## Chapter 5
## OPPORTUNITIES FOR REGIONAL ENERGY TRADE

In Chapter 2 we discussed the distribution of energy resources in the region and its neighbors, and also, briefly the energy use and the supply-demand situation and outlook. The opportunities for electricity trade emerging from these would fall under three groups:

- Central Asia- South Asia electricity trade
- Nepal, Bhutan, India, Bangladesh and Myanmar electricity trade
- Other opportunities such as Central Asia- Afghanistan bilateral trade, Pakistan-Iran bilateral electricity trade, India-Sri Lanka bilateral electricity trade, and India-Pakistan bilateral electricity trade

Similarly the opportunities for gas trade would fall under the following groups:

- Import of gas through pipelines into India and Pakistan from Iran and Central Asia (Turkmenistan, Uzbekistan and possibly Kazakhstan)
- Import of gas from Myanmar and Bangladesh into India and possibly to Bhutan and Nepal

Most of the trade (except the envisaged CA-SA electricity trade and gas trades) would be bilateral at least to start with and may later evolve into regional markets with multiple buyers and sellers. Bilateral cross-border trade is a natural starting point and an important long-term feature of regional trade, even in well developed multilateral regional markets. It helps develop physical infrastructure and commercial relationships in a gradual fashion, allowing participating countries to adjust, develop institutions and experience, build confidence and mutual comfort, and minimize risks.

One may envisage in this context the evolution of the regional market in the following geographic terms:

- The Western Energy Market in which energy trade would be among Central Asia, Iran, Afghanistan, Pakistan and India
- The Eastern Energy Market in which the energy trade would be among India, Nepal, Bhutan, Bangladesh, Myanmar and possibly Sri Lanka

India being in both would enable the eventual evolution of an integrated regional energy market.

Given the economic realities and outlook as well as the resource distribution across the region, India, Pakistan and perhaps Bangladesh would emerge as major importers, while Central Asia, Iran, Myanmar, Bhutan, Nepal would emerge as major exporters. Afghanistan and Pakistan would be key transit countries in the Western Energy Market, while Bangladesh could play that role in the Eastern Energy Market. Bangladesh has also the potential to emerge as an exporter of gas and electricity (see Map at the end of the document)

### 5.1 The Western Energy Market

As can be discerned from Table 2.4 Central Asia and Iran have considerable natural gas resources and surplus electricity to export. Kazakhstan, Kyrgyz Republic, Uzbekistan and Tajikistan, which presently constitute the Central Asian Power System (CAPS),[41] have a combined generation capacity of about 38,000 MW and an annual generation in excess of 135 TWh. Their comparative advantage in terms of electricity exports arises from the factors summarized in Box 5.1.

| **Box 5.1: Comparative Advantages of Central Asian Republics in Electricity Exports** |
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| • Dramatic decline in electricity demand upon the dissolution of the Soviet Union rendered their generating capacity excessive. Annual generation of electricity, although increasing, still lags considerably behind the pre-1990 level. |
| • Tajikistan and Kyrgyz Republic have huge hydropower potential. They operate predominantly hydroelectric power systems, have large surplus generation available for export in spring and summer and face supply deficits in winter due to lack of thermal generation capacity or lack of fossil fuels. |
| • Generating facilities, including those whose construction had been initiated but then stopped after the break up of the Soviet Union, were designed or optimized on the basis of large regional markets within the Soviet Union, and became excessive to the needs of newly independent republics. |
| • There were a number of large power projects the construction of which commenced during the Soviet regime and later were suspended after incurring considerable amounts of sunk cost, for want of funds to complete them. When completed, their outputs would be far in excess of the needs of the host countries and thus their completion would make economic sense only if export markets could be found. Because of the large sunk costs already incurred in the Soviet era, the marginal cost of generation based on incremental investments could be attractive to prospective importers. |
| • Similarly, the incremental generation costs from the moth-balled thermal generating assets in Kazakhstan (upon their rehabilitation) would also be attractive.[42] Export of surplus thermal power from Kazakhstan, Turkmenistan and Uzbekistan (with significant and developed fossil fuel resources) could complement the hydro power exports from Tajikistan and Kyrgyz Republic to make part of the supply firm year round. |

In these countries, practically 100% of the households have access to electricity. Based on present high per capita consumption levels, income elasticity and effective price elasticity, the demand for electricity in these four countries during 2005-2025 is expected to grow at a very modest annual average rate of about 2% only, if the tariffs are to increase to full cost recovery levels and commercial discipline is strictly enforced.[43]

[41] Turkmenistan's power system also used to operate synchronously with the system of the other four Central Asian countries. During the time of the Soviet Union, the power systems of the five countries were developed as an integrated system, operated from a regional dispatch center in Tashkent (Uzbekistan). Since May 2003, the Turkmenistan system has been operating synchronously with that of Iran and not with the rest of the CAPS.

[42] AES the owner of Ekibastuz Thermal power plant in Kazakhstan and related coal fields estimates power generation costs of 1.0 to 1.2 cents per kWh upon rehabilitation of units 3-7 (300 MW) (2005-2007), less than 2.0 cents/kWh upon rehabilitation of unit 8 (500 MW) (2009), 2.0 to 3.0 cents/kWh upon rehabilitation of Unit 2 (500 MW) by 2011 and unit 1 (500 MW) by 2013 (Presentation by Dale Perry of AES in Istanbul conference "Electricity Beyond Borders" on June 13, 2006).

[43] Price increases and substantial improvements in metering, billing and collection system and procedures to enforce payments, reduce theft and other commercial losses, should limit demand increase.

Supply options such as system loss reduction, rehabilitation of generating units and completion of the large projects presently languishing for want of funds, could produce enough electricity to meet the forecast demand and leave substantial surpluses for export. Presently the surpluses are of the order of 11 TWh but almost the entire surplus is in the spring and summer months. In winter there is actually a shortage of about 1 TWh. The total annual surpluses could exceed 30 TWh in the next five years and 50 TWh in the next 10 years if the envisaged investment program is implemented. The major portion of the surpluses would continue to be in spring and summer, while surpluses in fall and winter would be lower by about 10 TWh in comparison.

Further, the World Bank's Central Asian Regional Electricity Export Potential Study (2004) demonstrated that electricity exports from the projects (partially completed during the Soviet rule) would be competitive in possible export markets such as Afghanistan, Pakistan, China, Russia and Iran (see Table 5.1). These estimates were made on the basis of Central Asian fuel prices at $35 per 1000 cubic meters of natural gas and $20 per ton of coal. The world oil price levels at that time were around $35/barrel.

**Table 5.1: Comparison of Marginal Cost in the Export Market with Import Costs from Central Asia (Cents/kWh)**

| **Target Market** | **Marginal generation cost in the target Market** | **Generation Options in Central Asian Republics (CARs)** | **Cost of Supply from CARs** |
|---|---|---|---|
| **Afghanistan** | >10 | Sangtuda I, Rogun I, Talimardjan I and II | 2.26 to 3.43 |
| **Iran** | 3.6 | Sangtuda I, Rogun I, Talimardjan I and II | 2.29 to 3.46 |
| **Pakistan** | 5.6 | Sangtuda I, Rogun I, Talimardjan I and II and Kambarata II | 2.26 to 3.75 |
| **China** | 3.6 | Sangtuda I, Talimardjan I | 2.47 to 3.16 |
| **Russia** | 3.0 | Sangtuda I, Talimardjan I | 2.30 to 2.99 |

Turkmenistan has installed generation capacity of nearly 3000 MW. In 2005 it generated 12.3 TWh, of which nearly 10.5% was exported to Turkey, Iran and Afghanistan. Given its substantial natural gas resources, it could step up its capacity and generation for exports at an attractive marginal cost.

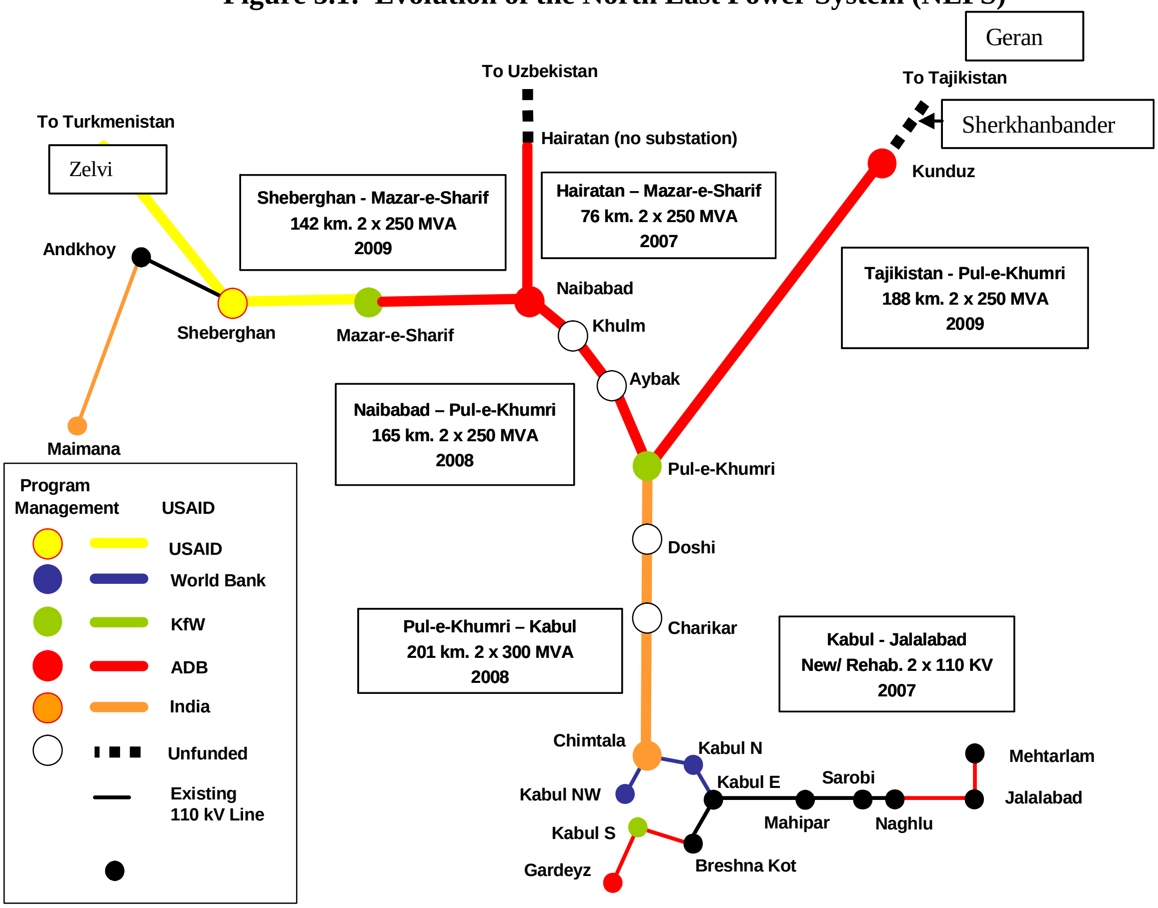
Iran has an installed power generation capacity exceeding 34,000 MW and an annual generation over 149 TWh. It operates three isolated power systems. The north eastern power system in Khorasan province and the southeastern power system in Sistan-Baluchistan province adjoining Turkmenistan, Afghanistan and Pakistan are isolated from the much larger western grid. Imports of power to these areas from Turkmenistan in 2003 were substantial (230 GWh), and there were small exports to Afghanistan (17 GWh) and Pakistan (47 GWh).

