# An Interdisciplinary Approach to the Dissemination of Mini and Micro Hydropower - the Case of Ethiopia

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## SUMMARY

Successful implementation of MHP projects in Ethiopia and subsequently a broader dissemination of the technology require an interdisciplinary approach. Based on the analyses of present hindrances in Ethiopia, crucial aspects are identified. Even though an adequate hydrological potential and electricity requirements are provided for at numerous sites, special attention must be directed to competing technologies, such as a diesel generator system or the connection to an existing grid, to investment and operating costs, profitability, financing instruments, financing partners, organisation forms, legal and political boundary conditions, tariff systems and paying modalities. All these relevant aspects are analysed individually and with regard to their causal interrelationships. The whole study provides the basis for the development of a decision support system.

By means of a regionalisation method, regression equations are developed which facilitate the estimation of the hydrological potential at a site with lacking runoff measurements. The evaluation of existing methods to forecast electricity consumption showed that usual specific consumption figures cannot be applied without taking into account the number of households per official connection and the effect of measures which stimulate market penetration and specific consumption. For example, incentives to purchase electrical appliances are one measure to promote the consumption. Simultaneously, an appropriate tariff system must optimise temporal balancing of loads by truncating peaks and filling of load gaps. Additionally it should help to adopt the continuously growing demand function to the stepwise increase of supply capacity. Selling of capacities in kilowatt instead of energy in kilowatt hours aligns with these objectives. Since profitability of MHP systems in Ethiopia revealed to be marginal and access to loans is limited due to the required collateral, mixed financing with different project partners is recommended. Firstly, some non- or less-profit oriented equity capital donors such as customers, development banks and NGO's and secondly, venture capitalists with significant equity capital for the provision of collateral and enforcing successful management should be involved. Thirdly, banks with loan capital are required to increase the ROE for the highly profit oriented investors due to a positive leverage effect. Some of the problems incurred can be solved by the issuance of juissance rights. They facilitate the participation of customers as co-financiers and allow dividend payment in kW's or kWh's. They reduce the risk of electricity sales, and delayed payments. They accommodate access to "cheap" quasi-equity capital from customers and thus ease the access to loans. In return, they offer the advantage of reduced monthly electricity expenses to the customer who, in case of a fixed rate of dividend, receives energy units unaffected by inflation. Juissance rights do not require a stock market and are permitted within the framework of several organisational forms. Since they do not confer any ownership rights, the management control remains with the (more) liable project partners. The participating partners, their number and liability, control aspects, the type of financing and finally the total investment volume decide on the favoured organisational form. A limited partnership is useful in case of investors with different liabilities, supplemented by consumers with juissance rights. A modern co-operative requires a well funded community, independent from big investors and banks. With regard to legal requirements, the investment licence turned out to be of primary importance, but can only be acquired for projects of a fixed minimum volume. The licence facilitates access to the one-stop-shop and thus to other requirements like operating licence, working permits, registration of the business organisation and the allocation of land and water rights.

In order to perspicuously illustrate the theoretical results all mentioned aspects together with the investigations on technical design, investment and operating costs are applied to two fictitious case studies of capacities of 50 and 150 kW. The analysis of prospects for international financing support with regard to the Flexible Mechanisms of the Kyoto Protocol, the Global Environmental Fund and others proved that these instruments can contribute to implement either barrier removal projects or concrete MHP pilot projects. In view of the collected information, the potential and the limits of a DSS tool are reviewed. Finally conclusions and recommendations on concrete measures, such as investment incentives, redemption from customs duties and improvement of loan conditions are given.

# ZUSAMMENFASSUNG

Die erfolgreiche Realisierung von Kleinwasserkraftprojekten in Äthiopien und die Verbreitung dieser Technologie erfordern einen interdisziplinären Ansatz. Aufbauend auf der Analyse gegenwärtiger Hindernisse wurden kritische Faktoren identifiziert. An den zahlreichen Standorten, die sowohl ausreichendes hydrologisches Potenzial als auch Strombedarf vorweisen, müssen Alternativen wie Dieselgeneratoren oder Anschluss an ein existierendes Netz berücksichtigt und das komplexe Zusammenspiel aus Investitions- und Betriebskosten, Wirtschaftlichkeit, Finanzierungsinstrumenten, Finanzierungspartnern, Organisationsformen, rechtlichen und politischen Rahmenbedingungen, Tarifsystem und Zahlungsmodalitäten analysiert werden. Die relevanten Aspekte wurden sowohl einzeln als auch im Hinblick auf ihre ursächlichen Zusammenhänge analysiert. Die Ergebnisse der Untersuchung stellen eine Basis zur Entwicklung eines Entscheidungshilfemodells dar.

