3 Energy

3.1 Overview

The imporance of energy has now been widely recognised in relation to the traditional factors of production, namely land, labor, capital and entrepreneurship. With modernization, production processes have become heavily dependent on energy, and sustainable economic growth cannot be achieved without sufficient and uninterrupted supply of energy. Therefore, it is imperative for a developing country to explicitly concede the importance of energy in pursuit of sustainable growth.

In Pakistan's case, growth potemtial seems to have hit a ceiling imposed by insufficient energy supply. Whereas energy demand has increased significantly during the last ten year period, supply has failed to match this growth due to policy failures with respect to: (a) setting up viable new power projects to augment supply line; (b) increasing exploration of natural gas, crude oil and coal; (c) tapping regional markets and setting up infrastrucure for energy imports; and (d) incentivizing development of renewable energy sources.

While failure to articulate a consistent energy policy has affected the country's economic performance over an extended period, the recent resurgence of circular debt has presented new challenges. Circular debt has emerged due to nonpayment of electricity subsidies by the government, default on payments by energy consumers, and build-up of payables and receivables within the energy sector.[1] In May 2011, the government disbursed Rs 120 billion to PEPCO in lieu of outstanding subsidy payments; however, this amount was not sufficent to resolve the issue conclusively, and total circular debt had reached to Rs 251 billion by end-June 2011.

In addition to the circular debt issue, the shortage of natural gas intensified during FY11 which severely affected power generation as well as overall industrial production (particularly of textiles and fertilizer). The supply shortfall of natural gas ranged between 10 to 15 percent of demand. Curtailment of gas supply to KESC and a select number of IPPs affected generation during the winter season, whereas bottelnecks in furnace oil (FO) imports disrupted power generation at the onset of summer.

Similarly, domestic production of crude oil and POL products also fell short of demand, requiring imports of US$ 12.3 billion in FY11.[2] Nearly 70 percent of crude consumption and 55 percent of POL consumption is met via imports. This dependence on imported oil makes the economy vulnerable to price shocks in the international oil market.

Going forwards, energy requirements shall continue to increase if economic growth is to be sustained. Urgent efforts are being undertaken to set up infrastructure for import of natural gas as well as generation of electricity. However, the public sector's ability to finance and execute projects is constrained by low tax revenues, creating a gap which only participation from the private sector and international institutions can bridge.

[1] These entities include suppliers of primary energy (i.e., oil and gas exploration and distribution companies) and electricity generation and distribution companies.
[2] POL denotes Petroleum, Oil and Lubricants.

While augmenting energy supply is crucial, managing demand across economic agents in an inclusive manner has also become very necessary. At present, the household sector is prioritized in terms of both tariff and quantity supplied of electricity and natural gas. This balance needs to be changed in favour of businesses and industries in the interest of sustainable economic growth. Therefore, policy makers must urgently weigh the impact on the country's industrial base versus appeasing the common man in deciding allocation and pricing of domestic energy supplies.

3.2 Electricity

The power sector in Pakistan has been facing several challenges for many years. Despite institutional restructuring in the recent past, efficiency in the provision of electricity to end-users has not improved significantly. The main institution entrusted to manage the power sector in 1959 was the Water and Power Development Authority (WAPDA). In an attempt to remove inefficiencies in the sector, this entity was restructured in 2007. While WAPDA still controls hydropower development, thermal generation, transmission and distribution have since been transferred to Pakistan Electric Power Company (PEPCO). Presently, the Central Power Purchase Agency (CPPA) at PEPCO coordinates payments between four generation companies (GENCOs), a National Transmission and Dispatch Company (NTDC) and ten distribution companies.[3]

Table 3.1: Energy Balances in the Power Sector (GWh)

	FY06	FY07	FY08	FY09	FY10	5-Year CAGR (percent)
Installed Gross Capacity *(MW)*	**19,450**	**19,419**	**19,420**	**19,785**	**20,921**	**1.8**
WAPDA - Hydropower	6,499	6,479	6,480	6,481	6,481	-0.1
GENCOs	4,900	4,900	4,900	4,900	4,900	-
KESC	1,756	1,756	1,756	1,955	1,955	2.7
IPPs	5,833	5,822	5,822	5,987	7,123	5.1
Nuclear	462	462	462	462	462	-
Net Supply *(GWh)*	**90,109**	**94,624**	**92,142**	**89,765**	**93,304**	**0.9**
A. Total Generation	93,629	98,213	95,661	91,615	95,358	0.5
WAPDA - Hydropower	30,862	31,953	28,707	27,784	28,093	-2.3
GENCOs	22,508	21,597	20,427	19,521	19,593	-3.4
KESC	9,130	8,169	8,219	8,262	7,964	-3.4
IPPs	28,645	34,206	35,231	34,431	36,814	6.5
Nuclear	2,484	2,288	3,077	1,617	2,894	3.9
B. Auxiliary Consumption	-3,463	-3,623	-3,688	-2,067	-2,260	-10.1
C. Net purchases from PASMIC*	-203	-137	-30	-10	-43	-32.2
D. Imports	146	171	199	227	249	14.3
Consumption *(GWh)*	**67,603**	**72,712**	**73,400**	**70,372**	**74,349**	**2.4**
Agriculture	7,949	8,176	8,472	8,796	9,689	5.1
Bulk Supplies	3,985	4,246	4,342	4,177	4,418	2.6
Commercial	4,730	5,363	5,572	5,252	5,606	4.3
Domestic	30,720	33,335	33,704	32,282	34,272	2.8
Industry	19,803	21,066	20,729	19,330	19,823	0.0
Other	417	527	581	536	541	6.7
T&D Losses	**22,506**	**21,912**	**18,742**	**19,396**	**18,957**	**-4.2**
as % of Net Supply	*25.0*	*23.2*	*20.3*	*21.6*	*20.3*	-

* Pakistan Steel Mills Complex

Source: Hydrocarbon Development Institute of Pakistan

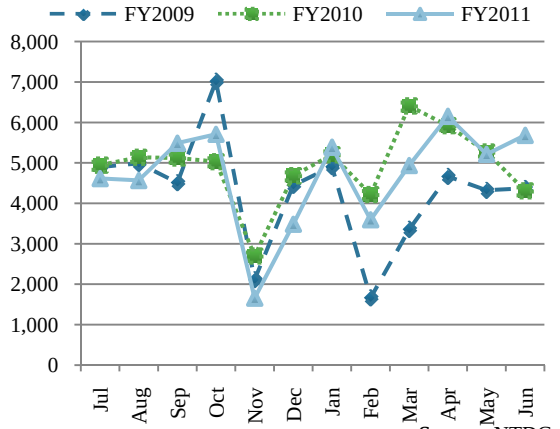
[3] GENCOs include Northern Power Generation Company, Central Power Generation Company, Jamshoro Power Generation Company and Lakhra Power Generation Company. Key distribution companies (DISCOs) are located in Karachi (KESC), Lahore (LESCO), Faisalabad (FESCO), Gujranwala (GEPCO), Hyderabad (HESCO), Islamabad (IESCO), Multan (MEPCO), Peshawar (PESCO), Quetta (QESCO) and Sukkur (SEPCO).

As of FY10, GENCOs accounted for 23 percent (4,900 MW) of gross installed capacity, and another 31 percent (6,481 MW) was being operated by WAPDA for hydropower generation (**Table 3.1**). However, output from hydropower generation fluctuates throughout the year, since majority of installed capacity is reservoir-based. Meanwhile, actual availability from GENCOs has declined substantially below rated capacity over time due to mismanagement of fixed capital and lack of investment in new power plants.

Participation by the private sector has been encouraged, but the generation mix has not been actively managed. Under the 1994 Power Policy, a large number of independent power producers (IPPs) entered the market, adding generation capacity that was based primarily on furnace oil. This trend continued over the past decade as additional incentives were provided to the power sector under the 2002 policy. The downside of this policy is that generation costs for thermal IPPs can be high, and their share in the generation mix now exceeds that of hydropower generation (34 percent). About 75 percent of these plants operate on furnace oil, whereas the remaining plants require natural gas for generation of electricity. Therefore, generation costs of electricity are now exposed to fluctuation in global oil prices, since dependence on imported furnace oil has increased over time.

Furthermore, distribution companies (DISCOs) have not been operated in a sustainable manner. Specifically, DISCOs have not been authorized to pass generation costs fully through to consumers; revenue collection from consumers (particularly from the public sector) has deteriorated over time; and, finally, electricity losses due to inadequate or ageing infrastructure as well as theft have increased unchecked. As of FY10, up to 20 percent of net electricity supply was being claimed by inefficiencies throughout the distribution sector, in the form of transmission and distribution (T&D) losses.