Iran and Turkmenistan have substantial natural gas resources for export and both (especially the latter) are looking for opportunities to diversify their markets and extend towards South Asia. Uzbekistan and Kazakhstan also envisage a rapidly growing production of natural gas and looking eastwards for new markets. Kazakhstan is also rich in low cost good quality coal and could offer competitively priced electricity generated from such coal for export. For Tajikistan and Kyrgyz Republic, export of hydroelectricity could be a key driver of their economic growth. Such exports would also enable the two countries, heavily relying on hydropower, to pay for the fossil fuel imports needed to mitigate their winter supply shortages.

### 5.1.1 Central Asia – Afghanistan Bilateral Electricity Trade

Afghanistan's modest-sized and extensively damaged power system is fragmented and includes four main isolated grids clustered around areas of Kabul in the east, Mazar-e-Sharif in the north, Herat in the west, and Kandahar in the south. Estimated unsuppressed demand at 363 MW outstrips the available capacity of about 270 MW and relentless daily load shedding has become inevitable. In the first eight months of 2006, electricity imports from Iran and Central Asia constituted 31% of the supply mix. Electricity peak demand is forecast to grow to 905 MW by 2020 at an average annual rate of 5.7%. Similarly, electric energy consumption is forecast to grow from 1,295 GWh to 3,868 GWh during 2004-20 at an average annual rate of 6.6%[44].

**Figure 5.1: Evolution of the North East Power System (NEPS)**




[44] Power Sector Master Plan, Transitional Islamic State of Afghanistan, (October 2004); prepared by Norconsult and Norplan.

Import of power is expected to remain an important cost-effective component in Afghanistan's supply mix for the foreseeable future, both because of its comparative cost advantage and the fact that reliance on imports would leave more funds to be available for electrification and distribution and transmission network extension[45].

Afghanistan's present levels of imports from Iran, Turkmenistan, Uzbekistan and Tajikistan have been given in Table 2.5. In order to increase the volumes of import and absorb them, Afghanistan needs to build its first stage backbone 220 kV transmission system called North-East Power System (NEPs) which will enable the flow of power to the key load centers. The various parts of it are under construction under the financing provided by a range of donors (WB, ADB, USAID, KfW, India and others). NEPs is expected to be completed by 2008-2009 (see Figure 5.1). Also transmission links within the Central Asian countries need to be strengthened. The details in respect of each country exporting to Afghanistan are discussed below.

*Tajikistan* has substantial surplus generation capacity during the spring and summer seasons and is looking for export opportunities. It has also partially completed large hydro projects such as Sangtuda I and Rogun, which when completed would provide very large volumes of surplus power for exports. It has a weak interconnection from Geran to Kunduz (Afghanistan) at 110 kV, operated at 35kV on the Afghan side. In an MOU signed in April 2005 and the subsequent agreements signed in December 2005, Tajikistan has agreed to supply 300 MW in spring and summer and whatever quantity it can, in fall and winter and construct a 220 kV double circuit line from Geran (Tajik) to Sherkhanbander (Afghan) to enable larger volumes of export. The double circuit 220 kV line from Sherkhanbander to Kunduz and then on to Pul-e-Khumri would be constructed by the Afghan side under ADB financing and would become a part of the backbone of the NEPS by 2008-09 (see Figure 5.1).[46] Tajikistan would also supply power from its system to some of the Afghan border towns. In addition, Tajikistan was planning to construct a double circuit 220 kV line from Lalazar to Kulab within Tajikistan and one circuit of which would be made available for extension into the Faizabad area in the Badakshan province of Afghanistan and perhaps eventually for interconnection with Kabul. Since the supply from Tajikistan would be seasonal it may have to be supplemented by imports from Uzbekistan and Turkmenistan during fall and winter.

*Uzbekistan* has an installed capacity exceeding 11,500 MW and an annual generation exceeding 49 TWh and a peak demand of about 7,700 MW. It has recently commissioned the first 800 MW unit of Talimardjan Thermal Power plant and three more units of the same size are expected to be constructed in the medium term. Uzbekistan has considerable natural gas and coal resources and its generation mix is predominantly

[45] Though the Power System Master Plan (2004) of Afghanistan calculates the long term average incremental cost of power generation at 5.0 cents/kWh, realistically short to medium term marginal cost of generation is most likely to be the economic cost of production by diesel generators, at around 10 to 15 cents per kWh. Imports from Central Asia and Iran presently are priced in the range of 2.0 cents to 2.65 cents per kWh, which probably reflects their short-term marginal cost and, at least in case of Iran, may contain a subsidy element as a form of external assistance. Given the general surplus of electricity in Central Asia, imports should remain cost-effective options for Afghanistan.

[46] ADB is also financing a dedicated 220 kV line from a substation near Sangtuda I to connect to the line in Afghanistan at Sherkhanbander.

thermal. Unlike Tajikistan and Kyrgyz Republic, it could provide year round firm supply of electricity to Afghanistan. Uzbekistan exports electricity through a 220 kV double circuit line from Termez to Mazar-e-Sharif presently operated at 110 kV. The supply which was suspended in 1999 during the Taliban rule was resumed in August 2002. In May 2003 a Protocol of Intentions was signed between the Afghan Ministry of Water and Power and Uzbekenergo, which indicated that Uzbekistan would provide up to 150 MW for a 10 year period. The price during the first year would be 2.0 cents/kWh. Prices for subsequent years had to be negotiated.[47] An Afghan delegation visited Tashkent in July 2006 with a request for imports up to 300 MW and for the establishment of the technical conditions. Uzbekenergo indicated the specific transmission constraints in its system which limit the supply capability to 85 MW. The Afghan side is following up with the Uzbek government for undertaking investments to eliminate these constraints to enable supply of 300 MW.

*Turkmenistan* is well endowed with natural gas resources and has a power system (with entirely thermal generation) capable of providing firm year round supply. With an installed capacity of nearly 3000 MW and a production level of 12.34 TWh of electricity in 2005 (an eight percent increase from 2004), Turkmenistan exported electricity in 2005 to Turkey (534.6 GWh), Iran (598.9 GWh) and to Afghanistan (160 GWh). Its total exports at 1.3 TWh were 13.8% more than in 2004. Turkmenistan is thus a good source of firm power to Afghanistan's western and north western provinces. In October 2003 Afghanistan is reported to have signed an agreement with Turkmenistan for supplying 165 GWh via the 110 kV line to Andkhoy –Jawzjan- Sheberghan area and another 160 GWh via the Gushby-Herat line (220 kV operated at 110 kV) to Herat area at a price of 2.0 cents per kWh. In an MOU of April 25, 2006, Turkmenistan has agreed to extend 220 kV lines to border towns and supply power. In principle Turkmenistan signed an MOU for the supply of 300 MW of firm power. On June 7, 2006 the Ministries of Energy of the two countries signed a protocol for the supply of 200 MW in the first stage However actual imports reported by DABM amounted only to 97.9 and 165.3 GWh in FY 2004-2005 and FY 2005-2006 respectively. In the first three months of FY2006-2007 the imports amounted to 47.7 GWh.[48] In order to increase the imports at least to the levels covered by the protocols, the operation of the Gushby to Herat line needs to be upgraded to 220 kV level and the proposed new 220 kV line from Zelvi (Turkmenistan) to Mazar-e-sharif should be completed. It is planned to build the 130 km long 220 kV double circuit line from Zelvi (Turkmenistan) to Sheberghan and then on to Mazar-e-sharif (Afghanistan) under USAID financing. The Feasibility Study for this would be completed in 2007. At that time arrangements will have to be in place to handle the situation arising from Turkmenistan operating synchronously with Iran and not with the rest of the Central Asian Republics.

*Iran* has an installed power generation capacity exceeding 34,000 MW and a generation exceeding 149 TWh. However the power systems in the provinces of Khorasan and Sistan Va Baluchistan provinces adjoining Afghanistan are isolated from the much larger

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[47] Price was increased to 2.3 US cents the following year and currently is 2.65 US cents per kWh.

[48] The financial year of Afghanistan government ends on March 20.

interconnected western grid and actually import 599 GWh from Turkmenistan (2005). However supply of the relatively small volumes contracted so far (50 MW and 6MW) to Afghanistan have not presented a problem. Iran supplies power now through a double circuit 132 kV line (150 km) from Torbat-e-jam to Herat, which it financed and constructed and commissioned in January 2005. In addition, power also flows to the Herat area through two 20 kV lines from Iran. Further Iran supplies Zaranj, a border town in the Nimroz province through a 20 kV line opened by Iran in March 2004.

Khorasan province of Iran is already importing notable quantities of power from Turkmenistan. Iran has recently signed an agreement with Tajikistan to invest in the construction of Sangtuda II hydroelectric project (270 MW run of river scheme), the output of which will go to Iran (Mashad area of Khorasan province). The related transmission line would most probably pass through Afghanistan providing the latter an opportunity to earn transit fees. It may also provide an opportunity to integrate the Herat Grid with NEPS. Presently Iranian power is being supplied at a price of 2.25 cents / kWh, which is valid through 2006.

Actual imports of electricity in Afghanistan appear to run well behind agreed volumes of power largely on account of transmission and distribution constraints, and donors are doing their best in providing timely funding for the needed improvements. Construction seems to be impeded by the cost and time needed to clear the areas of mines as well as by the need to ensure that compensation amounts for the right-of-way are paid fully and recorded in a timely manner. Some special efforts appear to be needed to reduce the cost and speed up the operation. Costs of de-mining need to be more fully incorporated into the cost structure of the projects.

### 5.1.2 Iran-Pakistan Bilateral Electricity Trade

The details of the existing import of power by Pakistan from Iran had been given in Section 2.3. The supply by 132 kV line is mainly for the area around the deep sea port of Gwadar in Pakistan. Anticipating an increase in demand induced by the port related developments, WAPDA has negotiated for increased supply levels up to 100 MW and has made arrangements for a new 220kV link. Gwadar is the only deep sea port, other than Karachi in Pakistan and growth in its hinterland is likely to be substantial. The import price of power appears to have risen from 3 cents to about 6.25 cents/kWh. When the Iran-Pakistan-India gas pipeline project materializes, it will pass through this area and there may be a possibility of constructing here a gas based combined cycle power plant to meet the likely demand growth.

