Executive Summary

Thematic Review IV.I
Electricity Supply and Demand Side Management Options

S1. Introduction

Large dams currently produce about 20% of the world's electricity. While Europe and North America utilise more than half of their economically feasible hydroelectric resources, 60-80 % of the potential in developing countries remains undeveloped[i]. Over 150 countries utilize hydropower resources; in 65 countries hydropower accounts for more than 50% of electricity generation; in 24 countries more than 90%; and for 10 countries virtually the total national generation. Choices over individual electricity options when viewed over time often reveal choices of an energy development path for a country (e.g. Norway-hydropower, France-nuclear, Denmark- imported coal). Whether past choices were based more on available resources, markets or deliberate social or industrial policy of the day may be argued.

Large dams could play a major role in expanding electricity services especially in the developing world. The magnitude and timing of this role will depend on several factors.

- national policies, strategic choices and national resource endowments;
- the ability to find common ground on a series of controversial social equity and ecological issues surrounding dam site selection, planning, construction and operation;
- the outlook for competing demand side management and electricity supply options including the emergent renewable sources;
- the evolving context of power sector market reform and regulation, and sources and the availability, structure and cost of project financing;
- the extent of stakeholder participation in planning and decision making; and
- emerging goals for sustainable development and its implementation, especially with relation to widening access to modern energy services in poorer countries and reducing the risks of environmental degradation at local, regional and global levels.

This paper is one of seventeen thematic reviews commissioned by the WCD. It examines issues forming the larger context for assessing the prospects for electricity supply and demand management options. The paper reviews forces shaping the regional and national context for electricity sector reform, and the influence on policy, planning, decision making and institutional reform, which affect all options. To simplify the analysis and in order to capture divergent perspectives on the options at different scales, three settings are considered. These are: (1) options for electricity grids serving cities, towns and industrial loads in developing and developing countries; (2) options for off-grid settings (rural electrification and small isolated communities); and, (3) options for the 1.6 to 2 billion rural poor in developing countries who are in a pre-electrification stage. Other aims of the paper were to identify constraints, enabling conditions and incentive frameworks to overcome barriers to emerging good practice in options assessment, including policy and institutional options.

The paper comprises five sections. The introduction outlines the paper's objectives, structure and approach, and the paper preparation and review process. Section two examines the overall electricity supply and demand situation and hydroelectricity's role within that. Section three looks at grid connected options in industrialised and developing countries and planning issues. Section four looks at off-grid and rural electricity options. And section five summarises overall findings, principles and recommendations for emerging good practice.

The review includes detailed annexes and is further informed by the other WCD inputs including the WCD's regional consultations and general submissions.

General Perspectives in the Debate on Dams

There are numerous issues of contention in the dams and electricity debate, having mostly to do with the continuing relevance of specific technologies, the appropriate ways to evaluate environmental and social costs and benefits, and the institutional mechanisms needed for policymaking and new investments. In particular, there are divergent viewpoints on:

- The impacts of market reform in the electricity sector including effects on investment choices and the potential loss of public benefits, including investments in energy efficiency, renewable energy technologies and widened access to electricity services for the poor;
- Whether hydropower in all circumstances should be classed as a renewable energy resource and should enjoy government promotion on that basis. There are also divergent viewpoints on the theoretical, technical and economically feasible hydropower potential and on what may be considered economically feasible related to the extent of internalisation of all costs and benefits;
- The role of community-based energy planning initiatives, particularly in rural areas of developing countries, and the extent to which they are supported or ignored in governments-based planning;
- The implications of regionalization of planning for electricity generation and the impact on internal political discourse within the country on which options to develop to support regional loads;
- How centralised and decentralised (distributed) power systems will co-exist and their computability;
- Whether leap-frog development in developing countries is likely and the enabling conditions;
- Whether access to capital for developing countries is skewed by considerations of ideology, political influence and other vested interests rather than on substantial questions of need;
- The potential for green power sales in market economies and whether “clean energy” will generally be more expensive than other forms of electrical supply; and
- The need for and likely success of public policy initiatives to increase the market share of efficiency and renewable sources.

This paper does not attempt to resolve such controversies, many of which reflect strongly divergent philosophical commitments; it tries rather to place the relevant issues in context, in the interests of advancing informed dialogue.

S2. Energy and Electricity Demand and Supply Trends

Energy is critical for human existence and, when used efficiently and wisely, can provide an important means to reach sustainable development goals. Although it is customary to view energy solely in terms of its supply and consumption, the real value of energy and of electricity, in particular, lies in its ability to provide services like lighting, cooking, motive power and transport. Economic and social development hinge on making these energy services more widely available and affordable. Cost-effective and environmentally sound energy policies and programmes would therefore be optimally designed to provide access to both power supply and the efficiency of the transmission and distribution system and the end-use technologies.

S2.2 Electricity Demand Trends

The global share of electricity use in overall energy end-use demand (conventional energy) rose from 9.4% to about 14% between 1976 and 1996. In OECD countries it rose from 14.3% to 18.3% in the same period. Because of its convenience and the wide number of end-uses it supports in homes, factories, offices and farms, access to electricity permits societies to modernise and improve productivity through savings in time and labour, and other social benefits such as education.

Global and regional statistics indicate the average per capita consumption of electricity is now 7,500 kWh/yr. in OECD counties as compared to 482 kWh/yr. in Asia (excluding China, which is 822 kWh/yr), 490 kWh/yr in Africa, and 1402 kWh/yr in Latin America. These figures mask variations in the number of people in a particular society with electricity access, and actual use per person, household or industry. Figure 1 highlights the electricity consumption per capita in developed and developing countries.

While electricity services are expanding in proportion to other end-uses, total electricity consumption in OECD countries is beginning to level due to zero population growth, less intensive industry structures, demand side management and energy conservation measures. Some transitional economies in Asia recently experienced a drop in the rate of electricity demand growth. The highly skewed regional distribution of electricity consumption suggests the enormous scope for growth in electricity production in developing regions. The differences in consumption patterns also have important equity implications.

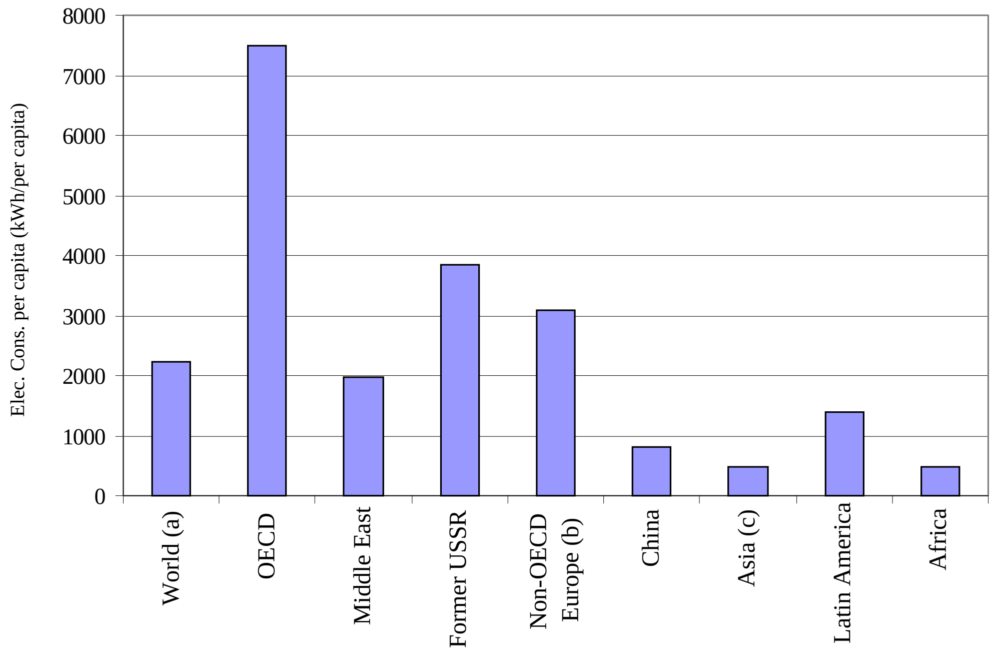

Figure 1: Variations in Electricity Consumption Per Capita by World Regions (1996)
Source: IEA Energy data

Close to one-third of humanity has no access to modern electricity services. Nearly all of those unserved by electricity live in developing countries that are characterised by low levels of social and economic development as well as inadequate infrastructure and institutions for the provision of energy services. Many live in isolated areas distant from existing electrical grids. For most, access to electricity is hampered by poverty as well as by technical, economic and institutional factors. There is strong evidence, however, that for countries with low levels of energy services, even small improvements in the availability of electricity services would result in significant welfare improvements (Suarez, 1995).

It is also evident that for countries that have already achieved a certain degree of social and economic development from modern energy services, further gains are not contingent upon increasing total electricity consumption, a phenomenon sometimes referred to as "GDP-energy de-coupling" (WEA, 1999). The de-coupling that has taken place between energy and GDP in OECD countries, as well as some developing countries, has been primarily the result of efficiency improvements, but it has also been impacted by broad sectoral shifts in such economies from manufacturing towards services.

There are numerous forecasts for future electricity demand and supply. Three scenarios are presented in the paper in Section 2. Comparison the projections indicate widely divergent views on what may occur in electricity energy efficiency side and the role of hydropower. However, all forecasts see a continued increase in thermal generation, primarily to meet growing demands for electrical services in developing countries (primarily urban and industrial demands) for the next 20 years.

S2.2 Electricity Supply Trends

The current global contribution to electricity generation is: coal (36%); oil (9.3%); gas (14.8%); hydro (20%); nuclear (17%); biomass and other renewable sources including geothermal, wind and solar (1.4%). The shift of electrical energy supply sources from oil to gas, nuclear, and hydro between 1973 and 1996 is shown below. Coal has remained steady, accounting for around 38% of the world's electricity generation, with hydro slightly reducing during the period.[1] At present wind energy is the fastest growing generation option in terms of its share, but remains small in total contribution at present overall.