Mittels einer Regionalisierungsmethode wurden Regressionsgleichungen entwickelt, die es erlauben, das hydrologische Potenzial eines Standortes im Falle fehlender Abflussmessungen zu schätzen. Die Bewertung existierender Methoden zur Vorhersage des Stromverbrauchs zeigte, dass die üblichen spezifischen Verbrauchszahlen nicht verwendet werden können, ohne die Anzahl der Haushalte pro "offiziellem Stromanschluss" und den Effekt von verbrauchsfördernden Maßnahmen zu berücksichtigen. Ein angepasstes Tarifsystem muss den Lastausgleich optimieren und zusätzlich geeignet sein, den *kontinuierlich* steigenden Bedarf an den *schrittweisen* Ausbau der Versorgungskapazität anzupassen. Der Verkauf von Leistung in kW statt elektrischer Arbeit in kWh ist hier eine mögliche Option. Da sich die Rentabilität von Kleinwasserkraftsystemen in Äthiopien als grenzwertig herausstellte und der Zugang zu Bankkrediten durch die erforderlichen Sicherheiten begrenzt ist, wird eine Mischfinanzierung unter Beteiligung verschiedener Partner empfohlen. Erstens sollten "wenig- bis nicht-profitorientierte" Eigenkapitalgeber wie zukünftige Kunden, Entwicklungsbanken und NROs involviert sein und zweitens Risikokapitalgeber mit genügend Eigenkapital zur Besicherung. Letztere gewährleisten i.d.R. auch erfolgreiches Projektmanagement. Drittens sollten Banken Darlehenskapital beisteuern zur Erzielung eines positiven Leverage-Effekts für die profitorientierten Investoren. Einige der auftretenden Probleme können durch die Emission von Genussrechten behoben werden. Sie ermöglichen eine Kofinanzierung durch die Kunden und eine Dividendenausschüttung in kW oder kWh. Sie reduzieren das Absatzrisiko und das Risiko verspäteter Zahlungen. Als günstiger eigenkapitalähnlicher Finanzierungsanteil erleichtern sie den Zugang zu Krediten. Dem Kunden bieten sie den Vorteil, seine monatliche Stromrechnung durch einmaligen Kauf von Genussrechten zu reduzieren. Im Falle einer fest vereinbarten Dividende erhält er eine inflationssichere Ausschüttung in Energieeinheiten. Genussrechte benötigen keine Börse und können unabhängig von der Rechtsform des Unternehmens emittiert werden. Da sie keine Eigentumsrechte übertragen, bleibt die Kontrolle über das Management bei den haftenden Projektpartnern. Anzahl und Haftung der Projektpartner, Kontrollaspekte, Finanzierungsform und schließlich das Gesamtinvestitionsvolumen bestimmen die bevorzugte Rechtsform der Organisation. Eine Kommanditgesellschaft ist geeignet für Partner mit verschiedener Haftung, ergänzt durch Kunden mit Genussrechten. Eine moderne Kooperative erfordert eine finanzkräftige Verbrauchergemeinschaft, die unabhängig von großen Investoren und Banken agiert. Im Hinblick auf rechtliche Erfordernisse ist die Investitionslizenz von zentraler Bedeutung. Sie kann jedoch nur für Projekte mit einem Minimuminvestitionsvolumen beantragt werden. Durch den Service des sogenannten "one-stop-shop" erleichtert sie den Erwerb von Betreiberlizenz und Arbeitsbewilligungen, die Registrierung der Gesellschaftsform und die Zuweisung von Wasser- und Landnutzungsrecht.

Die Ergebnisse wurden mittels zweier fiktiver Fallbeispiele mit Systemkapazitäten von 50 und 150 kW ausführlich veranschaulicht. Die Untersuchung internationaler Finanzierungsmöglichkeiten, wie die "Flexiblen Mechanismen" des Kyoto Protokolls, der Global Environmental Fund u.ä. zeigte, dass einige dieser Instrumente sowohl zur Finanzierung von Pilotprojekten als auch zur Beseitigung struktureller Hindernisse geeignet sind. Rückblickend auf die Untersuchungsergebnisse wurden Potentiale und Grenzen eines Entscheidungshilfemodells überprüft und schlussfolgernd konkrete Handlungsempfehlungen, wie z.B. Investitionsanreize, Befreiung von Einfuhrzöllen und Verbesserung der Kreditkonditionen abgeleitet.

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## ACRONYMS

| | |
|---|---|
| **AAU** | Addis Ababa University |
| **AAU's** | Assigned Amount Units |
| **ABB** | Asea Brown Boveri |
| **AEDC** | Austrian Embassy Development Co-operation |
| **AIB** | Awash International Bank |
| **AIJ** | Activities Implemented Jointly |
| **"Annex I countries"** | industrialised countries and countries with economies in transition Group of countries included in Annex I (as amended in 1998) to the UNFCCC, including all the developed countries in the OECD and Economies in transition. By default, the other countries are referred to as Non-Annex I countries. Annex I countries committed themselves specifically to the aim of returning individually or jointly to their 1990 levels of greenhouse gas emissions by the year 2000. |
| **"Annex II countries"** | Group of countries included in Annex II to the UNFCCC, including all developed countries in the OECD. These countries are expected to provide financial resources to assist developing countries to comply with their obligations, such as preparing national reports. Annex II countries are also expected to promote the transfer of environmentally sound technologies to developing countries. |
| **APFC** | Automatic Power Factor Correction |
| **Art.** | Article |
| **ATDO** | Appropriate Technology Development Organization (Pakistan) |
| **AVR** | automatic voltage regulator |
| **BfW** | Bread for the World (Brot für die Welt), Stuttgart/Germany |
| **CBB** | Construction & Business Bank |
| **CBD** | Convention on Biological Diversity |
| **CBE** | Commercial Bank of Ethiopia |
| **CBO** | community based organisation |
| **CDM** | Clean Development Mechanism |
| **CER(s)** | Certified Emissions Reduction |
| **$CH_4$** | Methane, a greenhouse gas |
| **$CO_2$** | Carbon dioxide, a greenhouse gas (GHG) |
| **COMESA** | Common Market for Eastern and Southern Africa |
| **COP** | Conference of Parties |
| **CSA** | Central Statistical Authority |
| **DBE** | Development Bank of Ethiopia |
| **DED** | Deutscher Entwicklungsdienst (German Development Service) |
| **DfID** | (United Kingdom) Department for International Development |
| **DSM / DSS** | decision support model / decision support system |
| **DUTEC** | Darmstadt University of Technology |
| **EEA** | Ethiopian Electric Agency |
| **EEA*** | Ethiopian Economic Association |
| **EECMY** | Ethiopian Evangelical Church Mekane Yesus |
| **EELPA** | Ethiopian Electric Light and Power Authority |
| **EEPCO** | Ethiopian Electric Power Corporation (former EELPA) |
| **EIA** | Ethiopian Investment Agency |
| **ELC** | electronic load controller |
| **EPSEMP** | Ethiopian Power System Expansion Master Plan |
| **EREDPC** | Ethiopian Rural Energy Development and Promotion Centre |
| **ERSHA** | Ethiopian Rural Self-Help Association |
| **ESRDF** | Ethiopian Social Rehabilitation and Development Fund |
| **ETB** | Ethiopian Birr |
| **EZE** | Evangelische Zentralstelle für Entwicklungshilfe (Protestant Association for |