### 5.1.3 Pakistan-India and Pakistan-Afghanistan Bilateral Electricity Trade

Towards the end of the 1990s, Pakistan faced a surplus power situation when demand did not grow as forecast, and when WAPDA had to face financial problems arising from the “take or pay contracts” with a significant number of IPPs. In that context, both Pakistan and the IPPs explored the possibility of export of surplus power to India. Despite a great deal of discussions at various levels, the trade did not materialize because of the big difference in the power price WAPDA wanted (7.5 cents/kWh) and the price which the Power Grid Corporation of India was willing to pay (2.25 cents/kWh). It was, however, recognized at that time that interconnections and operating agreements would present no major problems.[49]

Presently there are no electrical interconnections and no electricity trade between the two countries. The western and northern regions of the Indian national grid, which adjoin Pakistan's grid in Punjab and Sind Provinces, presently have peak capacity shortages of 6000 MW and 3700 MW and energy shortages of 25TWh and 21TWh respectively. The Pakistan grid is short of firm power and suffers from peaking shortages in summer. The seasonal variations in demand are about the same on both sides. There is thus no immediate export/import advantage to either side by interconnecting the grids. Medium or low voltage links could help border villages and settlements. However, strong extra high voltage links (400 kV or above) from Pakistan Grid to both northern and western regions of the Indian grid would be warranted in the context of major power imports from Central Asia, perhaps in the context of the stage II of the proposed CA-SA electricity trade project. Apart from enabling the import of Central Asian power, the two grids would have the advantages associated with synchronous operation of adjoining grids, namely better system security and reliability at a lower cost and better ability to take care of unanticipated outages arising from accidents, and the better ability to balance the systems in real time. Such interconnections could conceivably enable Nepal (and possibly Bhutan) to diversify their export markets to Pakistan in the context of the transfer capacity in the Indian grid being stepped up to more than 30,000 MW in the medium term. The thaw in the political tensions between the two countries and the progress in confidence building measures would seem to indicate that future development along these lines is likely.

Pakistan-Afghanistan bilateral electricity trade had been discussed on several occasions and WAPDA had even prepared proposals for several cross border interconnections at 20 kV. However none of them materialized. Pakistan appears to be concerned about the payment risks. Pakistan is finding it difficult to collect payments and disconnect non-payers from its own Federally Administered Tribal Areas adjoining Afghanistan. In this context disconnecting supply to the customers in Afghanistan might become a politically sensitive issue. Thus the bilateral trade may have to wait till the CA-SA trade arrangements materialize.

### 5.1.4 Central Asia-South Asia Multilateral Electricity Trade

During the Soviet rule the power systems of the five countries of the Central Asia (Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan) operated synchronously. Upon the dissolution of the Soviet Union, this multilateral "pool" was replaced by a system of bilateral cross border transactions. As a result, the volume of trade declined by about 68% during the 1990s from about 25 TWh to 8 TWh. The decline was caused by a range of reasons which included a dramatic decline in electricity demand, the use of barter of electricity for fossil fuels and the quick rise in the traded

[49] Presentation by Dr. Mahendra P. Lama of Jawaharlal Nehru University, New Delhi, *Economic Reforms and Power Sector in South Asia: Scope and Challenges for Cross Border Trade* available at the website of USAID SARI-E Program.

fossil fuel prices to world traded level, while electricity prices stagnated. However the most important reason was the breakdown of the traditional regional water sharing agreements and the associated electricity trading arrangements. These impediments have to be overcome to improve the volume of mutually beneficial trading among the Central Asian countries. However, electricity surpluses are there in all Central Asian countries and internal trade among them and trade with Afghanistan alone can not absorb the exportable surplus.[50] It is in this context that the idea of exporting the surplus to Pakistan and in the later stages possibly to India in a multilateral framework emerged.

Pakistan's peak demand now exceeds 14,000 MW and the present installed capacity of 19,500 MW (33% hydro, 65% thermal and 2% nuclear) has become inadequate on account of the wide variations in the water availability which greatly reduces the firm capacity available. The economy had been growing at around 6% to 7% in the past four years and is expected maintain such growth rates during the next several years. Electricity demand at the generation level is forecast to grow at 7% to 8% per year to about 20,000 MW by FY2010, and 44,700 by FY 2020. The country, which had a comfortable supply position during the last several years, has already started experiencing shortages during peak periods and it is anticipated that if no new capacity is added, firm power shortages would amount to 5,500 MW by FY2010. By FY 2011 energy shortages would amount to about 35 TWh. The array of options considered to meet this demand include supply efficiency, demand management, addition of new hydro and thermal power capacities both under the public and private ownerships, *as well as electricity imports from Central Asia, starting with 1000 MW in the initial phase*. If the imports prove reliable and competitive, the volumes could rise substantially in the second phase. The particularly attractive feature of this proposal is that Pakistan's peak demand occurs in summer, when the Central Asian power systems have large surpluses from their hydroelectric generating stations.[51]

Efforts to develop the first trans-regional electricity trade project commenced at the regional conference in Islamabad, in May 2006 which was attended by the experts of power utilities and governments officials of Afghanistan, Kyrgyz Republic, Pakistan, and Tajikistan as well as representatives of a number of IFIs and bilateral donors (World Bank, IFC, Asian Development Bank, Islamic Development Bank, and USAID) and interested private sector investors (AES of USA and RAO UES of Russia). In this conference Pakistan formally expressed its interest in importing 1000 MW of power from Tajikistan and Kyrgyz Republic. Should the arrangement for the first stage prove reliable and competitive, Pakistan indicated it would consider further increasing the import volume, perhaps as high as 4,000 MW. Tajikistan and Kyrgyz Republic confirmed their desire to export and Afghanistan agreed to enable the transit of power and also to eventually import some quantities for its own market. A Multi-Country Working Group (MCWG) was set up to initiate analytical, institutional, organizational and other activities for the preparation of this Central Asia – South Asia 1000 MW (*CASA-1000*) project with

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[50] For a more detailed discussion of these aspects see *Water and Energy Nexus in Central Asia*, World Bank ( February 2004) and Central Asia: Regional Electricity Export Potential Study, World Bank (December 2004)

[51] Pakistan also experiences supply shortages in winter months too, when natural gas supplies are diverted from electricity production to household use.

assistance from IFIs, led by the World Bank. The World Bank has financed the consulting services to assist the MCWG in the initial stages of the work. An important outcome of this meeting was the shared recognition that there are significant opportunities for, and advantages from, expanding the trade over time to include other countries both on the selling and buying sides, creating an integrated regional electricity market. At the subsequent regional conference in Dushanbe (October 26-28, 2006), the four countries signed a Memorandum of Understanding on Project Development for building a high-voltage transmission line between Tajikistan and Pakistan via Afghanistan, and created a Ministerial Council to coordinate the effort.
Several developments preceding the Islamabad conference are indicative of the potential for development of a broad-based electricity trade in the region:

- RAO UES of Russia has formed a joint venture (75% RAO UES and 25% Tajik Government) which has obtained the right to take over and complete the construction of the run-of-river hydroelectric project Sangtuda I (670 MW, energy 2,700 GWh/year, 60% of which would be in summer). The construction is under way, to be completed in 2009. The Joint Venture has approached the IFIs for possible equity participation and debt financing.[52] The output is targeted for exports mainly to Pakistan.

- AES, a US-based strategic international investor in the power sector, which already has assets in Central Asia and South Asia, has reportedly signed an MOU with the Tajik government for undertaking transmission investments and hydro power station rehabilitation investments and also offering to *handle* the export of 1500 GWh (about 300 MW) from the existing summer surplus of Tajikistan to Afghanistan and South Asia.

- A study by NESPAK, a Pakistani consulting firm, completed a preliminary evaluation of possible electricity transmission routes between Tajikistan and Pakistan. Two main routing options were considered: (i) a 650 km route passing through Kunduz and Kabul/Jalalabad in Afghanistan, with 170 km of the route passing through Tajikistan, 430 km through Afghanistan, and 50 km through Pakistan; and (ii) a 700 km route that would minimize the length of transmission through Afghanistan, with only 30 passing through the narrow Wakhan corridor, with the rest of the route going through Tajikistan (360 km) and Pakistan (310 km). The technological options included 500-kV and 765-kV AC lines and 250-kV and 400-kV DC lines. The Wakhan route was estimated to be costlier by 40% to 60% on account of the very high elevation and the extremely difficult nature of the terrain and weather conditions.

It may be noteworthy to mention some other developments indicative of the interests of the countries and private sector in regional electricity projects:

- Iran has signed a MOU with Tajikistan to set up a joint venture to develop a run-of-river hydroelectric project, Sangtuda II (220 MW, 990 GWh). The output is intended for export to Khorasan province of Iran via Afghanistan.

[52] Most probably, the equity of Tajik government would remain at 25%. RAO UES may divest a portion of its 75% shares to IFC and EBRD, but is expected to keep at least 50% of the shares for itself.

- A large Aluminum producer of Russia, Rusal, has evinced interest in investing in the Rogun storage hydroelectric project (3600 MW, 13000 GWh, incremental investment exceeding $2 billion) and has carried out feasibility studies by a German consultant. As a storage hydro project, Rogun would need inter-governmental agreement among riparian states on water use and reservoir operating regimes and might therefore may take a longer time to materialize.

In order to supply 1000 MW to Pakistan, other suppliers may have to join the Sangtuda Joint Venture Power Company, which can provide only up to 670 MW. The summer surpluses of the existing Tajik system may provide another 300 MW even after setting apart the 300 MW which it had agreed to provide for Afghanistan through the 220 kV lines (see section 5.1.1 for details). Golovnaya Hydro power station in the Nurek cascade of Tajikistan could provide an additional 80 MW to 100 MW after its rehabilitation. Summer surpluses from the Kyrgyz system could provide up to 600 MW, provided that the present transmission constraint of the lines passing through Uzbekistan is eliminated by constructing a bypass 220 kV line (capital cost estimated at $45 million) within the territories of Kyrgyz Republic and Tajikistan. Attractively priced thermal power from the northern parts of Kazakhstan (such as Ekibastuz) could flow to the Kyrgyz Republic through the second North-South 500 kV line, currently under construction in Kazakhstan, although it remains to be seen how much capacity would be available for exports vs. supplying the southern Kazakhstan. However, it could flow further south only if the above mentioned bypass line is upgraded to 500 kV level. In order to enable the Kazakh power and the Kyrgyz power to reach the Nurek cascade in the southern part of Tajikistan, a north-south 500 kV line has to be constructed in Tajikistan and this line has already been funded by the Chinese export credits of $267 million and is expected to be ready by 2008-09. Thermal power supplies from Kazakhstan could help to increase the volume of firm (year round) power supply to Pakistan. Rogun storage hydro could provide this type of support, if and when the plant is built. Uzbekistan and Turkmenistan also may have a potential to add thermal power to the export surplus of the region.

The CASA-1000 project, as agreed at the Islamabad and Dushanbe conferences, will start with analytical studies to examine the merits and the scope of the potential trade and commercial options for structuring the project as a public-private partnership (PPP) arrangement. One study would focus on technical, economic, and safeguard issues, while another one would examine institutional, financial, legal, and risk mitigation issues of the possible commercial structural options.

Apart from carrying out the usual due diligence needed to satisfy the potential financiers (which may come both from the private and public sectors), the two proposed studies would analyze and enable decision making in respect of some key issues:

- The assessment of trade potential and the associated benefits: the studies should establish the volumes of electricity available for export over time (including through additional investments in generation), the cost range for these exports, as well as demand in the importing countries and the price range which the importing markets could or would be willing to bear.