Among the emerging renewable options wind generation offers the greatest short and medium term potential. Projections are that in some European countries wind generation may reach up to between 10% -20% of total electrical generation by 2020. However, the full extent of local community acceptance is yet to be tested and there are many divergent views on this. In response to public pressure and background concern over climate change, European governments with electrical systems based on thermal generation have already or are now in the process of establishing "resource portfolios" with tariff and other subsidies to achieve such targets for renewable alternatives.

Table 1: Fuel Shares of Electricity Generation*, 1973 and 1996 - World

Generation Source	1973 (% of 6118 TWh)	1996 (% of 13 652TWh)	Change in %
Coal	38.3	38.4	+0.1
Oil	24.6	9.3	-15.3
Gas	12.1	14.8	+2.7
Hydro*	**21.0**	**18.4**	**-2.6**
Nuclear	3.3	17.7	+14.4
Other**	0.7	1.4	+0.7

*Excludes pumped storage.
**Other includes geothermal, solar, wind, combustible renewables & waste.
Source: IEA.Energy Statistics and Balances of non-OECD Countries (IEA).

The distribution of electricity production by source and between regions is shown below, followed by a table that illustrates the direction of change in regional generation shares by hydropower. Overall the United States of America is the largest producer of electricity, making up 26.8% of the world's total production. What is notable in Table 3 is that hydropower share of total generation decreased by 17% in OECD countries and increased or remained relatively stable in other regions.

[1] Statistics on the contribution of hydropower in electricity supply vary depending whether installed capacity or energy generation is considered.

Table 2: Regional Electricity Production 1995 (TWh x 1000)

Region	Thermal (TWh)	Hydroelectric (TWh)	Geothermal (TWh)	Nuclear (TWh)	Total (TWh)	Region (% World total)
Africa	0.30	0.06	0.00	0.01	0.40	3
Europe	2.30	0.70	0.01	1.10	4.11	31
North America	2.50	0.60	0.02	0.80	3.92	30
Central America	0.20	0.04	0.01	0.01	0.26	2
South America	0.10	0.50	0.00	0.01	0.61	4
Asia+Oceania	3.00	0.60	0.01	0.41	4.02	30
Total	8.30	2.50	0.05	2.34	13.19	100

(Source: World Resources 1998-99)

Table 3: 1973 and 1996 Regional Share of Hydro Power

Country groupings	**1973 (% of 1285TWh)**	**1996 (% of 2517 TWh)**	**Change in %**
OECD	70.9	53.0	-17.9
Former USSR	9.5	8.6	-0.9
Latin America	7.3	19.4	+12.1
Asia*	4.6	6.5	+1.9
China	3.0	7.5	+4.5
Non-OECD Europe	2.3	2.0	-0.3
Africa	2.2	2.4	+0.2
Middle East	0.3	0.6	+0.3

**Asia excludes China*

Source: IEA Energy Statistics and Balances of non-OECD Countries

In rural settings, initiatives to improve the sustainability of traditional energy resources and the development of appropriate technology and alternative energy sources may constitute options to both electricity use (in the short-term to medium-term), and to extension of the central electricity grid into the area. Traditional energy forms (biomass, agriculture and animal wastes) are dominant sources of energy and the resource base is increasingly over-exploited or under stress in many countries.

Based on current patterns of electricity consumption and business as usual development, it is estimated that about US$ 8.5 trillion (1990 levels) in new investment capital will be needed to satisfy growing global power needs between 1990 and 2020. More than a third of this, or nearly $3 trillion, will be needed in developing countries (Reddy et al., 1997), where domestic capital sources are inadequate, multilateral aid for infrastructure development is shrinking, and credit ratings to attract commercial sources of capital are poor.

S2.3 Energy Resource Base for Electricity Generation

In general, at both the global and regional level there is no shortage of primary energy resources to meet foreseeable demands for electricity generation over the next 50-100 years. Annex A of the paper provides details on the energy resource base by type and region.

There are several competing resources for electricity generation, including coal, oil, natural gas, nuclear, biomass, wind, solar, geothermal and ocean energy sources. The fossil resource base itself is at least 600 times current fossil fuel use or 16 times the cumulative fossil fuel consumed between 1860 and 1997. Similarly, it is estimated that any one of the available global renewable resources employing existing and near-term conversion technologies would be more than sufficient to meet today's global energy requirements and even the level of demand expected by the end of the 21st century (see Annex A; also, WEA, 1999).

The world's total technically feasible hydro potential is estimated at 14,320 TWh/year, of which about 8,100 TWh/year is currently considered economically feasible for development[ii]. About 700 GW (or about 2600 TWh/year) is already in operation, with a further 108 GW under construction. While OECD countries have dominated the global share of hydroelectricity, developing countries, led by Asia and Latin America, each with a 20 percent share in 1997, are fast closing the gap. There are estimated to be 45,000 large dams in the world and upwards of 800,000 dams of all sizes and functions. The ICOLD Registry of Large Dams (1998) has data on 25,400 large dams. From this population, 3,766 dams, or 14.8% are reported a single purposes hydropower dams, and a further 2,694 dams or 10.6% of the population are multi-purpose dams with a power generation function either as a main or secondary purpose. Section 2 of the paper shows the regional evolution of hydroelectricity production between 1971 and 1996. Key issues examined in this paper are the factors, which influence the likelihood of a greater, or diminished role for hydro-electricity generated from large dams in the energy supply and demand mix.

S2.3 Overview of electricity supply and demand side management options

The table provided at the end of this summary shows the main electricity supply and demand side management options. The table indicates whether particular supply options are suitable as grid connected, isolated grid and/or rural based generation technologies. The typical range of operation or role in the electric supply system is noted (e.g. peak, mid-range, base load, variable or intermittent supply). Details on the technical, environmental and economic aspects of each of the technologies are given in the Annexes of the paper.

The options available generally depend on the resource base of the particular country or region. Generally, the main competing supply options for grid-based hydropower in the 3 settings considered in this paper are:

Setting	Main Competing Options to Hydropower Generation
Grid Supply	gas and oil-fired combined cycle and gas turbine, coal-fired steam plant, co-generation, wind power, and DSM
Decentralized Grids and Isolated Supply	diesel plant, gas or oil-fired gas turbines, wind power, small and mini hydro power and DSM
Rural Supply	(1) Improvements in the efficiency of traditional energy systems and small-scale alternative energy sources; and (2) where electricity can be afforded: small, mini and micro hydropower, gas and diesel, wind power, photovoltaic solar home systems
Note: Many electric conversion options can compete depending on the resource base of the country and region (e.g. geothermal or biomass combustion).	

S3. Electricity grid system context

Grid-based power currently provides electricity services to more than half of humanity through a combination of thermal, hydro, nuclear and non-conventional generation options. Increasingly over the longer term, distributed power supply options are expected provide competition for centrally generated power in the grid connected setting.

S3.1 Strategic Outlook

The major trends and influences for grid systems which impact on the decision making process (market driven or government policy driven) and the enabling conditions for options include the following:

a) power sector reform
b) technology change and practices
c) regional power exchange and cooperation trends such as with existing and emergent power pools
d) emergence of decentralized and distributed power systems
e) emergence of consumer-oriented electricity supply approaches and reforms
f) new electricity markets oriented to a hydrogen economy or transition to sustainable practices or energy-environment considerations in other sectors (e.g. electric vehicles), and
g) public attitudes and acceptance

Some of these major themes are discussed in this summary, whose details are available in the main text of the paper.

S3.1.1 Power sector reform

In recent years, in both developed and developing countries, the electricity supply industry has undergone some very important institutional and technological changes under the general rubric of power sector reforms. These have taken place as various combinations of corporatisation, privatisation and re-regulation in the power supply industry. In the majority of circumstances, the changes have involved a broad shift from vertically integrated and monopolistic utility structures to diverse entities in the interests of increased competition in generation and distribution through commercialisation and privatisation, accompanied by new forms of regulation. In North America and the European Union, the focus is more on deregulation or re-regulation with retail competition. In Asia and Latin America, privatisation through government divestiture and green-field projects for private generators have brought in significant amounts of capital for increased generation capacity.

Over the period 1990-1997, the private sector has taken over the management of operations, rehabilitation and construction risk of 534 projects in 62 developing countries with total investments of US$ 131 billion (Izaguirre, September, 1998). However, the reform process in developing countries has also generated several unanticipated problems. In some cases (e.g., Pakistan and the Philippines), poor forecasting coupled with relatively easy financing has resulted in over-capacity. In others, such as India, overly generous concessions provided to IPPs during the early stages, coupled with poor institutional safeguards, led to expensive contracting, especially since the government felt compelled to make numerous modifications to the rules for counter-guarantees, fuel linkages and other terms of power purchase. Many of these problems were the result of decision-makers focussing unduly on financing for new capacity while neglecting new institutional concerns and risk management.

It is broadly anticipated, however, that over the medium term power sector reform will improve the financial stability of electricity supply industries, improve cost recovery, and increase the availability of investment capital. Particularly in developing countries, to improve cost recovery and the financial health of utility systems, there is increasing pressure to price electricity at its marginal cost and allow independent power producers (IPPs) to sell to the grid. At the same time, there are emerging concerns of pricing and equity associated with the direction and pace of reform in both developing and developed countries. Several models of regulation have also emerged through the reforms, ranging from independent commissions that conduct a broad range of planning and regulatory functions to entities within government that primarily manage generation dispatch and fix tariffs.

