilling to extended depths, typically only reached in oil and gas operations, and fracturing the surrounding rock using hydraulic pressure. The objective is the creation of directional fracture groups that can be connected to surface conversion facilities. Exploiting this resource involves the creation of commercially-viable EGS systems which maintain connectivity and pressure using injected, pressurized fluids sufficient to generate electricity with minimal heat and water loss over time – essentially a closed loop of heat extraction.

EGS by definition is not a hydrothermal resource, where a naturally occurring flow of hot water is accessible through drilling and pumping, but once in operation, is analogous to hydrothermal energy, and with similar incidence of cost, including:

- Surface and subsurface exploration and mapping
- Drilling of test, injection and extraction wells
- Pumping and transmission to power conversion systems
- Power conversion through flash or binary generators
- Sales and transmission of power via a transmission interconnect

What marks this technology and technique as uniquely different is its dependence on reaching deeper sub-surface heat reservoirs than hydrothermal zones; there is also a need to fracture deep rock resources and initiate connection and conductivity between injector and producing wells. Finally, sustaining the ability to conserve heat flow required to maintain a sustainable resource is critical. This can be achieved through low overall losses either in the form of heat or heat transfer fluid.

Since EGS is not dependent on existing hydrothermal systems, it can be tailored more closely to load centres and transmission access, although the need to build transmission interconnections from regions with access to high voltage transmission facilities may represent an engineering as well as economic challenge.

EGS Role in the Grid

Geothermal electric resources are dispatched as baseload power, which constitutes a given region’s continuous energy demand, producing energy at a constant rate, typically at a lower unit cost relative to other technologies bid into the system. The characteristic of baseload power generation is generally a combination of high capital costs and low fuel costs, along with a dependable and low fluctuation power delivery curve. Technologies with these characteristics are not exclusive to baseload power generation, but also are not always competitive in terms of the cost of energy (COE) for load following or peaking capacity required by the grid. Typical generation in this category (of baseload power generation) includes hydrofacilities with surplus capacity, coal, nuclear fission, and geothermal.

Baseload facilities are dispatched first in the merit order of variable cost. They are generally price takers (most baseload power generation will effectively bid zero into the hour or day-ahead market and the market clearing price will reflect their marginal cost (MC) of operation. They usually run continuously (aside from forced and planned outage) at high levels of output. The result is a generally high capacity factor[2] and, depending on the area served, most geothermal units in operation today have a correspondingly high availability factor as well.[3]

In terms of capacity factor, the EGS system can be expected to operate closer to maximum capacity than hydrothermal resources. This reflects the closed loop design which circulates an injected fluid, such as water or carbon dioxide, with no corresponding decline rate for water stored in the subsurface rock body. Production should match the injection rate, thus the internal rate of return and PV calculations will be based on the amount of flow established when the system is completed and stimulated.

Consequently, there are no make-up wells needed by the system. On the other hand, re-stimulation is a significant factor of production since the reservoir pore and fracture space will naturally tend to close or diminish in flow capacity over time[4] (Tester et al, 2006).

The Economic Role of Hydrothermal

Commercial power production from EGS is not occurring at present, although the Soultz complex in France is close to that point. However, the experience of hydrothermal resources is a reasonable guide to the evolution of a role for this technology in grid operations. For instance, in the merit order dispatch of available technologies, EGS can expect to play a competitive role, especially compared to nuclear power or coal-fired generation at maturity.

Hydrothermal resources have played an important role in baseload energy supplies in the past. According to the Geothermal Resources Council (2008), US geothermal installed capacity remains concentrated in California. For instance, by 2005 California's geothermal capacity exceeded that of every country in the world (CEC c, 2005). In 2007, 4.5 percent of California's electric energy generation came from geothermal power plants, amounting to a net-total of over 13,000 GWh. California currently has 2555.3 MW of installed hydrothermal generating capacity. In Mexico, a growing percentage of geothermal resources are now contributing more than 3 percent of total national needs (Klapp 2007).

Record of Achievement So Far in EGS

I have described EGS as a logical extension of hydrothermal generation, yet not dependent on existing hydrothermal location or pre-existing hot liquid flows. As such, it should be seen first and foremost as a sophisticated deep drilling operation that ultimately will be connected to surface conversion technologies. The key ingredients are successful wells to depths where adequate temperature regimes exist. Table 1 shows drilling and temperature relationships established to date, in EGS-type operations.

Table 1: Drilling and Temperature Achievements for EGS Operations

Location	Years of drilling	Depth	Temp and flow
So. Germany	1987 - 1989 1990 - 1994	4 Km 9.1 Km	Max 278°C and 25 l/s
Bad Urach Germany	2002 - 2004	4.5 Km 2.5 Km	170°C and 25 l/s
Cooper Basin, Aus	2005 - 2007	~4.5 and 5.0 Km	250°C and 20 l/s
Basel, Switzerland	2001 2006	2.7 Km 5.0 Km	200°C and 20 l/s
Soultz-sous-Forets, France	1987 - 1997 1998 = 2005	3.8 Km 5.0 Km	200°C and 50 l/s

Source: Tester et al 2006, EGS URL's and personal communication D. Yang, Shell Canada.

This summary does not take into account the need to reliably fracture the rock around the well formations, sufficient to carry fluid continuously in the reservoir, ultimately at rates in excess of 60 liters per second (l/s) which is difficult in practice, although fracturing and adequate flow rates are currently reported at near commercial rates at Soutlz and are expected in Cooper Basin in Australia (Tester et al, 2006).

Current Cost of Energy

EGS operations as noted above are not currently commercially competitive. However, the role and performance of hydrothermal systems suggests that they can be if capital and operations costs can be lowered through learning rates for drilling operations, R&D and achieving better flow rates in subsurface fracture zones.

In order to see this in context, it is important to consider how the levelized cost of energy (LCOE) is calculated for EGS, and what level will ultimately be competitive. LCOE is the average per unit cost of generating electricity from a given EGS project over the useful life of the facility. It is an economic assessment that accounts for the cost of the entire complex through its lifetime, including overnight costs of capital (all wells, pumps, surface conversion technology), operations and maintenance, land lease, and the cost of transmission interconnects. The major factors which influence the cost(s) of EGS-based energy are the depth and number of wells per complex, the fracturing and stimulation cost (initial, plus re-stimulation during the lifetime of the well), well lining, pumps for circulation, surface conversion technology used, and the transmission linkage or interconnection.

Hydrothermal complexes, which are typically drilled to relatively shallow depths, and which do not typically require fracture and stimulation of the surrounding rock, have LCOE ranging from .04 to .07 per KWh (CEC d 2004). Costs available for recent contracts in the Geysers in California (see Table 11) show higher costs, but are based on needs for RPS[5] requirements and may not be viewed as necessarily representative of their marginal cost, especially when viewed against more traditional fossil generation used in base load electricity generation (REPP 2003).

These costs may be fairly represented as a sum of overnight costs, which are levelized over a time period that represents the life of the well complex. This is depicted in the formula below.

Costs per Complex = Wexp + Wi + (X*Wext) + (Frc (x)) + Pu + Gen + Ti

where
Wexp = assumed cost per exploratory well
Wi = well cost primary injector
Wext = well cost extraction
Frc = equals fracturing cost per well (assumed constant)
Pu = total cost for installed pumps (extraction and injection)
Gen = generator cost
Ti = transmission interconnect
X = number of extraction wells per complex

LCOE reveals the minimum average price over the life of the facility for the energy produced from this technology in order to break even.

Thus, the LCOE is the minimum price at which energy must be sold for an energy project to break even.

LCOE is reflected generally in the following equation for hydrothermal generation.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where:

LCOE = Average lifetime levelized electricity generation cost in currency per KWh.
It = Investment expenditures in the year t
Mt = Operations and maintenance expenditures in the year t
Ft = Fuel expenditures in the year t (the proxy here is the pumping cost of water plus make-up water charges)
Et = Electricity generation in the year t
r = Discount rate (assume 7%)
n = Life of the system (assumed to be 30 years with 3 interim re-stimulation periods for injector wells)

For the purpose of calculating LCOE, the capacity factor[6] for EGS may reasonably be assumed to range from 95-98 percent.

A comparison of levelized costs for key baseload generating technologies when bidding into grid operations provides an illustration of the competitive position of each as shown in Table 2 below.

Table 2: Levelized Cost Comparison for New Generating Capacity in the United States
(2004 Dollars per Megawatt hour)

Cost Element	Coal	Natural Gas	Wind	Nuclear
Capital	30.4	11.4	40.7	42.7
O&M	4.7	1.4	8.3	7.8
Fuel	14.5	36.9	0.0	6.6
Total	53.1	52.5	55.8	59.3

Source: EIA, http://www.eia.doe.gov/oiaf/archive/ieo06/special_topics.html.

The MIT (Tester et al, 2006) report estimated the LCOE for six selected sites within North America. It shows a range of initial cost from 10.3 cents kWh to 75 cents, with an assumed average levelized cost of energy in five years of 35.9 cents *falling* to 6 cents at maturity. The average well depth of 6.0 km is assumed from current mapping records.

Table 3: Hypothetical Levelized Cost of Energy from Sites within the US for EGS Operations

Site Number	Initial Case	Commercially Mature	Fall in Cost	Depth in km
1	29.5	6.2	23.3	7.1
2	24.5	5.9	18.6	6.6
3	17.5	5.2	12.3	5.1
4	74.7	5.9	68.8	4.0
5	26.9	5.9	21.0	4.0
6	10.3	3.6	6.7	5.1
7	68.0	9.2	58.8	10.0
Average	**35.9**	**6.0**	**29.9**	**6.0**

Source: Tester et al, 2006 pg. 9-21.

This table does not include calculations of risk and uncertainty, both of which ultimately are reduced through development and research efforts, although at a rate which cannot be precisely estimated. We can, however, use historical analogies, especially those from the drilling industry, as well as other technologies in the renewable energy field, to suggest what the learning curve would be as well as the impact on direct costs from technological innovation.

Accounting for Risk

The question of risk is inherent in any predictive use of statistics or field experience. Here I use risk to reflect the expected value that an event will be followed by undesirable outcomes. It is a probability estimate of the event occurring and the seriousness of the outcome. For example, the probability that a well circulation system or the surface technology might fail in five years could be .001 percent. The outcome of this failure is the loss of electricity to the grid and the likelihood that the well must be re-drilled or fractured. These two combine in a single value that communicates risk.