Figure 3.1: Monthly trend in peak load management (MW)



Source: NTDC

Due to these developments, peak load management has increased tremendously during recent years, from 2,645 MW in FY07 to a level of 6,151 MW recorded in FY11. Load management typically peaks annually with the onset of the summer season since electricity demand rises sharply (**Figure 3.1**). Electricity shortages also tend to increase during winters, despite low seasonal demand, since generation is affected by gas supply curtailments and low reservoir levels in large dams.

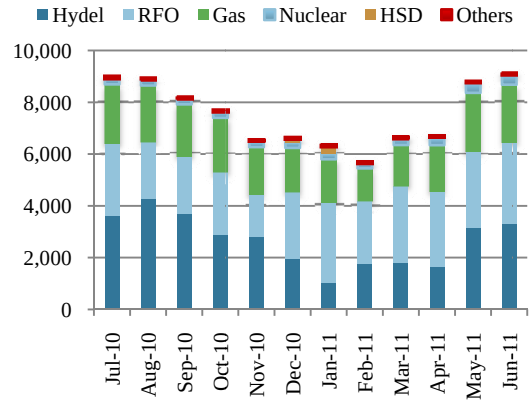
Table 3.2: Trend in Peak Electricity Demand, Generation and Load Management (MW)

	FY07	FY08	FY09	FY10	FY11	5-year CAGR (percent)
Peak Demand Load	15,838	17,398	17,852	18,467	18,511	4.0
Peak Generation Load	13,645	14,151	14,055	14,309	14,468	1.5
Peak Load Management	2,645	5,454	7,018	6,408	6,151	23.5
% of total demand	*16.7*	*31.3*	*39.3*	*34.7*	*33.2*	-

Source: PEPCO

Official figures suggest that the demand-supply gap for electricity decreased during FY11 (**Table 3.2**). This improvement, however, was only marginal. According to official figures,[4] the average shortfall during the off-peak season (August – February) stood at around 3,000 MW in FY10 versus 2,500 MW in FY11. The shortage during the peak season (March – July) stood at about 3,800 MW in FY10 as against 3,300 MW in FY11. To this effect, urban load shedding has averaged between 4-6 hours during FY11, and peaked at 10 hours on average during April 2011. The incidence of load shedding in rural areas has been substantially greater by comparison, with supply interruptions frequently exceededing 10 hours since March 2011.

Figure 3.2: Monthly electricity generation (GWh)



Source: PEPCO

These issues ultimately boil down to lack of incentives to be efficient in the public sector. Long term planning has been deficient whereas public sector generation, transmission and distribution infrastructure has not improved significantly.

Finally, the financial implications of these challenges have come to bear strongly in recent years in the form of circular debt. In our view, resolution of circular debt is inextricably linked with creating a culture of self-sustainability within DISCOs, for which public sector presence may need to be phased out in a gradual manner whilst strengthening the regulatory environment. Based on KESC's experience with labor unions during FY11, accomplishing this in practice may be extremely difficult, since vested interests must be overcome first.

Power generation during FY11

As of June 2011, total electricity generation stood at 90,489 GW, indicating that overall generation for the full year declined by 5 percent as compared to FY10 (**Figure 3.2**). Whereas hydropower generation for FY11 exceeded full year supply in FY10 by at least 14 percent, generation from thermal power plants operating on gas and furnace oil declined by 18 percent and 11 percent respectively, largely due to unavailability of primary energy supplies (gas and FO).

Supply side constraints

The primary cause of extended load management is the generation constraint. Specifically, whereas maximum generation capacity in the country stood at 21,591 MW in June 2011 (excluding KESC),[5] dependable generation capacity as determined in February 2011 by the Ministry of Water and Power was significantly lower, at around 10,184 MW as seen in (**Annex Table 3.11**). The main reasons for this difference are: (a) seasonal fluctuation in generation capability of hydropower plants – such as Tarbela (3,478 MW) and Mangla (1,000 MW); (b) insufficient supply of gas to thermal power plants from SNGPL / SSGC; (c) insufficient and

[4] Press reports paint a different picture. On 5th May 2011, official figures noted load management of 5,890 MW, while media reports noted a shortfall of 7,200 MW, due in large part to fuel shortages. Although the daily furnace oil requirement for power generation is in excess of 30,000 tons, oil companies were forced to ration 11,000 tons on a daily basis amongst power producers, since circular debt had affected POL imports at the time. Differences in reported versus official figures may arise depending on the time of day at which electricity generation is measured.

[5] Due to decommissioning of old plants, dependable capacity at KESC stood at 1,821 MW in June 2011.

irregular furnace oil supply to thermal power plants; (d) frequent forced outages for GENCOs due to capacity degradation; and (e) scheduled outages for inspection / maintenance of equipment and replacement of parts of existing plants.

The supply-side response to address electricity shortages has been to commission new power plants. To this end, 1,602 MW of new capacity was added by the private sector during FY11, of which 852 MW was based on gas. With this, total generation capacity directly or indirectly dependent on gas has increased to 7,221 MW, which requires 1,571 mmcfd of gas.[6] However, actual supply of gas to the power sector had dropped to 1,005 mmcfd by FY10, and has not improved appreciably this year.

Furthermore, new power plants also required furnace oil for operation, which had to be met through imports. However, imported supplies of furnace oil were disrupted in April 2011, when circular debt receivables reached unsustainable levels for OMCs. Based on anecdotal evidence, furnace oil supply may have declined to 30 percent of the daily requirement for thermal generation to this effect.[7]

It is therefore, clear that policy response to supply side issues were not well-conceived and large part of newly installed capacity remained idle, placing additional financial burden on the economy.

Proposed demand-side measures

The extent of seasonal variation in demand is fairly high in Pakistan since the domestic household and agriculture sectors together account for about 60 percent of total consumption. Demand from these two sectors is heavily dependent on seasonal requirements (**Table 3.3**). This also contributes considerably to the rising incidence of electricity shortages in summer. In FY11 alone, demand varied by over 7,400 MW, from a minimum level of 11,081 MW in November 2010 to a peak of 18,511 MW during June 2011.

Table 3.3: Consumption Mix of Electricity by Province and Sector – FY10 (percent)

Sector	Punjab	Sindh	KPK	Balochistan	AJK	Grand Total
Agriculture	6.8	1.2	0.5	4.5	0.0	13.0
Bulk Supplies	3.5	1.7	0.7	0.1	0.0	5.9
Commercial	4.7	2.0	0.7	0.1	0.1	7.5
Domestic	28.0	9.3	7.3	0.6	0.8	46.1
Industry	18.3	6.1	1.9	0.2	0.1	26.7
Other	0.3	0.3	0.0	0.0	0.1	0.7
Grand Total	61.7	20.6	11.1	5.5	1.1	74,349 GWh

Source: Ministry of Water and Power

Hence, the primary short-term response towards load management is to implement demand-reduction measures. In FY10, the government implemented an Energy Saving Plan to this end and was successfully able to reduce consumption by approximately 1,300 MW. Some of the key measures to feature in the plan were reduction of the work week, early closure of commercial areas and shifting towards daylight savings time. Similar demand-management steps were under consideration for FY11, resulting in potential savings of 1,000 - 1,100 MW (6 percent of total

[6] The unit mmcfd denotes gas flow of a million cubic feet per day.

[7] With the existing consumer base, the daily furnace oil requirement is approximately 30,000 MT as per the Ministry of Petroleum and Natural Resources. As against this requirement, daily supply allegedly declined to 11,000 MT in early May-2011. PSO's existing fuel supply agreements with power companies ensure supply availability for the next 5 to 10 years, but renegotiation may be affected due to non-clearance of circular debt.

demand in FY10), but consensus on implementation was only reached recently in October 2011, well after the peak demand period had passed.

3.2.2 Circular Debt

The stock position of circular debt receivables deteriorated considerably during FY11 (**Table 3.4**).[8] The impact of higher oil prices on electricity subsidies was somewhat muted, since fuel cost variations have been directly adjusted in consumer tariffs from August 2010 for ex-WAPDA distribution companies. However, generation costs increased considerably due to higher utilization of furnace oil in the generation mix, owing to gas shortages and low water availability during the winter season. Consequently, in the backdrop of poor revenue collection and operational inefficiencies in distribution companies, circular debt has also increased with severe ramifications for downstream energy sector companies. By end-June, it was estimated to have reached Rs 251 billion.