| | |
|---|---|
| | Cooperation in Development) |
| **GEF** | Global Environment Facility |
| **genset** | generating system comprising a prime mover in the form of a combustion engine and an electrical generator; a generator is the electrical machine which converts mechanical shaft power into electrical power |
| **GHG** | greenhouse gas(es); the Kyoto Protocol regulates six gases: carbon dioxide ($CO_2$), methane ($CH_4$), and nitrous oxide ($N_2O$), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride ($SF_6$) |
| **GO** | governmental organisation |
| **GTZ** | Deutsche Gesellschaft für Technische Zusammenarbeit (German Technical Co-operation) |
| **GWP** | Global Warming Potential (is the climate forcing effect for an individual type of GHG. The GWP for $CO_2$ is 1, while it is 21 $CH_4$, and 310 for $N_2O$. These latter gases have a stronger impact on climate than carbon dioxide.) |
| **hh** | household |
| **ICS** | Inter-Connected System |
| **IFC** | International Finance Corporation |
| **IGC** | induction generator controller |
| **IMAG** | induction motor used as generator |
| **IPP** | independent power producer |
| **IRR** | internal rate of return |
| **ITDG** | Intermediate Technology Development Group |
| **JI** | Joint Implementation |
| **KfW** | Kreditanstalt für Wiederaufbau (German Bank for Reconstruction and Development) |
| **LDC** | Least Developed Countries |
| **LRMC** | long-run marginal cost |
| **Ltd.** | Limited (Company) |
| **LUPO** | Land Use Planning and Resource Management Project in Oromia Region |
| **LV** | Low Voltage |
| **M.O.** | Magalata Oromiyaa (Megeleta Oromia) |
| **MFI** | Micro Finance Institution |
| **MfM** | Menschen für Menschen (German NGO) |
| **MGP** | MEGEN Power Ltd. |
| **MHP** | Micro and Mini Hydropower (< 300 kW) |
| **MME** | Ministry of Mines and Energy |
| **MoWR** | Ministry of Water Resources |
| **MV** | Medium Voltage |
| **N.G.** | (Federal) Negarit Gazeta |
| **$N_2O$** | Nitrous Oxide, a greenhouse gas |
| **NBE** | National Bank of Ethiopia |
| **NGO** | Non-Governmental Organisation |
| **Non-Annex I Countries** | The countries that have ratified or acceded to the UNFCCC that are not included in Annex I of the Climate Convention (mainly developing countries). |
| **NPV** | net present value |
| **NRECA** | National Rural Electric Cooperative Association (United States) |
| **O&M** | operation and maintenance (O&M costs = operating costs) |
| **oc** | "official" connection |
| **OECD** | Organisation of Economic Co-operation and Development |
| **OIO** | Oromia Investment Office |
| **(O)WMERD(B)** | (Oromia) Water, Minerals and Energy Resources Development Bureau |
| **P.L.C.** | Private Limited Company |
| **PA** | Peasant Association |

| | |
|---|---|
| **PCF** | Prototype Carbon Fund (World Bank) |
| **REEF** | renewable energy and energy efficiency fund for emerging markets |
| **ROE** | return on equity |
| **ROI** | return on investment |
| **ROSCA** | Rotating Saving and Credit Association |
| **SACC** | Saving and Credit Cooperative |
| **SC** | Service Co-operative |
| **SCS** | Self-Contained System |
| **Selam TVC** | Selam Technical and Vocational Training Centre |
| **Sh.C.** | Share Company |
| **SME** | Small and Medium-Scale Enterprise Programme |
| **UNDP** | United Nations Development Programme |
| **UNFCCC** | United Nations Framework Convention on Climate Change |
| **USD** | US dollar |
| **WB** | World Bank |
| **ZIT** | Center for Interdisciplinary Studies of Technology (Zentrum für Interdisziplinäre Technikforschung) |

## Units:

| | |
|---|---|
| **Gg** | giga gram = $10^9$ gram |
| **kVA** | Kilovoltampere |
| **kW** | Kilowatt |
| **MW** | Megawatt |
| **RPM** | revolutions per minute |
| **Tg** | tera gram = $10^{12}$ gram |
| **TJ** | Terra Joule = $10^{12}$ Joule |
| **VA** | Voltampere |
| **W** | Watt |

## Variables, parameters and constants:

| | |
|---|---|
| $\phi$ | (real) impedance per length [Ω/km] |
| **a** | wave velocity [m/s] |
| **A** | area [km²] |
| **A** | cross section of the conductor [mm²] |
| **AET** | actual evapotranspiration [mm/year] |
| **C** | consumption [kWh] |
| **D** | internal pipe diameter [m] |
| **E** | modulus of elasticity of pipe [kgf/cm²] |
| **f** | frequency [Hz] |
| **g** | acceleration due to gravity (= 9,81 m/s²) |
| **g** | conductivity [m/(Ωxmm²] |
| **gr** | growth rate [ ] |
| **h** | gross head [m] or average altitude of the catchment above sea level [m] |
| **HC** | hydraulic conductivity [m/day] (or [cm/s]) |
| $h_f$ | head loss due to friction [m] |
| **I** | current [A] |
| **K** | fluid bulk modulus (= 2.1 x $10^4$ kgf/cm² for water) |
| **l or L** | length [m] or [km] |