- Selection of transmission corridor and technology: connecting a number of disparate power systems over difficult terrain would present significant technical challenges. The options involving High Voltage Direct Current (HVDC) technology may minimize initial problems, but are costlier and less flexible for further expansion in comparison with the High Voltage Alternate Current (HVAC) technologies. The trade-off would need to be carefully considered and evaluated.

- Institutional, financial, and regulatory issues: There would be a number of potential exporters: Sangtuda Power Company, Barki Tajik and the Kyrgyz Power Generation Company, to start with, and at a later stage private trading companies set up by investors; and possibly other countries (Kazakhstan and Uzbekistan). The importers would be the Pakistan power utilities, with the possibility of Afghanistan's DABM also becoming an importer, perhaps at a later stage. The trade volume would increase over time and there may be a need to expand the transmission capacity. There are the issues to be sorted out and agreed upon. They include: structuring the trade with multiple sellers and, at a later stage, multiple buyers; responsibility for transmission investments; allocation of the transmission risk; dealing with non-payment risks; ensuring the neutrality of the transmission system planning, ownership, operation and maintenance; allocation of the transmission capacity among the sellers (and buyers); determination, administration and oversight of transmission access rules; payment clearance and settlement; and, last but not least, the method of resolution of the potential dispatch conflicts between regional and domestic transactions.

- Risk mitigation strategies: The project would face a number of risks, some of them unique to this case, such as the nature and the level of security risks through Afghanistan and innovative risk mitigation strategies they would call for, combining financial risk mitigation instruments with social, technical, and operational measures.

- Intergovernmental agreement: An overarching intergovernmental agreement may have to be concluded covering the key aspects on which government approvals and cooperation are needed. The agreement, inter alia, would deal with institutional and regulatory arrangements, coordination and harmonization of policies and regulations, right of way issues, coordination of water releases and electricity generation, risk mitigation, and the rules for expanding the arrangements to additional players and volumes of trade. Laws may have to be enacted and rules under them may have to be issued in the relevant countries to enable the construction, ownership and operation of the project by transnational entities or their subsidiaries.

These are complex issues which need to be thoroughly investigated and analyzed to inform decision makers on the available options and their trade-offs. A number of similar projects carried out elsewhere in the world could offer valuable lessons and guidance. The region itself also has some relevant experience and expertise. Pakistan has extensive experience in dealing with private investors and IPPs in the power sector. The Tajik government also has some experience in dealing with private sector on the basis of the PPP arrangements in the Gorno Badakshan area in respect of Pamir Power Project. Central Asia has experience in operating interconnected systems. Considering the poor access of most of the countries to the capital markets and the limitations of the resources which the IFIs could offer, some form of public private partnership appears highly desirable and even inevitable for the materialization of the project and its dependable operation with commercial discipline. Private interests have already materialized in the generation component and have been evinced for the transmission and trading components as well.

### 5.1.5 Turkmenistan, Afghanistan and Pakistan Natural Gas Trade (TAP)

The governments of Turkmenistan, Afghanistan and Pakistan have been examining since 2002 a gas pipeline project to enable Turkmenistan export about 30 bcm of gas per year to Pakistan via Afghanistan.[53] A series of related studies have been carried out with Asian Development Bank assistance.

The pipeline with a diameter of 56 inches would be 1680 km long and is estimated to cost $3.3 billion and would have the capacity to transport 30 bcm of gas per year. Gas will come from the Daulatabad fields of Turkmenistan which is estimated to have a reserve of 1.4 trillion cubic meters of gas. Its present level of production is 20 bcm a year, while it is capable of producing 45 bcm of gas per year. In November 2006 the Turkmenistan government announced the discovery of a new gas field near Mary with a reserve of 1.0 trillion cubic meters. The TAP pipeline project would transport about one trillion cubic meters of gas over its life span of 30 years.

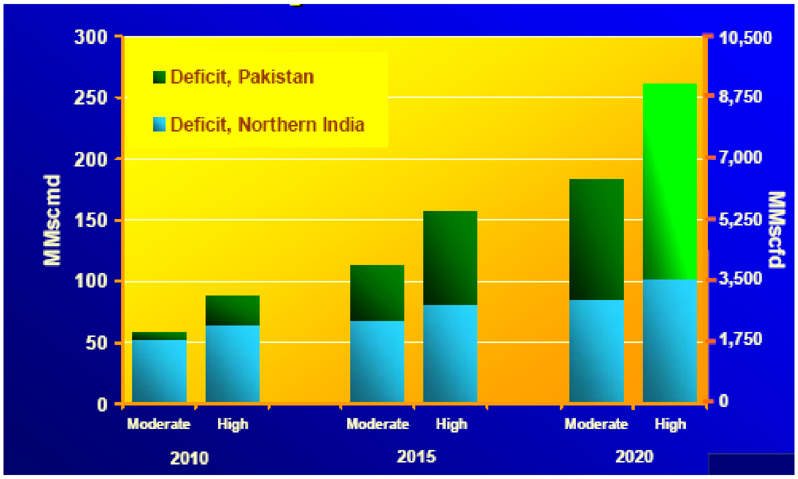
Gas market reviews in Pakistan indicate that Pak gas demand alone can support an import project of 20 bcm per year. The participants therefore are desirous that India should join the project as an importer to improve the economics of the project, and have formally extended an invitation to India, when it attended the Steering Committee Meeting on February 9, 2006 as an observer.[54]

The study finds that the pipeline option compares favorably with LNG option and the option of importing gas from Qatar. Based on the gas input price at Turkmenistan of $58 to $51 per thousand cubic meters of gas (corresponding to $1.63 to $1.44 per million BTU) and sale price in Pakistan of $77.5 to $71.04 per thousand cubic meters (or $2.18 to $2.0 per million BTU) the project FIRR was estimated at 10.1% and 10.4% respectively. Using early 2005 range of border and end user prices, FIRR seems to be around 15%. Afghanistan hopes to earn transit fees in the range of $100 million to $300 million and has promised full cooperation.

[53] This section is drawn on the presentation made by ADB in the Second Regional Economic Conference for Afghanistan held in Delhi in November 2006 available at the website :http://meaindia.nic.in/srec/frame.php?s=internalpages/rbusiness.htm

[54] Integrated Energy Policy Report (2006) of the Government of India envisages import dependence for natural gas from 0 to 49% during the period through FY2032, depending on the price of natural gas. At prices higher than $4.5 per million BTU, natural gas is not believed to be competitive with coal (which remains at $ 2.27 per million BTU even after blending with imported coals) even for peaking power.

**Figure 5.2: Natural Gas Deficit Projections in Pakistan and India**




Source: ADB presentation in the Delhi Conference of November 2006

Some of the key issues to be sorted out include: the robustness of the reserves data in Turkmenistan and the need to have it properly certified; possible need to associate Uzbekistan and Kazakhstan to provide supplemental gas resources; the ability and willingness of Turkmenistan to feed this pipeline while fully honoring its earlier commitments to Gazprom for the European and former Soviet Union markets; and the extent of possible private sector interest.[55] Further the sharp increases in gas prices delivered to the European markets could make the option of exporting to South Asia less attractive to Turkmenistan and thus the export price could also become a major issue. Challenges include mitigation of the security risk in Afghanistan, improvement in India-Pakistan relations, and programs to minimize or phase out fuel subsidies in both countries and finally the ability of the pipeline option to withstand competition from LNG in the long run (see Box 5.2).

[55] Bridas Corporation of Argentina, China National Petroleum Corporation, Gazprom, and OMV of Austria are believed to have shown interest in the project at different times.

**Box 5.2: Gas Sector in Pakistan**

Proven natural gas reserves of Pakistan as of January 2005, are reported as 26.83tcf (759.2 bcm) by the Oil and Gas journal. The website of the Ministry of Petroleum and Natural Resources, however, reports a slightly higher reserve figure of 28.51 tcf (807.4 bcm) as at the end of June 2005. More recent reports suggest a reserve level of 32.8 TCF (929.2 bcm). Production in FY 2005 amounted to 38.26 bcm. Total length of transmission pipelines was at 9,183 km and that of distribution and service lines amounted to 72,434 km as at the end of March 2006. There were a total of 4.5 million consumers with a total consumption of 32.89 bcm in FY 2005 and a consumption of 25.9 bcm in the first nine months of FY 2006. The largest share of consumption went to power (43.7%) followed by general industry (19.5%), fertilizer (16.4%), households (14.8%), commercial consumers (2.3%) and transport (2.1%). Gas losses in the system amounted to about 7% to 7.5% of the total input into the system.

Past demand growth in gas consumption was at about 8.5% a year. Future demand growth is forecast at about 7% a year. It is estimated that the domestic production will peak in FY 2010 and start declining rapidly after FY 2013. Supply shortfall is expected to be between 4%and 10% of the demand by 2010 and would thereafter increase rapidly to 20% of the demand. It is in this context that import options through pipelines from Iran, Central Asia and Qatar and LNG imports are being pursued. A LNG terminal with a capacity of 3.5 million tons will be built in Karachi by a project developer to be selected on a competitive basis. First shipments of LNG are expected by 2011. Attempts are also being made to discover new gas fields and improve yields from existing fields. An agreement has been concluded with Gazprom for research and development regarding future gas fields.

As per the tariff prevailing on January 1, 2006, the end-use gas tariffs per million BTU for the lowest block (below 100 cubic meters per month) and the highest block (above 300 cubic meters per month) of household consumption were $1.35 and $5.13 respectively. The tariffs for commercial consumers and general industries (including power) were at $ 4.53 and $ 4.03 respectively. Supply to the fertilizer industry for use as feedstock was at rates from $0.61 to $1.48. The tariff for the power companies at around $3.95 does not appear to be unduly subsidized. The first block of household tariff covered 82% of the consumption in winter and 54% of the consumption in the remaining months. The tariffs for this block and for fertilizer factories were heavily subsidized and did not cover even the commodity cost of gas, let alone the transmission and distribution margins. In FY 2003 the total subsidy for these two categories amounted to Rs 23 billion (or $397 million).

In the tariffs revised on 30 June 2006 one new block was introduced for households. The lowest block had a consumption ceiling of 50 cubic meters/month. The price for this block was increased by 5% while the prices for all other categories were increased by 10%. However in the revised tariffs notified effective from 1 February 2007, price for this category has been reduced by 7.8%. Commercial consumers had a reduction of 10%. In the context of the need for the expensive imports of piped gas and LNG further domestic price corrections would be necessary.

Sources: www.mpnr.gov.pk , www.dawn.com/2006/07/29/top16.htm , www.ogra.org.pk, Country Analysis Brief of US DOE available at www.usdoe.eia

### 5.1.6 Iran-Pakistan-India Natural Gas Pipeline (IPI)

The possibility of import of natural gas from the South Pars gas field of Iran to Pakistan and India by a 2,670 km long 48-inch diameter overland pipeline passing through Iran, Balochistan and Punjab provinces of Pakistan and then on to India, at a cost of around $7 billion, had been discussed for over a decade now. It was originally intended to supply 150 million cubic meters per day (or 54.75 bcm/year) of gas to India and 60 million cubic meters/day (or 21.9 bcm/year) of gas to Pakistan for a period of 25 years. Gazprom of

Russia (with whom Pakistan has an agreement for research and development of future gas fields) has expressed its interest in investing in this project.