Impact on the energy sector

Receivables of electricity distribution companies falling under PEPCO crossed Rs 300 billion, but were passed completely through to upstream sectors. Therefore, as of end-April 2011, net receivables were unsurprisingly concentrated in the POL exploration, refining and distribution sectors. Companies with the greatest share of circular debt were OGDC, PSO and PARCO. Whereas accumulating interest payments eroded profitability across the board, the operational implications for POL distribution and power generation were more severe.[9]

In particular, PSO's ability to honor L/C payments was jeopardized as receivables reached unsustainable levels in April 2011, and imported supplies of HSD and furnace oil were temporarily choked. The resulting fuel shortfall for power generation companies could not be bridged in the short-term, leading to aggressive load management. Capacity utilization in GENCOs – which constitute 4,900 MW of installed capacity – subsequently declined to 23 percent in May 2011.[10]

Table 3.4: Distribution of Circular Debt Receivables (billion Rupees)

Company	Receivables	Payables	Net Position		Change
			30-Apr-11	30-Apr-10	
PSO	149	98	51	30	21
SSGCL	51	44	7	-1	8
SNGPL	11	25	-13	-9	-5
PEPCO	304	302	3	-40	42
OGDCL	116	0	116	80	36
PARCO	38	-	38	30	8
KESC	68	40	28	-24	51
GHPL	10	-	10	11	-1
PPL	22	-	22	26	-4
KW&SB	7	8	-1	0	-1
Grand Total	**775**	**517**	**259**	**104**	**155**

Source: Ministry of Finance

[8] Our estimates incorporate the difference between receivables and payables for companies in the energy sector that are fully or partially owned by Government of Pakistan. As such, figures quoted in parliament and the print media are much larger since they include private sector receivables as well.

[9] As companies are deprived of liquidity due to increasing receivables, reliance on short-term bank borrowing has increased tremendously. Secondly, interest is also accrued on overdue receivables from other companies.

[10] Anecdotal evidence suggests that the actual daily furnace oil supply dropped as low as 2,000 MT versus a requirement of approximately 30,000 MT, leaving furnace oil based plants to rely on inventories to meet deficit requirements or operate well below capacity.

Similarly, electricity generation from thermal IPPs also declined, extending the shortfall by another 2,000 MW. Private power producers in particular continue to be weighed by circular debt. As PEPCO's financial position deteriorates, delayed payments to private power companies have perpetuated the generation shortfall. To this effect, four furnace-oil based IPPs invoked sovereign guarantees in June 2011 for settlement of outstanding receivable claims against PEPCO. Whereas the required disbursement was subsequently made, the key issue of regularizing payments to private power producers is still outstanding. If this issue is not resolved urgently, other IPPs are likely to follow suit.

Issues that need to be addressed

Presently, key issues pending resolution are removal of electricity subsidies,[11] weak revenue collection and line losses amongst distribution companies. Furthermore, escalation in generation costs needs to be managed in the medium-term by inducting cheaper fuels into the generation mix.[12]

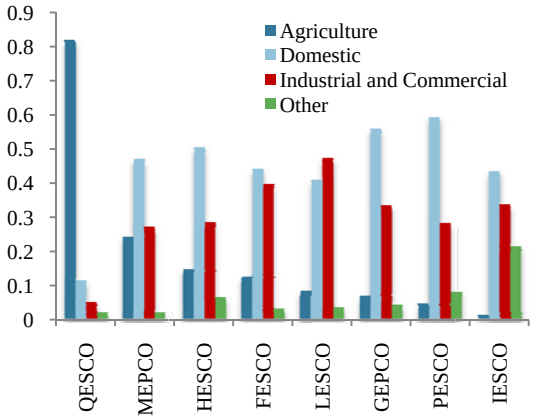
a) **Electricity subsidies:** Subsidies payable by the government during July-March FY11 had accumulated to Rs 119 billion, equivalent to a monthly increase of Rs 13 billion. As of March 2011, the subsidy paid by the government per unit of electricity consumed stood at Rs 1.99/kWh.[13]

   When the price paid by consumers for using electricity is less than the cost of generation, a subsidy equal to the difference must be paid to utility companies by the government. However, if these payments are not made regularly, the stock of circular debt increases.

   This subsidy varies for each distribution company, and for each category of consumer. Although consumer tariffs have been increased since July 2010, generation costs have also increased, and the subsidy element remains active in contributing towards circular debt.

b) **Revenue collection:** Another underlying issue giving rise to circular debt is insufficient revenue collection by distribution companies. As seen in **Table 3.5**, overall revenue is insufficient to cover the cost of electricity supplied to consumers. Revenue collection cannot be improved easily for companies where the sales mix is skewed towards the agriculture and domestic sectors, or to the government (Error! Reference source not found.Error! Reference source not found.**Figure 3.3**). Based on the annual revenues in FY10,

Figure 3.3: Sales-mix for distribution companies (FY10)



Source: DISCOs

[11] These subsidies amount to the differential between generation cost determined by NEPRA and consumer tariffs notified by the government.

[12] As generation costs increase, the gross payments to be made to fuel suppliers and IPPs for purchase of power by PEPCO increase proportionately, thereby leading to a growth in circular debt receivables. Secondly, in an environment where consumer tariffs are centrally administered, escalation in generation costs widens the tariff differential or subsidy on electricity as well.

[13] As quoted by the Ministry of Water and Power during the National Assembly Session held on 22nd April 2011.

estimates suggest that the monthly impact of weak revenue collection on circular debt stock is Rs 4 billion.

c) **Line losses:** As of FY10, Transmission and distribution (T&D) losses ranged between 11- 37 percent amongst public distribution companies (**Table 3.5**). T&D losses affect the payables and receivables for utility companies.[14] Estimates suggest that T&D losses contribute Rs 8 billion to circular debt on a monthly basis.
The severity of the problem may be gauged by examining non-technical distribution losses, which indicate that improving distribution infrastructure can only solve part of the problem. The larger issue of electricity theft is therefore likely to increase as subsidies are phased out, leading to an increase in circular debt. The challenge is greatest for QESCO where, as per official statements, there are around 5,000 illegal tube-well connections leading to an annual revenue loss of Rs 4 billion.

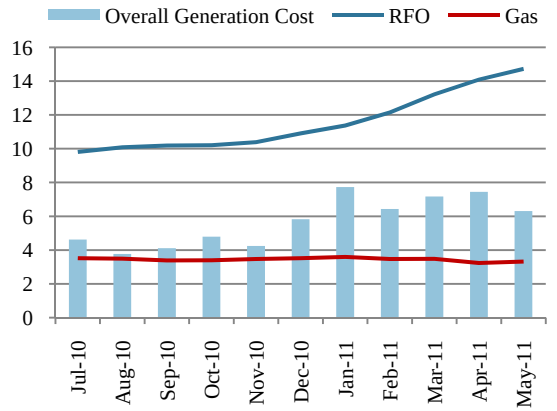
Table 3.5: Revenue Collection and Composition of T&D Losses for the Public Sector – FY10

Distribution Company	**Revenue Billed** (Rs mln)	**Collections Rate** (percent)			**T&D Losses** (percentage of sales)			
		Private Consumers	Government Clients	Overall	Non-Technical Loss	Total Distribution Loss	Transmission Loss	Overall
HESCO	45,945	59.8	72.5	18.2	22.2	31.2	3.6	34.8
QESCO	24,044	75.6	77.0	60.8	3.7	14.2	6.5	20.7
PESCO	38,016	85.4	84.2	53.8	19.2	32.6	4.5	37.1
LESCO	117,297	93.2	94.7	73.5	6.3	11.5	2.3	13.8
MEPCO	72,150	94.2	84.9	52.9	6.4	15.0	4.0	19.0
GEPCO	48,137	95.7	93.9	52.0	5.3	10.2	0.9	11.1
IESCO	60,433	95.9	98.4	83.2	0.9	7.8	2.0	9.8
FESCO	63,537	97.0	96.7	51.3	2.6	9.7	1.1	10.8

Source: Ministry of Water and Power, USAID

d) **Generation Costs:** The overall cost of generation depends heavily upon furnace oil prices, since furnace oil accounts for 35 percent of the monthly generation mix on average. During FY11, the overall cost of electricity generation has increased by roughly 36 percent since per unit furnace oil costs have increased this year, from Rs 9.81/KWh in July 2010 to Rs14.73/KWh by May 2011 (**Figure 3.4**). Escalation in generation costs exerts upward pressure on consumer tariffs, which may worsen revenue collection rates. Alternatively if consumer tariffs are held constant, electricity subsidies increase in proportion to generation costs. In either scenario, circular debt receivables tend to increase.