| | |
|---|---|
| **n** | roughness coefficient [ ] |
| **N** | turbine speed [RPM] |
| **p** | (real / useful) power [kW] = $U \cdot I \cdot \cos \varphi$ |
| **P** | precipitation [mm/year] |
| **perc** | percentage [ ] |
| **PET** | potential evapotranspiration [mm/year] |
| **pf = cos$\varphi$** | power factor [ ], with $\varphi$ = phase angle between current and voltage |
| **$p_{max}$** | maximum total pressure put on the pipe [m water column] |
| **po** | number of poles [ ] |
| **pr** | "official" penetration rate |
| **$p_s$** | maximum surge pressure [m water column] |
| **Q** | flow [$m^3/s$] |
| **Q(x,daily)** | x standing for 50, 70 and 90, meaning the runoff (read from the duration curve based on daily data) which is statistically reached or exceeded in x % (here x = 50 %, 70 % respectively 90 %) of the time [$m^3/s$] |
| **Q(x,monthly)** | x standing for 50, 70 and 90, meaning the runoff (read from the duration curve based on monthly data) which is statistically reached or exceeded in x % (here x = 50 %, 70 % respectively 90 %) of the time [$m^3/s$] |
| **$q_{el}$** | reactive volt amps [kVAr] = $U \cdot I \cdot \sin \varphi$ |
| **$Q_{soil}$** | water flow in the soil [$cm^3/(cm^2 \times s)$ or cm/s] |
| **$r^2$** | coefficient of determination |
| **$R_L$** | ohmic part of the line impedance [$\Omega$/km] |
| **s** | slip [ ] |
| **S** | slope [%] |
| **S** | apparent power [kVA] = U x I; rated capacity |
| **SC** | specific capacity [l/s/m] |
| **shh** | size of household [ ] |
| **t** | wall thickness [mm] |
| **U** | voltage [V] |
| **v** | flow velocity (in the pipe) [m/s] |
| **$X_L$** | reactance of inductive part of the line impedance [$\Omega$/km] |
| **δ** | density of water (= 1 $kg/dm^3$) |
| **η** | (overall) efficiency [ ] |

The study being based on information mainly gathered in the year 2000, it is calculated with the **exchange rates**:

**8.2 ETB = 1 USD**
**7.1 ETB = 1 €**

# 1 MOTIVATION AND OBJECTIVE OF THE STUDY

Numerous studies in different African, Asian and South American countries confirm that rural electrification can substantially contribute to improved living conditions and development.[1] Considering the fact that Ethiopia possesses a significant hydropower potential, especially in the Western and Southern regions, it seems amazing that this potential remains almost unexploited for decentralised rural electrification. Although the hydropower potential has been estimated for different regions and several feasibility studies have been carried out, the dissemination of the technology of micro and mini hydropower (MHP)[2] has not even started.
Although the demand for electricity, the ability to pay for it and the technical solution are existing, some hindrances seem to prevent the development of MHP systems. Obviously, the view must be broadened and further crucial elements and the relations between them must be ascertained in order to deduce properties and principles of the "decision-system" as a whole. The present dissertation is guided by the following thesis:

**The factors influencing the successful implementation of a micro or mini hydropower scheme are not only manifold but also closely interlinked (economy, technology, finance sector, legislation, organisation forms, tariff system, political framework etc.). The disregarding of these complex interrelationships has hitherto hampered successful planning and implementation processes. Explicit consideration of these factors and their interrelationships can facilitate successful project implementation.**

This thesis is confirmed by the results of this study. The decision-making process leading to the successful implementation of an MHP project can be regarded as a complex system of different influencing elements. Since the system is not understandable solely by investigation of the elements in isolation, it requires an interdisciplinary approach. The most relevant elements must be selected and comprehensively analysed. Simultaneously, the linkages and interdependencies, the interactions of processes and features are investigated. The somewhat mystical expression, "the whole is more than the sum of parts" implies that the characteristics of the complex, compared to those of the elements, appear as "new" or "emergent".[3]
Although, the classical system theory helps to identify system boundaries, subsystems and interlinkages and derives mathematical equations valid for systems in general, it is anything but a solution oriented approach. The present problem, however, requires a solution oriented empirical approach which makes use of the background of system theory. Therefore, data and information are analysed to roughly identify and characterise an initially unknown system, its crucial elements and their interrelations. The findings allow to define crucial input parameters such as available energy potential, expected consumption, interested financiers, their liquidity etc. and target values such as tariff and tariff system, return on investment, required organisational arrangements etc.. The resultant system description can be termed a specified model. If the "elements of the system" are regarded as conditions to be simultaneously fulfilled for successful project implementation, the model allows a "consistency check". It is the basis for a decision support model (DSM) for local authorities, water resource planners, consultants and potential investors like private investors, NGO's and bilateral donors. Besides the consistency check the "toolkit" offers an extensive information- and database and facilitates a sensitivity analysis. For example, by variation of energy demand, best and worst case scenarios can be investigated, thus supporting a feasibility assessment or even a comparison of different prospective sites for MHP development in rural Ethiopia.
Providing the basis for a decision support model, the present study can substantially contribute to the facilitation and promotion of a long-term dissemination process of MHP technology in Ethiopia. Although the study explicitly refers to the Ethiopian context, the scientific approach is basically generic and thus transferable to other countries and to other decentralised energy systems. For the most part, the crucial aspects and their interrelationships are similar in different developing countries.