The most general reasons for power sector reform are to:

a) improve the services provided by the utility (i.e., to improve access, affordability, quality, etc.);
b) improve the financial situation of the utility (i.e., to ensure that the net present value of cash flows is positive at reasonable discount rates for profitability and capital formation);
c) reduce the direct involvement of government in infrastructure financing and enhance its policy role (i.e., to free up public resources for other social expenditures and to avoid conflicts of interest where the government is owner, regulator and major user of electricity);
d) increase competition and set the stage for innovation (i.e., by encouraging new players, new technologies and new models for the provision of electricity services to develop); and
e) mitigate negative externalities generated in power production and supply (i.e., to reduce pollution and resource use, although privatisation and deregulation may often have the opposite impacts in many cases).

There are numerous implications of power sector reform, particularly with respect to the comparative attractiveness and future development of hydropower.

<u>Grid System and Generation Options:</u>

(a) Shift to gas turbines and combined cycle plant for generation: By transferring investment risk from public to private sector and improving access to electricity markets for various prospective power producers, the reform process has tended to favour more efficient generation technologies that are lower in capital cost and have shorter gestation periods. Industry forecasts suggest that between 1980 and 2010, gas turbine technology is expected to increase its share of worldwide gross power generation from 12% to 28%, **primarily at the expense of steam turbine technology,** whose share of the market will have dropped from 58% to 40% over the same period.

(b) **Move towards Peaking Hydro**: Although the share of gross generation from hydroelectric projects dropped **there is a move of hydro towards peaking capacity projects**, reflecting the fact that many power systems in Asia are capacity constrained.

(c) **Implications of mix of generation on the system and large, medium and small hydro portfolio**: The general trend may be towards medium to small hydroelectric projects because of their lower risk profile (faster completion times, lower cost over-runs, lower environmental risks, etc.) in an increasingly competitive environment.

(d) **Implications for multi-purpose vs. single purpose hydro:** With the increased emphasis on cost recovery and the reduced willingness of power-sector stakeholders to subsidise non-power uses of water, multipurpose projects are less likely to be undertaken in the future, or at least less driven or led by power considerations. If a multi-purpose project is decided for other needs (e.g. irrigation, water supply or flood management) then the hydroelectric function would be added.

(e) **Implications for non-dam renewable alternatives and DSM:** Demand-side efficiency improvements will be of fundamental importance if the demand-supply gap is to be fully closed. With higher tariffs resulting from transition to market-orientation tariff practices in developing economy settings, it can be expected that gradual stock turnover will move towards more efficient electrical appliances and end-use equipment. The prospects for these forms of energy supply/end-use management depend more on Government policy than on the power sector reforms cited above. In the short-term, the trend towards lower electricity prices in developed countries will make it more difficult to promote such activities. For many developing countries, the **increases** in electricity tariffs resulting from power sector restructuring will tend to make the environment more conducive for renewables and DSM; although close vigilance by Government and/or the Regulator will continue to be needed to assure that ongoing programs in these areas continue. There are also equity implications where governments will need to consider the impact of tariff increases on low-income consumers.

(f) **Implications for Rural Electrification (RE) vs. Urban Supply**: In the short- to medium-term, it is anticipated that the private sector will be primarily interested in supplying electricity to areas of high demand density at the expense of rural areas, because of the low **financial rate of return** in such settings. RE may therefore remain under government purview, with the assistance of government utilities and/or cooperatives, or with public/private partnerships. Local entrepreneurs may also be willing to provide new solutions.

(g) **Implications for centralised vs. decentralised supply:** Deregulation of the power sector will make it easier for decentralised or distributed power producers to sell to the grid; however, they will be in a competitive environment where margins will be less.

(h) **Implications for power pools and regional power trade:** The reforms are increasing the levels of regional power trade and also giving an impetus to establishing and/or expanding existing regional power pools arrangements. While there is a continuous emphasis on maintaining the quality of power supply, there is also the expectation that electricity prices will drop through reducing the amount of reserve capacity required and introducing competition**.**

<u>Economic, Finance and Tariffs:</u>

(i) **Implications for macro economic / country level financing:** The trend toward private sector financing for hydropower may increase developing countries' foreign debt exposure and may therefore serve to place a cap on the amount of power sector development that may be possible in national affordability terms, unless limited recourse financing is feasible.

(j) **Transfer of risk from the public to the private sector:** IPPs have by and large made a significant difference in many countries in covering construction, operating and fuel availability risk. For hydropower the transfer or sharing of risk (hydrological, project risk, commercial risk) is not yet clearly defined and often considered on a project-by-project basis.

(k) **Higher costs of financing, leading generally to higher tariffs, for developing countries as compared to concessional financing:** Commercial rates are have shorter maturities and interest well above LIBOR, while state owned utilities have traditionally had access to long borrowings or refinance at subsidised interest rates with a government guarantee. In addition, the transaction costs for private power schemes tend to be significantly higher compared to balance sheet financing.

<u>Institutional</u>

(l) **New roles for government:** In the pre-reform period, the state was often solely responsible for power supply and was concurrently the regulator, producer, arbitrator, provider of subsidies, and frequently a dominant consumer of electricity. After the reforms, government responsibility moves to being the facilitator/regulator of the development of the power sector.

(m) **Need for regulatory structures and institutional capacity becomes a critical factor in facilitating the reform:** Without adequate institutional safeguards such transparent regulation and credible rules, divestiture or the opening up of markets to private investors may contribute to market failure by increasing rent-seeking and introducing new opportunities for corruption. In developing countries, the establishment of strong institutions--formal rules, informal constraints and their enforcement mechanisms--to promote sustainable development of the electricity sector is now being recognised as one of the most important challenges facing the sector. For instance, many developing country utilities have problems of poor performance (characterised by high system losses, recurrent financial loss, low efficiency of plants, poor quality of supply, low plant capacity utilisation, unreliable fuel linkages, sub-optimal reserve margins and significant environmental impacts). Their resolution depends critically on the improvement of institutional capacity, which may include the creation of transparent, participatory and effective governance structures, the provision of adequate training to utility management and staff and possibly the introduction of new regulatory systems.

In developed countries, the contentious issues of reform generally relate to the policies of the regulatory agencies, their application; and further down the chain at what occurs at the re-licensing stage when the future of the project is decided.

The contentious issues in developing countries, where the power sector reforms represent a more significant departure from past practice, are perhaps more numerous and diverse. They range from:

- concerns over the transparency of the processes of power sector reform;
- the policies and functions of regulatory agencies;
- the influence of the regulatory policies on promoting different supply and demand options, including demand-side management, and the introduction of renewable energy systems;
- the degree of foreign and direct investment in the generation, transmission and distribution to be permitted under the reforms;
- issues around the divestiture of public assets;
- equity implications of what is implied with the associated changes in electricity tariff levels;
- issues of employment after the state monopolies are dismantled; and
- issues of ensuring that the reform process does not discourage end-use efficiency and environmental practices.

Environmental and social concerns, both regional and global, are increasingly important determinants of the evolving global power sector and major drivers of generation choice. Regional air pollution (specifically acid deposition, smog and particulate matter) has led in many areas to regulation of sulphur, nitrogen, and ash emissions. Climate change mitigation is likely to become the forefront issue, substantially affecting investment decisions both in industrialised and developing countries. Both regional air pollution and greenhouse gas emissions will increasingly discourage the use of all fossil fuels, especially coal, and correspondingly increase interest in hydroelectricity, with its comparatively lower life-cycle greenhouse gas emissions, although concerns about the inundation of ecologically sensitive habitats persist. Generally, as environment concerns continue to grow in prominence, renewable and efficient energy technologies can be expected to receive increasing attention from investors prompted by regulatory requirements, policy initiatives, and consumer demand for “green power”.

Power sector planners, investors and regulators are also according social concerns much greater attention than was historically the case. Most affected is nuclear power, which is nowhere likely to enjoy further growth without considerable opposition – on the grounds of reactor safety, radioactive waste disposal, the risk of nuclear weapons proliferation, unresolved decommissioning issues and non-transparent decision-making. Plans for hydroelectric facilities are also being closely scrutinised for their potential dislocation of local communities and other social impacts.

S3.2 Supply options for electricity grid systems

There are numerous technology options for the provision of energy services:

Conventional Generation Options

- Utility scale conventional generation options include gas- and oil-fired gas turbines and combined cycle plant; coal-, gas- and oil-fired steam plant; nuclear plant and diesel plant.
- Increasingly co-generation facilities are used to provide (district) heat and power in cold climate settings, with very high efficiencies.
- Gas turbines and combined cycle plant are increasingly popular on the account of their low capital cost, short lead-time and high efficiency.

- When no gas is available, the prime choice is the coal-fired plant for baseload and oil-fired gas turbines for peaking and standby
- Nuclear power in its present form is perceived to have high investment costs, limited public acceptance (in OECD and other settings) and unresolved concerns on high level waste disposal and decommissioning

Renewable and Non-Conventional Generation Options

- The main renewables are hydro, geo-thermal, wind, solar, ocean (tidal, wave and OTEC) and biomass.
- All renewable sources (except for geothermal, biomass, storage hydro, and some forms of ocean energy (thermal gradient) are inherently variable or intermittent sources of power generation;
- Consequently for grid system operation, a back up generation source is needed to cover demand in periods during the day, or seasonally, when the source is not generating;
- Most renewables sources thus operate in a fuel saving mode on the grid, to reduce the burning of fuel at existing thermal stations or (biomass) generation, where power can be available on demand;
- Hydropower can be stored in a reservoir project (if sites are available) and stored water released to follow load patterns on a daily or seasonal basis depending on the amount of storage;
- Geothermal is an established technology;
- Wind power now costs 5 to 10 USc/kWh. The actual cost is depends on the wind speed at the site. Grid-connected wind can almost compete with thermal generation and many commercial demonstration projects are operating (with subsidies).
- Offshore windmills are projected to offer even better economics. 10% penetration in power systems by 2020 is projected as an industry target.
- An equivalent thermal or other storage power plant is required to meet the demand when the wind is not available.
- PV Solar generation still costs 5 to 10 times as much as conventional generation, but is suitable for isolated locations away from the grid.
- Solar thermal now costs in the order of 10 USc/kWh and can almost compete with conventional thermal in some settings (excluding cheap gas).
- Biomass and dendro steam units: can be viable if enough burning material is available.
- Waste Incinerator: viable if incineration is needed and power added as a component of the plant. Problems with emissions sometimes exist.
- Wave Generator: best technology is TapChan, all others far from viable at present.
- Ocean thermal: up to now only two small prototypes have been built.
- Tidal Energy: conventional technology, damming part of an estuary, only for large tidal difference of say 8 to 10 m.