Figure 3.4: Generation costs during FY11 (Rs./KWh)



Source: PEPCO

[14] Transmission losses occur as electricity is purchased from power producers, resulting in payables exceeding the value of electricity available for sale to consumers. Distribution losses subsequently lead to lost revenue from consumers, resulting in an increase in receivables. These may be further subdivided into technical losses, which depend on the quality and scale of the distribution network, and non-technical losses arising from theft, poor administration and weak commercial oversight.

Management of circular debt during FY11

The policy response to circular debt during FY11 has been two-fold. In order to stem the monthly increase in circular debt stock, electricity subsidies for distribution companies were phased out. In this respect, notified tariffs were increased in October 2010 (30.7 percent) and November 2010 (2.1 percent).[15] Secondly, the consumer tariff notification mechanism was adjusted, empowering NEPRA to adjust consumer tariffs directly for any monthly variation in fuel costs incurred by generation companies.

The second aspect of the policy response pertains to the outstanding stock of circular debt receivables. The primary source of concern has been PEPCO's receivables for electricity subsidies from the government, and payments for electricity consumption from its customers, of which over Rs 300 billion have already been transferred to the Power Holding Company Limited.

Furthermore, Rs 120 billion in electricity subsidy payments to PEPCO was settled in May 2011. This amount was used primarily to clear dues of HUBCO (Rs. 60 billion) and KAPCO (Rs. 29 billion).[16] HUBCO and KAPCO subsequently retired Rs 89 billion to PSO, of which Rs 61 billion was paid onwards to refineries and Rs 10 billion in tax payments to the government. Therefore, of the total disbursement, only Rs 31 billion was available for PEPCO to clear dues to private power producers, which had increased to Rs 167 billion as of July 2011.

However, in addition to the accumulation of payables to IPPs, the issue of collections needs to be addressed urgently. As of July 2011, receivables from the public sector totaled Rs 106 billion whereas private consumers owed Rs 146 billion.[17] In this regard, some positive steps have been taken by completing operational audits of distribution companies in accordance with the Power Distribution Improvement Program (PDIP) being pursued in conjunction with USAID, but key deliverables shall not be realized before FY13.

3.3 Primary Energy Supplies

3.3.1 Hydropower

Despite being the primary clean, renewable energy source in the country, hydropower resources contributed 35 percent of the total electricity generated during FY11. Generation in FY11 showed substantial improvement over last year (up 14 percent YoY), primarily due to higher reservoir levels in the Tarbela and Mangla Dams with the passage of floods in August 2010.

Presently, about 6,720 MW of hydropower generation capacity is installed in the country, and is largely owned and operated by the Water and Power Development Authority (WAPDA). Electricity generated from this source is subject to a high degree of seasonality, primarily because 69 percent of installed capacity relies on reservoirs for electricity generation, as opposed to the run-of-the-river. Consequently, hydropower is primarily used to supplement the thermal electricity generation base during times of peak demand in summers, and to supply water for irrigation.

According to the Private Power Infrastructure Board, about 89 percent of Pakistan's hydropower potential was untapped by FY11 (**Table 3.6**). Hydro-electric generation is primarily

[15] Our calculation is based on tariff schedules for IESCO, which offer an indicative figure. In practice, tariffs determined by NEPRA vary for each distribution company whereas consumer tariffs notified by the government are fixed throughout the country.

[16] Outstanding receivables for HUBCO and KAPCO had reached Rs 108 billion and Rs 70 billion respectively by 3rd May 2011. As against these receivables, the payables to PSO stood at Rs 86 billion and Rs 40 billion respectively.

[17] The definition of public sector in this regard includes Federal/Provincial Government Departments/Agencies, AJK Government & KESC.

concentrated in KPK, with the remainder in Punjab, AJ&K and Gilgit-Baltistan. By comparison, identified hydropower resources of up to 53,076 MW are yet to be harnessed, of which 79 percent lie in Gilgit-Baltistan and KPK.

Table 3.6: Hydroelectric Potential of Pakistan (MW)

Province	**Projects in operation**	**Projects under implementation**		**Solicited Sites**	**Raw Sites**	**Total Hydropower Resources**
		Public	Private			
KPK	3,849	9,482	2,398	77	8,930	24,736
Gilgit-Baltistan	133	11,876	40	534	8,542	21,125
Punjab	1,699	720	1,028	3,606	238	7,291
Azad Jammu and Kashmir	1,039	1,231	3,264	1	915	6,450
Sindh	-	-	-	67	126	193
Balochistan	-	-	-	1	-	1
Total	**6,720**	**23,309**	**6,730**	**4,286**	**18,751**	**59,796**

Source: Private Power and Infrastructure Board

Whereas feasibility studies for a vast number of projects have been completed, the number of projects presently under construction is considerably limited. Specifically, nearly 6,176 MW of hydroelectric generation is expected to become available by 2019 from projects which are already under construction.[18] However, since majority of these projects are publicly funded, raising financing could prove to be a key obstacle in terms of implementation. Presently, assistance of up to US$15 billion is being sought in the form of soft loans and suppliers credit from Friends of Democratic Pakistan (FoDP) for implementation of identified hydropower projects. Based on the economic climate in key donor countries and domestic political outlook, funding may be delayed and only materialize in stages, depending largely upon the urgency accorded to hydropower development by the government.

[18] The construction cost is estimated at around Rs 1,056 billion. Key projects amongst these include the Diamer-Basha Dam, and the Neelum-Jhelum, Allai Khawar and Duber Khawar hydropower projects. The former two projects are expected to be commissioned around 2019, whereas the latter may become operational as early as 2012.

Table 3.7: Overview of Crude Oil Production, Imports and Consumption (million MT)

	FY06	FY07	FY08	FY09	FY10	5-Year CAGR (percent)
A. Production	**3.21**	**3.30**	**3.43**	**3.22**	**3.18**	**-0.2**
OGDC	1.54	1.78	2.03	1.98	1.78	3.7
BP	0.62	0.54	0.47	0.48	0.56	-2.5
PPL	0.18	0.24	0.25	0.23	0.26	9.6
Others	0.87	0.74	0.68	0.53	0.58	-9.6
B. Imports*	**8.60**	**8.22**	**8.42**	**8.06**	**6.89**	**-5.4**
PARCO	4.60	4.36	4.56	3.56	3.56	-6.2
NRL	2.39	2.37	2.22	2.32	1.71	-8.0
PRL	0.91	0.78	0.85	1.30	0.98	1.9
Byco	0.70	0.71	0.79	0.88	0.63	-2.6
Total Supplies (A + B)	**11.81**	**11.52**	**11.85**	**11.28**	**10.07**	**-3.9**
C. Demand (Crude Processed)	**11.35**	**11.24**	**11.69**	**10.74**	**9.87**	**-3.4**
PARCO	3.79	3.72	3.87	3.66	3.56	-1.6
NRL	2.77	2.79	2.73	2.42	2.14	-6.2
ARL	1.87	1.84	1.93	1.70	1.74	-1.8
PRL	2.14	1.98	2.18	1.89	1.60	-7.0
**** Others**	0.78	0.91	0.98	1.06	0.83	1.6

* As reported by DG Oil, Ministry of Petroleum.

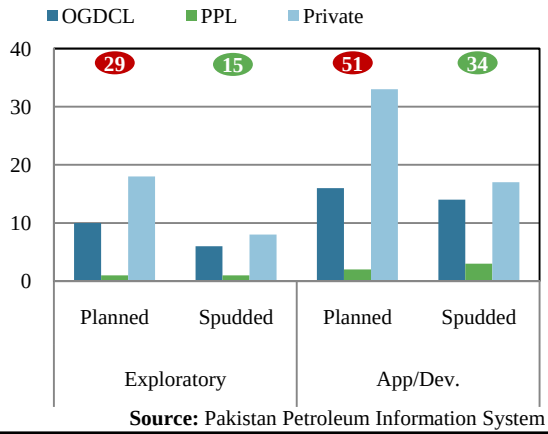
** These include Byco, ENAR, Dhodak.

Source: Hydrocarbon Development Institute of Pakistan

3.3.2 Crude Oil

Total supplies of crude oil available to refineries from imports and indigenous production increased to 10.1 million MT in FY11. Imports depicted an increase due to improvement in refining margins and marginal increase in processing capacity. Historically, local production has contributed 30 – 35 percent of total crude processed domestically, and stood at 3.3 million MT in FY11 (up marginally by 0.6 percent YoY). It is pertinent to mention here that domestic production is inelastic to changes in demand, and largely depends on the available reserve base as well as exploration and production activity in the upstream sector. The gap between domestic demand and production is therefore met via imports, which increased by 3.8 percent YoY in FY11 to 6.8 million MT.[19]

Figure 3.5: Drilling Activities during Jul-Jun FY11



Source: Pakistan Petroleum Information System

Exploration and production activity

Activity in the exploration sector remained subdued in the outgoing year. Up to 80 wells were targeted for exploration, development and appraisals in FY11.[20] However, work on 49 wells was in progress as of June 2011, of

[19] As reported by the Oil Companies Advisory Committee (OCAC), which includes most major refineries and POL distribution companies. This dataset is largely representative of the sector's performance.