[1] Ramani, 1993 and Cisar, 1998
[2] In the present study "MHP" stands for mini and micro hydropower systems of capacities below 300 kW (see also section 3.2.3)
[3] Bertalanffy, 1968, p. 37 and 55

# 2 PROBLEM ANALYSIS - ACTUAL ENERGY SITUATION IN ETHIOPIA

## 2.1 Access to electricity

With 90 % of its population living in "rural settlements" being villages with less than 2,000 inhabitants scattered over the whole country, the provision with infrastructure, especially electricity, appears to be a big challenge for Ethiopia. Up to now the Ethiopian Electric Power Cooperation (EEPCO) provides electricity to about 500,000 domestic customers via the Inter-Connected System (ICS)[4], 230,000 of them in Addis Ababa. Taking into account a household size of about 4.7 persons (see also section 4.2.4) and adding those people supplied by the Self Contained Systems (SCS)[5], a total of about 5 % of the population mainly in bigger cities have access to electricity.[6] The remaining 95 %, not having access to modern energy, use wood, crop residues etc.. The relative importance of the various energy sources is depicted in Table 2.1.

| **energy source** | **percentage of total Ethiopian energy consumption [%]*** |
|---|---|
| fuelwood | 77 |
| dry dung | 9 |
| agroresidues | 8 |
| petroleum products and electricity | 5 |
| charcoal | 1 |

*Human and animal tractive force not included

*Table 2.1: Relative importance of different energy sources in Ethiopia*[7]

The use of biofuels is time consuming, it provokes severe deforestation, subsequent erosion problems and damages women's and children's health through smoke production during the cooking activities.[8]

Most energy-sector development activities have been concentrated in the urban or more accessible areas, where the largest number of people can be supplied with minimum effort and expense.[9] Thus, less than 1% of the rural population has access to electricity. The per capita yearly electric energy consumption in Ethiopia of 25 kWh is far below the world average of 2,200 kWh.[10] This figure is an average value and conceals the enormous economic gap between rural and urban population and, among the rural dwellers again, between poor famine areas and rich cash crop regions.

Over 300 Ethiopian towns have been nominated to receive electricity in the near future (2001-2005). Approximately 170 of these towns with a total estimated population of 750,000, are scheduled to be connected to the ICS. Some of these new connections will be the result of the expansion of the system to new towns, sometimes former SCS centres, and expansion within recently electrified towns. The remaining 130 towns are scheduled for diesel or mini hydro supply. An additional 260 towns were added to the rural electrification plan for interconnection over the period from 2006 to 2025. All towns on this second list are to be added to the ICS.[11]

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[4] The ICS consists of a base system, a number of interconnections and system extensions implemented over the past 20 years. As opposed to the Self Contained system, all generation points and supply centres are interconnected.
[5] The SCS consists of numerous independent generation points (primary diesel based). Many of the SCS centres have been incorporated within the ICS through system extensions.
[6] EEPCO/ACRES 2000, p.1-3, p.6-3
[7] Mengistu Teferra, speech on "The Ethiopian Energy Scenario", held at the seminar "Energy in Ethiopia", 1999, p.10
[8] Feibel, 1999, p.104
[9] Workshop Proceedings 3/2000, introduction p.3
[10] loc. cit. p.3 and Mengistu Teferra, speech on "The Ethiopian Energy Scenario", held at the seminar "Energy in Ethiopia", 1999
[11] The Ethiopian Herald: "EEPCO to supply...", 19th January (2001) and EEPCO/ACRES 2000, p.6-6

At present, especially in rural regions with cash-crop farming, informal power producers supply electricity through diesel units, meaning a diesel engine driving the shaft of a generator. The latter can be bought as a complete set and can be easily installed. Prices for this source of energy are between 5 and 10 ETB/kWh.[12] Lack of alternatives forces the rural population to accept high prices, whereas their urban counterparts enjoy tariffs of around 0.6 ETB/kWh, including the comfort of almost 24 h availability of electricity. Due to the occasionally inadequate availability of fuel especially in rural areas and its high price, the operational continuity of those informal systems is hardly satisfactory and often they operate not more than a few hours per day.[13] Access to an affordable and reliable supply of energy promotes productive activities, creates employment opportunities and thus offers potential for growth and real development.[14] Processing of agricultural products to give added value to crops in rural areas is strongly restrained. Peasants have no other possibility than selling their agricultural raw products at low prices in big cities, where they are processed and treated using subsidised electricity. Those finished products are then frequently bought by the same farmers. Oil extraction from nough and other oilseeds, grain milling, sawing, welding, bakeries etc. supplied with affordable electricity would allow local manufacturing and thus could significantly improve rural living conditions. The government of Ethiopia pursues a development strategy called Agricultural Development Led Industrialisation (ADLI). According to this strategy the development of the agricultural sector is to serve as the locomotive for the overall development of the economy. With the current state of electrification, however, the envisaged development of the agricultural sector as a main base of the overall economy is not even remotely possible.[15] The distribution of national electricity consumption among different consumer groups is:[16]

- households 43 %
- industry 44 %
- commercial sector 12 %
- others 1 %

In the mid 1980s, households accounted for only 27 % and industry for about 62 % of the total electricity consumption in Ethiopia. The objective aimed at, namely the consumption in productive sectors like industry and agriculture with positive contributions to the economic growth, seems to be still out of reach.
Apart from energy uses that boost agricultural production, access to electricity also promotes development indirectly by better education, rendered possible by the use of electric lighting at night, when people have time to read and by enabling health centres to provide better health care. Such synergetic benefits, including improved communication and security at night, also contribute to the reduction of migration to cities.[17]

## 2.2 Hydropower and electricity

Ethiopia is supplied with excellent potential hydropower resources of which only 1-2 % have been exploited.[18] Electricity is mainly generated by large hydropower stations and after transmission distributed by means of the ICS. Besides three smaller hydropower schemes in Yadot (350 kW), Dembi (750 kW) and Sor (5 MW) providing the SCS, 90 % of the generated power with an installed capacity about 415 MW[19] is provided to the ICS. EEPCO also runs about 30 off grid diesel systems.[20] About 80 % of electricity generation is based on hydro-