A Joint Working Group of the three governments was working out the details while financial, technical and legal consultants were advising each of the three governments. Pricing appeared to be a major issue in concluding the negotiations. Iran's approach seemed to adopt the same level of pricing, at which the government of India concluded a deal with the National Iranian Oil Company in January 2005, for the import of 5 million tons per year of LNG (later rising to 7.5 millions tons /year) for a period of 25 years commencing from FY 2010.[56] The buyers thought that this approach to piped gas was not happy. As of 28 November 2006, the price for piped gas had not been agreed upon and the consulting firm engaged by Iran had been requested by the buyers to come up with a revised offer.

However in January 2007, Pakistan and Iran signed a bilateral agreement in terms of which Iran will supply for a period of 30 years 2.1 bcf/day(21.7 bcm/year) of gas in the first phase and an additional 3.2 bcf/day (33.1 bcm/year) in the second phase to the Iran-Pakistan border at a price of $4.93/mmbtu.[57] Iran has already commenced the construction of a 56 inch diameter gas pipeline from the Assaluyeh gas field (located 80 km north of the South Pars field) to Iran Shehr located within Iran 200 km west of the Pakistan border to meet the demands of its eastern provinces with a completion date of 2010. The supply to Pakistan border will be by one 56 inch diameter pipeline in the first phase. In the second phase the pipeline will be doubled.

Pakistan has proposed that it will construct a 1036 km long pipeline in its territory from its Iranian border to the Indian border (at an estimated cost of $ 3.5 billion and a completion date of 2013) and supply Iranian gas to India as shown below:

[56] The FOB price of LNG per million BTU was stipulated in the contract as 6.5% of the average Brent crude price in dollars per barrel at the time shipping (subject to a maximum crude price of $31 per barrel) plus a fixed charge of $1.2 per million BTU. On this basis the maximum FOB price of LNG would be $3.215 per million BTU. In the context of the massive increase in oil prices since then, Iranian government stated in August 2006, that the Supreme Economic Council had not approved the deal and wondered whether the contract was effective. Thus these prices are likely to be renegotiated, especially in the context of Iran having concluded a contract subsequently with China for supplying 3 million tons/year of LNG for 25 years at a price of $5.0 per million BTU. It is understood that the Indian government has proposed the ceiling price to be adopted for Brent crude at $55 per barrel resulting in the maximum FOB price of LNG at $4.775 per million BTU. The Iranian side seems to be bargaining for a maximum LNG price of $5.425 per million BTU adopting a ceiling price of $65 per barrel for Brent crude. In addition LNG transportation cost from Iran to India, computed at $0.30 per million BTU, has to be paid.

[57] The pricing formula is similar to that proposed for LNG export. It consists of a variable part linked to the specified crude oil price, a fixed component and a transmission charge. The variable part is 6.3% of the Japanese Crude Cocktail Price in the range of $30 to $70/barrel. Presently it is $3.78/mmbtu corresponding to the crude price of $60/barrel. The fixed charge is $1.15/mmbtu and the transport charge to Pakistan Border is $1.0/mmbtu. This results in the quoted price of $ 4.93/mmbtu for Pakistan. When crude price is below the range of $30-$70, the fixed price will increase to $1.54/mmbtu. When it is above the range the fixed price will be $2.06/mmbtu. This has been found acceptable to both India and Pakistan. (see http://timesofindia.indiatimes.com/articleshow/msid-186370 news item dated 6 April 2007)

Table 5.2: Planned Supply of Gas from Iran to India and Pakistan (mmcfd)

| Phase | Share of Pakistan | Share of India | Total from Iran |
|---|---|---|---|
| Phase 1 | 1.05 | 1.05 | 2.1 |
| Phase 2 | 1.05 | 2.15 | 3.2 |
| Total (both Phases) | 2.1 | 3.2 | 5.4 |

Pakistan has proposed that India pay a transit fee and a transmission charge to Pakistan, since it will transmit the gas through its territory and will be responsible for the safety and protection of the pipeline. India appears to have made a counter proposal (see Table 5.3. These are under discussion and likely to be settled in the next few weeks.

Table 5.3: Price proposal for the supply of Iranian gas to India ($/mmbtu)

| Proposal of | Gas Price at Iran/Pak border | Pakistan Transit fee | Pakistan Transmission charge | Total landed cost at the Indian border |
|---|---|---|---|---|
| Pakistan's proposal | 4.93 | 0.49 | 1,57 | 6.99 |
| India's proposal | 4.93 | 0.25 | 0.50 | 5.68 |

Source: http://timesofindia.indiatimes.com/articleshow/msid-186370 News of April6, 2007

The issue of price thus seems to be close to a resolution. The problem of transit through Balochistan seems to have been lessened by Pakistan assuming responsibility for transport and protection of the pipeline. The project seems to be poised for implementation on a priority basis. Other matters to be resolved would include the implications of the US law which bars transactions with Iran valued at $20 million or more, and the UN sanctions regime, as these might discourage the participation by international contractors. To sustain this trade on a commercial basis and to expand trade on similar lines, Pakistan and India may need to improve their domestic gas price regimes and minimize subsidies (see Box 5.2 and Box 5.3 and also Chapter 6).

**Box 5.3: Gas Sector in India**

Indian natural gas reserves were estimated at 1101 bcm in FY 2006. With annual production of about 32.2 bcm the reserve-to-production ratio is about 34 years. In addition, LNG imports have just commenced at the rate of 2.3 million tons/year. The largest share of the total gas consumption was in the power sector (37%) followed by fertilizer (35%), transport (9%), steel (6%) and others (14%).

About 79% of the gas production in the country is by the state-owned companies Oil and Natural Gas Corporation (ONGC) and Oil India Limited (OIL). The remaining 21% is by the private investors and Joint venture companies. The reserve data does not include the significant and recent discoveries in the Krishna Godavari basin off India's eastern coast. In this basin Reliance Industries Limited (RIL) and Gujarat State Petroleum Corporation (GSPC) are believed to have reserves of 396.6 bcm and 566.57 bcm respectively. RIL would produce 29.2 bcm of gas per year. Production of GSPC would be about 25.5 bcm per year.

On the basis of GDP growth rate of 9% per year, the demand for natural gas is forecast to grow at the compounded annual growth rate (CAGR) 8.0% from 31 bcm in FY 2004 to 267 bcm in FY 2032. Gas demand for power would grow faster at 9.34% from 11 bcm to 134 bcm, while the gas demand for non-power uses would grow at 7.0% from 20 bcm to 133 bcm during the same period.

The Integrated Energy Policy Report of the Expert Committee of the Planning Commission of India (August 2006) conservatively assumes that the annual domestic gas production would increase to about 111 bcm by FY 2032. On this basis the import dependency would be about 156 bcm or about 58%. At 8% annual GDP growth rates the import dependency may fall to about 108 bcm or 49%. The recent sharp increases in the price of oil and the associated price of traded LNG, as well as piped gas from abroad may affect the gas demand growth especially in the power sector, as, at prices of $4.5 per million BTU of gas or higher, gas is not considered competitive in relation to coal, even for peaking power as long as coal price remains at $ 2.27 per million BTU ($45/ton of imported coal with 6000 kcal/kg).

The gas pipeline infrastructure in India is rapidly expanding. GAIL is constructing the various links to create the national gas grid to handle the expanding domestic gas production as well the gas from the several terminals importing LNG. Reliance is constructing the pipelines to transmit gas from Krishna Godavari basin area to Mangalore in the south, Jamnagar in the west and Dadri in the north. RIL, GAIL and ONGC are forming a joint venture to set up gas distribution projects. Reliance has applied for gas distribution rights in 100 cities. Many other domestic and foreign investors too have applied for distribution rights in other cities. GSPC will carry out gas distribution and CNG distribution (for vehicles) in 40 cities and towns of Gujarat.

LNG terminals at Dahej (5 million tons/year) and Hazira (2.5 million tons/yr) are in operation. The one at Dabhol (5 million tons/yr) is expected to be in operation any time now. The terminal in Cochin (5mt/yr) will be in operation by FY2009 and that in Ennore (2.5 million tons/yr) and Phase II of Dahej during 2009-2012. By 2010 LNG re-gasification capacity would be 25 million tons/year. One half of this is already tied up through long term contracts with Qatar and Iran. Rest will be tied up by FY 2010.

ONGC of India is involved in exploration, development and production of oil and gas in at least 12 countries abroad. These countries include: Myanmar, Russia, Vietnam, Qatar, Sudan, Nigeria, Ivory Coast, Libya, Egypt, Syria, Iraq and Iran. In Myanmar GAIL of India is also involved in exploration and production of offshore gas. Equity oil and gas from these investments are expected to improve the energy security of India. In addition the supply strategy relies also on imported LNG and imported piped gas from Myanmar, Iran, Central Asia and possibly also from Bangladesh.

A substantial body of public opinion exists both in India and Pakistan that this would be a "peace pipeline" somewhat like the gas pipeline between Egypt and Turkey creating mutually beneficial economic interdependencies and thus pave the way for speedier normalization of bilateral relations.

The project was first put together by BHPBilliton, a subsidiary of BHP of Australia, and subsequently several parties such as Petronas, Total, Shell, British Gas and Chinese National Petroleum Corporation have expressed investment interest in the project at different points in time. [58]

### 5.1.7 Qatar-Pakistan-India Submarine Gas Pipeline

Another proposal to construct a gas pipeline from the Dome gas field of Qatar to India via United Arab Emirates, and Karachi of Pakistan had also been considered for a long time. The 1,830 km long pipe line from Dome to UAE would be under the sea. It will cross UAE on land and go under the sea up to Karachi and then again go under the sea till it reaches the west coast of India. It has the advantage of avoiding the risk of possible supply disruption faced by surface pipeline passing through Balochistan, but is considered expensive in relation to the overland pipeline alternative and even in relation

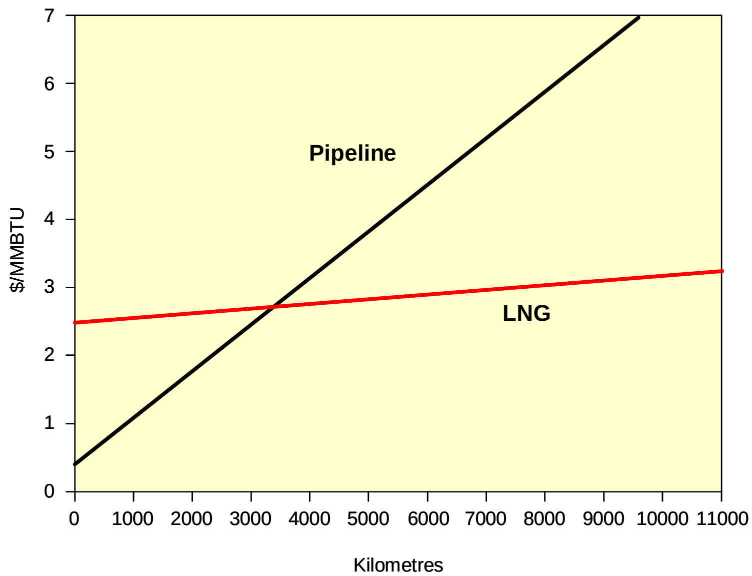
[58] This section is based on various sources including: www.indiadaily.com/editorial/3149.asp www.petroleum.nic.in ,www.atimes.com/atimes/South Asia/GA11Df07.html ,
www.hinduonnet.com (August 12, 2005) and (August 5, 2006)
www.atimes.com/atimes/South Asia/HC28Df06.html (May 28,2006)
www.dawn.com/weekly/encounter/encounter3.htm, www.stratfor.com

to the LNG option. It is worth noting that India has already concluded contracts with Qatar for the supply of 7.5 million tons of LNG per year for 25 years commencing from 2003. Qatar has recently indicated that most of its gas is committed for LNG trade and could not spare the 2.6 bcf/day of gas required for the pipeline project during the next 8-10 years.