The basic tenet is that without uncertainty, there is no risk. A corollary of this is that the more uncertainty, the higher the risk of making a poor decision. As a consequence, the objective is to manage uncertainty, especially in early learning and adaptive development of EGS.

When planning well fields, the largest risks are inherent in the uncertainty of information and the knowledge using predictive models on which financial and policy decisions are based. Risks of this nature are commonly addressed by the oil and gas industry, which routinely drills to depths (>5km) that are forecast to accommodate EGS production potential (Tester et al, 2006). Here, the risk analysis includes:

- The accuracy of field information and modeling
- The level of understanding of the subsurface physics and heat gradients
- The consistency model analysis and interpretation

In the case of EGS, decision risk has little to do with events (as in traditional risk analysis) but rather is focused on what is known and the decisions based on this knowledge. As a consequence, the risk of production from a new technology such as EGS is not well-revealed or modeled yet using standard industry-proven probabilities and must rely on Bayesian-type methods. Probability in this case will depend on emerging but still uncertain knowledge and ultimately the interpretation of information and models.

We are left with three critical questions:

- How likely is it that power can be generated from greater depths of hot-dry rock?
- What is the impact of not succeeding (or success)?
- What are the cost and system implications of an initial failure, or subsequent failures up to some arbitrary point of termination?

Minimizing Risk

Although EGS is not a proven technology, in the sense that it occupies a competitive market niche, hydrothermal electricity generation is a proven, widely adapted, cost effective contributor to baseload generation. Thus, the question of managing risk to a point where costs are predictable enough to allow a calculation of benefits or revenues, becomes salient. This is not only true for investors, but for governments concerned with public R&D expenditures and power operators who must look to future technologies and costs to ensure grid stability.

I categorize EGS system development in the context of phases as well as components. They are shown in Table 4.

Table 4: Risk Management for EGS

Category	Relative Risk of Success vs. Failure	Comment
Location - relative to load or transmission	Low	Initial and subsequent site locations can be chosen and controlled using decision matrices that optimize subsurface heat potential with location close to load This is also a function of mapping to establish minimum heat isoquants (>150oC) at minimum drilling depths for initial facilities
Drilling	Medium	For depths just beyond hydrothermal levels, the cost of drilling can be estimated using current drilling experience For drilling to depths beyond 6 km, the risk of failure becomes greater, a function of increased depth and rock type
Fracturing and circuit completion	High	Consistent fracturing and establishment of flow zones to connect injection and extraction is critical to success, and the most unpredictable task given the current state of knowledge
Fluid losses	Medium	Circulation of fluids and minimizing loss either through migration to adjacent subsurface zones or surface loss can impose costs of replenishment or overall heat loss
Surface conversion technology	Low	The technology performance is well known and modeled, with costs of construction and operation falling as a function of volume and industry experience
Power line interconnect	Low	Location at points adjacent to or within reasonable distance from existing substations or transmission facilities can be planned and negotiated well in advance of drilling complex completion
Power Purchase Agreements	Low	PPA's can be negotiated and bidding protocols established for the capacity available for baseload generation
Environmental Benefits	Variable	Renewable Energy Credits or Carbon Offset Credits can be anticipated but not guaranteed unless acquired on a long term basis, due to changing policy objectives for local or national governments

Given the relative costs and risks associated with them, the focus on early projects becomes clearly associated with mapping and drilling to establish relatively attractive heat locations, and then becomes absolutely limited at the second phase which is stimulation and flow testing of the resource. Failure at any of these steps effectively renders the project useless at several obvious levels.

Cost of Capital

The capital costs for geothermal plants in 2003 were estimated to range from $1150 to $3000 US per installed KW, depending on the technology chosen (REPP, 2003). Plant, as well as well lifetimes range from 28 years (Tester et al, 2006) to as much as 45 years (REPP 2003). Financing schemes may vary, but most financial lending in the renewables industry is based on recovery of capital costs in approximately half of the expected life of the project, approximately 15 years on average. Costs in the remaining years thus reflect primarily operations and maintenance and periodic re-stimulation of the well system to maintain flow rates.

Costs of Exploration and Mapping

Recent experience in EGS, in North America, Australia and in Europe does *not* provide a rule of thumb for estimating success in consistently mapping deep heat resources. On the other hand, other efforts (Peterson et al, 2003, Blackwell 2004, Tester et al, 2005, Majorowicz and Moore 2008) suggest that early efforts to designate areas of promise can be correlated with formations such as the cordillera on the eastern slope of the Rocky Mountains in the US, in the deep sedimentary basin in Alberta, or in areas previously tapped for oil and gas exploration in the Permian Basin.

As Blackwell (2004, 2007) points out, ultimately the value of surface heat flow becomes the building block for temperature-at-depth calculations that will support research or exploratory funding. Individual sites have thermal conductivity that varies with depth and, thus, the average thermal gradient depends on the depth interval studied – whereas, heat flow does not. This work suggests that the areas deserving special notice, especially in the interest of lowering exploration costs, are those associated with hydrocarbon development, i.e., wells that have been drilled to 3 to 6 km (10,000 to 19,000 ft) depths, where predicted temperatures can be checked against measurements in deep wells.[7] In the areas of geothermal drilling, there are few research wells that serve as data points at depth (Blackwell, 2007 and Majorowicz and Moore, 2008).

Costs of Drilling

The costs of drilling injection and production wells and the pumping and supply of fluids are currently the major cost barriers to commercializing HDR/EGS technology. Solving this problem is complex, typically involving drilling to great depths in very hard formations, while minimizing the number of casing sections and changes in diameter – all the while securing the bore hole. Included as well is the issue of consistent lateral connective fractures at depth and ultimately achieving desirable rates of hydraulic flow.

Basic binary cycles are most effective when used with EGR fluids below 176°C. In two-phase binary systems, the low pressure steam from a flash tank is condensed in the vaporizer of the binary system, and the hot brine is used to preheat the organic motive fluids, resulting in lower pressure steam during the condensing cycle (Grassiani and Krieger, 2000).

With drilling costs related both to the geological formations and to well depth, power plants which can effectively make use of lower temperature fluids from shallower wells will reduce power production costs and overcome those barriers. Experience with both oil and gas and hydrothermal wells suggest that well costs grow non-linearly with depth. However, the estimates available suggest that the 1,500 meter, 2,500 meter and 3,000 meter well cost estimates from the model were used.[8] Costs beyond this depth are difficult to estimate, especially when the cost of fracturing is taken into account. EGS well depths beyond 4,000 meters may also require casing weights and grades that are not readily available (Tester et al, 2006). A sample of well cost estimates from the CEC survey shows the following:

Table 5: CEC Assumptions for Hydrothermal Drilling Costs

Average well cost in $US	Cost per foot	Cost per meter	Average depth in ft.	Average depth in m
2458855	481	160	5330	1777

Source: (CEC d, 2004)

The economic rationale for well complexes is dictated not only by well depth, but by the difference in drilling effort due to hardness of rock, trouble, and number of casing strings. The relationship of these characteristics is shown in Table 6.

Table 6: Well Depth and Casings in $ US / M

Shallow			Mid			Deep		
Depth in M	# of casing strings	$/M	Depth in M	# of casing strings	$/M	Depth in M	# of casing strings	$/M
1,500	4	2.3	4,000	4	5.2	6,000	5	9.7
2,500	4	3.4	5,000	4	7.0	6,000	6	12.3
3,000	4.0	4.2	5,000	5	8.3	7,500	6	14.4
						10,000	6	20.00

Source: Tester et al 2006

The predictive data from hydrothermal development provide a reasonable guide for future costs when combined with newer models such as Wellcost Lite (Tester et al., 2006). In this study, well costs were estimated for depths ranging from 1,500 m to 10,000 m. The resulting curves indicate drilling costs that grow non-linearly with depth. The 1,500 m (4,900 ft), 2,500 m (8,200 ft), and 3,000 m (9,800 ft) well-cost estimates from the MIT model compare favorably with actual geothermal drilling costs for those depths (Tester et al, 2006).

Since well costs reflect up to 50 percent of total installed capital costs, achieving savings or cost breakthroughs in this area is critical to controlling the ultimate cost of energy.

Using estimates from the CEC (CEC d 2004) and the MIT report (Tester et al, 2006) of a range of $385 to $500US per foot, the cost for 6 km wells will average from $6.9M to $9MUS with approximately $250,000 for initial field test and well test per complex.

Alternative Drilling Techniques

Since drilling costs represent such a large fraction of development costs, reductions in this area can carry great benefits in making EGS more competitive in grid operations. As a caution, EGS well depths beyond 4,000 m (13,100 ft) may require casing weights and grades that are not widely available to provide the required collapse and tensile ratings.

Overall drilling costs might be reduced ultimately by one half (Thorsteinsson et al, 2008) using a combination of longer drilling sequences and fewer casings and diameter changes using monoboring techniques. This combined with new polymeric casings (Purdin 1980, Tester et al, 2006) and cementing processes (Kukacka, 1995) offer additional avenues of cost reduction. Ultimately, a combination of increased learning experience in individual fields and better drilling techniques are the most likely source of new cost reductions in EGS (Fridlleifssona and Eldersh, 2005).

Fracturing

Costs for subsurface fracturing are expected to vary widely depending on the lithography encountered at depth. Based on estimates from Cooper Basin and from Soultz (Tester et al, 2006) a figure of $500,000 per well is assumed to be the most realistic figure today. This is assumed to be consistent even in re-stimulation exercises.

Costs for Surface Conversion Technologies

Surface conversion technologies are mature and have been deployed widely throughout the world. Costs vary by the technology chosen, but for convenience I have assumed the use of Flash Technology such as that available from ORMAT to be combined with EGS installations.

The installed specific cost ($/kW) for either a conventional 1- or 2-flash power plant at EGS reservoirs is inversely dependent on the fluid temperature and mass flow rate. Over the range from 150-340°C: For a mass flow rate of 100 kg/s (the upper limit of the resource assumed in the MIT study), the specific cost varies from $1,894-1,773/kW (1-flash) and from $1,889-1,737/kW (2-flash). Costs would vary from $50 million to $260 million, with a fluid temperature ranging from 150-340°C; the corresponding power rating would vary from about 30-265 MW. If the reservoir were able to supply only 100 kg/s, the plant cost would vary from $5.6 million to $45.8 million over the same temperature range; the corresponding power rating would vary from 3-26.4 MW (Tester et al, 2006).