Hydropower Options

Hydropower options for grid connected applications vary considerable in scale and type. The main types are:

- **Run-of-River**: Hydropower station without seasonal regulation or storage. Two types may be distinguished: (i) pure run-of-river without any regulation, the water is turbined as it comes; (ii) run-of-river with daily or weekly pondage, whereby the releases during the electricity peak demand hours are maximised. This requires a storage pond to provide the daily or weekly regulation. A run-of-river project may divert the water to another basin, and this would affect the seasonal streamflow pattern in both the downstream and the recipient river.

- **Hydro with Storage**: Hydropower station with a dam and a storage reservoir for seasonal regulation. Some schemes have carry-over storage, regulating water over a period of several years. In all cases, the streamflow pattern of the downstream river is affected. Sometimes, a storage project may divert the water to another basin, and this would affect the seasonal streamflow pattern in both the downstream and the recipient river. Often storage projects are multi-purpose, combining for example hydropower, irrigation and flood control. A downstream reregulating weir may be needed to regulate power releases into the river over the day or week.

- **Pumped Storage**: Hydropower station with an upper and a lower storage reservoir for daily or weekly regulation. During hours of low-cost off-peak hours, the station would pump water from the lower to the upper reservoir. This water is used to drive the turbines during peak hours, offsetting expensive thermal generation. Pumped storage plants also provide what are called ‘dynamic benefits’, such as frequency and voltage control of the system, load following operation, and spinning reserve. Sometimes the units are used without water for synchronous condenser operation.

S3.3 Demand Side Efficiency

The inherent attraction of energy efficiency is unassailable. Energy efficiency initiatives can have multiple purposes that target local development goals. From a Life Cycle Analysis (LCA) standpoint, most energy efficiency measures contribute few if any net emissions and other adverse environmental impacts. By lowering electricity expenditures, implementation of new, high-efficiency technologies and processes and low-cost housekeeping measures can improve the competitiveness of energy-intensity industries. Consumer re-spending of energy cost savings can spur substantial macroeconomic growth and job creation (Bernow et al, 1999). And in many cases, domestically produced, high-efficiency goods and services can substitute for imported fuels, improving balance of trade and further stimulating local economies.

In addition to demand side end-use efficiency, the efficiency of all elements of the supply system (generation, transmission and distribution) is important.

Experience with technological and policy approaches over the past 20-30 years have shown a mix of successes and failures in demand-side efficiency. Early efforts were a direct response to oil shocks and rising electricity prices in the 1970s. Under regulatory pressure in North America and other regions, electric utilities developed demand-side management (DSM) programs to introduce more efficient technologies and curtail peak demands, and to overcome widespread informational, institutional, and other barriers. While many utility-run DSM programs achieved major energy savings at low costs, and grew to account for 1% of utility expenditures in the US by the early 1990s (Eto, 1996) [iii], deregulation and declining electricity prices have drastically reduced the scale of activity. This has led to the modification of regulatory frameworks to include rules which discourage growth in electricity sales and encourage end-use efficiency and the use of renewable sources (ACEEE 1999). Governments throughout the world have raised awareness, provided financial incentives, and instituted codes and standards for improving end-use efficiency[iv]. Building codes and equipment standards are now in place in over 20 countries. In the US electrical appliance efficiency standards are estimated to have saved consumers over $100 billion in energy costs and displaced the need for over 15,000 MW of new power plant capacity. (Geller, 1997; Turiel, 1997) In addition, many developing countries have created energy efficiency centres, which have implemented thousands of energy audits, leading to low-cost reductions in electricity use, and improving the competitiveness of local industries. There have also been numerous energy conservation programmes conducted through international co-operation between state agencies or utilities and industry associations or multilateral organisations[v]. Nevertheless, the actual world-wide investments in energy efficiency and the savings realised are still small in comparison with the potential.

Many observers have questioned why energy efficiency, if such an attractive resource, has remained untapped. Sceptics have argued that transaction costs for DSM are inherently high, and their systematic underestimation explains why many energy efficiency options are less cost-effective than often reported. (Joskow and Marron, 1992). Proponents, on the other hand, point to pervasive market barriers and imperfections, including low energy prices, inefficient industrial policy encouraging cost-plus pricing and lack of credible commitments that have inhibited wider penetration of efficiency measures. One perspective is that societal costs are not fully incorporated in fuel prices and thus there is less price incentive for DSM generally in thermal dominated grid systems. Effective policies, they counter, can reduce transaction costs and overcome barriers. These policies include information and product promotion through well respected channels, training programs for energy efficiency service suppliers and consumers, minimum efficiency standards, labelling and endorsement of high efficiency equipment, selective government procurement, innovative financing and contracting mechanisms, removal of subsidies for conventional supply options, creation of power sector regulatory frameworks that encourage DSM, and building capacity to design and deliver efficiency policies and programmes in government agencies and utilities. Some have also argued that a major obstacle is political, and that “diversity of efficiency technology producers in industry and services… [cannot]… develop a lobby structure similar to the energy supply dominated by some 50 global players.” (p. 6-1, WEA, 1999)

Since the early 1990s, the principal drivers and actors of energy efficiency efforts have begun to change. In many OECD countries, deregulation, and unbundling of electric utilities are providing large energy users now have access to lower-priced power supplies and there are fewer incentives for generation utilities to invest in DSM. On the other hand, distribution utilities can benefit from performance-based competition to develop energy efficiency programmes either directly or through third-party energy service companies (ESCOs). At the same time, in some developing countries, power sector reform is leading to higher prices for electricity, and consequently, is providing a better environment for adopting energy efficiency measures. For instance, reform in distribution requires the removal of subsidies, effective billing and collection procedures and innovative arrangements to make bulk sales to co-operatives, time-of-day pricing to smoothen peak demand, etc. Furthermore, national governments and multinational institutions are increasingly recognising the value of energy efficiency in meeting environmental and development goals. Domestic and international climate change mitigation, in particular, may be the most potent motivator for future efficiency programs and investments. On major hurdle in accelerating DSM is the long replacement cycle of motors. Electric motor loads (in industries, buildings and homes) account for between 45%-80% of total electricity use in all societies, and represent the largest single barrier to efficiency of use.

The enormous potential for electricity savings will only be achieved if strong, coordinated actions are taken, and conditions are favourable. These could include:

- Strong commitment by governments and international institutions. Priority procurement procedures for energy efficient products and services support their commercialisation and development. Measures such as installing solar water heaters for government canteens and housing or requiring energy efficient lighting in government building have had an important multiplier effect for bringing down the costs of these technologies.
- Capacity building through training and education. Outreach, public education and technical support to businesses, equipment manufacturers, distributors and trade associations have been effective in transforming the markets for energy efficiency.
- Innovative project-based approaches (e.g., innovative financing and risk sharing)
- Private sector incentive framework (e.g., government procurement of energy efficiency goods and services)
- Market recognition of high efficiency equipment (e.g., labelling, efficiency standards). Standards for energy efficiency in household appliances and office equipment, based on financial plus environmental cost-benefit have been quite effective in industrialised countries in the diffusion of cost-effective energy-efficient technologies.
- An effective, transparent and credible regulatory environment (e.g. energy efficiency legislation that regularly "raises the bar" of minimum efficiency, a power sector regulatory framework that encourages demand side management, and a mandatory LCA planning process)

S3.4 Competitiveness of Large Hydro

The main conventional competitors for large hydropower plant are thermal-electric installations, particularly combined cycle, and gas turbine and steam plant. Power system economics is still critical factor influencing the choice of options. The most important planning data for utility and system planners for small and large plant are summarized in the following table. The specific characteristics may differ somewhat, depending on local conditions and fuel quality.

Max Hydro Investment Cost in US$/kW - Large Power Systems - Cheap Fuel

Degree	Gas-Fired Generation			Coal-Fired Generation		
Utilization	i=10%	i=15%	i=15%+emis	i=10%	i=15%	i=15%+emis
10%	600	500	500			
20%	800	600	700			
40%	1000	700	900	1800	1500	1800
70%	1100	1000	1100	2000	1700	2300
100%	1200	1100	1200	2200	1900	3000

Max Hydro Investment Cost in US$/kW - Small Power Systems - Expensive Fuel

Degree	Gas-Fired Generation			Coal-Fired Generation		
Utilization	i=10%	i=15%	i=15%+emis	i=10%	i=15%	i=15%+emis
10%	900	700	800			
20%	1200	900	1000			
40%	1700	1300	1400	2400	2100	2700
70%	2000	1700	1800	3000	2400	3200
100%	2400	2000	2200	3200	2600	3800

The analysis in section 3 indicated that these break-even values can be increased by US$200 to US$500 if the GHG emission credits are considered, and by a further by US$200 to US$500 hydropower plant in question provides appreciable dynamic system benefits to the grid network (also called ancillary services) such as:

- rapid load following capability
- frequency and voltage control
- VAR control
- coping with sudden major load increase and decrease (steep ramp rates)
- synchronous condenser operation
- system black start
- smoother operation and lifetime extension of thermal plant.

The observations **from the utility economics perspective** are as follows:

General:

- the effect of crediting hydro for avoided emission of thermal plant is stronger for base load plant than for peak load facilities;
- the largest credits result against coal and lignite fired power plant running at base load;
- dynamic benefits can be of the same order of magnitude as the value of avoided emissions.