[20] Wells drilled for exploration are used to determine whether crude oil reserves are present at a particular location. By contrast, appraisal wells are used to estimate the size of reserves, whereas development wells constructed to start production from a field with known reserves.

which 15 were earmarked for exploration, whereas the remainder had been identified for development/appraisal in previous years (**Figure 3.5**). The primary focus of exploration and production (E&P) companies therefore remained fixed on developing the existing resource base rather than investing in discovery of new fields.

Table 3.8: New Discoveries of Oil Reserves during FY11

Operator	Province	Development Status	Potential Production (bpd)
MOL	KPK	Started	3,029
POL	Punjab	Started	942
OGDC	Sindh	Started	100
Total			**4,071**

Source: Ministry of Petroleum & Natural Resources

Three significant discoveries of oil reserves were made during FY11 (**Table 3.8**), with a production potential of 4,071 bpd.[21] Once fully developed, these could contribute 6 percent to annual crude production. Furthermore, ongoing projects are expected to contribute 9,000 bpd or 14 percent to production over FY12-FY13.

Having said this, realizing the country's crude oil production potential remains a challenge due to the prevailing security situation, particularly in KPK and Balochistan. Several incidents of attacks on officials from E&P companies were reported during the year and operations on a few wells and fields suspended to this effect.

Crude processing

Demand for crude is capped to the extent of installed processing capacity, which stood at 14.3 million MT in FY11. Historically, growth in refining capacity has remained stagnant despite protection offered in the form of a deemed duty of 7.5 percent on HSD (**Box 3.**), and domestic refineries have tended to operate at capacity utilization levels of 85 percent on average during FY06-10. In a market with deficit POL production such as Pakistan, higher capacity utilization levels could reduce the POL import bill.

Crude oil processed by refineries continued to decline in FY11, to a level of 9.6 million MT,[22] due to the impact of supply side disruptions. The rate of decline, however, has been arrested substantially from 8.3 percent in FY10 to 1.0 percent in FY11. Several developments weighed heavily on demand for crude oil from refineries during FY11: (a) the closure of PARCO during Sep-Oct FY11 due to floods; (b) during May 2011, ARL was shut down due to a technical fault; and (c) activity at

Box 3.1: Pakistan's Refining Sector

Pakistan's POL refining sector consists of five refineries with a total capacity of 13.1 million MT per annum. These include Pak-Arab Refinery (PARCO, 4.5 million MT), National Refinery (NRL, 2.7 million MT), Pakistan Refinery (PRL, 2.1 million MT), Attock Refinery (ARL, 1.9 million MT) and Byco (1.7 million MT). Since the product slate is determined by the configuration of a refinery and demand for key POL products is capped by domestic consumption, capacity utilization in the sector is largely determined by the margin between individual POL product and crude prices.

Majority of the capacity in the sector is based on the hydro-skimming configuration, as a result of which the product slate includes a high proportion of furnace oil (typically sold at a discount to crude prices). Consequently, margins in the sector have been lower than otherwise possible, and refineries have been unable to invest towards improving technology. Tariff protection through deemed duty provided by the government for this purpose, and to meet more stringent Euro-II quality standards for POL products, has also been phased out from different products except HSD over the years **(Table 3.9)**.

Table 3.9: Deemed Duty Protection on POL Products
percent

Product	FY06	FY07	FY08	FY09	FY10
Kerosene	6.0	-	-	-	-
JP-4*	6.0	5.0	-	-	-
JP-8	6.0	5.0	-	-	-
HSD	10.0	10.0	10.0	7.5	7.5
LDO	6.0	-	-	-	-

***** JP denotes Jet Propellant; LDO denotes Light Diesel Oil
Source: OGRA

[21] The term bpd denotes barrels per day.
[22] For member companies of the OCAC.

Byco was temporarily suspended due to internal financial issues at the refinery, which had a marginal impact on overall crude procurement in May 2011.

The crude processing potential of the country, however, remains largely unrealized. Whereas total domestic consumption of POL products stood at 18.4 million MT in FY11, 49 percent of this requirement was imported. If POL imports were to be substituted completely for local production based on imported crude, additional processing capacity of up to 15.0 million MT would be required. Presently, new capacity of 5.0 million MT per annum is in the pipeline from Byco, and additions of up to 20.0 million MT are planned going forward; it remains to be seen how much of this capacity will actually be brought to market.[23] Meanwhile, existing refineries are presently focused on upgrading production configurations to reduce the share of furnace oil in the product-mix and meet Euro-II specifications for HSD.[24]

3.3.3 Natural Gas

Pakistan experienced some of the worst gas shortages in its history during FY11, and supply to the industrial, CNG and power sectors was significantly curtailed. The shortfall peaked during the winter season, when gas consumption for domestic heating increases, and demand reached 4,580 mmcfd versus supply of 3,878 mmcfd. Throughout the remainder of the year, shortfall in the system varied between 10 to 15 percent of demand (400-700 mmcfd), depending on supply availability from key fields.

Table 3.10: Curtailment of Gas due to Load Management (mmcfd)

	Industry	CNG	Power	Total
Punjab				
Oct-10	98	13	0	111
Nov-10	224	20	0	244
Dec-10	354	26	0	380
Jan-11	295	26	0	321
Feb-11	261	28	0	289
Mar-11	197	26	0	223
Sindh				
Oct-10	131	0	0	131
Nov-10	147	0	0	147
Dec-10	225	0	0	225
Jan-11	284	0	0	284
Feb-11	234	0	0	234
Mar-11	168	0	0	168
Balochistan				
Oct-10	0	0	3.8	3.8
Nov-10	0	0	10	10
Dec-10	0	0	10	10
Jan-11	0	0	10	10
Feb-11	0	0	10	10
Mar-11	0	0	10	10

Source: Ministry of Petroleum and Natural Resources

To rationalize consumption, a load management plan was therefore implemented in October 2010 (**Table 3.10**). According to the plan, gas supply to the industrial sector in Punjab and Sindh was curtailed for two days on a weekly basis,[25] whereas supply to the CNG sector was reduced to five days a week. The impact on textile production was particularly damaging (**Section 2.3.2**) and supply to fertilizer producers was curtailed by up to 20 percent vis-à-vis their allocation. Natural gas availability to the power sector also remained below requirement. In particular, gas availability to KESC averaged around 55 percent of official

[23] These include additions from Trans Asia (4.5 million MT), Indus (4.5 million MT) and Khalifa Coastal (11 million MT).

[24] Currently, four of the five refineries have hydro-skimming configuration while PARCO has CCR/ Diesel Max/ Visbreaker configuration. Hydro-skimming configurations yield products with high sulfur content (1.0 percent by weight), resulting in lower margins. Refineries need additional investment to install diesel desulfurization units so as to meet the Euro-II emission standards (i.e. 0.05 percent Sulfur by weight).

[25] The notified amount of curtailment varied throughout the year, increasing up to three days per week to the industrial sector depending on demand-supply conditions. In fact, actual curtailment to the textile sector was increased to 3.5 days per week from February-11 onwards (see **Section 2.3.2**).

allocation (276 mmcfd) whereas IPPs based on gas were forced to remain idle or operate below capacity.[26]

On the supply side, temporary disruptions (due to the floods and technical faults) from key fields have been largely responsible for short-term fluctuations in gas availability. Supply was also affected from time to time due to annual turnaround (ATA) of key fields for maintenance, which can take up to 30 days at a time.

Factors contributing to prevailing shortages of natural gas

Natural gas exploration in Pakistan has not been undertaken aggressively, and hence production has historically remained undiversified. As of FY10, natural gas was being produced from 98 fields, of which nine fields accounted for 80 percent of total daily supply. Exploration and production activity has been largely concentrated in Sindh (71 percent of total production in FY10, **Table 3.11**), and the most recent significant gas discovery dates back to 1998. Consequently, the reserve base has not witnessed significant expansion and, by FY11, 49 percent of original recoverable reserves (54 TCF) had been exhausted. The country now has sufficient reserves to last just over 20 years, under the increasingly unlikely scenario that current production rates are maintained throughout. In effect, Pakistan must aggressively explore alternatives to diversify supply of this precious commodity.