[12] Collin 2000, p.1 and Megen Power 1998, p.8
[13] Fitjer 1990, in: Water Power and Dam Construction p.37
[14] Oromia Regional State OWMERD Bureau, 1997, p.3f and World Bank Report No. 17170-ET, 1997, p.4
[15] Workshop Proceedings 3/2000, contribution of Asrat Bulbula
[16] Mengistu Teferra, speech on "The Ethiopian Energy Scenario", held at the seminar "Energy in Ethiopia", 1999, p.6
[17] http://www.worldbank.org/afr/findings/english/find177.htm ; African Region Findings No. 177 February 2001
[18] Ostrowski, 1994, p.8
[19] At present the construction of two further big plants is scheduled: Takeze (300 MW) and Gojeb (150 kW), each at costs of around 300 million USD (see: Renewable ENERGY World, p.29, Sept/Oct 2002)
[20] Feibel, 1999, p.104

power and the remainder on diesel fuel.[21] In the years 1986 to 1997, the annual expenditures for the import of fossil fuels varied between 25 and 60 %[22] of the total export earnings. This percentage strongly depends on the price of coffee on the world market. Especially small isolated electricity grids powered by diesel systems are frequently out of service due to diesel shortages. Major consumers of petroleum are transport (70 %), households and power generation plants. On any account the figure indicates the enormous economic effort required for the import of petroleum.

The estimated economically exploitable hydropower potential ranges between 15,000 and 30,000 Megawatts.[23] Careful estimations suggest that there are more than 5,000 potential sites for mini and micro hydropower (MHP) in Ethiopia in addition to the sites for large hydro-plants.[24]
The pivotal disadvantages of big hydropower plants in the range of tens or even hundreds of Megawatts are technical sophistication, high cost of transmission and the negative ecological and socio-economic impacts of water impoundment, such as resettlement, loss of fertile arable land, dissemination of water born diseases like malaria, schistosomiasis etc..[25] In addition, most components of big plants have to be imported and thus do not contribute added value to the Ethiopian economy. Whereas smaller systems could at least partially be equipped with locally produced components with regard to civil engineering structures and mechanical components.

Traditionally, since the last century, hydro power was used in Ethiopia for grain milling. About one thousand “arab mills“, so-called yareb wefcho were in operation of which only about 50 % remained, mainly due to confiscation following the 1974 revolution and discouragement of private business during the years of socialist rule. During the last ten years only 33 micro hydropower plants for grain milling purposes have been implemented, 30 by the Ethiopian Evangelical Church of Mekane Yesus (EECMY) and the remainder by the Ethiopian Rural Self-Help Association (ERSHA).[26] Due to lower investment cost, spatial flexibility and ease of installation most mills in operation are driven by diesel gensets and a few hydropower driven mills were even superseded by so-called "diesel mills".
On the other hand the above mentioned tradition of arab mills substantiates the existence of well-founded knowledge about the application of hydropower in rural areas of Ethiopia, e.g. diversion of water, channel construction, water wheels, and thus in a basic sense also turbine-technology. Micro and mini hydropower schemes can be designed and built by local staff and off-the-shelf components or locally made machinery can be used. In other words, a regional approach to a local problem can be adopted[27], resulting in a local product.

During 2001 one MHP system for electricity supply was set up to supply the town of Yayé (Sidamo Region). The plant with a capacity of 187 kW was planned and financed by "Sidama Development Programme" and "Ireland Aid".[28] It is the only electricity generating plant actually in operation, apart from the EEPCO plants mentioned above.

## 2.3 Energy sector policy

The general Ethiopian policy, with its privatisation program, aims at changing the highly centralised economic system into a market-oriented one, by recognising the role of the private sector in generating economic growth. Domestic and foreign investors are encouraged to

[21] Ostrowski, 1994, p.8
[22] Mengistu Teferra, speech on "The Ethiopian Energy Scenario", held at the seminar "Energy in Ethiopia", 1999 and Bruke 1995, p.8
[23] Ostrowski,1994, p.3: 15,000 MW; Fitjer, 1990, p.34: 15,000-30,000 MW (based on EELPA/ACRES 1983, p.18); EEPCO leaflet "facts in brief": 15,000-30,000 MW
[24] Workshop Proceedings 3/2000; contribution of Dr. Fekadu Shewarega; p.3
[25] http://www.ethiopians.com/Main_FSS_Paper1.htm Dessalegn 1999 p.12
[26] Feibel, 1999, p.104
[27] Workshop Proceedings, 3/2000; contribution of Dr. Fekadu Shewarega; p.3
[28] personal communication: Brendan Mc Grath (Irish Aid), 11/2000

participate in the privatisation process. To accomplish the latter, the Ethiopian Privatisation Agency (EPA) was established in February 1994 by Proclamation No. 87/1994. "With regard to power industry, it is stated that major power generation shall remain a government holding while the policy acknowledges the need to jointly operate with private capital to develop energy resources requiring substantial investment and technological input".[29] This statement exactly fits to the actual situation in the energy sector. On the one hand official policy is aware of the necessity of improvements and expresses willingness for liberalisation whereas on the other hand a certain governmental or public control over electricity infrastructure is regarded to be non-negotiable.
The government has issued an amendment code to the investment proclamation[30] opening the electricity generation from hydropower for local and foreign investors without any limit of capacity. Several new proclamations and regulations give the legal frame for liberalisation, controlled by the newly established Ethiopian Electric Agency as regulating body.
However, the weakness of the financial sector is one of the hindrances to the wider dissemination of (private) MHP systems. Especially the fact that the general legal framework hinders a broad usage of loan financing due to a lack of legal means for the transfer of ownership and for the garnishment of salaries.[31]