A development strategy that includes successive modules of generation between 20-60 MW per installation is likely to be the most effective (Stefansson, 2002 and Frieliefsson and Eldersh, 2005)), resulting in an efficient relationship location to grid delivery. We can expect average surface conversion costs of $1,000US per kW with a relative error of 10 percent.

Table 7: Assumed Costs of Development

Total Cost	Expected Costs in USD/kW	Range w/in 1 standard deviation
Surface Cost Only	977	762 - 1192
Total Cost for known field	1,267	762- 1692
Total Cost for unknown field	1,440	1,122 - 1,992

Source: Stefansson, 2002

This agrees with recent work by the California Energy Commission, which found a range of cost for binary power plants from $1,550 to $3,475 and a range of Flash costs from $1,564 to $2,270. The average cost in $/kW of $1,500 excluded the highest two values with one standard deviation of $470US (CEC d 2004).

Cost of Transmission Line Extension

The cost of transmission line extension(s) from the project to main interconnect is assumed to be $325US per mile, with an average of 2 miles. Site substations will vary by expected output and are expected to be priced at $69US in 2008 dollars (CEC d 2004).

The Cost of Energy (COE)

The Cost of Energy (COE) is a function of the overnight cost of capital, access costs to transmission, fuel costs, and the operations and maintenance cost of the technology in use. Normal hydrothermal power generation has no fuel cost beyond makeup water; as a consequence the variable COE is relatively low compared to fossil or other renewable energy resources excluding the existing hydroelectric base. As a consequence, this technology tends to be dispatched as baseload.

To a higher degree, EGS systems will be sensitive to reservoir, capital cost, and financial parameters shown in the MIT EGS model (Tester et al, 2006). The COE is *most* sensitive to drilling and completion costs, the flow rate, and ultimately to the thermal drawdown rate. The nonlinearity of the sensitivity of costs to drawdown rate is a result of the fixed plant lifetime of 30 years and the variability of the interval for reservoir rework/re-stimulation. Because a small fraction of the total capital cost is in the surface plant (in relation to the drilling cost), the LCOE is relatively insensitive to the surface plant costs for lower-grade resources, but the sensitivity increases for higher-grade resources.

In the MIT study (Tester et al, 2006), estimates of the cost of energy are shown to fall predictably with increased deployment and achieve parity with market price beyond 11 years from initiation of a widespread program to develop EGS on a multi-regional basis. This assumes that development is focused on areas where the resource initially is in a high-grade, minimal-depth-to-resource zone.

Comparison of Baseload Energy Capital Costs

Geothermal-based generation (Lovekin, 2000), whether hydrothermal (or EGS in the future), as pointed out above, is most efficiently dispatched as baseload power. The economics of base load power, whether renewable or fossil based, is governed primarily by initial capital costs. Ultimately the cost of capital governs all investment, subject to the contracts for delivery, and the competitive position of delivered energy. Thus, it is useful to consider it in the context of other competitive technologies such as coal, nuclear power, and biomass to appreciate the wide range of overnight capital costs as well as the associated costs of upkeep and operations. EGS operations are expected to diverge from these relationships primarily in terms of the overnight capital cost associated with drilling.

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors. The EIA points out in their description of the National Energy Modeling System – NEMS – that the technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained with approximately 4 wells in a complex (as opposed to a regional area, see Tester et al, 2006) the technological optimism factor is gradually reduced to reflect higher and higher confidence in outcomes which will in turn encourage new commercial development.[9]

Geothermal energy is competitive in the merit order of dispatch normally based on thermal resources but also in terms of renewable generation such as hydro or biomass. The current installed cost of energy technologies available as *renewable* energy resources shows the competitive position of hydrothermal generation in the absence of fossil-fueled electric generation shown in Table 8 below.

Table 8: Installed Costs and COE of Renewable Energy Resources

Technology	Installed Cost in $US (2004)	COE In cents/kWh
Biomass	900- 3000	5 - 15
Solar PV	5000 - 10,000	25 - 125
Solar Thermal	3,000 - 4,000	12 - 18
Hydroelectric	1,000 - 3,500	2 - 10
Geothermal	800 - 3,000	2 - 10
Wind	1,100 - 1,700	5 - 13
Tidal	1,700 - 2,500	>25

Source: Hammons, 2004

The most competitive role for geothermal power, whether hydrothermal or EGS, will continue to be baseload generation, competing against coal, biomass, and nuclear fission for dispatch. The relationship of these types of technologies in terms of capital and operating costs is shown in Table 9 below:

Table 9: Capital and Variable Costs for Baseload Technologies

Type	Size in MW	Overnight Cost in $US / kWh	Variable Costs of O&M in mills/kWh	Fixed Costs of O&M in mills/kWh
New Coal Scrubbed	600	1534	4.46	26.79
IGCC	550	1773	2.84	36.72
IGCC w/CCS	380	2537	4.32	44.27
Advanced new nuclear	1350	2457	.48	66.05
Biomass	80	2809	6.53	62.70
Geothermal (Hydrothermal)	50	1110	0*	160.18

Source: EIA assumptions for 2008 Long Term Energy Outlook
*Does not account for cost of make-up water

Other Costs of Initial Development

Development of new EGS facilities will involve a coordinated deployment of capital and investment in system improvements that will involve private investment and public approvals, including R&D to support innovation and cost efficiency. The business case for EGS in the future must take account of time commitments in the development process, which are summarized in Table 10 below, and represent a necessary addition to the time discount of money calculation that must be made in order to finally achieve power delivery to the grid.

Table 10: Time Estimates for EGS Development

Reconnaissance and Market Studies	1 Year
Surface Exploration	1 Year
Exploratory Drilling	1 Year
Production Drilling and Power Plant Construction	3 Years
Transmission Line Interconnect Study	1 - 2 Years
Total	7 - 8 Years

Public investment can reduce these time commitments, specifically in the areas of land and resource identification and potentially in the transmission interconnection phase, where the regulator can pre-set standards that will shorten times while still maintaining public safety.

Land Costs, Tax Incentives

Land costs are likely to be borne as long term leases, negotiated individually. These costs may also include diversion of a revenue stream to the landowner, or a partial franchise fee to the owner or to a public agency. Clearly they will affect the IRR for the project and must be negotiated accordingly.

Public costs of approval can add considerably to the cost of operations and development (Jenkins, 1996). Regulatory approvals may add $450,000 to project costs, with associated costs of administration assumed to be $750,000 per project (CEC d, 2004). Renewable energy projects carry a generally higher tax burden than fossil fuel resources, largely because they have not been the subject of policies or tax incentive programs to make them more competitive in grid operations. Rather, the incentive has been to provide incentives to generally increase the volume of renewable generation. This focus has ignored the longer-term competitive position of such technologies after being developed through programs such as RPS.

RPS, Ancillary Benefits, Competitive Auctions, Carbon Offsets and Green Credits

Many national or state/provincial programs are built on the concept of increasing the share and role of renewable energy through public market intervention (CEC a, 2007). These include requirements for Renewable Portfolio Standards, pricing so-called ancillary benefits, crediting renewable producers with “green” credits or carbon offsets, or allowing the market to set competitive prices through bidding auctions. There are varying opinions about the overall success of these programs, but there can be little question that the role of renewable energy, such as geothermal electric generation, is increasing.

Recent bids in the California market attest to this role. California now sets a goal of 33 percent of total supply to be met with renewable energy by 2020 (California Governor’s Office 2008). This ambitious requirement has driven up the contract price for geothermal, effectively eliminating competitive bidding, reflecting the imbalance of supply for new RPS-based utility demand.

That outcome is apparent in Table 11 below, which shows the dramatic increase in contract price.[10]

Table 11: Estimated Hydrothermal Contract Sales - California

Term	Cost per KWh	Minimum Block	Contract Amount Estimated
Short Term (Monthly Bilateral	7.6 cents per KWh	Per 100 MW	80 GWh
Existing Long Term	6.8 - 8.4cents / KWh	Per 225 MW	1000 GWh
New Long Term	13.4 cents / KWh	Range 75 - 350 MW	624 - 3000 GWh

Source: CEC Staff Communication, October 2008

It is worth noting that this effectively represents monopsony power that is the result of a public policy objective. Nonetheless, the price (not bid) achieved by these contracts does not represent the LCOE, which in the case of hydrothermal is competitive without the RPS, with fossil generation.

Many of the benefits from EGS operations in the future may lie in so-called attribute values, either as offsets for CO_2 emissions from other sources (Baldacci and Sabatelli, 1995, Murphy and Niitsuma, 1999, Fridleifsson et al, 2008, Thorsteinsson et al, 2008,) or as storage locations for CO_2 as a medium for fluid transfer (Paglianti, 1995, and Brown, 2000). Linking EGS investments, whether private or public, can provide a standard for overall emissions reductions as well (Kolstad and Wolak, 2003), where relative shares for reduction are based on the contribution of this technology.

Summary

Hydrothermal power is used as a reliable source of baseload energy for grid operations. It is, however, limited to those areas with suitable geologic formations and flow conditions that can yield high heat at reasonable depths. Further, it is limited in the proximity to load and access to transmission lines with available capacity.

EGS systems offer the potential to supplement these existing hydrothermal systems by extending their vertical reach as well as creating access for deep heat resources closer to load and transmission systems.

The expected levelized cost of EGS-based electric power is forecast to be approximately the same as thermal resources such as coal under competitive market conditions with a reasonably effective program of R&D plus field development. The capital costs for EGS are similar to those for other technologies and are expected to be more than competitive when drilling costs are reduced as a function of field experience and continued Research and Development.

In addition, EGS systems can contribute so-called attribute benefits or carbon offsets which further reduce the effective cost. The development of EGS opportunities will be important not only for these factors, but in light of forecast shortfalls in baseload capacity over the next two decades.

Next Steps

Similar to wind technology development, the expansion of the EGS capability of the energy system will be a function of continued public investment in R&D and providing access and support for one or more test facilities to prove the concept. Ideally, these test facilities would take advantage of known mapped resource areas and proximity to existing transmission systems in order to demonstrate the greatest potential contribution. Finding solutions for energy development in closer proximity to urban areas will help as well, not only by creating facilities that are closer to load, but by minimizing transmission connection costs (Tester et al, 2005, Teodoriu and Falcone, 2008). Further public support in the form of advanced surface and subsurface mapping can help reduce development costs and encourage private merchant development in new capacity.