Table 3.11: Production and Consumption of Natural Gas (mmcfd)

	FY06	FY07	FY08	FY09	FY10	5-Year CAGR
Production	**3,836**	**3,873**	**3,984**	**4,002**	**4,063**	**1.4**
Sindh	2,691	2,741	2,830	2,870	2,877	1.7
Balochistan	904	872	876	837	790	-3.3
Punjab	186	188	197	209	190	0.6
KPK	55	72	81	86	205	38.9
Consumption	**3,347**	**3,345**	**3,494**	**3,478**	**3,501**	**1.1**
Power	1,343	1,185	1,178	1,107	1,005	-7.0
Gen. Industries	722	795	837	836	878	5.0
Fertilizer	543	530	549	551	603	2.7
Domestic	469	508	559	587	601	6.4
Other	271	326	371	397	413	11.1
Unaccounted for gas	**488**	**528**	**490**	**524**	**562**	**3.6**
% of production	*12.7*	*13.6*	*12.3*	*13.1*	*13.8*	-

Source: Hydrocarbon Development Institute of Pakistan

Part of the explanation for why gas exploration has remained subdued may be found in the pricing structure of the commodity. Exploratory prices of gas are linked to crude oil, but impact of changes in reference crude prices is not fully passed on to investors,[27] as benchmark prices for compensation are computed on a bi-annual basis only.[28] Furthermore, exploration and production companies accrue only 50 percent of any upside price movements in the price of gas with respect to the aforementioned base level, with the remainder collected by the government in the form of a windfall levy. Producer (well-head) prices of gas therefore do not particularly incentivize exploration of the commodity, and production companies receive prices below import parity levels.

[26] These include Orient Power, Saif Power, Sapphire Electric and Halmore Power, accounting for 908 MW.

[27] As per the Petroleum Policy (2009), the reference crude price is based on a basket of Arabian/Persian crude oils, but is capped at $100/bbl for calculation of domestic gas prices. Furthermore, a sliding scale discount is applied to the reference crude price if it exceeds $20/bbl, followed by a zonal discount based on the domestic region where gas is produced. Consequently, gas prices cannot exceed a level of $5.35/BTU when actual crude price is above $100/bbl. At current exchange rates, this price equates to approximately Rs 460/BTU.

[28] The reference crude price is averaged over a six-month period for calculation of gas prices, which means investors are not rewarded for intermediate upside price volatility in the commodity.

These features of domestic gas pricing may come across as peculiar at first, but are justifiable so long as the benefits accrue squarely to the country's industrial base. However, downstream pricing of the commodity has significantly subsidized residential consumers and fertilizer manufacturers at the expense of the industrial and power sectors for quite some time, which arguably leads to allocative inefficiencies. Secondly, gas prices are maintained at a uniform level throughout the country, for which the different costs of transmission and distribution are built into gas pricing notified by the ECC.[29]

For these reasons, the supply-demand position of natural gas has deteriorated significantly, and shortages of the commodity with reference to indigenous supply are projected to increase to 3,021 mmcfd by FY16 (48 percent of projected demand, **Table 3.12**). Nearly half of this deficit may be bridged by imports, if arrangements presently under consideration are implemented as scheduled. However, supply rationing of natural gas is inevitable in the near future, and meaningful steps must be taken to curtail residential consumption, while prioritizing supply to the fertilizer and power sectors.[30]

Table 3.12: Projected Demand, Supply and Shortfall of Natural Gas (mmcfd)

	FY12	FY13	FY14	FY15	FY16
Net Demand	**5,497**	**5,670**	**5,788**	**5,820**	**5,970**
SNGPL	2,374	2,486	2,556	2,542	2,576
SSGCL	2,132	2,193	2,255	2,279	2,343
Independent Systems	991	991	977	999	1,051
UFG and T&D Losses	279	307	320	322	330
Gas Consumed Internally (GIC)	49	55	57	54	54
Gross Demand	**5,825**	**6,032**	**6,165**	**6,196**	**6,354**
Committed Supply	3,124	2,933	2,663	2,417	2,249
Anticipated Supply	242	447	1,198	1,166	1,084
Import from Iran	-	-	263	487	750
LNG-I	300	500	500	500	500
Total Supplies	**3,667**	**3,880**	**4,623**	**4,570**	**4,583**
Gas shortfall					
w.r.t. indigenous supplies	**2,458**	**2,652**	**2,305**	**2,613**	**3,021**
w.r.t. imported & indigenous supplies	**2,158**	**2,152**	**1,542**	**1,626**	**1,771**

Source: OGRA; Ministry of Petroleum & Natural Resources

Bridging the supply-demand gap

According to the Ministry of Petroleum and Natural Resources, demand for gas is projected to increase steadily at 2 percent per annum from FY12 to reach 5,970 mmcfd by FY16. The most rapid increase in demand has already been factored in during FY11, due to commissioning of new gas-based IPPs with a capacity of 852 MW. With additional projects, overall gas

[29] Gas prices are determined based on annual revenue requirements submitted by SNGPL and SSGC. These calculations factor in the purchase cost of gas, transmission/distribution (T&D) costs, a benchmark level of unaccounted for gas (UFG) wastages, and lastly a fixed return on assets (17.5 percent for SNGPL; 17.0 percent for SSGC). Hence, companies have an incentive to expand the distribution network; but only a weak incentive to do so efficiently since T&D costs are included in gas pricing, and ultimate cost of breaching UFG benchmarks (4 percent for SNGPL; 5 percent for SSGC) must be borne by the exchequer.

[30] Presently, the Natural Gas Allocation Policy accords priority to the residential sector, followed by fertilizer and industrial sectors to the extent of production process requirements. Power producers with firm gas supply commitments are ensured supply for nine months, with the remainder supplied on a best efforts basis. Similarly, supply for captive power generation and to KESC, WAPDA and IPPs without gas supply agreements is conducted on a best efforts basis, and accorded fifth priority in terms of allocation.

requirement for power generation may climb to 1,731 mmcfd by FY13 (or 41 percent of anticipated production).

Demand growth is expected to outpace increase in supply, and gas shortages may intensify in the near future. Based on supply projections, domestic production of gas is likely to peak by FY14 at 3,860 mmcfd and is set to decline thereafter. Natural depletion in gas fields will ensure that committed supplies fall considerably short of demand, which is projected to reach 5,970 mmcfd by FY16. Production from fields presently indentified for development will therefore become critical in managing the demand-supply gap. Key projects scheduled to come online by FY14 will contribute 460 mmcfd to gas supplies.

Furthermore, since domestic production of gas will no longer be sufficient to meet consumption requirements, reliance on imports will increase. Between FY12 and FY16, the domestic gas shortfall is projected to increase from 2,458 mmcfd to 3,021 mmcfd, which may be reduced by 40 percent via imports (**Box 3.**).

If ongoing projects to import natural gas are delayed, gas shortages could worsen considerably. Strong interest has been shown by the private sector towards developing import infrastructure for LNG. However, imports from Iran could be set back if pipeline construction within Pakistan's border does not proceed as scheduled, due either to a deteriorating security situation in Balochistan or delays in securing financing. Nevertheless, in our view, the pipeline is unlikely to face significant delays, since financial support can be sought from China and Pakistan's foreign policy is likely to acquire a greater regional bias as US forces withdraw from Afghanistan.

Box 3.2: Projects for Natural Gas Import

The following projects are presently being undertaken to set up infrastructure for natural gas imports:

The Mashal LNG Project has been retendered in FY11 and received strong expression of interest from the private sector. With SSGC appointed as a facilitator, an offshore floating terminal is scheduled to be developed at a cost of $150 million for this project, with a supply capacity of 500 mmcfd. Shipments of up to 300 mmcfd may be imported through this project as early as FY12.

Imports from Iran are expected to commence by FY14, with first delivery of 264 mmcfd. Construction work for the pipeline is expected to commence from November 2011, at an expected cost of $1.5 billion, for which financing is being sought from China. The pipeline is capable of supplying 2,100 mmcfd gas up to Nawabshah, and gas import from Iran has recently been negotiated upwards from 750 mmcfd to 1,000 mmcfd.

Additionally, work on the Turkmenistan-Afghanistan-Pakistan-India (TAPI) project is also underway. An Inter Governmental Agreement (IGA) and Gas Pipeline Framework Agreement (GPFA) have been signed, and key impediments in the Gas Sales and Purchase Agreement (GSPA) are being worked out. The project is being coordinated by the Asian Development Bank (ADB) with a combined cost of $7.6 billion, and first gas flow is targeted by 2016. Pakistan's share of total supply from the pipeline is likely to be 1,365 mmcfd.