### 5.1.8 Summary of Prospects in the SAR Western Energy Market

The collection of the bilateral electricity trade deals and the emergence of the multilateral projects such as CASA-1000 could become the stepping stones for the eventual creation of an integrated Central Asia – South Asia Electricity Market (CASAREM), which could over time extend from the Central Asian republics and Iran to Afghanistan, Pakistan, and possibly India, linking with the large neighboring markets of Russia and China and creating a new paradigm for regional development and integration in the once divided region. The same hope holds good for the emergence of a similar gas market also, especially when the distance between Iran or Central Asia and India is less than 3500 km up to which gas through pipeline is competitive with LNG imports and re-gasification (see Figure 5.3)[59]

**Figure 5.3: Gas Transport Economics (Piped Gas Vs LNG)**




A summary of the prospects for energy trade as perceived at present in the Western Energy Market is given below in Table 5.4

[59] Options for Gas Supply for Sri Lanka- Presentation by Nexus (June 2003) available at www.sari-energy.org/resourcereports.asp?cat=2

**Table 5.4: Summary of the prospects for trade in the Western Energy Market**

| Importing countries | Exporting Countries | | | | | |
|---|---|---|---|---|---|---|
| | **CARs** | **Turkmenistan** | **Iran** | **Afghanistan** | **Pakistan** | **India** |
| **CARs** | x | Some gas exports are possible; mutual electricity support | Unlikely (uncompetitive) | No scope | Limited (some emergency support possible) | No scope |
| **Turkmenistan** | Mutual electricity support | x | Unlikely (similarity of resources – gas; little scope in electricity) | No scope | No scope | No Scope |
| **Iran** | Limited power exports possible | Power exports are ongoing | x | No scope | No scope | No Scope |
| **Afghanistan** | Power exports are ongoing and should grow | Power exports are ongoing and should grow | Power export ongoing and may grow | x | Small cross-border power export possible | No scope |
| **Pakistan** | Potential for power exports | Significant potential for gas exports | Significant potential for gas export; cross-border electricity trade could grow | No scope for trade; Transit of electricity and gas | x | Mutual short-term trading support in power |
| **India** | Gas and power exports possible | Significant potential for gas exports | Significant potential for gas exports | No scope; Transit of gas | Mutual short-term trading support in power; transit of gas | x |

Note: CARs in this table denotes Tajikistan, Uzbekistan, Kyrgyz Republic and Kazakhstan only.
Red Color denotes that trade prospects are significant and are either being exploited or can be brought to fruition in the short-to-medium term. Green Color denotes that prospects of the trade are good and may materialize in the medium term. Yellow Color denotes that prospects for the trade are more limited and may materialize in the medium-to-long term, and Grey Color denotes that the prospects for the trade are weak.

## 5.2 The Eastern Energy Market

In the potential Eastern Energy Market Bhutan, Nepal and Myanmar have significant undeveloped hydropower potential and are likely to emerge as major exporters of hydroelectricity mainly to India and possibly to Bangladesh (to a small extent). Major gas resources of Myanmar and Bangladesh could enable them to export natural gas mainly to India and to a much smaller extent to the border areas of Bhutan and Nepal.

The Indian power market is large and the demand growth is constantly outpacing supply growth. In FY 2007 India faced a capacity deficit of 13,727 MW (or 11.9%) and an energy shortage of 54,916 GWh (or 7.6%). Within India only the Eastern region had an energy surplus of 8,500 GWh (or 12.2%) and all other regions had shortages of capacity and energy. Internal trade induced by the ABT and UI rate regime discussed in the earlier chapter in the national grid amounted to about 15,000 GWh or 3% of the total volume handled in the national grid. The deficit is expected to widen in the foreseeable future. The average traded price ranged from Rs 5.5 (12.5 cents/kWh) (off-peak) to Rs 5.75 (13.7 cents/kWh) (peak) in the third quarter of 2006. Bids under ICB for large power stations based on indigenous coal from captive mines indicate a levelized price of Rs 1.196/kWh (2.99 cents/kWh) and such bids for plants based on imported coal show levelized price of Rs.2.29/kWh (5.72 cents/kWh). Gas based power with gas prices of $7/mmbtu is expected to cost Rs 3.7.kWh (9.25 cents/kWh). Prices from large hydro projects constructed or under construction range from 3.5 to 6 cents/kWh. While domestic coal will continue to play an important role in India, it will not be possible to meet the entire demand for power in the country by domestic coal alone because of the difficulties relating to the expansion of coal mining and transport bottlenecks. The need for imported fuels (coal, LNG and piped gas) and imported electricity will remain significant. Thus India is an attractive power market from the point of view of volume and power prices.

### 5.2.1 Bhutan-India Bilateral Electricity Trade

Bhutan-India bilateral trade had been going on for several decades and is the largest in the region in terms of volume. Bhutan exports more than 75% of its generated electricity to India. Power export receipts constitute 45% of the Bhutan Government revenue and 12% of Bhutan's GDP. When all the six units of Tala Hydropower project are commissioned by the end of 2006, the export receipts would provide 60% of the government revenues. India had provided 60% grant and 40% loan for the capital costs of Chukka (336 MW), Kurichu (60 MW) and Tala (1,020 MW) hydropower projects during 1974-2006 and has been purchasing all the surplus power at prices negotiated between the parties (currently 4.07 cents/kWh for Kurichu and 4.65 cents per kWh for Chukka). The price for Tala power is still being negotiated.[60]

Out of the total hydropower potential of Bhutan, 23,760 MW is considered techno-economically feasible. Of those about 1,490 MW had been developed. India has signed an umbrella agreement with Bhutan under which the former provides project investigation, design and engineering services as well as construction supervision services for hydropower projects, apart from providing highly concessional finance. In return it would be entitled to import all the surplus power, after meeting the needs of Bhutan. Under the umbrella agreement, the Indian authorities have prepared detailed project reports for four major projects: Punatsangchu I (1095 MW), Wangchu (900 MW), Bunakha (180 MW), Sankosh Multipurpose project (4,060 MW). Detailed Project Reports are under preparation for two more projects: Punatsangchu II (1000 MW) and Mangdechu (360/600 MW). Pre-feasibility Report has been prepared for one multipurpose project, Manas (2,800 MW)[61]

[60] A price of Rs 1.8/kWh (or 4.5 cents) is reported to have been agreed for FY 2007 only (see *Power in Asia*, Issue # 459 August 17, 2006).

[61] Inter-Country Cooperation in Development of Hydropower, a presentation by the Central Electricity Authority of India in the BIMSTEC Workshop on Sharing Experience in Developing Hydropower Projects in New Delhi, held during 30-31 October 2006 available at www.powermin.nic.in

Bhutan government has updated in 2004 its Power System Master Plan (2003-2023) with technical assistance from Norway. This examined 76 sites in all 3 river basins with a total capacity of 23,760 MW and prioritized six projects with a total capacity of 4,484 MW and total energy output of 21,085 GWh at an average capital cost of $835/kW for construction through 2024. Using a discount rate of 12% the average economic unit cost of generation was computed as 2.87 cents/kWh in 2002 prices.[62] Overall generation investment needs work out to $200 million a year to add 244 MW a year during the period 2007-2024. All are run-of-river projects with little adverse environmental consequence, but about 70% to 76% of the annual power output would be seasonal.

Bhutan power is delivered in the eastern region of India which will not be able to absorb it both from the price point of view and from the point of view of system needs. Thus simultaneous with the commissioning of Tala project the transfer capacity from the eastern region to northern region is being raised (see Chapter 2). Recent studies (assuming that the sale price of Tala power at the generation station would be the same as in the case of Chukka, 4.65 cents/kWh) indicate that the cost of Tala power when transmitted to Delhi will be comparable to the price of power from coal fired units in the northern region, but will be lower than the LNG based thermal power there. The northern region has severe shortages of both capacity and energy in all seasons and would be able to absorb Tala power despite its seasonality of supply and its price.

The rapid expansion of the inter-regional transfer capacity in India (see Chapter 2), the development of real time balancing using availability based tariffs and UI charges in the national grid should greatly improve the chances of the Bhutan power being absorbed in any part of the national grid, whose requirement matches the supply pattern from Bhutan.

Given the cost and the seasonal output structure of the Bhutan hydro projects, a recent study concludes that large hydropower projects such as Tala would not be attractive to the private sector and that therefore they are best pursued as before based on bilateral cooperation with India or as joint ventures with Indian public sector entities. Medium hydropower projects (25 MW to 300 MW) could be pursued on the basis of public private partnership basis with the involvement of IFIs and that small hydropower projects (below 25 MW) could be pursued with bilateral and multilateral donors.[63] However, in the context of the gradual liberalization of the Indian power sector with third party access to the national and regional grid and with the availability of a number of licensed power trading companies, it should be possible for some of large entrepreneurs in India to be interested in the generation investments in Bhutan.

A significant problem which would adversely impact on the growth of electricity exports from Bhutan is the very high level of subsidy provided to the domestic consumers and the incentive schemes it operates for attracting power intensive industries. Such distorted price signals would lead to serious misallocation of resources and cut into the surplus

[62] These economic calculations are based on preliminary desk studies averaged over a range of project sizes. Financial analysis of the completed Tala Hydropower project (assuming an export price of 4.5 cents/kWh) seems to show financial internal rates of returns of 7% to 8% which would not be attractive to private investors.

[63] Parts of this section are drawn from the Pricewaterhouse Coopers' recent draft report, *Bhutan Hydropower Sector Study: Opportunities and Strategic Options* (June 2006).

available for export. Development of power projects exclusively for export should be considered to mitigate this risk. In the medium to long term the level of subsidy should be phased out substantially.

### 5.2.2 Nepal-India Bilateral Electricity Trade

Although discussions about the Nepal-India electricity trade have been going on for over five decades, and many of the major Nepal hydropower sites and related project proposals have been studied by wide range of consultants over that period, electricity trade/exchange between the two countries remains insignificant, with Nepal being the net importer (see Chapter 2). Nepal's hydroelectric potential is estimated at 83,000 MW, of which 43,000 MW is considered techno-economically feasible. Only 627 MW have actually been developed. Bilateral assistance from India helped in the construction and financing of Pokhra (1MW), Trisuli (21 MW), Western Gandaki (15 MW) and Devi Ghat (14.1 MW) during 1968-1983, mainly for meeting local demand. Other major projects under discussion between the two governments at various levels include: Karnali-Chisapani Multipupose Storage Hydropower Project (10,800 MW), Sapta Kosi High Dam Multipurpose Project (3,300 MW) along with Sun Kosi Storage/Diversion Project, Pancheshwar Multipurpose project (5,600 MW), Burhi Gandaki (600 MW), Upper Karnali (300 MW).