The value of strategic subsidization of renewable generation has been proven over the past decade. Other avenues of public financial support can be helpful as well, including the extension of insurance for well completion and development or ownership shares in EGS complexes or ultimately using the historic model for municipal improvement bonds, in diminishing the cost of borrowing in the form of bonds for capital investment in baseload energy facilities.

Conclusions

Robust, resilient and affordable electricity systems are critical for economic development and growth in both developing and developed economies. This makes the issue of stability and security of the technologies and dispatch capability critical as well. At the heart of stable electricity systems is the technology, fuels and bid or dispatch system related to baseload power supplies. With changes in the environmental compliance regulations world-wide, accepted sources of baseload power such as coal and nuclear fission may be reconfigured or not renewed as permits expire or operating lifetimes are reached.

Simultaneously, most electric systems are seeking to add system diversity in terms of technology, reliance on threatened or expensive fuel supplies or variable dispatch capability. One approach is to provide incentives for the inclusion of renewable resource technologies or to mandate inclusion of some level of purchase by utilities or municipalities of alternative energy sources.

Enhanced Geothermal Systems would seem to address these issues very well if proved to be cost effective and reliable on a wide scale. To date, we have examples that are not to commercial development scale, but offer the promise of affordable, reliable and dispatchable baseload alternative power. What is missing is the deployment of test facilities, initially located at proven hydrothermal operations; testing can be extended into deeper zones where artificial hydraulic stimulation can provide the basis for more precise engineering and economic estimates of value.

What is clear, however, is that widespread use of this type of energy production could provide affordable substitutions for environmentally-costly fossil fuel generation, free up valuable hydro resources, currently used for both baseload and load following, for agricultural or wildlife preservation and make the transition from a coal, nuclear, and large-scale hydroelectric world more predictable and sustainable.

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Cooper basin: http://www.geodynamics.com.au/IRM/content/home.html
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Endnotes

[1]A useful forecast of this capacity is found in (Dickson and Fanelli, 1993).

[2]The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous name plate power operation during the same period.

[3]The availability factor of a power plant is the amount of time that it is able to produce electricity over a certain period, divided by the amount of the time in the period. Generally, plants that are run less frequently have higher availability factors because they require less maintenance; this can be offset through higher maintenance attention and frequent attendance to demineralization and thermal expansion/contraction related failures.

[4]A reasonable estimate is three re-fracturing and stimulation after initial system completion, or periodicy of 6 to 8 years per re-stimulation, with a corresponding total well decline in ~ 25-26 years.

[5]RPS or Renewable Portfolio Standards – a policy tool designed to support the integration of renewable energy resources in the overall power mix by requiring a set fraction of utility energy purchases to come from renewable resources.

[6] Blackwell (2007) points out that another scenario exists for geothermal development in many of the areas exploited for deep oil and gas production, especially in the Gulf Coast and mountain states regions. In these areas, EGS development in the deep, high-temperature part of the sedimentary section might be more cost-effective than basement EGS systems.

[7]Wellcost Lite in (MIT 2006).

[8]The EIA illustrates how a capacity credit associated with component learning for various technologies works in the field. As an example they assume that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts toward turbine learning, and 0.33 gigawatts toward steam learning.

[9]Estimate based on the NP 15 Price Index + $15 per MWH.

The Future of Arab Economy Against the Backdrop of the Global Financial Crisis and Risks of New and Emerging Energy Technology

*By Sulayman S. Al-Qudsi**

Introduction

Applying analytical narrative along with a simple formal modeling approach, this paper examines recent developments in the Arab economies against the backdrop of the global financial crisis and subsequent global recession. In the process, the paper discusses the role of conventional and renewable energy in the Arab economies, retrospectively and prospectively. It concludes with some discussion of emerging risks that will challenge the region in the years to come. The risks are threefold: The first is in terms of oil demand destruction due to severe and protracted global downturns. The second emanates from global innovations in new and renewable energy technologies which might be dubbed "the oil-replacement risk factor". The third emerging risk stems from the sharply increased volatility of the "*oil and financial investments*" portfolio that the global crisis caused, rocking the underlying assumptions of the long-term strategic vision of the Arab economies. The salient conclusion is that policy makers and the populace at large should hedge against emerging risks in order to safeguard the future of the region and to elevate overall productivity and living standards of its children and its future generations.

Geographically, the Arab world straddles two continents covering a distance of 6,370 km – from Rabat on the Atlantic to Muscat on the Gulf.[1] Representing nearly 10 percent of the world's geography and with a share of 3 percent of the world's GDP, the Arab World is home to about 5 percent of the world's population. The region gained increasing importance during the 2002-2008 period when the world witnessed massive increases in the prices of commodities such as oil and natural gas. Being resource-rich, the area was sizzling with economic growth and trade and investment in-and-out flows. Many oil-exporting countries of the region experienced unprecedented growth and realized huge foreign reserves accumulations. These petro-surpluses led to the enhancements of sovereign wealth funds (SWFs) that were largely invested in the international financial centers of the world, notably in the US and the EU.

Despite its linguistic, religious, and cultural cohesion, the Arab region is also rich in diversity. In territorial size, some countries (Sudan and Saudi Arabia) comprise vast areas that approach 1 million square miles while others (Bahrain) are small enough to fit into a major Western city. It is the home of diverse ethnic and religious groups including Muslim and Christian Arabs, Kurds, Druze, Berbers, and Armenians. It is also a font of political and ideological ferment and locus of some of the most persistently explosive conflicts in the world. No country on earth can be unconcerned with the course of major developments in the region.[2]

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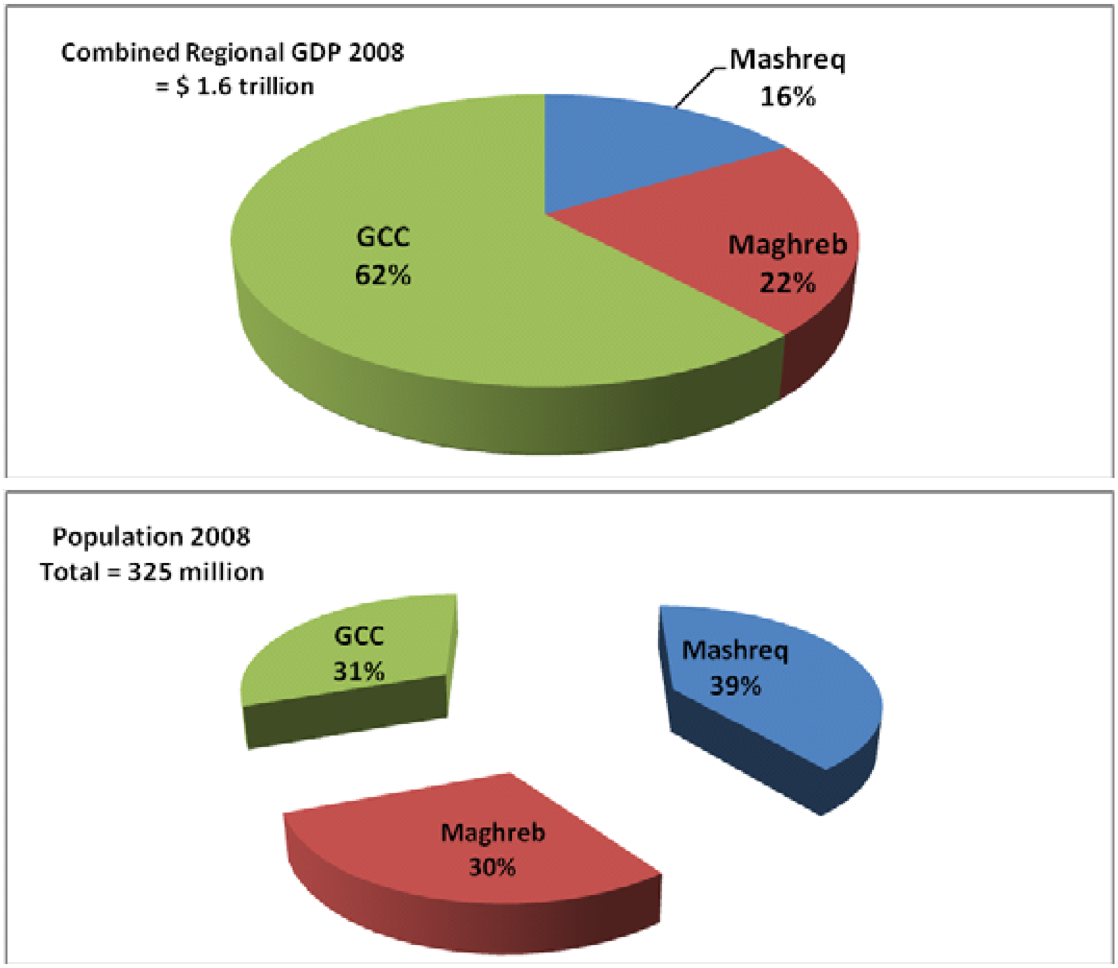
With a total population of 325 million that is doubling every 25 years and with 68 percent of the population in the employment productive years of 15-67, the Arab economies represent a vast and expanding market potential and holds largely un-harvested human capital potential over and above its vast natural energy resources. As of 2008, the region's combined GDP at $1.6trn puts it at levels comparable to that of Canada. The distribution of GDP and population amongst GCC, Mashreq and Maghreb countries is shown in Figure 1.

Figure 1: GDP and Population of the Arab World According to Mashreq, Maghreb & GCC



Source: AMF, IMF & EIU. GCC countries= Bahrain, Kuwait, Qatar, Oman, Saudi Arabia and UAE. Mashreq countries = Egypt, Jordan, Lebanon and Syria while Maghreb countries= Algeria, Libya, Morocco and Tunisia.

Over the past few decades, and especially since the latest oil wealth of 2002-2008, the Arab economies stashed hefty financial resources. For instance, the combined asset sheets of all Arab Banks stood at 2.5tr, or nearly 160 percent of their combined GDP. Moreover, of the top 1000 global banks, more than 80 are Arab banks. As well, the stock markets in the Arab region have attracted international investors and the Islamic finance, especially Sukuk, which is the fastest growing of all financing means in the world.