3.3.4 Coal

Coal is primarily used for cement (56 percent) and brick (37 percent) manufacturing in Pakistan (**Table 3.13**). Although measured reserves of coal were well in excess of medium-term consumption requirements as of FY10, production (3.1 million MT) was still insufficient to cover domestic consumption requirements (8.14 million MT). The gap has historically been bridged by imports, which have increased annually by 13 percent on average over FY06-10.

Presently, the key debate surrounding coal reserves is whether imported fuels may be substituted for domestic coal. Specifically, it is now generally acknowledged that coal reserves are present in sufficient quantities at Thar (176 billion MT), Thatta (4 billion MT) and adjoining areas in Sindh to meet long-term energy requirements. However, the quality of such known reserves may

not be sufficiently high. For instance, reserves discovered in Thar are lignite or brown coal, thus possessing a moisture content of up to 55 percent and a lower heating value.

Table 3.13: Overview – Consumption and Production of Coal (million MT)

	FY06	FY07	FY08	FY09	FY10	5-Year CAGR
Consumption*	**7.71**	**7.89**	**10.11**	**8.39**	**8.14**	**1.4**
Domestic	-	0.00	0.00	0.00	-	-
Brick-Kiln Industry	4.22	3.28	3.76	3.27	3.01	(8.1)
Cement / Other Industry	2.78	4.14	5.72	3.80	4.58	13.3
Pakistan Steel	0.56	0.31	0.47	1.20	0.43	(6.4)
Power (WAPDA)	0.15	0.16	0.16	0.11	0.13	(3.5)
Production	**4.87**	**3.64**	**4.12**	**3.74**	**3.48**	**(8.1)**
Sindh	2.01	1.00	1.06	0.84	1.20	(12.1)
Balochistan	1.96	1.83	2.27	2.06	1.50	(6.5)
Punjab	0.57	0.51	0.55	0.57	0.59	0.9
KPK/FATA	0.33	0.30	0.24	0.27	0.19	(12.9)
Imports	**2.84**	**4.25**	**5.99**	**4.65**	**4.66**	**13.2**
Reserves	**-**	**-**	**-**	**-**	**186,008**	**-**
Of Which:	-	-	-	-	-	-
Measured	-	-	-	-	*3,450*	-
Indicated & Inferred	-	-	-	-	*68,259*	-
Hypothetical	-	-	-	-	*114,298*	-

* Sector-wise consumption data for coal is not available and hence estimated

Source: Hydrocarbon Development Institute

Nevertheless, steps are being undertaken to expedite domestic production of coal, specifically for use in power generation. Specifically, the Thar Coal Authority has been formed with the Chief Minister of Sindh as Chairman, to work towards the development of indigenous resources.[31] Furthermore, the Sindh Coal Authority (SCA) and Thar Coal and Energy Board (TCEB) have also been constituted to encourage private sector participation.[32] In this regard, the Government of Sindh has signed a joint venture with Engro Power Generation to develop a coal mine in Thar Block-II which shall fuel a 1,000 MW power plant by 2016. Similarly, a memorandum of understanding has been signed with a UK-based company for mining and power generation, and development of infrastructure at Block-IV has commenced in this regard. Prospects for underground coal gasification (UCG) are also being explored in parallel. To this end, the Government of Sindh has awarded a mining concession to Cougar Energy under which Thar Block-III shall be developed for UCG, leading to commissioning of a 400 MW power project.

3.4 POL Products

The domestic market for petroleum, oil and lubricant (POL) products is characterized by overconsumption and underproduction, and Pakistan depends heavily on imports to bridge the deficit. In the five year period extending till FY11, consumption of POL products has grown at an average rate of 4.8 percent whereas domestic production – sufficient to meet only 50 percent of the domestic requirement – has actually declined by 3.8 percent on average. To bridge the demand supply gap, imports have increased sharply to 12.4 million tons as of FY11 from a level of 8.3 million tons in FY07 (**Table 3.14**).

[31] As per the Constitution, coal is a provincial subject. The Federal government has the mandate to generate basic geological data through surveys, which is presently undertaken under auspices of the Geological Survey of Pakistan.
[32] While these developments are commendable, there is a need to include professionals, who can understand the technicalities of the project and provide input for policy formulation. Moreover, there may be conflicts of interest amongst various regulatory agencies here.

The import bill for POL products increased to $8.3 billion in FY11 from $6.6 billion in the previous year, due to adverse movements in both volume and prices. Whereas the volume of imports increased to 12.4 million MT, regional oil prices crossed US$ 120/barrel as unrest in the Middle East intensified during April 2011.[33]

Table 3.14: Overview of POL Demand, Supply and Imports (million MT)

	FY07	FY08	FY09	FY10	FY11[1]	5-Year CAGR(%)
Consumption[2]	**16.85**	**18.08**	**17.91**	**19.13**	**20.33**	**4.8**
Transport	7.98	9.38	8.84	8.86	8.99	3.0
Power	6.74	7.08	7.57	8.81	8.15	4.9
Industry	1.60	1.07	0.97	0.98	1.52	-1.3
Other	0.53	0.54	0.53	0.47	1.67	33.2
Domestic Production	**10.86**	**11.31**	**10.34**	**9.54**	**9.32**	**-3.8**
Furnace Oil	3.19	3.32	3.09	2.48	2.41	-6.8
Motor Gasoline	1.22	1.34	1.29	1.35	1.25	0.6
HSD	3.24	3.56	3.26	3.14	3.23	-0.1
Aviation Fuels	1.17	1.01	0.96	0.94	0.82	-8.5
Others	1.50	1.52	1.23	1.08	1.12	-7.0
Non-Energy Products	0.55	0.56	0.51	0.54	0.49	-2.8
Imports	**8.33**	**9.03**	**9.97**	**11.18**	**12.41**	**10.5**
HSD	3.97	4.51	4.40	4.39	3.76	-1.3
Furnace Oil	4.31	4.27	5.08	5.60	6.79	12.0
Motor Gasoline	-	0.13	0.25	0.58	1.06	-
Others	0.05	0.12	0.25	0.61	0.80	100.0
Exports	**1.34**	**1.34**	**1.21**	**1.45**	**1.43**	**-**
Bunkering	**0.27**	**0.30**	**0.32**	**0.41**	**-**	**-**

[1] Indicative data from Federal Bureau of Statistics and the Oil Companies Advisory Committee.

[2] Based on OCAC data.

Source: Hydrocarbon Development Institute of Pakistan

More worryingly, the increase in POL demand is concentrated in the power sector and has lead to a permanent increase in domestic furnace oil requirements. Since domestic production of furnace oil was sufficient to meet only 27 percent of consumption in FY10, the remainder must be imported annually for electricity generation. Substitution away from furnace oil is urgently required in the power sector, for which options available to policy makers are limited.

The second product in deficit supply is High-Speed Diesel (HSD). In FY10, total consumption of HSD stood at 6.8 million MT, of which 90 percent was concentrated in the transportation sector. Consumption of HSD remains structurally high since road transport has historically received stronger patronage as compared to railroads. If Pakistan Railways were to operate efficiently, HSD consumption could arguably be reduced significantly, which would also result in substantial foreign exchange savings for the country.

Whereas consumption is more difficult to check, domestic production of HSD has long been incentivized by providing a fixed percentage margin (deemed duty) to refineries on sales of the product. However, profits accruing from deemed duty protection have not been invested towards technology up-gradation in the past, and have instead been accumulated as a buffer against volatility in refining margins resulting from massive oil price fluctuations. The present configuration of domestic refineries therefore features limited production of HSD and a high

[33] Import data is representative of OCAC member companies.

proportion of furnace oil in the product mix (**Box 3.**), and the benefits of incentivizing HSD production remain yet to be realized.

POL consumption in FY11

Consumption of POL energy products declined by 2.4 percent in FY11 as compared to an increase of 9.4 percent in the same period last year. The decline in annual consumption during FY11 was largely due to lower sales of FO (declined by 1.9 percent), which account for 45 percent of the energy product consumption mix.

Consumption of FO witnessed the greatest decline in August 2010 in particular, since widespread flooding affected product availability at the time. A second substantial reduction in sales was witnessed in April 2011, due to inventory management problems experienced by oil marketing companies (OMCs), resulting from circular debt.

Sales of non-energy products declined by 22.6 percent in FY11 as compared to an increase of 3.9 percent during FY10.[34] The overall decline in this group is primarily attributable to weaker consumption of asphalt (down 34.3 percent YoY),[35] which is used in road construction and accounts for about 65 percent of the non-energy product group. Meanwhile, lubricant sales increased marginally in FY11 as compared to sales growth of 11.1 percent in FY10.