Observations for *large power systems with plenty of natural gas available for power generation:*

- only the very cheapest hydro will compete. The maximum capital investment is US$500 to US$1,000 for peak and midload, and US$1,000 to US$1,200 for baseload plant. With dynamic benefits US$200 to US$500 more.

Typical hydro types which could compete in such circumstances:
- high head plant with plenty of water;
- installation of turbine(s) in dam projects built for another purpose (e.g. irrigation or water supply);
- possibly pumped storage, depending on availability of very cheap energy in off-peak hours (nuclear or coal).

Observations for *small power systems with plenty of natural gas for power generation:*

- only cheap hydro can compete. Maximum investment is US$700 to US$1,200 for peak, US$1,500 to US$ 1,700 for mid load, and US$1,700 to US$2,400 for baseload plant. With dynamic benefits US$200 to US$500 more;
- since also the hydroplant will have to be of rather small size, and therefore quite expensive, it will be difficult to find projects which can compete;
- base and mid load hydro seem to have a better chance, but specific installation cost per kW is of course also somewhat higher for this type of plant.

Typical hydro which could be compete in such circumstances:
- high head plant;
- installation of turbine(s) in dam projects built for another purpose (e.g. flood mitigation, irrigation or water supply).

Observations for *both large and small power systems with plenty of natural gas for power generation:*

- the effect of changing the discount rate from 10% to 15%, depending on public or private sector financing) is greater or equal than the effect of including the emission penalty, and in the order of US$200 to US$300 per kW, equivalent to 10% to 20% of the investment costs.

Observations for *large power systems with plenty of cheap coal, but no natural gas*:

- hydros with specific investment costs of US$1,500 to US$ 1,800 per kWh (midload) and US$1,700 to US$3,000 per kW (baseload) can compete. With dynamic benefits US$200 to US$500 more;
- the prospects (utility economics) for all sorts of hydro, except possibly low head, are reasonable;
- the prospects for pumped storage plant are good, especially if peak load covered by oil-fired gas turbine.

Observations for *small power systems with imported coal, and no natural gas*:

- hydros with specific investment costs below US$2,100 to US$ 2,700 per kWh (midload) and below US$2,400 to US$3,800 per kW (baseload) can compete (utility economics). With dynamic benefits US$200 to US$500 more;
- the prospects(utility economics) for all sorts of hydro, except possibly low head are good;
- the prospects for low head baseload plant are reasonable.

Observations for *both large and small power systems with plenty of coal, but no natural gas:*

- changing the discount rate from 10% to 15%, depending on public or private sector financing) leads to US$300 to US$600 per kW lower break-even costs for hydro;
- taking emission penalties into account increases the maximum permissible hydropower cost by US$300 to US$600 per kW for midload plant, and to US$600 to US$1,200 per kWh for baseload plant with dynamic benefits US$200 to US$500 more.

Concluding Observations arising from the analysis of the utility economics perspective include:

- a major problem facing hydropower is its financial competitiveness in the new project financing environment;
- for countries without fossil fuels, but with ample hydro resources the competitive prospects for all types of hydro from a utility economics perspective are higher, with the possible exception of pumped storage;
- only exceptionally cheap, large hydro schemes can compete with gas-fired generation where gas is readily available;
- in systems without gas, but with plenty of coal, hydro can be competitive where offsets of significant amounts of green house gas emissions are credited;
- pumped storage plant may be competitive in large systems, particularly if cheap base load is unused; and
- only exceptionally cheap, large, hydro can compete with gas-fired generation.

S3.5 Life Cycle Analysis (LCA)

It is necessary to extend the conventional financial analysis of power supply options shown in the previous section to illustrate a broader range of costs incurred over the lifetime of the options, in a way consistent with Integrated Resource Planning (IRP) approaches. LCA is proving to be a helpful analytical approach in this regard. LCA provides tools for providing generic comparisons between electricity options which can be discussed by stakeholders and provides insights for policies which are either used to guide subsequent planning activities under IRP, or to inform regulatory policies on options. In Europe and North America governments, utilities and regulators are increasingly looking toward LCA approaches as a strategic entry point for generic options assessment to inform power sector policy on generation options. As noted, in many European countries targets are being set for new generation from renewable energy sources.

The literature review suggests that LCA has progressed to a point where basic yet powerful comparisons of options in terms of their resource use implications per unit of electrical service over the life of the option can be developed. At present, the parameters in LCA analysis are generally limited to quantification of energy payback conditions, emissions, land use aspects and technology efficiencies (e.g. years to payback, land use/kWh, GHG emissions/ kWh, and efficiencies etc.). Thus some views are that LCA approaches respond more directly to the current policy agenda for the power sector in industrial countries where resource portfolios are being established, and perhaps less so to in developing country settings (partly due to their data intensive nature). ISO standards have recently been developed to guide LCA work though applications are still few. Recently efforts in European and North American energy policy bodies are focusing on extending LCA methods to cover a broader range of social and environmental parameters including biophysical and health impacts as a basis to compare options; though these efforts in this direction tend to be academic in nature at the moment.

Section 3.5 of the paper provided illustrations of the initial results emerging from LCA of electricity options for power utilities. Among the general conclusions for comparison of grid-connected supply options include the following:

- all electricity generation options contribute GHG emissions either directly or indirectly. This is considering the full chain from resource extraction, manufacture of equipment, construction or operation to decommissioning including all thermal, nuclear, hydro, wind, solar and biomass.
- renewable technologies, hydro and nuclear have intrinsically less GHG emissions per unit of energy produced (greater than a factor of 10 in many cases). The emerging practice of LCA is quantifying the relative emission impacts per unit of energy delivered;
- the production of GHGs from supply options per unit of electricity produced varies widely and is influenced by many factors that are unique to the energy system and country; (e.g. fuel source, type and quality, source of materials, manufacturing and construction processes);
- DSM options have the best GHG profiles and always lead to a net reduction in GHG emissions;
- biomass options are generally net in carbon emission terms; the time profile of emissions release is changed.
- hydropower, geothermal and cogeneration technologies have among the highest ratio's of net energy produced over the lifetime of the technology (in the order of 180-200 times; though dramatic improvements are occurring in wind energy systems with recent improvements in materials technologies and efficiency improvements, better locations in higher wind regimes offshore.
- biofueled and biomass generation (with dedicated land), wind and solar have among the highest land area requirements per unit of energy produced; measures for hydropower especially storage are more complex and the quality of land use needs to be taken into account in such comparisons;
- the net energy supplied over the lifetime of equivalent capacity energy systems varies by a factor of 4 to 5 between conventional energy generation technologies (nuclear, thermal) and emerging renewable energy technologies with hydropower typically in the mid range.

Because LCA approaches are conceptually powerful and are gaining ISO status, they are very useful tools to respond to issues in the dams debate and for electricity options assessment. They are expected to increasingly do so in future as the detailed techniques gain wider application and acceptance. At present there are a limited number of LCAs for developing countries that reflect climate conditions in those setting particularly for solar, wind and biomass conversion technology comparisons.

S3.6 Integrated Resource Planning (IRP) in the context of changing electricity markets

Integrated Resources Planning (IRP) approaches are among the best approaches for power sector planning for accommodating issues that are raise in the dams debate regarding options assessments IRP processes have been in use for a number of years by utilities in industrialised economies. In some cases in the new regulatory environments IRP processes are complemented or are giving way to policy-driven approaches where "resource portfolios" are established by governments and regulators to direct market-based decision making on options.

IRP approaches are describe in Section 3.5 of the paper for grid-systems and are noted in section 4 of the paper for off-grid planning and options assessment processes. IRP is an approach to power planning comparing different demand- and supply-side options for providing electricity services on an equivalent basis, considering the full economic, environmental and social impacts. Traditionally, electricity planning has sought to expand supply resources to meet anticipated demand growth with very high reliability, and to minimise the economic cost of this expansion. IRP, however, broadens the range of supply and demand options considered in electricity planning - including new supply technologies (such as renewables) and demand-side management (DSM) - as well as addressing the costs and benefits of transmission and distribution. IRP also takes into account the environmental and social costs of generation, transmission and distribution that are not captured in financial calculations.

In traditional utility-run IRP, the regulatory framework provides utilities special incentives to adopt DSM resources as valid alternatives to supply-side resources; so that reduced electricity demand does not thereby reduce profits. Price impacts of DSM are shared by consumers, with appropriate measures to mitigate equity concerns.

As the paper notes, IRP planning processes have application at the local, national and regional level with specific goals. National level IRP processes are most common and increasingly used in developing countries as described in section 3.6 of the paper. The process begins with an analysis of current conditions that include an assessment of the remaining lifetimes of existing resources (power plants, transmission and distribution networks), forecasts of future electric loads, and identification of objectives (e.g., reliable service, minimal environmental impacts, and reasonable prices for consumers). The second phase identifies resource options that would compensate for discrepancies between expected loads and existing capacities. In the third phase, the identified alternatives are tested and re-evaluated with consideration given to a variety of assumptions about economic, environmental, and societal conditions. In phase four of the planning process, a mix of resource options is identified that will meet the demand for electricity, that are consistent with the utility's corporate goals, that avoid exposure to undue risks, and that satisfy other environmental and social criteria. After approval by the appropriate administrative or regulatory bodies for public utilities the plan is implemented in the fifth phase and the final phase involves monitoring and evaluation of the plan.

Local integrated resource planning (LIRP), is being explored by growing numbers of electric utilities to reduce capital expenditures by deferring or avoiding expensive local transmission and distribution investments. LIRPs can also form the basis for electricity and energy supply planning for off-grid and rural areas and is the philosophical basis for many of the submissions received by the WCD on rural energy planning.