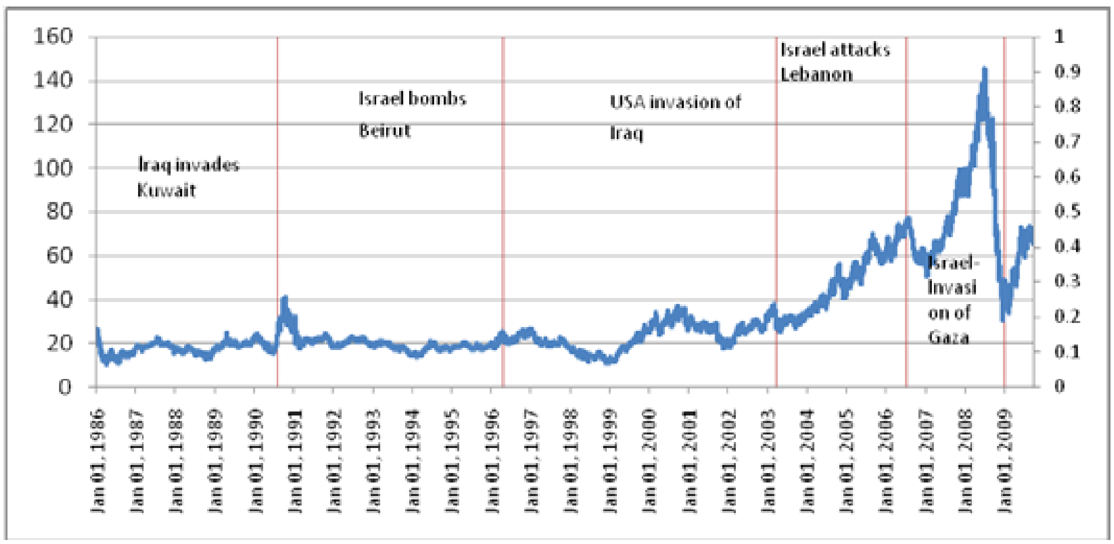
Oil and the Arab Economy

With two thirds of Arab countries producing oil, crude is undoubtedly the most important factor in the region's economic development.[3] The economies of the Arab world exhibit great diversity in income and structure. The variety is highlighted by the fact that GDP per capita of the wealthiest country, Qatar, is 73 times higher than that of the poorest coun-try, Mauritania. In addition, the economies are charac-terized by a multiplicity of structures. Some countries have accumulated significant wealth through the extrac-tion of natural resources while others follow more tradi-tional trajectories of development, starting with lower-end manufacturing and slowly moving up the value chain. These differences affect the competitive perform-ance in many ways, the most important being the avail-ability of resources for public investment.

That oil and gas have fueled economic growth and propelled social and political transformations in the Arab economies is amply demonstrated from the fact that hydrocarbon energy is the major source of foreign exchange, the predominant source of export earnings, the major source of government revenues and the main engine of economic growth in the six GCC economies, in 2 of the four Maghreb economies, two of the Mashreq economies, as well as in Iraq, Sudan and even Yemen, all of which are oil exporters. The rest of countries are affected, mostly positively from the region's vast reservoir of oil and gas, through trade and investments and remittances transmission networks and linkages.

Yet the impact of oil is far from strictly positive. The region has suffered from the vagaries of international oil markets that historically emanated from market fundamentals, deliberate tax and trade policies of the consuming countries, especially in Europe and, on top of that, from regional and international instability and geopolitical considerations. Figure 2 portrays salient geopolitical episodes that have been inflicted on the Arab economies, mostly as direct results of its oil richness and oil-dependence.

Figure 2: Oil Prices and Geopolitical Conflicts in the MENA Region

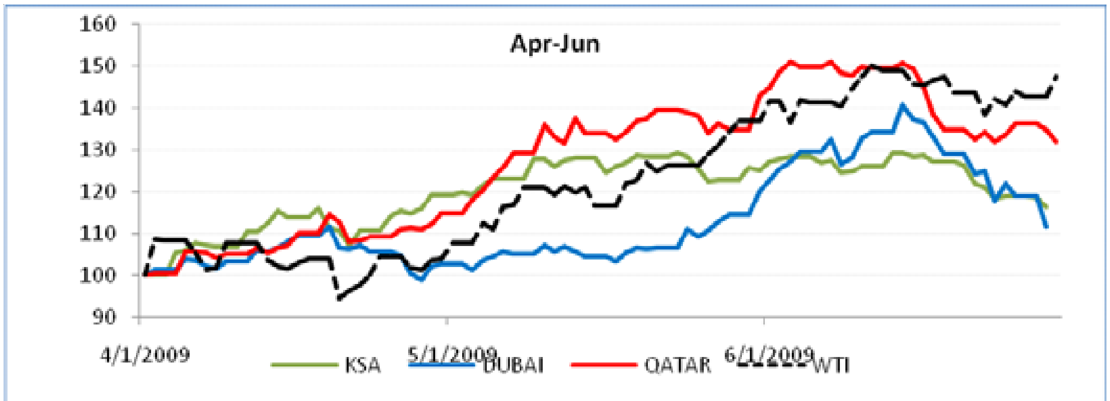


Although some geopolitical spells are known to cause oil prices to spike, their effect on the Arab region tend to be more prominent and even catastrophic. By and large geopolitical events in the region tend to be growth-destabilizing especially those which take the form of open military conflict that often destroy physical and human infrastructures and in the ultimate analysis pull down the actual output level of the Arab economy from its steady state, or long-term potential.

While oil has a sweeping impact on Arab economies in terms of labor movements, trade and investments and inflows of FDI from oil-producing to labor-surplus economies, the impact of oil is especially influential in the GCC economies. This is seen from the transmission between oil prices, WTI, and the performance of three GCC stock markets as shown in Figure 3.

Formally, time series analysis has confirmed the existence of transmission channels between oil prices and several stock markets in the Arab economies, especially the Egyptian, Jordanian and Gulf markets.[4] As well, recent research has corroborated that oil price shocks have "indirect" effects on the profitability of the financial sector, especially banks in the Arab economies. These indirect effects are channeled through country-specific macroeconomic and institutional variables.[5]

Figure 3: Daily Market Indices and Oil (base 1Apr09=100)

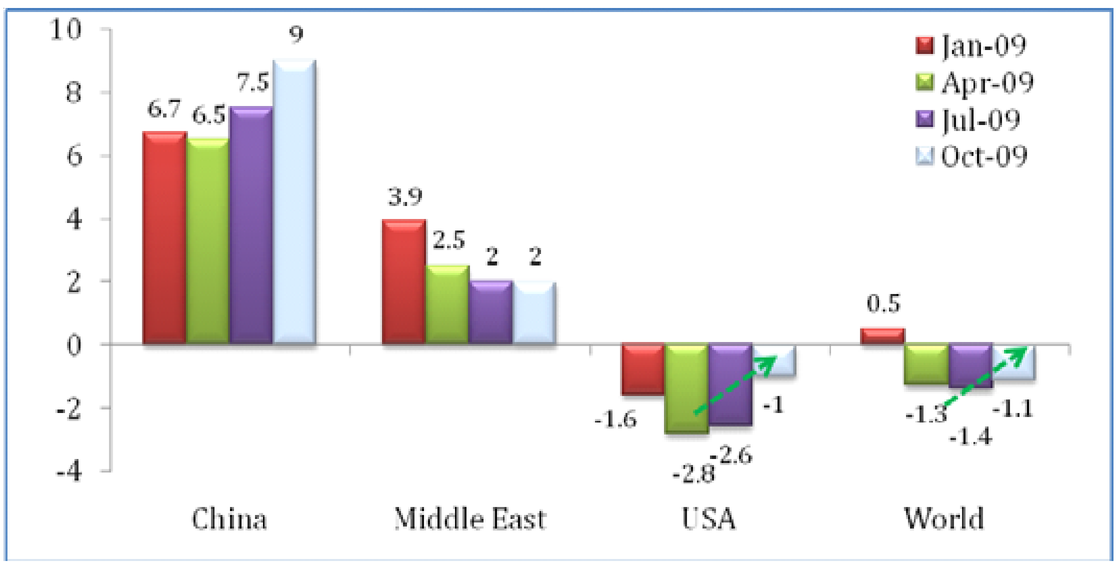


Source: Zawya and EIA

Arab Economies and the Eruption of the Global Financial Crisis

When the global financial crisis erupted, the Arab economies appeared well-poised to withstand the crisis. The GCC economies especially had accumulated huge financial reserves in terms of foreign exchange, SDR and gold, among others. In the subsequent months however, it became clear that the financial sector of the GCC economies was discernibly exposed to the crisis. The region's expected growth has been successively revised downwards by local and international organizations. For instance, the IMF has reduced its forecast of economic growth in the Middle East from 3.9 percent in January 2009 to 2 percent in October 2009. Yet with the exception of Asia, the Middle East regional outlook remains well above the global average and well above expected growth in the western hemisphere (see Figure 4).

Figure 4: Global and Regional Economic Outlook



Source: IMF, Oct 2009

The underlying reasons for the exposure of the Arab economies to the global crisis include the following: First and foremost, the economies of these countries are basically energy-driven and the global crisis had destroyed demand for oil and caused the price of their basic asset to plunge from the heights of $147/b in June 2008 to $30/b in early 2009. Volatile oil price movements exacerbated economic volatility, overall and at the sector-level. For instance, when oil prices were especially high, liquidity was abundant and the financial markets thrived. By contrast, the global financial crisis and attendant credit freeze, played havoc with the financial systems and overall environment of the GCC and by contagion of the Mashreq economies of Egypt, Jordan, Lebanon and Syria. The Maghreb countries of Libya, Algeria, Morocco and Tunisia were affected to a much lesser degree. Second, the banking sectors of these countries saw rapid expansion in loan growth in the buoyant years. In retrospect, some of the loans turned out to be risky and some borrowers defaulted as the economies suddenly slowed down and the business took sharp downturns. Third, in their big rush to open up, economies became highly dependent on foreign funding. This was particularly true in the case of Dubai that followed an exceptionally open border policy to foreign capital and foreign investments. Some of the capital infusions turned out to be of the speculative and "hot money" nature whose short–term objective of speculative profits do not jive with the longer-term standards of credit expansion. Fourth, the GCC economies, particularly Dubai and Bahrain had large exposures to the real estate sector. Finally, in retrospect, some countries – basically the GCC – turned out to rely on structured financial products to a much larger degree than other Arab economies such as Jordan, Egypt, Syria or Morocco.