[29] Workshop Proceedings, 3/2000, contribution of Getahun Moghes, p.26
[30] Proc. No.116/1998 (N.G.)
[31] Collin, 2000, p.30

# 3 RESEARCH APPROACH AND INTENDED RESULTS

## 3.1 Why a decision support model ?

Decision support systems (DSS) were first mentioned in the early 1970's, defined as interactive systems which help decision makers utilise data and models to solve unstructured problems.[32] DSS strive to go beyond pure provision of information towards the mapping of managers' behaviour. They range from models strictly describing cognitive processes up to the operation of optimisation methods. In general they are interactive IT[33]-supported systems, assisting managers to solve problems in rather inadequately structured decision-making situations by means of problem-oriented data, methods and models. Their main objective is to improve the user's discernment and thus the quality of his final decision. A crucial characteristic of DSS is their orientation towards models and methods.[34]
The present study can be understood as a kind of a **data mining process**, directed towards the development of a DSS. Data mining describes the extraction of implicitly available, non-trivial and useful knowledge out of a bigger, dynamic and relatively complex database. Intelligent procedures of data analysis try to salvage the buried treasure out of the floods of raw data.[35] The objective of "knowledge discovery" defines the database to be selected. The comprehensive database is then reduced in size so that it includes only the attributes actually required for the analysis. The remaining data are investigated to look for significant correlation patterns. By interpreting achieved results explicit new knowledge essential for the objectives of the investigation is acquired. In general, data mining is used for classification, clustering and revealing interdependencies.[36]

As far as **water resources management** in general is concerned numerous decision support systems have been developed. Overviews are given by Ostrowski (1999)[37] and Hahn & Engelen (2000).[38] For example, the Hydrologic Engineering Center (HEC) of the US Army Corps of Engineers have developed manuals and comprehensive computer programs for water resources planning and management including planning analyses like "HYCOST" (Small-Scale Hydroelectric Power Cost Estimates), but also reservoir simulation, statistical hydrology etc..[39]
With regard to hydropower, many detailed DSS for **lake and reservoir management** are existing. Professional and comprehensive DSS like VISTA[40] estimate the yields from any complex of lakes, rivers, reservoirs, hydroelectric plants, water supply systems, and irrigation works. Such systems are mainly focused on technical and economic aspects. Other simulation models like TALSIM try to link operational rules with changing boundary conditions such as climate, land use, demand and socio-economic as well as environmental objectives. The combination of various elements of integrated watershed modelling and management of the TALSIM approach allows it to represent a wide range of different reservoir systems controlled by manifold operation rules and strategies.[41]

Concerning the decision-making process in the field of micro and mini run-of-river hydropower schemes, it has probably not been regarded to be sufficiently complex to require spe-

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[32] Brännback, 1996, p.16
[33] IT = information technology
[34] Gabriel, Gluchowski, 1998, p.9
[35] Bissantz, Hagedorn, 1993, p.481
[36] Gabriel, Gluchowski, 1998, p.31f
[37] http://www.tu-darmstadt.de/fb/bi/wb/ihwb/Mitarbeiter/ostrowski/steel_ds/steeldssintroductorypaper.html; Improving sustainability of water resources systems using the group decision support system STEEL-GDSS
[38] Hahn, Engelen, 2000, p.9-44
[39] http://www.hec.usace.army.mil/publications/index.html
[40] http://www.synexusglobal.com/product_generators_vista.html
[41] Ostrowski, Lohr, Leichtfuß, 2000, p.53f

cial attention. Apart from a very few exemptions[42], no comprehensive DSS has been developed so far. Only single aspects such as flow estimation have been investigated with regard to MHP[43] and different software to solve particular technical problems, such as design of penstock pipes, turbines etc., is offered.[44]

A PhD research project at Dresden University has taken a typical rural region in Ethiopia as a representative case study to establish a self-contained regional grid and to carefully investigate hydropower development alternatives, taking into account the existing technical, socio-economic, environmental and geographical problems. The main focus is laid on optimisation, using different optimisation techniques. It arrives at an optimal solution after comparing various alternative systems. The associated cost from the optimal solution will then be scrutinised, using financial feasibility analysis methods, to find out if it meets the profitability criteria of private investment.[45] In contrast to this investigation, the present study intends to take a broader view of influencing factors, as described in section 3.2.1.

One of the problems in examining interdisciplinary, regional approaches in an environment of entrenched bureaucracy is the lack of a synthesis of even basic information on a regional level. A useful procedure therefore should select all relevant aspects and analyse linkages between them, the final target being at the development of user-friendly, interactive spreadsheets, maps, charts, tables, databases, presentations, useful references etc.. Thus with little additional investment and without an extensive survey of new data, the collection, processing, display and assembly of existing information can contribute to more extensive insights and a more synoptic view. The reasons for past project failures are manifold, such as wrong prediction of energy potential or consumption, management problems, exaggerated technical standards, etc..[46] In particular, shortcomings can be assigned to the limited access to information at the *beginning* of the planning process, a phase in which many decisions are implicitly taken, and the concentration of attention on technical aspects, at best perhaps also including economic factors. The planning process begins with decisions that are based on inadequate data. At this stage a broader view on different aspects can be more helpful than analysing specific e.g. technical details. The same phenomenon is observed as far as financial analysis is concerned: Most of the system's cost are estimated at the beginning of the planning process. At this stage of the life cycle, however, the designer does not have sufficient knowledge to get an overview of the consequences of the decisions that are taken. The knowledge increases in later project phases, whereas the possibility of influencing the cost situation decreases.[47] The task of obtaining as much information as possible, beyond economic data, at the beginning of the project cycle, can be facilitated by a DSS.