The use of LIRP-type planning essentially started in the 1990’s, yet already a large number of utilities have begun to explore the option. A number of case studies have shown that LIRP can be applied in urban, suburban, and rural settings, and in a wide variety of countries where utilities are adapting to increasing competition. Local IRP focuses on a geographically smaller area, and covers all the decisions, which can be made on local level. In this regard, it has shown great promise, in some cases cutting expenditures in utility supply in industrialised countries by two- to ten-fold (Lenssen 1996). The options typically considered under LIRP include customer-based energy efficiency improvements, load control, local generation (including renewable resources) and storage, fuel switching, alternative rates, and targeted local transmission distribution reconfiguration and investments. The relevant information from higher planning levels is the cost of electricity supplied to this specific area, including financial and non-financial costs as well as the time-dependency of these costs. This information is then used to optimise the electricity system on the local level. In turn, local IRP will produce demand forecasts as input for national IRP.

The paper notes that large potential for capital savings have been achieved. Ontario Hydro in Canada estimated that three recent LIRP projects are expected to avoid conventional investments valued at C$730 million by spending some C$149 million on a host of distributed resource and revised transmission and distribution investments (Lenssen 1996). Lenssen (1996) reports that about 100 LIRP-type analyses had been or were being conducted by North American utilities in 1996. In countries where competition in the electric power industry is further advanced than in North America, such as Australia, Sweden and the United Kingdom, Lenssen (1996) reports that utilities also were pursuing LIRP-type projects.

Regional IRP-type approaches are emerging and may be influenced by local and national IRP decisions and, in turn, influence decisions made on these planning levels. On a regional the main focus of IRP is the sharing of electricity generation resources between different countries in a sustainable manner and how to use transmission resources efficiently in regional co-operation where long distances of transmission could result in immense losses. Motivations include improving options for power exchange and sales; complementary operation of grids to improve stability, emergency power, and diversity; and to reduce overall investment in new power plant by sharing reserves. The main links between regional and national IRP levels are the regional societal costs of electricity generation and transmission as input for national IRP and demand forecasts from the national level planning as input for regional IRP.

Interconnection is also enabling large units sized to take advantage of economies of scale. The interconnection of regional grids could also facilitate renewables (solar, wind, hydro) by providing larger markets for intermittent power sources than would otherwise be possible; however they must compete with the better efficiencies from larger size units. Gas and oil delivery networks are expanding regionally, which are expanding and fuelling the thermal generation choice on the regional level.

For regional IRP, the geographical area covered consists of several, independent countries, such as the Southern African Development Community (SADC) region. To date, IRP has not been applied to a whole region (Graeber & Fecher 1997). But the objective - to optimise the electricity sector from a societal perspective for a whole region is in the interest of all the region's inhabitants. The optimum solution for a whole region will be better than the sum of optimum solutions for all individual countries in a region. General drivers behind regional IRP include the following:

- Take advantage of different peak demand times in different parts of the region,
- Share generation reserve margins among several utilities or countries,
- Increase supply security,
- Decrease electricity prices, and
- Reduce environmental degradation.

For example, in Southern Africa, where limited co-operation in the energy sector existed for over 40 years due to political conflicts, there are even stronger drivers for regional co-operation within an IRP framework:

- Utilise complimentary energy sources, i.e., hydro in the northern part and fossil in the southern part.
- Harmonise large investment decisions: Due to economic growth and electrification efforts, electricity demand is rapidly growing and large-scale investment decisions will have to be made soon throughout the region. Independent planning of the utilities in the region might lead to disadvantageous decisions from a regional perspective.
- Utilise existing capacity more effectively: In the short term, existing generation capacity could be used more efficiently and technical co-operation could help to improve the system performance in several countries.
- Co-ordinate DSM initiatives: Harmonising and co-ordinating energy efficiency initiatives (e.g., energy efficiency standards for the region) and DSM could reduce electricity demand more effectively than isolated national programmes and create larger markets for energy efficiency.

For regional planning, political integration must go hand-in-hand with co-operation in the electricity sector.

The general barriers to IRP relate to its high transaction costs in general, relating to the difficulty and expense of collecting detailed customer load data and to contracting and co-ordination risks with respect to customers and different segments of the utility. Careful regulatory design and organisational incentives can help overcome these barriers.

Following reforms, in a open market where competition is allowed at all levels of industry, DSM programmes may suffer because 1) non-participating customers harmed by rate increases from DSM could switch to another electricity provider, and 2) participating customers in DSM might be tempted to switch providers and forego repaying for the capital costs of installed efficient appliances through their electricity bills. With externalities not built into pricing at different levels and increasing retail competition emphasising short-term investments in the sector, there are now new institutional barriers to designing and implementing IRP.

Although power sector restructuring provides consumers with an array of options to choose from for their end-use services, it is likely that their choices will be determined more by the price and convenience of the services than by their supply routes, notwithstanding the recent interest in "green" power. This provides some flexibility for policymakers to deliver electricity from a portfolio of resources, technologies, organisational structures and servicing mechanisms, keeping open the potential for more innovative forms of IRP.

S4. Isolated Community and Rural Energy Context

S4.1 Isolated and Stand-Alone Systems

Of the approximately two billion persons who are estimated to have no access to electricity, many live in rural areas or in remote communities that are unserved by the conventional electricity grid. The percentage of people with grid-based electricity varies widely: it is over 95% in mature market economies and 5-20% in low-income countries. In some countries, like India and South Africa, a large number of people live within easy reach of the grid, but are either not able to pay for a connection or are deterred by the extremely poor quality and reliability of supply. Widening access to electricity therefore represents a major challenge and an opportunity to implement new institutional approaches and technologies to provide affordable energy services through decentralised energy systems or grid extensions.

There are many options of providing electricity to rural areas ranging from the conventional to emerging methods. The selection of the most appropriate options depends on the socio-economic conditions and resources available in the area or the country.

Access to electricity is low even in developing countries where electricity is generated primarily from hydroelectric sources and tariffs are relatively low. In fact, countries in Sub-Saharan Africa that have some of the lowest rates of electrification in the world (Zaire, Malawi and Ethiopia, where only between 3-5% of the population are connected to the grid) are also predominantly hydro-based, although their generation capacities are themselves very low. Institutional considerations, relating to governance and utility performance, therefore appear to be at least as important as generation choice and technical limits in determining the extent of electrification within a country.

Extending the grid can be cost-effective for locations that have reasonable loads and are at some minimum distance from the existing grid. Low load density and low loads during off-peak hours are frequently barriers to extending the grid to remote areas. Simple innovations like low-cost metering (for instance, "ready boards" in South Africa), incentives for off-peak commercial use and load management, bulk sales, etc., can lower the cost of grid extension to remote areas. Such approaches will also help to lower connection costs and thereby widen access to electricity even where the grid is already present.

Grid extension has both advantages and disadvantages. It is a proven technology that enjoys scale economies, can be adapted to meet urban and rural demand and, because of its long-term presence, can access cheap investment credit and government guarantees. On the other hand, it is capital intensive and often dependent on imported technology, produces environmental externalities, requires long gestation periods, is typically inflexible to the requirements of quickly extending supplies to remote areas with low demand, is subject to high levels of technical loss and theft and often results in poor quality and unreliable supply.

Each of the options has its own niche in remote area electrification—grid extension in the more populous areas, and decentralised systems in less populous ones and where conventional electrification is likely to take place only far into the future. In addition, the availability of decentralised alternatives means that there are more options for less developed areas that would supplement, not delay, the extension of the national grid.

Decentralised electrification options provide simple and flexible ways to extend energy services to remote areas. They include simple household lighting systems and mini-grids powered by diesel generating sets, small steam or gas turbines, micro-hydel units, windmills coupled to generators, modified engines using biofuels and coupled with generators, and photovoltaic systems.[vi] These technologies can be used for rural industry, to meet agricultural needs like crop processing or water pumping, and for household lighting, with a range of financing mechanisms to recover capital and operating expenses. Rapid improvements in technology and organisational learning have made systems based on renewable energy (biomass, solar, wind and small hydro) increasingly attractive where such resources are available[vii].

Decentralised options have the advantages of potential reliance on local renewable energy sources, quick implementation, portability and modularity, little or no fuel costs (for solar, hydro and wind) and transmission/distribution losses, decreasing costs with technological advancement, the possibility of steeper cost reductions through expanding markets, potential for local employment, low environmental impacts, and the likelihood of strengthening local institutions through community interaction.[viii] However, the intermittent energy availability of some technologies based on renewables, high first costs, organisational demands on their utilisation and foreign exchange implications can act as barriers. Innovative financing and organisational arrangements, training in the servicing and use of new technologies, and the application of hybrid systems based on a mix of renewable sources and diesel, where appropriate, have been important ways of overcoming these barriers in many field situations.

S4.2 Rural Energy-Poverty Nexus

In developing countries, people living in rural areas typically use very low levels of commercial energy and relatively high levels of biomass (e.g., fuelwood, agro-wastes, dung), which is gathered each day mostly by women and children who spend long hours and considerable human energy in the effort. Cooking is by far the predominant end-use of energy in rural areas, followed by agricultural processing and small industry, water pumping and lighting.

Low demand for electricity and low levels of monetisation tend to persist in rural areas since utilities themselves see little commercial incentive to extend grid supplies. Yet, lack of access to modern energy services for daily uses has serious adverse implications for the welfare of the vast numbers of the poor, including ill-health, malnutrition, environmental degradation and worsening conditions of poverty and gender inequality (Reddy et al., 1997).

A broad range of advanced technologies for using locally available renewable resources can play an important role for sustainable development in rural areas, where traditional biomass fuels and kerosene tend to be used inefficiently for cooking and lighting, respectively. Improved cookstoves, for instance, can reduce fuelwood requirements by about half and also lower indoor air pollution levels significantly (Dutt and Ravindranath, 1993; Kammen, 1995), while switching from kerosene to electricity for lighting can improve system efficiencies by as much as a factor of 19 (Rajabapaiah et al., 1993). Similarly, advanced energy services for industrial development can increase rural employment and reduce the burden of massive migration on urban areas.