Direct Effect of the Global Crisis: Oil Demand Destruction

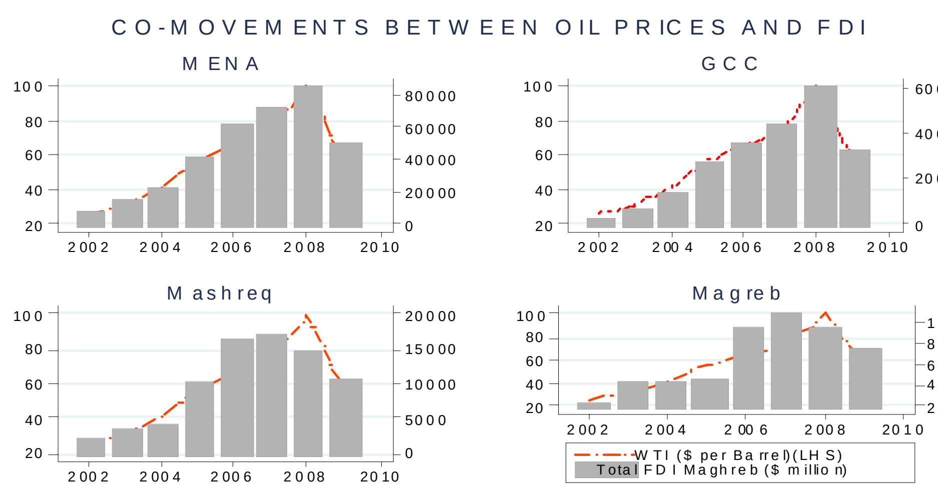
One of the direct effects of the global financial crisis was oil demand destruction which invariably reduced oil prices and alleviated the urgent need to build up spare capacity. According to initial EIU forecasts, world oil demand is falling, largely driven by falling consumption in developed countries. Indeed, estimates point to a decline of 2.9 percent in oil demand in OECD countries in 2008 and a further drop of 1.8 percent is also forecast in 2009. All in all, global oil demand declined by nearly 3.2 million b/d in the first half of this year, H1 2009. OECD countries accounted for most of the decline. However, economic turnaround in Asia continues to fuel expectations and a rebound in oil demand in the US pushed OPEC and the EIA to raise oil consumption upwards by 0.2 mb/d for the remainder of 2009 and for 2010.

Reduction in demand in OECD countries is largely due to falling demand in North America, estimated at about 2 percent in 2009, and in Europe, estimated at 1.7 percent. Non-OECD demand for oil is forecast to grow by 1.4 percent in 2009 and by 2.3 percent in 2010. Underpinning these estimates is the expected increase in demand in developing countries. However, even if that demand is expected to increase, it will not be sheltered from the consequences of the global economic turmoil, as it is forecast to grow at a slower pace over the short- to medium-term. Broadly speaking, growing oil demand in developing countries has recently been driven by two major components, namely increasing demand in both China and India and Arab oil-exporting countries. Hence, the extent to which oil demand in developing countries will be impacted largely depends on the underlying elements in each of the above- mentioned components. The expected slowdown in the demand for oil in emerging countries is greatly dependent on the demand outlook in China and India which is, in turn, related to their growth prospects. According to the EIU, Chinese oil consumption will grow by just 2.5 percent in 2009 (down from a 4.8 percent growth the previous year), and by 3.5 percent in 2010.[6]

Additional Effects: FDI and Accumulated FX Reserves

As indicated at the outset, the region is affected by oil directly and indirectly. One of the forms of indirect transmission is the infusion of foreign direct investments, especially in the less oil endowed Arab countries such as Lebanon, Jordan and Morocco. The association between oil prices and FDI is proven by country experiences and corroborated by standard causality tests, Granger causality, as shown graphically in Figure 5.

Figure 5: Oil Prices and FDI in Arab Economies



It is worth noting that the attraction of FDI into the Arab economies was facilitated by the adoption of economic, investment and regulatory reforms that aimed at promoting FDI by creating favorable legal environment for foreign investors. These policy efforts date back to the early 1990s when many Arab countries initiated and adopted reform strategies that included privatizing state-owned enterprises and companies and retrenching public sector employment and roles in economic activities, reducing corporate and personal income tax rates, in addition to the adoption of investment promotion programs. Jordan and Tunisia were pioneer reformers in the region with programs in place that date back to the late 1980s. As a result, in Jordan for example, government participation in shareholding decreased 250 percent, or to merely 6 percent by the end of 2008. As well, the percentage of foreign ownership, non-Jordanian ownership in companies stood at nearly 49 percent.[7] Other Arab countries including the GCC, Egypt, and Morocco followed suit while Syria and Libya were lagers that just started more recently, over the past five years.

Likewise, the oil-rich GCC countries have been privatizing and liberalizing their economies and aligning them on the tracks of economic and financial reforms in order to develop their private sectors and attract back home some of their own investments abroad (already the GCC wealthy private investors hold an estimated 25 percent of their portfolios in local financial products, up from 15 percent in 2002)[8] along with FDI, into the GCC economies. Examples include allowing foreign shareholders in Saudi Arabia to own up to 60 percent of the capital of the existing Saudi banks (up from the previous 40 percent cap). Foreigners were allowed to invest in the Saudi stock market since November 1999, but only through the mutual funds offered by Saudi banks. This changed in March 2006, when the Saudi authorities decided to allow expatriates to invest directly in the faltering market. Foreign players are now permitted to set up a business, own land, and sponsor their own employees in the Kingdom without having to act through a Saudi partner.[9] The latest such reform in Bahrain planted the seeds of a major overhaul of the laws and conditions that govern foreign labor which enhances their mobility and protects the rights of expatriate workers.[10] The changes came in August 2009 when Bahrain abandoned its policy of tying foreign workers visas to particular employers which makes it easier for workers to change jobs and enhance labor mobility and labor market competitiveness.[11]

Needless to say, the eruption of the global financial crisis led to marked contractions in the inflows of FDI and de-accumulation of foreign reserves. Globally, FDI decelerated sharply by 14 percent in 2008 relative to levels of 2007 or from $1,979bn to $1,697bn in 2007 and 2008 respectively. Regionally, FDI inflows had increased substantially during the period 2003-2007; rising in the GCC economies for example from $6.6 in 2003 to $63.4 billion in 2008.[12] The eruption of the global financial crisis forced the inflows to shrink substantially: overall by about 10 percent with wide disparities across countries; with some losing as much as 30 percent. Reduced foreign investments in the GCC economies have threatened to push back planned investment projects for increasing “oil excess capacity” whose ultimate objective is to meet probable rapid growth, including random spikes, in global demand for crude.

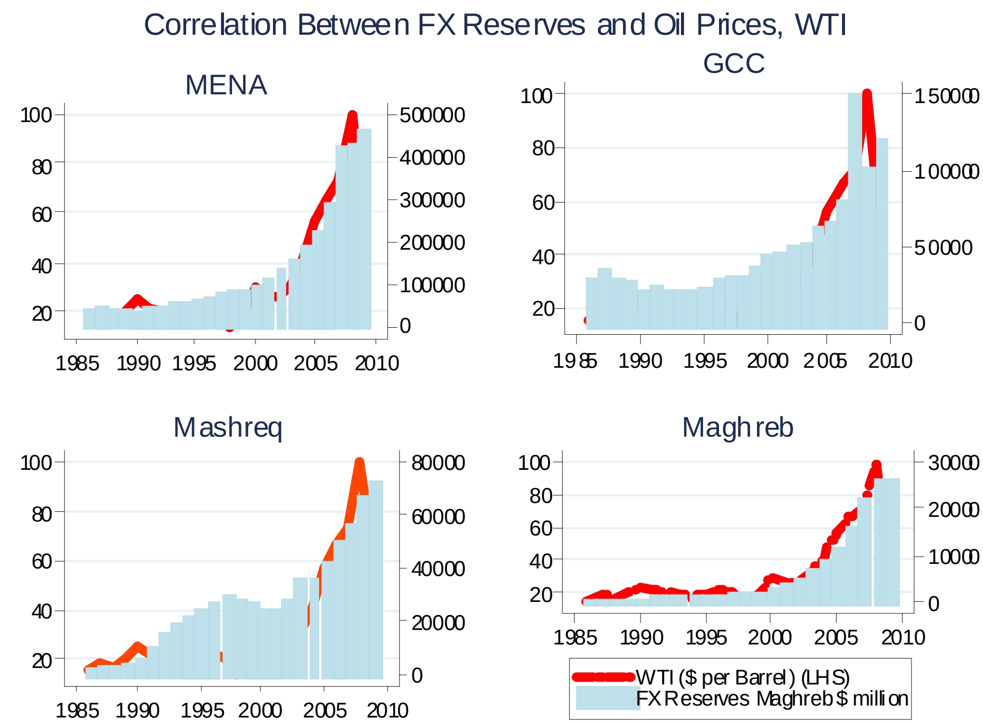
Despite effective policies in place, the depressing effect of the global crisis ended up spreading to the accumulation of foreign exchange. Similar to FDI, the accumulation of foreign exchange is sensitive to global oil prices, with reserves fast accumulating during periods of escalating oil prices and depleting during environments of declining oil prices, as portrayed in Figure 6.

While the speed of accumulating foreign reserves was reduced overall, in several countries FX reserves have recently reached record highs. For example, Jordan registered record levels of FX reserves in June (USD 9.2bn) stemming from strong capital inflows over the past months from tourism, expat remittances, and foreign direct investments,[13] while Lebanon saw its reserves on a steady rise throughout 2008 and so far in 2009.