Nepal's peak demand is forecast to grow from 580 MW in FY 2005 at the rate of 7.6% per year to 1,750 MW by FY 2020. During the same period the energy needs are forecast to grow from about 2.8 TWh to 8 TWh. This calls for an addition of 220 MW by 2010 and another 1000 MW by 2020 raising the total capacity in the country to about 1900 MW. Demand growth of this size would not be able to accommodate large sized cost effective hydropower stations unless the domestic demand is supplemented by substantial export demand. Construction of medium and small sized hydropower stations with a high cost per KW installed has resulted in the provision of a very high-cost-power supply system in Nepal. It is also a system with very little thermal power capacity (less than 8.5%). It is thus in the economic interests of Nepal to promote the construction of relatively large sized cost effective hydropower projects in Nepal mainly meant for export to India and import from India thermal power to meet its dry season power needs. Given the relative sizes of the north Indian power system and that of Nepal this should not present any major problem, despite the capacity and energy deficits in the Indian system.

Unfortunately the transmission capacity of the existing 132 kV and 33 kV lines between the two countries limit the exchanges to about a third of the agreed level of 150 MW. The IPPs of Nepal complain that on account of this they are forced to spill water. There is thus an urgent need to increase the transfer capacity to the Indian northern and eastern regional grids. Proposals to construct four 220 kV single or double circuit links: Butwal-Ghorakpur, Dhalkebar-Muzafferpur, Duhabi-Purnima, and Anarmani-Siliguri, need to be pursued on both sides.[64] The distances involved are all small and cost levels should present no major problems. Even more importantly the Nepalese parliament needs to ratify the Power Trade Agreement between the two countries. The recent formation of a Joint Technical Committee consisting of the Power Trading Corporation of India, NEA and the Nepal Government for preparing the term sheets and for scheduling the exchanges should greatly help Nepal in marketing its power and receiving its imports without having to deal with the various electricity boards of India.

Recent restoration of democracy in Nepal, ending of the armed conflicts and domestic turbulence, the agreement of "maoists" to work as a part of the parliamentary democracy, and the announcement by the "maoist" leader that his party welcomes foreign investment in power facilities has created a political climate conducive to attract investors. The liberalization of the Indian power sector at the level of the national and regional grids and the emergence of major private sector investors and traders in the power sector has created fresh opportunities for power export projects in Nepal. The serious power cuts which Nepal faced in the last one year and the more liberal approach of the new government appear to have resulted in a strategy of attracting Indian private sector for investing in Nepal hydropower projects.

In the "Power Summit" organized by the Independent Power Producers of Nepal (IPPAN) and PTC of India in September 2006, a wide range of Indian private sector companies and investors participated and expressed serious interest in pursuing the opportunities. Subsequently in November 2006 US Embassy in Nepal, USAID, Nepal US Chamber of Commerce and American Chamber of Commerce in India organized a seminar "Powering Nepal- Connecting Markets" attended by leading prospective investors, businessmen and officials. A great deal of enthusiasm was displayed by the investing community to develop power export projects.

The government has prioritized three project sites for private sector investment, namely, Upper Karnali (300 MW), Burhi Gandaki (600 MW) and Arun III (402 MW) and has issued a request for proposals for them from the prospective investors recently with a closing date in the last week of December 2006. Bids are expected or have already been received from several reputed Indian firms (Reliance, GMR Group, Jaypee, Larson &Toubro, Avantika, KSK Energy Ventures and NHPC) one investor from Singapore (SN power) and one from Turkey (Nepal Energy) either by themselves or in the form of consortia.

Overall, the Nepal's strategy seems to be (a) to focus on run-of-the-river projects (with a daily peaking pond), (b) implement the projects on the basis of public private partnerships, (c) gain experience in the new realities of the Indian power market and, (d) based on such experience and familiarity, scale up the project sizes and operations. [65]

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[64] USAID financed consultants International Resource Group have analyzed these options and consider the first two lines to be a priority. They will have transfer capacities up to 800 MW and would cost about $55.6 million and $52.4 million respectively.

[65] This section draws from the information found at websites of IPPAN namely www.ippan.org and of the Department of Electricity Development www.nepal-doed.org on the two conferences. Also useful were: www.siliconindia.com/shownews/34218

It is also worth noting that Snowy Mountain Engineering Corporation of Australia received a license way back in 1994 to develop West Seti storage hydropower project (750 MW; 3,300 GWh). Ten percent of its output was to be provided to NEA free of cost (as royalty) and the remaining 90% was destined for export to India. The cost was estimated in 1997 at $1,098 million. Power Sales Agreement was reported to have been executed with PTC of India in 2003 at a price of 4.95 cents/kWh. The project will include a double circuit 400 kV transmission line from the project site to Bareilley in India (190 km).The license was renewed annually and it was announced in May 2005 that SMEC has secured financing from Chinese Export-Import Bank and Asian Development Bank and that construction would commence in September 2005. However the ADB loan to enable the government to hold equity in the company is expected for approval in the course of 2007 and financial closure is expected soon thereafter with equity participation from investors of Australia, China, Nepal and India and debt mainly from China. A Chinese company had already been awarded the EPC contract for the project.

Hydropower projects in Nepal tend to be expensive because of the geological and seismic problems of the Himalayan region, remote and inaccessible terrain, unfavorable hydrology, and unusually high sediment loads. Power from such projects (especially from the run-of-projects) is not necessarily very competitive in the Indian market. Careful and intelligent marketing is necessary to find the niche in the Indian grid which could absorb it. It may not be marketable in Bhutan and Bangladesh at all. Projects therefore have to be selected to have a large size and economy of scale, resulting in competitive prices. West Seti project represents one such case.

### 5.2.3 Myanmar-India Bilateral Electricity Trade

Myanmar has a total hydropower potential of 39,720 MW of which 747 MW (2%) had been developed. Another 10,398 MW is reported to be under various stages of preparation or construction. By FY 2009, nine projects with a total capacity of about 916 MW are expected to be commissioned. Another four projects with a total capacity of 1,172 MW are expected for completion by Fy 2010. The rest would be commissioned by FY 2021. Most of this capacity is being developed as joint venture projects with EGAT and MDX Group of Thailand, and YMEC of China for export to Thailand. Indian government organizations have cooperated in the Sedawyagi and Yeywa Hydropower projects. The Central Electricity Authority of India prepared in 2005 the pre-feasibility study for the Myanmar government for developing the Tamanti multipurpose project with a hydropower component of 1,200 MW in the first stage. It is located in the northern portions of Myanmar, fairly close to the Indian border and will have substantial irrigation, navigation and flood control benefits for Myanmar. Power is mainly for export to India. The second and third stages of the project will have a 400 MW and 700 MW power stations down stream. A transmission line has to be constructed to the Indian border as a part of the project. The power will be fed into the NE region of India which is synchronized with eastern and northern regions. Given Myanmar's approach favoring

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www.nepalnews.com/contents/2006/englishweekly/spotlight/nov/nov10/economy.php
www.nepalnews.com/contents/2006/englishmonthly/businessage/nov/cover.php
www.peoplesdaily.com

Joint Venture mechanisms for power development mainly destined for export it is likely that this cooperation will materialize and Myanmar-India electricity trade will commence with the commissioning of this project around 2014. BIMSTEC related initiatives would help in this regard.

### 5.2.4 Bangladesh-India Bilateral Electricity Trade

Bangladesh has been experiencing an annual power demand growth of about 9%during the last decade and is expected to have a similar growth rate (8% to 9%) through FY 2020. Financial resource constraints (arising mostly from poor operational efficiency) slow down the pace of capacity additions in generation, transmission and distribution, resulting in a perpetual shortage situation.

Import of power from the Eastern and North Eastern regional grids of India had often been considered an option to meet the shortages in Bangladesh and bilateral discussions between the two countries during the last 15 years focused on interconnections from Jessore, Rangpur, and Sylhet, but did not result in any action. In March 1999 Power Grid Corporation of India made a feasibility study for enabling an exchange of power between India and Bangladesh of the order of 150 MW proposing transmission links between Farakka (India) and Ishurdi (Bangladesh) and Kurnarghat (India) and Shahjibazar (Bangladesh).

Subsequently the focus shifted somewhat towards the possibility of exporting gas based power to India, while augmenting supplies in Bangladesh. A pre-feasibility study prepared for the government of Bangladesh under the USAID SARI-E program in 2000 demonstrated that a gas fired combined cycle power plant of 500MW to 1000MW capacity located at Bheramara or Sirajganj and exporting a minimum of 400 MW to the eastern grid of India would be competitive in the Indian power market with a delivered power cost of about 4.4 to 4.7 cents/kWh and supporting a well head price of gas of $1.5 to $1.85 per million BTU. Similar power plants located at Sylhet or Fenchuganj exporting power to the northeastern grid of India would also be economic and competitive.

Since then several proposals have been made to the government for similar power plants in Bangladesh which will be primarily for export to India and partly for meeting local demand. In 2000, NTPC of India proposed to build a 1000 MW thermal power plant at Bheramara. The most recent and spectacular example is the proposal of the Tata Group of India (see section 4.4 for details). However the Bangladesh authorities have not been able to respond positively to any of these proposals. Natural gas is the only energy resource (apart from the recently developed coal resources) available to meet domestic energy demands and the government did not want to make any export commitment till it is sure of the true size of the recoverable reserves of gas in the country. Discovery of significant coal resources and its recent development for a coal fired power plant might have a (favorable) bearing on such decisions.

Increasing the use of coal for power generation, and importing hydropower from Nepal and Bhutan, might release gas or gas fired power for export. Electrical interconnections and trading agreements are, however, essential prerequisites for exploiting such opportunities.

### 5.2.5 India-Sri Lanka Bilateral Electricity Trade

Sri Lanka has already exploited most of the economic hydropower potential and has to depend on imported fuels to create additional thermal power capacity and move the hydroelectric generation to meet the peak demand. Given the relatively short distance between the south-east tip of India and the northern tip of Sri Lanka (about 30 km) one option would be to build a sub-marine cable to interconnect the CEB power system and the southern regional grid of India, which will be fully synchronized with the other four regional grids of India by FY2012. Once this is done, CEB could use the imported power from India for base load and the domestic hydropower for meeting the peak demand. It may even be able to sell some peak power to India at a good price. SARI-E program of USAID carried out a pre-feasibility study in 2002 covering four alternative technically feasible HVDC interconnection options and demonstrated that benefits would accrue to both sides in terms of least cost dispatch, peak displacement and reliability.

Madurai-Anuradhapura 400 kV HVDC bipolar interconnection at a capital cost of $133 million appeared to be the best solution. This transmission link would consist of 200 km of overhead line in India and 150 km of overhead line in Sri Lanka and a 30 km under sea cable to connect them both. It will have a transfer capacity of 1000 MW with indicative levelized transmission charges of 0.6 to 0.9 cents/kWh at loads above 500 MW and a plant load factor of 85%. The delivered cost of power in Sri Lanka could be about 6.5 to 8.0 cents/kWh compared to its marginal cost at 7 to 9 cents/kWh.