POL production in FY11

Refinery production in FY11 saw a decline of 2.3 percent to 9.3 million tons.[36] The decline in production has slowed down as compared to FY10 largely due to improvement in refining margins especially during H2-FY11 in response to rising international oil prices.[37] Estimated gross margins for Attock and National refineries crossed the $5/bbl mark in April 2011, and were positive even for refineries with a higher percentage of furnace oil in the product mix.Changes in POL pricing & fiscal impact

The consumer impact of rising oil prices has been proactively managed during FY11, with some adverse implications for indirect tax revenues. Specifically, OMC margins on various POL products were fixed at lower levels,[38] whereas the petroleum development levy (PDL) built into the ex-depot pricing formula was reduced across the board.[39] Calculation of ex-refinery prices was also adjusted by OGRA to exclude the impact of shipping and incidental costs in deriving POL prices.

Furthermore, changes in the pricing mechanism for POL products have been notified by OGRA, which have become effective from FY12. Accordingly, the prices of MS, HOBC, LDO, and aviation fuel have been deregulated at the refinery and depot level, subject to a ceiling of import parity price plus incidentals for ex-refinery prices. Prices for HSD, however, are being

[34] Non-energy products include asphalt, lubrication oils, solvents and greases.
[35] Asphalt sales generally vary in tandem with allocations to PSDP, which were reduced substantially in FY11 due to fiscal constraints.
[36] Production data is representative of OCAC member companies.
[37] Gross refining margins are calculated on the basis of C&F prices notified by OGRA, and assuming a one month inventory holding period for Arab Light Crude.
[38] Previously, OMC margins were calculated as a percentage of ex-refinery prices plus an inland freight equalization margin, resulting in monthly variation in line with oil prices. However, margins were subsequently fixed to Rs 1.5 per liter for MS, Rs 1.35 per liter for HSD and Rs 1.72 for HOBC.
[39] Reduction in PDL has fiscal implications. In FY10, receipts from PDL fell short of target by Rs 10 billion, whereas this deficit is expected to widen to Rs 20 billion for FY11. Nevertheless, in our view, next year's PDL target of Rs 120 billion remains achievable, provided regional crude prices remain below $80/bbl for FY12, as was witnessed during FY09.

determined by OGRA at the refinery level, whereas the price of Kerosene is announced at both the refinery and depot level.

Although deregulation would ideally lead to lower prices in a competitive market, the impact of these changes is likely to be neutral for consumers in our view. The key component of ex-depot prices are OMC and dealer commissions, government taxes and the inland freight equalization margin (IFEM). Under the new framework, OMCs do not have control over either of these components, since commissions continue to remain fixed, taxes are determined by the government, and IFEM continues to remain in place despite recommendations to the contrary. Hence, the impact of price deregulation at the depot level on consumers remains neutral.

Box 3.3: Infrastructure for Import of Crude and POL Products

Pakistan meets majority of its crude oil imports from the Middle East, and the main suppliers include Saudi Arabia, UAE and Iran. Pakistan National Shipping Corporation (PNSC) maintains 3-4 dedicated tankers capable of delivering 600,000 MT of crude on average every month.

At present, crude oil and product imports can only be handled at two terminals: Keamari and FOTCO (Port Qasim). Both ports are located in Karachi and connected via a 25 km pipeline (capacity 2.0 million MT per month). The pipeline is primarily used for upcountry movement of imported POL products (particularly diesel), through linked pipelines at FOTCI. Majority stake in the pipeline is held by Pak-Arab Pipelines (51 percent) while PSO, Shell and Chevron hold the remaining shares. PARCO, PRL and NRL are linked with this pipeline.

Currently, the combined cargo handling capacity for POL products at ports is 33.0 million MT (24.0 million MT at Keamari and 9.0 million at FOTCO). However, handling capacity for crude is significantly lower (6.0 million MT at Keamari; 0.6 million MT at FOTCO). Furthermore, some crude handling capacity may become unavailable during 2013-2015 due to scheduled maintenance at KPT OP-I. Moreover, increase in POL product demand and refining capacity in the future is likely to exert stress on the existing cargo handling infrastructure.

To improve cargo handling capacity for crude imports, enhancements in infrastructure are urgently needed. Specifically, introducing night time navigation and increasing the draft of FOTCO can immediately improve cargo-handling capacity. The following options need to be explored:

- Single-Buoy Mooring[40] (SBM) at HUB connecting the Byco refineries for crude imports;
- White-oil pipeline link between KPT and FOTCO for effective utilization of KPT's three modern oil piers, to provide KPT access to PAPCO's product terminal, and reduce ship demurrages;
- Second berth at FOTCO to handle rising FO demand for power generation.

[40] SBM is a complete, self-contained single point offshore terminal facility which allows for both mooring and transferring cargo of very large crude oil carriers (VLCC) or floating offshore facilities. SBM systems are regarded as instant ports since they can be installed in deeper areas without any need for construction of jetties.

Annex Table 3.1: Status of Installed and Available Generation Capacity in February-2011 (MW)

S.No.	Project Name^	Fuel	Installed	Available	Reason
	GENCOs		**3,550**	**1,380**	
1	Lakhra	Coal	30	-	Complex F/O*.
2	GTPS Faisalabad	Gas	210	-	U-5 S/O**. Gas Quota NIL
3	Kotri	Gas	140	-	Gas Quota NIL.
4	Quetta	Gas	25	-	Gas Quota NIL.
5	Muzaffargarh	RFO	1,130	480	U-5,6 F/O, U-1 S/O.
6	SPS Faisalabad	RFO	100	-	U-1,2 Standby,
7	Guddu	RFO/Gas	1,155	620	U-1,2,4,5Ä, 8 F/O, U-7 S/O.
8	Jamshoro	RFO/Gas	700	280	U-1, 2 F/O
9	Multan	RFO/Gas	60	-	U-4 F/O, U-1 S/O, U-3 Standby
	IPPs		**7,487**	**3,915**	
1	Uch Power Limited	Gas	551	-	Complex F/O.
2	Engro Powergen	Gas	217	218	-
3	Orient Power Limited	Gas	213	-	Gas Quota Nil.
4	TNB Liberty Power	Gas	212	-	Complex S/O.
5	Saif Power Limited	Gas	210	-	Gas Quota Nil.
6	Sapphire Electric Company Ltd.	Gas	209	-	Gas Quota Nil.
7	Liberty Power Tech Limited	Gas	200	177	U-9 S/O.
8	Fauji Kabirwala Power Company	Gas	151	121	-
9	Habibullah Coastal	Gas	129	64	U-3,4 F/O.
10	Altern Energy	Gas	27	-	Complex F/O.
11	CHASHNUPP	Nuclear	300	304	-
12	Rousch Power Limited	RFO	395	205	Half Complex F/O.
13	AES Lalpir	RFO	348	342	-
14	AES Pak Gen	RFO	348	-	Complex F/O.
15	Atlas Power Limited	RFO	214	193	U-1 F/O.
16	Nishat Chunian Power Limited	RFO	195	195	-
17	Nishat Power Limited	RFO	195	196	-
18	Attock Gen Limited	RFO	156	102	U-3,5 F/O. U-8 S/O.
19	Saba Power	RFO	126	-	Complex F/O.
20	Kohinoor Energy Limited	RFO	120	92	U-1, 8 S/O.
21	Southern Electric	RFO	119	-	Shortage of Fuel.
22	Japan Power Generation	RFO	77	23	Less sharing due to Oil Shortage.
23	Gulf Rental	RFO	62	62	-
24	Techno Power	RFO	60	-	Complex F/O.
25	KAPCO	RFO/Gas	1,342	680	U-4, 10 F/O, U-1,3,7,8 S/O.
26	HUBCO	RFO/Gas	1,200	900	U-3 F/O. _
27	Malakand-III	Run-of-River	81	41	U-3 F/O
28	Jagran	Run-of-River	30	-	Complex F/O.
	WAPDA Hydropower		**6,444**	**4,889**	
1	Tarbela	Reservoir	3,478	2,345	R/L 1437.45 ft., U-4,10 S/O
2	Mangla	Reservoir	1,000	776	R/L 1109.35 ft, U-5 F/O
3	Chashma Hydro	Reservoir	184	128	U-7 S/O
4	Ghazi Barotha	Run-of-River	1,450	1,450	-
5	Warsak	Run-of-River	243	150	U-1, 4 S/O.
6	Small Hydel	Run-of-River	89	40	-
	Total		**17,481**	**10,184**	-

* Indicates forced outage (F/O) for entire complex.

** S/O indicates scheduled outage for maintenance. U indicates the affected power generating unit within the complex. R/L indicates reservoir level.

^ Capacity installed at KESC is not shown in this table.

Source: Ministry of Water and Power

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