The Dollar-priced Oil and the Currency Peg

There is another consideration relating to energy and the economy in the Arab countries. This is the pricing of oil in dollars. Countries like the GCC and Jordan peg their currencies to the dollar, so if the dollar is not used to price oil, oil-importing countries may have to worry about converting their currencies into perhaps a basket of currencies when dealing with oil market transactions. The dollar has been falling in FX markets in recent months. The dollar’s share of global currency reserves fell in Q2 of 2009 to 62.8 percent, from 65 percent in Q1. The euro’s

Figure 6: Oil Prices and Accumulation of Reserves in Arab Economies



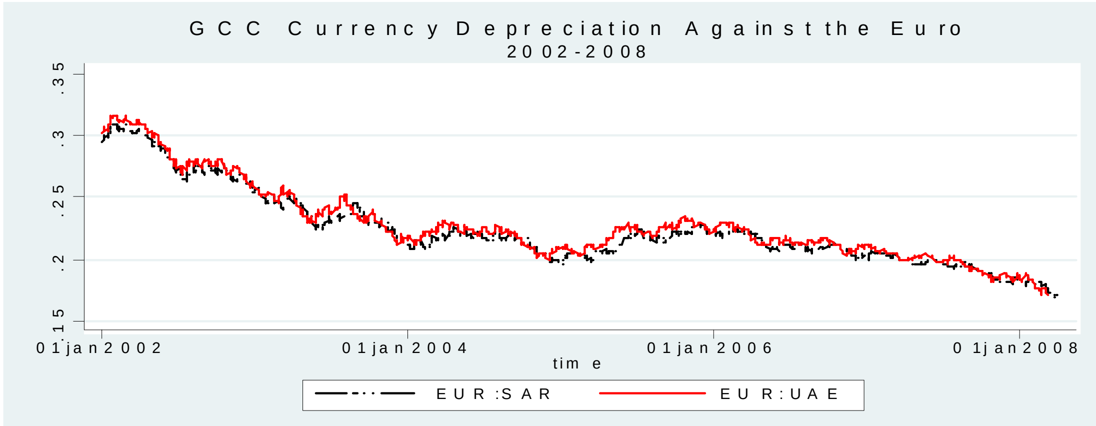
share rose to 27.5 percent, from 25.9 percent.[14] The dollar has dropped 14 percent against a basket of seven currencies since early March. Finally, one should note that US inflation has been higher than that of the EU and Asia and unless productivity growth in the US resumes at rates seen only in the 1990s, pressures will mount again on countries to re-consider the dollar peg.

Because oil is priced in dollars, several Arab countries that peg their currencies to the greenback suffered inflationary expectations during 2007 and 2008 when the dollar depreciated against major currencies – as global commodity prices, including food and energy, soared. In the ultimate analysis the effect of the dollar peg depends on the magnitude and speed of the so-called "pass-through; that is the transmission between the falling dollar and rising inflation in the GCC and other Arab countries that peg their currencies to the dollar. The literature dubs this transmission as the exchange rate "pass through". Specifically, the rate of exchange rate "pass through" is the degree to which a change in the value of a country's currency induces a change in the price of the country's imports and exports.[15] Earlier empirical findings suggest that the pass-though effect of dollar depreciation is in the order of magnitude of 0.25 to 0.35. So when the dollar depreciates by say, ten percent, approximately 3.0 percent of such depreciation is transmitted on average into the domestic economies of the GCC countries. To illustrate the policy implications of this particular empirical finding, Figure 7 shows the time-path of the Saudi Riyal And Emeriti Dirham. The Saudi Riyal has been pegged to the US dollar and has been constant at SR3.75 per US dollar since 1999. The US dollar's weakening condition is accordingly shared by the Saudi Riyal. In fact, both the SAR and the UAD have depreciated by approximately 31.1 percent against the Euro since it began its meteoric ascend against the dollar in 2002.

In the light of existing empirical findings,[16] such depreciation implies a transmission rate in the order of nine percent (0.3*0.31). So the effect of greenback depreciation translates into an increase in the inflation rate in the order of 10 percent, which is significant.

Our rudimentary estimates of the "pass through" above are smaller than estimates gleaned in other, mostly advanced, economies. For example, in the OECD countries as a whole, a 1 percent change in the exchange rate will, on average, generate a 0.64 percent change in import prices over the course of a year, although there is wide variation around this mean. For the Euro area, the average pass-through rate is substantially higher at 0.81. Estimates of pass-through for Japan differ considerably, but the rate is usually found to be high and close to complete. By

Figure 7: GCC Currency Depreciation Against the Euro



Source: Pacific Exchange Rate Service

contrast, for the United States over this three-decade period, a 1 percent change in the exchange rate has, on average, yielded only a 0.42 percent change in import prices.[17]

Modeling Bust Transmissions: From Global to Arab Economies

In order to firm up our understanding of the likely transmission channels between global recession and Arab economies, we utilized a formal econometric framework. The specific objective is to estimate the possible contagion effects between the occurrence of growth and recession spells in the US, Europe, and Asia (China) and likely transmission into countries within the Arab and MENA economies. The time span of the analysis spreads over the period 1970 to 2007, and the data sources are those of the United Nations and EIU. Based on existing literature and contemporaneous dynamics developments, as well as lessons gleaned from the econometric modeling, the paper provides an assessment of future economic outlook in the MENA region including Arab economies.

Given the rapidly changing economic landscape, we attempt to glean lessons from past global recessions in terms of incidence on our economies. Because of various data limitations, our analysis focuses on the interactive role of a small set of variables only. These are briefly summarized in Figure 8.

Estimation was performed on pooled data that spans over 1970-2007 for 24 countries including advanced economies (US, UK and Germany), emerging economies (China, S. Korea) and Arab economies. Model varieties included the random-effect model (Population-Averaged Model) and dynamic pooled model (Arelleno Bond Method).

Beyond basic statistics, we estimated the parameters of two models: the dynamic panel data growth model and the random-effect panel data growth model. The models were estimated using all observations for all twenty-four countries that comprise our sample. Three advanced economies – the US, Germany and the UK – are included in the sample. As well, the sample includes the emerging economies of China, India, S. Korea, N. Korea, Turkey, Iran, and Israel.

The empirical findings, summarized in Tables 1 and 2, are briefly discussed here. Because the dynamic panel data model (the Arelleno and Bond dynamic method) is more comprehensive, our discussion focuses mainly on findings of that model (Table 1).

First, in conformity with findings from a large body of literature, oil prices invariably exert growth impact. The relevant coefficients in the whole sample of countries indicate that the current and lagged oil prices do matter a great deal for growth in Arab economies.

Figure 8: Growth and Bust Causality – Global to MENA, 1970-2007

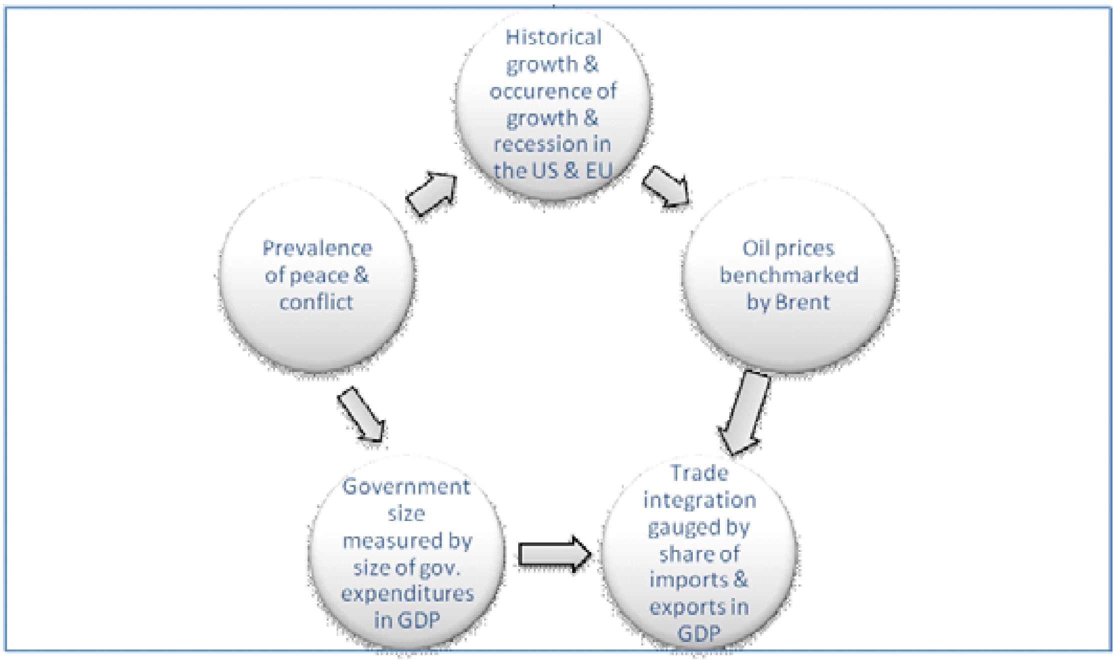


Table 1: Regression results of the Random Effect Pooled Probit Model: (Whole Sample)

Variable	Coefficient	Std. Err.
Lag of oil price	0.027	0.011
Lag of oil lag	-0.038	0.01
Conflict = 1	-0.014	0.006
Trade integration	-0.13	0.028
Trade integration lag	0.137	0.028
Investment-share	0.107	0.036
Intercept	0.052	0.016
sigma_u	0.013	
sigma_e	0.087	
Rho	.022 (fraction of variance due to u_i)	
Number of observations	864	
Number of groups	24	
Wald chi2(6)	59.43	

As well, our findings indicate that economic growth in the Arab economies is positively influenced by economic growth in the US but the growth effect of Germany is less marked, as gleaned from the size and sign of the relevant coefficients. A third finding pertains to the effect of openness to trade and hence exposure to international economic cycles. Specifically, we find that trade integration reinforces growth; that is, countries grow faster when they trade more intensively with one another. This is probably due to the effects of the transfer of technology and know-how that is associated with trade linkages and flows.

Table 2: Dynamic Panel Data Growth Model Summary Results: (Arellano-Bond Method)

Variable	Coefficient	Std. Err.	Z- Value
Growth L1	0.099	0.035	2.86
Log oil price	0.040	0.011	3.5
Log oil price L1	-0.044	0.010	-4.2
US Growth	0.461	0.205	2.24
US Growth L1	-0.413	0.184	-2.25
Germany growth	-0.284	0.234	-1.21
Germ. growth L1	0.509	0.240	2.12
Conflict	0.020	0.007	-3.12
Trade integration	0.038	0.018	2.11
Investment Share	0.034	0.058	0.58
Government Size	-0.394	0.091	-4.33
Constant	0.121	0.029	4.22
N 816			
Number of groups 24			
Wald chi2(6) 77.48			

**The model is estimated using the Arelleno and Bond dynamic method.*

The sign and size of that variable gauging "government size" is noteworthy and supports the hypothesis that large governments might stall or at least decelerate economic growth. Our findings here agree with empirical economics which show that large-size governments tend to be associated with marginalizing the private sector through a combination of excessive bureaucracy and "crowding-out" effect. Beyond that, large government size might hinder economic growth through increased bureaucracy and perhaps corruption.