In particular, significant reductions in energy use and welfare improvements can be achieved by switching from traditional fuelwood stoves to improved biomass, gas, or kerosene stoves. Depending upon local resource availability, there may also be opportunities to substitute liquid or gas (fossil- or biomass-based, for instance, biogas, natural gas, liquefied petroleum gas, kerosene) stoves for biomass stoves. The transition to more efficient cookstoves and fuels will free up substantial amounts of time and labour that are currently expended to gather biomass fuels and largely eliminate indoor air pollution from smoky biomass (or coal) fires. On the other hand, high quality fuels will increase monetary costs to the individual consumer, which could be addressed if concurrent income-generating opportunities became available as a result of electricity inputs to agriculture and industry.

Electricity for lighting in rural households produces major improvements in people's quality of life and also enhances opportunities for income generation; for instance, by providing longer hours for home-based crafts like tailoring, weaving, food-processing, etc. Similarly, small cooperatives using bulk power purchased from the grid or employing decentralised energy sources and mini grids can help provide low cost electricity services for multiple uses, like welding, carpentry, flour mills, etc.

The transformation to sustainable energy in rural areas will require that attention be paid to **technical, economic and institutional issues.** Considerable experience with disseminating energy efficiency technologies in rural areas has shown that technical, social, economic and institutional barriers may hinder their widespread adoption. For instance, to avoid the top-down approach to the dissemination of improved cooking technologies that undermined many earlier programmes, it has been necessary to involve end-users, mainly women, in initial discussions, feedback, and training programmes and to develop designs and programmes subsequently that are best suited for particular local conditions (Kammen, 1995). More generally, sustainable energy transformation will generally involve demonstration and monitoring programs on promising renewable energy technologies; training of engineers, technicians, planners, project developers; resource assessment studies and integrated rural energy planning in target areas; establishment of quality standards for locally-manufactured systems and components; continuing R&D, demonstration and monitoring programs on promising renewable energy technologies to reduce their costs to competitive levels; appropriate pricing; incentives for market penetration of efficient technologies; coordination among key players in the renewable energy field; international cooperation and technology transfer.

S5. Principles and Emerging Practice

Five key principles can guide the identification of good practices for planning and decision making in electricity supply and demand. These principles, as illustrated in the box below, place the goals of efficient economic growth, equitable access to affordable electricity, and sustainable development within an overall framework of good governance:

- *Enabling growth in electricity services* is essential for economic development particularly in developing countries, which will need increases in electricity supply and demand-side efficiency to meet their growing demands.

- *Widening access to electricity services* is an urgent task for most developing countries. One-third of the world's population -- 2 billion people -- still lack access to any electricity. Keys to success include: a) matching the scale of supply options with needs and income levels; and b) allowing scope for self-determination by the affected communities.

- *Promoting sustainable paths and options* can be accomplished through strategic planning and policy. Sustainable development is now widely accepted as the normative standard for all projects and programmes, especially those expected to have wide-ranging impacts. It requires decision-makers to incorporate objectives of environmental quality, equity and empowerment into traditional investment or planning roles.

- *Ensuring economic and financial efficiency* can help to accelerate and maximise the achievement of power sector development goals. Examples include pricing strategies and widespread power sector reform efforts aimed at attracting capital, promoting competition, expanding supply, lowering costs, and spurring innovation.

- *Enhancing participation and transparency in decision-making* can improve the credibility and effectiveness of power sector governance, especially if applied from the earliest stages.

Principles:
❑ Accommodating Growth in Electrical Services ❑ Expand Access to Electrical Services ❑ Select Sustainable Paths and Options ❑ Accommodating Economic and Financial Efficiency ❑ Enhance Participation and Transparency in Decision-Making
Emerging Good Practice
Options Assessment with Life Cycle Analysis Multi-Criteria Policy Formulation ❑ Diversity of Policy Objectives ❑ Other Level Playing Field Policy Measures Integrated Resource Planning (IRP) Framework ❑ Special attention to Off Grid and Decentralised Paths ❑ Special Attention to Regional Co-operation (Multi-country)

Principles and Emerging Good Practice for Decision-making on Electricity Supply and Demand Management Options

Emerging Good Practice

The major findings of this thematic review suggest that good practices consistent with these principles are emerging on a number of dimensions:

- comprehensive options assessment using multi-criteria decision-making tools, least cost analysis (LCA) and environmental impact assessment (EIA) at the *project/investment level*
- integrated resource planning (IRP) at the *sectoral level*
- complementary government policies at the *national level*
- sound institutional arrangements at *all levels*

These practices are reviewed in Section 5 and described briefly below.

Comprehensive options assessment
Given the many alternatives available to accommodate the expansion of energy and the multiple principles suggested above, major investment decisions should be complemented by a comprensive assessment of available options in a multi-criteria framework. For instance, decentralised electrification options, such as mini-grids powered by renewables, co-generation or fossil fuel options, are often neglected in the pursuit of rural electrification by central grid extensions. Yet they can provide simple, flexible, and affordable means to extend energy services to poorly served areas. Comprehensive options assessment at the project or programme level, though essential is often insufficient to achieve the above principles. For instance, decentralised electricity supply may face obstacles that are legal or institutional, rather than technical or economic. Therefore, options assessment must often be complemented by initiatives at the level of national and regional policies, laws, and institutions.

Options assessment can utilise life cycle assessment (LCA) for competing technologies (fossil fuel, geothermal, hydro, nuclear, solar, wind, ocean and biomass-based) to facilitate the comparison of the direct and indirect environmental impacts of these technologies, at each stage of their life cycles. The full life cycle includes extraction, refinement and delivery of the primary resource, manufacture of equipment, construction and operation of the power supply facility, transmission and distribution of electricity and eventual decommissioning of the power plant.

In addition to the environmental impacts identified above, the decision-making process needs to consider the social and economic impacts on communities affected by projects, including their livelihoods, habitats and cultural practices. Environmental impact assessment (EIA) and social impact assessment (SIA) offer well-established tools for this purpose. Multi-criteria policy formulation can be facilitated using appropriate decision-making tools to evaluate the tradeoffs ultimately required and to provide a framework for consultation and public participation. This framework can be used to lay out all relevant qualitative and quantitative impact measures and compare divergent approaches to their evaluation.

Integrated Resource Planning

Integrated resource planning (IRP) is a well-developed approach for embedding comprehensive option assessment in sector-wide planning and investment decisions. (Section 3.6 and Planning Approaches Thematic V.1.). The IRP process generally consists of the following steps:

- Develop multiple baseline demand forecasts to reflect wide range of possible future conditions;
- Identify and evaluate all suitable supply and demand side management options;
- Incorporate environmental and social externalities in decision-making framework, using LCA where possible;
- Derive a small number of attractive, but diverse, development plans matching supply and demand using level playing field treatment of all supply and demand side options;
- Foster the participation of stakeholders in selecting the most attractive development plan (based on multi-criteria decision making) using transparent and explicit decision criteria, and making data and stakeholder input publicly available;
- Develop an action plan to implement proposed measures (technical, financial, institutional)
- Repeat the IRP exercise regularly (yearly) to account for changing conditions.

IRP-type approaches have applications at local, national and regional levels. In locations where regional power pools exist or are under consideration, the IRP process can be conducted on a regional basis or incorporate the options for, and benefits of, increased regional integration. Power pools can increase regional energy security, lower the costs of system operations, spread hydrological and financial risk, and improve the economics of larger projects where individual utility markets are small. For instance, in Southern Africa, where a regional power pool is under consideration, IRP can be useful in addressing the efficient use of transmission resources (where long distances can result in system losses and stability problems), in promoting harmonisation of technical and environmental standards among countries, and ensuring consideration of transboundary river basin impacts.

A number of questions need to be addressed with regard to the IRP exercise:

♦ <u>What are the major enabling conditions for carrying out this exercise?</u> These include a clear articulation by government of its commitment to the policy principles stated above and its support of emerging good decision-making practice in support of the principles. In addition, government will need to assure that the institutions are in place to carry out this exercise as well as the substantial financial resources needed to undertake this planning work. The international donor community could be supportive of this process through providing financing for (part of) the planning effort;

- Which organisation is responsible for carrying out the IRP exercise? It is preferable that the IRP exercise be carried out by the organisation best equipped to do so (such as the public utility) and then reviewed by the regulator. (For example in South Africa, the IRP was carried out the power utility (ESKOM) and then reviewed by the regulator). *Inter alia*, the resulting plan would reflect government policy on fuel and technology diversification. In reviewing the IRP, the regulator would assure the appropriate level of public participation of stakeholders in this process.

- Where does system planning fit in? In the more traditional command and control power sector, system planning for grid systems was undertaken by the power utility and reviewed by the regulator. The critical point is that it is undertaken by the entity that has the technical expertise to give credibility to the whole exercise.

- Is planning required at all in an open market situation? In this situation, system planning is still important particularly to avoid congestion in the transmission system and to assure system security and reliability. It could be undertaken by the transmission company (TRANSCO) or the independent system operator (ISO) and then reviewed by the regulator.

- Are technologies in recommended plan an adequate basis for solicited project proposals? What degree of freedom do private entrepreneurs have (choice of technology, size of plant and units, site)? It would be expected that solicited project proposals would be based on technologies of the recommended plan. The size of plant and unit size would take into account the system stability and load forecast requirements.

Complementary Government Policies
Legislative and regulatory policies of national and regional governments can act as fundamental drivers of electricity development consistent with each of the principles. If formulated carefully, after a full evaluation of the likely consequences, they could help expand electricity services and widen access through sustainable practices and technologies in an economically efficient manner, while ensuring transparency and participation in decision-making.