**Figure 5.4: Proposed India-Sri Lanka HVDC Interconnection**


Source: USAID SARI-E Program Study carried out by Nexant (February 2002

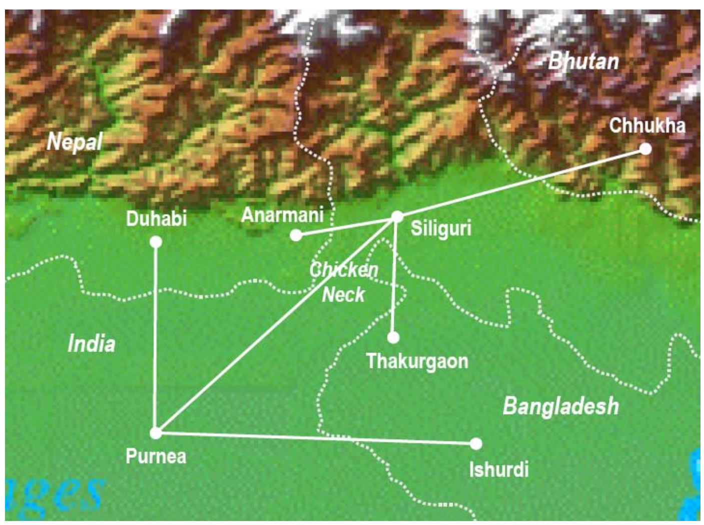
This proposal seems to be making some progress. The Power Grid Corporation of India has made a fresh feasibility study for a HVDC link between Madurai and Anuradhapura. A specially appointed task force with representation from Ministry of Power, CEA and Power Grid Corporation of India and their counterparts from Sri Lanka will review the feasibility report and advice the Steering Committee of the two Secretaries of Power from Indian and Sri Lanka, which hopes to have the agreement between the two countries signed by early 2007.[66] For a small system like that of Sri Lanka this may be a better option than the import of LNG.[67]

### 5.2.6 Bangladesh, Bhutan, Nepal and India Multilateral Electricity Trade

Bangladesh had been desirous of being able to import hydropower from Bhutan and Nepal. Bhutan had been desirous of diversifying its markets. Nepal had been desirous of being able access hydro power from Bhutan and gas-based thermal power from Bangladesh. India is already interconnected to Bhutan and Nepal. The geographic location and the country aspirations as well as energy resource distribution (hydropower in Nepal and Bhutan, Gas in Bangladesh, and coal in India) are conducive to establish a power exchange among all four countries in some form of multilateral electricity trade. The borders of Nepal, Bhutan and Bangladesh converge near Siliguri of the state of Assam in India and the distances involved are very short.

The SARI-E program of USAID carried out a study "Four Borders Project: Reliability Improvement and Power Transfer in South Asia (November 2001) which suggested connecting Siliguri (India) to Anarmani (Nepal) and Thakurgaon (Bangladesh) initially by 132 kV lines capable of being upgraded to 220 kV as the volume of interchange increases. It also suggested the alternative of connecting Purnea (India) to Duhabi (Nepal)[68] and Ishurdi (Bangladesh). Connections from Chhukha (Bhutan) to Siliguri and then on to Purnea already exist (see Figure 5.5).

**Figure 5.5: Suggested Interconnections among India, Nepal, Bhutan, and Bangladesh**




System studies confirmed the technical feasibility of the option, which was considered better than the option of constructing 220 kV lines from the beginning or having 132 kV

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[66] http://www.hindustantimes.com/news/181_1860601,0008.htm news item dated December 6, 2008.

[67] NTPC of India and the government of Sri Lanka have signed an agreement in December 2006 for the construction of a 500 MW coal fired thermal power project in Sri Lanka by a Joint venture company to be formed by NTPC and CEB. An agreement for another 300 MW coal fired power station is believed to have been made with a Chinese company also. The impact of these (on the justification for the India-Sri Lanka power interconnection) needs to be assessed.

[68] Duhabi-Purnea 220 kV line is also required to enable higher volumes of exchange between Nepal and India (see section 5.2.2)

lines all the time. It could support power transfer capacities in the range of 50 MW to 500 MW and capital costs would range from $9.0 million to $52.0 million. Cost of transmission could fall to 0.2 cents/kWh when interchanges amount to 500 MW. The project is expected to have acceptable rates of return, easy to implement in a five year time frame and had no major environmental issues.

Possible problems of synchronous operation of the four systems have to be identified and resolved. The ABT and UI interchange pricing in the Indian regional grid should help in facilitating such exchanges, especially when power trading companies handle the business. It will be useful to follow up with detailed studies and discussion among the three utilities and the Power Grid Corporation of India. Given the modest cost and the modest scope, this may be a good beginning for the multilateral electricity trade in South Asia.

### 5.2.7 Myanmar-India Natural Gas Trade

Myanmar has estimated natural gas reserves of 89.722 tcf, of which 18.012 tcf are considered proven recoverable reserves. It has three main large off-shore and 19 on shore oil and gas fields. In the first 11 months of FY 2006 natural gas production and exports amounted to 10.53 bcm and 8.06 bcm respectively. Gas related export receipts amounted to $942 million. Investors from Australia, Britain, Canada, China, Indonesia, India, South Korea, Malaysia and Thailand are engaged in the oil and gas sector of Myanmar. Sun Group of India and Itera of Russia have signed recently a production sharing contract with Myanmar Oil and Gas enterprise for exploring off-shore Block M-8. ONGC and GAIL of India have a 30% stake in the partnership with Daewoo of South Korea(60%) and South Korean Gas Corporation (10%) in the off-shore gas exploration of Blocks A-1 and A-3 off the western Rakhine coast. These blocks hold a recoverable reserve of 5.7 to 10 tcf of gas. GAIL(30%) in partnership with Silver Wave (70%) signed a deal with Myanmar to drill in the A-7 block.[69]

To transport this gas to the state of West Bengal in India, negotiations were held with Bangladesh government to provide transit facilities. In January 2005, Bangladesh agreed to allow the 559 mile pipeline to pass through its territory. Bangladesh Gas Transmission Company will have the responsibility to manage the 180 mile pipeline in its territory and would receive an annual transit fee of $ 125 million. Such acceptance by the Bangladesh government, however, was subject to several conditions such as: grant of several trade concessions including removal of tariff, non-tariff and administrative barriers to Bangladesh exports to India, provision of access to hydroelectricity from Nepal and Bhutan and an establishment of the free trade corridor to these countries. As Bangladesh continued to press for these wide ranging trade concessions, Myanmar and Indian companies have begun considering alternative options such as (a) overland route to India bypassing Bangladesh[70] (b) under sea pipeline to India, and (c) LNG shipments. As

[69] See news item dated December 14,2006 at www.business-standard.com/general/printpage.php?autono=267844

[70] In June 2006 GAIL completed a feasibility study for a 1,573 km pipeline which will bypass Bangladesh and passing through North eastern territories and Assam of India terminate in Gaya of Bihar state. Its initial capacity would be 18 million cubic meters per day which can be increased to 28 million cubic meters per day by the installation of additional compressors. The capital cost is estimated at $3.0 billion.

negotiations with Bangladesh government continue the prospects for a pipeline through Bangladesh appear uncertain.

Meanwhile GAIL of India has finalized a feasibility study for a 1,573 km long overland pipeline bypassing Bangladesh, from Myanmar to Gaya in India through Mizoram, Assam and West Bengal with an initial capacity of 18 million cubic meters /day. This could be increased to 28 million cubic meters /day by adding more compressors. The project was expected to cost about $3.0 billion.

If Bangladesh and India could find their way to have the much shorter pipeline passing through Bangladesh approved, it could possibly pave the way for the multilateral gas trade among the eastern nations of the South Asia.

However latest news reports from India indicate that the Myanmar government is reviewing the possibility of exporting this gas as LNG or of selling it as piped gas to China. A decision in this regard is likely after the independent audit of the reserves of the A-3 block.[71]

### 5.2.8 Bangladesh-India Bilateral Gas Trade

Bangladesh has substantial gas reserves. However estimates of reserve from different sources vary. Oil and Gas Journal indicated a proved reserve level of 10.6 tcf as of January 2005, but has revised it downwards to 5 tcf as of January 2006. The reasons for this are not clear. In mid 2004 Petrobangla estimated the proved reserves at 15.3 tcf In the same year the Ministry of Finance estimated a total reserve of 28.4 tcf of which 20.5 tcf were considered recoverable. In June 2001, US Geological Survey estimated that Bangladesh contained 32.1 tcf of additional undiscovered reserves. At the present levels of production this should last for over 100 years.

A recent report *Gas Strategy for Bangladesh* (January 2006) prepared for Petrobangla by Wood Mackenzie Ltd assumes a proved level of 9.2 tcf, proven plus probable reserve of 14.4 tcf, and a proven plus probable plus possible reserve of 22.2 tcf. This appears to be the most conservative estimate. The government has been reluctant to make any commitment for the export of gas or gas based electricity on account of the uncertainty of its reserves position and the fear that the country may run out of its only major energy resource sooner than expected. It is claimed that if coal mining and coal based power development takes root, and if the country has access to the hydropower of Nepal, Bhutan and Myanmar, it might adopt a little more liberal approach to gas exports or the exports of gas based power or fertilizers and steel products made using gas as fuel.

### 5.2.9 Summary of the Prospects in the SAR Eastern Energy Market

A summary of the prospects for energy trade as perceived at present in the Eastern Energy Market is given below in Table 5.5.

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[71] See http://www.hinduonnet.com/thehindu/thscrip/print.pl?file=2007032203941500.htm&date=2007
http://www.saag.org/%5Cpapers23%5Cpaper2210.html
http://www.zeenews.com/articles.asp?rep=2&aid=361252&ssid=51&sid=BUS

**Table 5.5: Summary of the Prospects for Trade in the Eastern Energy Market**

| Importing Countries | Exporting Countries: India | Bhutan | Nepal | Bangladesh | Sri Lanka | Myanmar |
|---|---|---|---|---|---|---|
| **India** | x | Significant quantities of hydropower (H) | Significant hydropower export possible | Significant amounts of gas or power possible. Some resource uncertainty | Some peak power support possible | Significant gas and power supply possible |
| **Bhutan** | Dry Season Support | x | Unlikely. Similarity of resources and seasonal shortages | Small amounts of thermal power and gas; connection via India (L) | No scope | Unlikely (far off; too small market) |
| **Nepal** | Thermal power support. Dry season support | Unlikely. Similarity of resources and seasonal shortages | X | Small amounts of thermal power and gas; Connection via India (L) | No scope | Unlikely |
| **Bangladesh** | Sharing reserves; Electricity swaps | Some hydropower. Connection via India (L) | Some hydropower. Connection via India (L) | x | No scope | Unlikely (although some potential in hydropower) |
| **Sri Lanka** | Dry season and thermal power support | Unlikely (far off) | Unlikely (far off) | Unlikely (far off) | x | Unlikely (far off) |
| **Myanmar** | No scope | Uncompetitive | Uncompetitive | Uncompetitive | No scope | x |

For notes on color coding see Table 5.4