Arab Economies and Financial and Energy-Related Risks

One of the lessons learnt from the global financial crisis is that financial and economic models based on presumptions of rational behavior are appealing but inherently false; they have blinded risk managers and regulators alike.[18] Specifically, our human behavior is often premised on assumptions and perceptions. For instance, while driving, people usually make all sorts of assumptions about the overall mechanical health of their vehicles, the safety of the roads, the behavior of fellow-drivers, as well as the behavior of pedestrians and commercial and other vehicles. Most of these assumptions are not tested and when some or all prove wrong, accidents result with exorbitant costs of time, finances, and human loss.

Likewise, economists are particularly fond of assumption-making. For example, they invariably assume that the invisible hand has a "corrective balancing power" – that individuals and managers behave rationally and in an "expected" manner to maximize corporate and social profit. Such assumptions were considered "articles of faith". But the global crisis changed matters. Now a good many economists consider human behavior as *fundamentally irrational*. In other words, irrationality is the real invisible hand that drives human decision making.[19] And economists are not the only ones whose faith is shattered: a recent poll indicates that just 38 percent of self-described informed adults in the United States trust business, a decline of 20 percentage points from the previous year, and the lowest level of trust in a decade. In another survey, conducted online by Public Strategies and Politico, 61 percent of respondents said they believe federal regulation of business should be increased. Armed with knowledge that human beings are motivated by cognitive biases of which they are largely unaware (a true invisible hand if ever there were one), businesses can start to defend better against foolishness and waste. The emergent thinking suggests that the market will not produce the desired results on its own, giving rise to the regulatory role of government: Government will be less interested in barring corporate actions that might possibly harm the public and are more inclined to reward actions that will almost certainly help. The new regulatory paradigm will involve a close working relationship between government and business, but one sufficiently consistent and transparent to maintain public trust while addressing the challenges at hand and motivated by unconscious biases.[20]

Changing economic models and altered perceptions of human rational behaviour – as well as the changing companion role of governments – surely have important ramifications to the Arab economies and societies *where institution-building is still nascent*. Accordingly, existing economic institutions have fairly "youthful" experience; well-established economic and social institutions are far from complete, let alone mature. It will take time and concerted efforts in order to alter whatever exists in order to satisfy the needs of the new paradigm of behavior and the emerging role of government.

Natural Environment and the Greengas Emission

The natural environment and the Greengas emission represent new risks that threaten the livelihood of the Arab economies in two ways. The first is exorbitant tax rate policies that are levied on oil at the importing and consumption gates of the oil-importing countries. These taxes enable governments, especially of the advanced consuming countries, to realize nearly as much "oil-taxed money" as governments of the oil-exporting countries themselves. In other words, oil becomes an important fiscal revenue source to all governments: in the oil-consuming as well as the oil-producing countries.

Second, the economies of the Arab region tend to be adversely affected from the vast hydrocarbon supply chains that crowd the environment. In the absence of effective and enforceable legislation to cut back on emissions from older vehicles, particularly those that run on diesel, the environmental imprint is multiplied in the Arab region.

Globally, the agenda to combat emissions is moving front and centre. The December Copenhagen Climate Change Summit will work towards an agreement to cut back greenhouse gas emissions for decades to come. The most efficient step to implement that goal would be a massive shift away from fossil fuels to clean, renewable energy sources. As well, former US vice president Al-Gore threw down a gauntlet: to repower America with 100 percent carbon-free electricity within 10 years. Even more ambitious is the goal of some research that seeks to satisfy all global energy needs for all purposes from wind, solar and water.[21]

Who is Advancing? Answer: The Renewable Energy Technologies

As the world's attention has been fully centered on the financial and economic downturn and recovery, fundamentally, the Arab region has an additional concern: the penetration of new and renewable energy sources and the future of oil and natural gas on the global energy scale. While fossil energy supplies are plentiful, technological progress and innovations might deem these "technologically obsolete". To be sure, technological and delivery systems for renewable energy have improved dramatically. Many countries are even factoring environmental investments into their economic stimulus packages – especially in Asia where over a third of China's recovery spending is being focused on infrastructure plus energy efficiency and renewables while almost 80 percent of Korea's $31 billion package is aimed at promoting energy efficient buildings and water and waste management and investments in renewable energy, low emission vehicles and railways.[22] Last year, for the first time, a worldwide private investment in renewable power was greater than that of in fossil-fuel power.[23] Overall, governments across the globe are pledging $163bn on programs to promote renewable energy.[24] As well, China plans to generate 401 gigawatts (or 36 percent) of electricity via renewable energy by 2020.[25]

Less known, however, is the fact that raw materials used to produce renewable energy are heavily concentrated. For instance, metals like yttrium and lanthanum – essential for everything from hybrid cars to iPods to precision-guided weaponry – are heavily concentrated in China which currently produces 95 percent of the world's supply and holds 60 percent of global reserves. These metallic elements happen to be essential to many emerging green technologies; they are essential to electric vehicles, carbon–monoxide reduction, and the high performance metallurgy behind wind gearboxes. They are also a key component in Toyota's famous green car, the Prius[26] which first went on sale in Japan in 1997, making it the first mass-produced hybrid vehicle. It now sells in more than 40 countries and regions.[27]

In order not to be left behind, some Arab countries are investing in renewable and new energy technologies. For instance, the UAE aims to generate 7 percent of its power from renewables by 2020 while state-owned Masdar is looking towards a renewable energy market valued at $6-

8bn. In the Maghreb, Morocco seeks to produce a fifth of its electricity from renewable energy sources by 2012 while Algeria aims to raise the percentage of its energy mix coming from solar power to 5 percent by 2010 with one of the biggest projects a 150 MW hybrid solar combined-cycle power plant in northern Algeria, linking solar thermal technology to a conventional power plant.[28] Egypt plans to invest €50 million received from the European Investment Bank in a wind farm project on the Red Sea and the country aims to generate 20 percent of its power from renewable sources by 2020.[29] Under Jordan's national energy strategy, the Kingdom is looking to produce 600 MW of wind and 300-600 MW of solar energy by 2020. Further, the EDAMA Initiative, a private sector partnership, seeks innovative solutions for energy and water independence as well as establishing new renewable energy production companies. Moreover, bids are currently under evaluation to construct a wind farm with cost of $150mn.

Global Crisis Reverses Fiscal Euphoria

The financial crisis, with its demand destruction, directly reduced the revenue takes of the oil-based economies, primarily the GCC, Algeria and Libya but also other oil exporters such as Egypt, Syria, Yemen, and the Sudan. There were other forces that contributed to reversing the fiscal euphoria and plunged some Arab economies into the red. Salient amongst these were the high spending patterns and the inflexible nature of public spending. Because of the large historical state role in the region, the state was considered employer of last resort. The state provided employment opportunities for high school and university graduates in the GCC, Egypt, Jordan, and Yemen amongst others. The wage bill, while rising, was difficult to restrain during the downturns, for how could governments refrain from paying wages to their public servants?

There were other associated forces as well. For instance, Dubai, which embarked on the construction of fancy bridges and skyscrapers to outclass Singapore or Las Vegas. To build that second-to-none real estate infrastructure, the city had to rely on international funding which, as the crisis penetrated, saw debt soar to as much as $90bn, or 126 percent of GDP – much of it in short-term bonds and loans from the world's top banks. Dubai could get away with so much borrowing as long as real estate and other asset prices kept rising. But the crash occurred and property prices have fallen by as much as 48 percent.[30] While uncertainty surrounds Dubai's debt position, especially the debt of government-related entities such as Dubai World, the fact of the matter is Dubai's debt is backed by the UAE central bank which has ample reserves to pay back debt obligations.

This said, the recent increase in oil prices over Q2 and Q3 of 2009 have changed the prospects of fiscal budgets, especially in oil exporting Arab countries. Saudi Arabia, to cite one example, is likely to see a small budget surplus in 2009 compared to the projected budget deficit, due to a successful public spending scheme and higher-than-expected oil prices.[31]

Portfolio Strategy at Risk: Oil, Global Capital Markets and Sustainable Growth

Conventional wisdom holds that the long-term strategy of the Arab economies is as follows: continue the extraction of finite hydrocarbon resources, invest surplus revenues in the global financial markets, and use investment returns to build up domestic human capital that can shoulder the responsibility of implementing sustainable economic growth over the long term. Several countries in the region have in essence followed this long-term strategy, notably Kuwait and the rest of the GCC countries. To a lesser extent the strategic paths of Algeria and Libya have also been in line with this paradigm. The strategy makes a fundamentally critical assumption about the diversity of oil and finance: it assumes that such portfolio diversity produces desirable outcomes in terms of mitigating overall portfolio volatility, saving the Arab economy from the ravages of highly volatile oil market investments alone. More specifically, the strategy assumes that returns on investments in international capital markets are basically safe with negative covariance with oil markets investments. Hence *oil and financial market investments* are seen as an efficient portfolio strategy whose returns are subject to reasonably low risks that can be managed and mitigated. However, this assumption was proven fatally wrong in light of the global financial crisis of 2007-2009.

The crisis has reminded the world of something we should have known all along: international capital markets are subject to major and unpredictable risks and are surrounded by tremendous uncertainties. The new fundamentals call into question the very essence of the long-term strategy of converting hydrocarbon resources into investment funds. Accordingly, major revisions are required of the Arab strategic developmental path that satisfactorily alter it in a manner that successfully takes into account standard and emerging global risks. These include not only financial risks but also risks of potential future global oil demand destruction – demand destruction caused by economic downturns and the dynamics of new and renewable energy technologies. Finally, at risk is nothing less than the very future of Arab children and future Arab generations.

Conclusions

In addition to significant oil demand destruction, the global financial crisis has caused a setback to the growth momentum in the oil-based Arab economies. Global trade, capital flows, and regional and international FDI are declining. With a depreciating greenback, the Arab currency peg to the dollar is again in focus; this might renew strong inflows of speculative investor money and thereby invite monetary authorities to intervene. Risks are also emerging in the areas of new and renewable energy technologies which made substantial inroads over the past few years. These risks, in tandem with the financial risks that the global crisis posited, have important implications for the very long-term strategic vision of sustainable development in the Arab, especially GCC, economies.

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