For the three settings grid, off-grid and rural nexus, there is need for a clear statement of government policy. The role of **government** in the planning process includes setting and/or providing:

- Targets for reduced environmental impact (air, water, soil);
- Targets for diversification of fuels and technologies;
- Targets for power system security and reliability;
- Guidance on treatment of externalities. This could involve the use of environmental adders to internalize social and environmental costs;
- Policies and framworks for enabling local IRP processes and supprting outcomes;
- Framework for exports and imports with the detailed technical arrangements being worked out between the utilities concerned; and
- Policies on regional cooperation in electricity supply.

In relation to options assessment for grid and off-grid systems, the role of the government or the independent **regulator** should be to assure that the process and the substance is carried out in accord with the good practice procedures. For governments in developing countries, a priority in electricity development relates to the major equity concerns of poverty and lack of access by 2 billion people to electricity. Ministries responsible for electricity services can commission national and regional level demand forecasts and least-cost portfolios that utilise decentralised and off-grid options in their resource mix. These assessments then provide guidance for sanctioning specific projects that meet multiple objectives.

IRP itself may also be of more limited application where reform and deregulation leave investment decisions largely to the market. For example in the US and UK, power sector reform has led to deregulation, investments in demand-side management (DSM) programmes have declined, while the role of IRP has diminished or has been streamlined. Here, additional policy and legal instruments have been necessary to level the playing field and uphold the principles noted above. Examples include:

- public benefits charges to fund DSM programs, renewable energy investments, competitive offerings for clean electricity sources, and R&D for emerging technologies. (e.g. in US, UK, Germany)
- resource portfolio standards (and generation performance standards) with the option of tradable credits among participating generation or distribution utilities.
- government priority procurement procedures for energy efficient and renewable energy products and services, to support commercialisation and development.
- adoption of policies for the internalisation of the full social costs in fuel prices.

While many of the above policy instruments have been formulated within industrialised country contexts, they can also be applied in developing countries where policymakers have a firm commitment to promoting energy efficiency, renewables and sustainable development generally.

Special emphasis is also needed on conducting options assessments for decentralized and off-grid development as well as the poverty-rural nexus (Sections 4.1-4.3). Particularly important issues are interfuel substitution (such as substituting traditional cookstoves by LPG cookstoves) and improving the efficiency of traditional energy end use utilization (such as improving the efficency of traditional woodstoves). Governments could play an important role in **removing barriers to decentralised energy service options** by reducing high import duties on renewable energy equipment, easing licensing laws on self-generation and mini-grids, permitting the use utility lines and equipment to buy back power to the grid where feasible and making available training, financial assistance and technology support. In many countries, only the national parastatal company has the legal right to delivery energy services in rural areas. There is considerable room for innovation for introducing mechanisms (such as buy back rates) to offset the high costs (including transactions and negotiations) between the utility and the promoters of such systems.

Sound institutional arrangements

Robust institutional arrangements are increasingly recognised as major factors for addressing electricity concerns in nearly all countries and contexts. Some examples of good practice can include:

- **Promoting innovative institutional mechanisms** such as the granting of independent, regulated franchises for the delivery electricity services to under-served rural areas or encouraging the creation of renewable energy service companies can hasten the expansion of electricity provision.
- **Establishing training and capacity building programmes** for utility management and staff
- **Strengthening the capacity of regulatory agencies and public institutions responsible for rational planning processes** and specifically emphasise negotiation of private sector arrangements (financial and risk analysis), economic regulation, monitoring and compliance.
- Establishing an **independent regulator** to avoid potential conflicts of interest when the government continues to have a stake as electricity producer in a competitive environment.

In the changing context of power sector reform, institutional change is likely to be associated with the following activities, details of some of which are listed below:

- Regulation (economic, siting and environmental, technical, and safety)
- Systems Planning (Generation and Transmission)
- Load Forecasting and Demand Side Management Planning

- Options Assessment (LCA and multi-attribute analysis; public participation)
- Project Specific Feasibility Studies
- Hydropower Screening and Ranking

Table 4-4: List of ESDM Options

Option / Technology	Grid Connected	Isolated & Stand-alone	Rural Based	Total production cost US$/kWh	Typical Duty
Supply					
Thermal					
Conventional Steam Generation:					
Oil Based – Steam Generation	X			0.05 – 0.06	Base and Mid Load
Coal Based – Steam Generation	X			0.03 – 0.05	Base Load
Gas Based – Steam Generation	X			0.038 – 0.047	Base and Mid Load
Biofuelled – Steam Generation	X			0.05 – 0.07	Base and Mid Load
Fossil Fuel Turbine				n.a	
Combustion Turbine Generation	X			0.04 – 0.07	Peak Load and Standby
Combined Cycle Generation	X			n.a	Base and Mid Load
LNG Technologies	X			n.a	As Above
Diesel Generation				0.07 – 0.12	
Stationary	X	X	X	n.a	Whole Load Range
Moveable		X	X	0.10 – 0.13	Whole Load Range
Other Steam/Combustion				n.a	
Co-Generation	X			n.a	Usually Base Load
Fluidized Bed Generation Technologies	X			n.a	Base Load
Oil Condensing		X		n.a	
Nuclear Generation					
Light Water (LWR/PWR) and Heavy Water Uranium Fueled	X			0.02 – 0.05	Base Load
Fast Breeder _ U-238 and Plutonium	X			n.a	Base Load
Other Advanced				n.a	Base Load
Hydro-Electric Generation					
Storage Dams	X			0.01 – 0.10	Peak to Base Load
Run-of-River Diversion Dams	X			0.01 – 0.10	Peak to Base Load
Simple Run of River	X			n.a	Base Load
Pumped Storage	X			0.01 – 0.10	Peak Load
Small Hydro	X	X		0.015 – 0.070	Peak to Base Load
Mini and Micro Hydro		X	X	0.03 – 0.10	Peak to Base Load
Other Renewables					
Geothermal Generation	X	X			Base Load
Biofuelled Combined Heat and Power				0.05 – 0.07	Base Load
Wind Energy Generation	X	X	X	0.04 – 0.10	Variable
Solar Electric (PV)	X	X	X	0.1 – 0.5	Variable
Solar Thermal-Electric	X			0.06 – 0.75	Base to Mid Load
Other Solar Technologies	X	X	X	n.a	Variable
Ocean Energy Systems					
Tidal Energy Systems	X			0.07 – 0.14	Variable
Wave Energy Systems				0.09 – 0.20	Variable
Ocean Thermal Energy Conversion Systems	X			0.12 – 0.40	Base Load
Advanced Systems					
Fuel Cells	X	X	X	0.07 – 0.30	Peak to Base Load
Hydrogen Systems	X	X		0.04 – 0.025	Peak to Base Load
Demand Side Management Options					
Pricing Policies	X	X	X		Peak Load Shaving
Direct Control Practices	X	X	X		Interruptible Power
End-Use Efficient Devices	X	X	X		Bulbs, motors, etc.
Voluntary and Life Style Measures	X	X	X		Appeals to the Public
Other Approaches	X	X	X		

[i] The International Hydropower Association's estimates of the percentage of economically feasible hydro currently in operation are: North America (60.75); South America (19); Europe (60.7); Africa (6.8); and Austral/Asia (39.6). Estimates of economically feasible hydroelectricity may vary, however, depending on how direct and indirect costs are considered and assumptions regarding the future costs of competing resources. In instances where existing projects are required to be decommissioned, i.e., where they have become "stranded" investments, the economically feasible potential can actually be considered negative.

[ii] The latter is estimated on the basis of the historically observed fraction of the technical fraction utilized in industrialised countries with extensive hydropower developments (WEA, 1999).

[iii] A study of 40 of the largest U.S. utility commercial-sector DSM programs found that they were highly cost effective when compared to the avoided cost of new generation and had, on average, saved energy at a cost of 3.2 ¢/kWh (Eto, 1996). The success of DSM in realising energy savings will depend on the rate of turnover of equipment stock, but this may be less of a concern if leap-frogging opportunities are seized in industrialising countries.

[iv] More than 20 countries have adopted energy efficiency legislation, including labelling, building codes, technical standards for equipment, etc., and many have created agencies to promote energy conservation (Duffy, 1996).

[v] For instance, the China Green Lights Programme, which is supported by UNDP and promotes the sales of compact fluorescent lamps and other high-efficiency illumination products, is estimated to save 22 billion kWh and avoided emissions of 7.4 million tons of carbon dioxide over a five-year period ending in 2000. A similar programme has been supported in Mexico (ILUMEX) by the Mexican Electricity Commission, GEF and the Norwegian government, and others are being introduced in several other Latin American countries (WEA, 1999).

[vi] Small hydropower generation (generally comprising run-of-the-river systems under 30 MW, all the way down to a few kW in capacity) is an attractive, low-cost, reliable (because of high availability) and environmentally safe alternative to large dams in many areas where hydroresources are available. Mini-hydro systems that power village grids or remote esates are unlikely to cause significant environmental damage or require resettlement and have proved to be extremely effective technologies for extending electricity services in Sri Lanka and Nepal.

[vii] There are new opportunities for adopting leapfrogging institutional mechanisms and technologies to spur the development of decentralised options. These include innovations such as mini-grids using advanced biomass gasification coupled with micro-turbines (or, in the conceivable future, fuel cells) and rural concessions, as in Argentina, where development rights are conferred on private bidders who are then obligated to provide energy services to a rural area through technologies of their choice but are subject to minimum service conditions.

[viii] Solar photovoltaic modules, especially for household applications, have seen a phenomenal growth in the 1990s, with a cumulative production of about 800MWp in 1998. Several private and multilateral initiatives to promote PV development are also in place even as system prices are as low as $8/Wp and expected to drop further to about $1-2/Wp by 2020, with a projected market growth rate of about 25% for the next several years. Harnessing energy from biomass using advanced technology such as gasifiers is especially attractive in rural areas for community power, with the additional bonus of providing process heat for industrial applications. Biomass energy is greenhouse gas neutral and has potential for generating rural employment, but its widespread application may be restricted by land-use limitations, in particular, competition with food production.