Models by definition are simplifications of reality; this simplification is needed to comprehend complex systems with little known information so that decisions can be made. The **steps to a DSS** are, to:[48]

1. identify the spatial, sectoral and temporal extent and resolution
2. identify major problems, stakeholders and decision-makers, preferably with group meeting(s) at the start and throughout the DSS construction, implementation and revision to identify major issues and incorporate feedback
3. determine the extent of available and potentially available data
4. design appropriate information systems to manage the data, preferably using interactive spreadsheets etc. to organise quantitative and qualitative data
5. develop a useful schematic of the system considered
6. integrate interdisciplinary aspects

[42] Anderson, 1992
[43] http://www.nwl.ac.uk/ih/www/research/Refresha/frm_dfid.htm Regional Flow Regimes, Estimation for Small Hydropower Assessment (REFRESHA) and Rees, Croker, 1998
[44] http://www.microhydropower.net/download/software.html
[45] Zelalem, 2002
[46] Meier, 1981, p.19f and 31f
[47] Götz, 2000, p.296
[48] modified according to http://www-esd.worldbank.org/rdv/training/harsh/harsh.htm

7. develop the DSS with the participation of intended users, and, finally,
8. test the DSS with potential stakeholders and decision-makers.

Points 1 to 3 are concerned with the detailed identification and scope of the research object. Points 4 to 6 include the detailed investigation of crucial aspects and their interdependence. The final implementation of the developed procedures into a DSS software is not part of the present study. The study is rather understood as a basis for the DSS development.

## 3.2 Theoretical approach, methodology and scope of the research work

### 3.2.1 Selection of aspects to be analysed

To identify and understand a system, highly specific details are not of importance. On the contrary, the more fuzzy they are, to a certain extent, the more obvious and lucid the relations between them emerge and tell us what the picture portrays in its wholeness. Indeed, a more truthful image of a real system can be achieved when working with a few carefully selected key variables and their cross-linking instead of analysing every aspect in profound detail in order to finally yet result in one main arbitrary decision variable like e.g. investment cost. Main objective of the broader interdisciplinary view is to figure out certain command variables and target values, which can lead to a cybernetic approach.[49] To reach that specified goal a profound analysis of every individual aspect has been rejected and several simplifications have been made in favour of ascribing higher importance to linkages, causes and effects. Vester[50] cites the illustration in Figure 3.1 as an example for the usefulness of the described methodology.

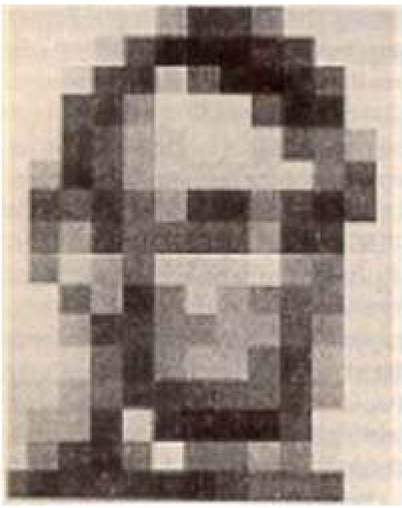

*Figure 3.1: The whole and the details. To find out what is illustrated here, you have to step back and have a look from the distance or look blurred by blinking or taking of your glasses[51]*

Metaphorically speaking, to perceive the sense-making context, the image of Lincoln, one has "to step back" to allow the picture to become blurred and hence see "clearer", rather than approaching too close and analysing the greyscales of every single square.

Proceeding on the assumption that a variety of aspects are influencing the dissemination of MHP, the first step is to find out which of them are pivotal, the second is to analyse their indi-

[49] Vester, 1985, p.37, p.46, p.55
[50] loc. cit. p.36
[51] Vester, 1985, p.36

vidual importance and weight and the third to find out how they are inter-linked. In order to reach this goal a **stakeholder analysis** was made.[52] Political and economical stakeholders and decision makers, concerned with the MHP process in a broader sense, were interviewed about their attitude towards MHP, in detail about the prospects they see for MHP, hindrances and possible solutions. In addition a stakeholder workshop with presentations and working groups was organised in March 2000 at the Faculty of Technology of Addis Ababa University in order to bring those persons together and to work on the formulation of **weaknesses and strengths** and practical proposals for future activities.[53]

These activities showed that:
- no reliable method exists to determine the hydropower potential at a site without runoff data
- electricity consumption patterns are difficult to predict
- cost estimates, also for operation and maintenance, are still very theoretical, because practical experience is lacking and no call for tenders has been done so far
- there is a strong prejudice that diesel plants are more economical
- financing, which is closely linked to the availability of collateral and guarantees, is extremely difficult
- there is little private initiative to take the risk of long-term investment
- governmental support for MHP is very weak
- organisational problems have a major impact on sustainability
- licensing procedures and administrative responsibilities are still unclear
- tariffs applied by EEPCO are heavily subsidised and not applicable for MHP.

Figure 3.2 depicts the complex causal structure of involved stakeholders, hindrances and the most important aspects relevant for the MHP dissemination process.

To better understand or even to overcome these main obstacles, the implementation of a scientifically guided **pilot project** is most advisable in the near future. Such a pilot project will demonstrate the technical and economic feasibility of MHP for rural electrification in Ethiopia to public and private donors, investors and finance institutions, thus initiating the second step of broader dissemination itself. This implies three main postulates for the pilot project[54]: fast implementation, appropriateness as a working model for dissemination and sustainability.

Once a pilot project is implemented further dissemination can be facilitated by a decision support model which - by rehearsing different scenarios for a specific site - will allow the weighing of pros and cons and will provide recommendations on important aspects. Such a tool should overcome the main obstacles that have been identified.

[52] Klein, 2000
[53] Workshop Proceedings 2000
[54] loc. cit. p.20

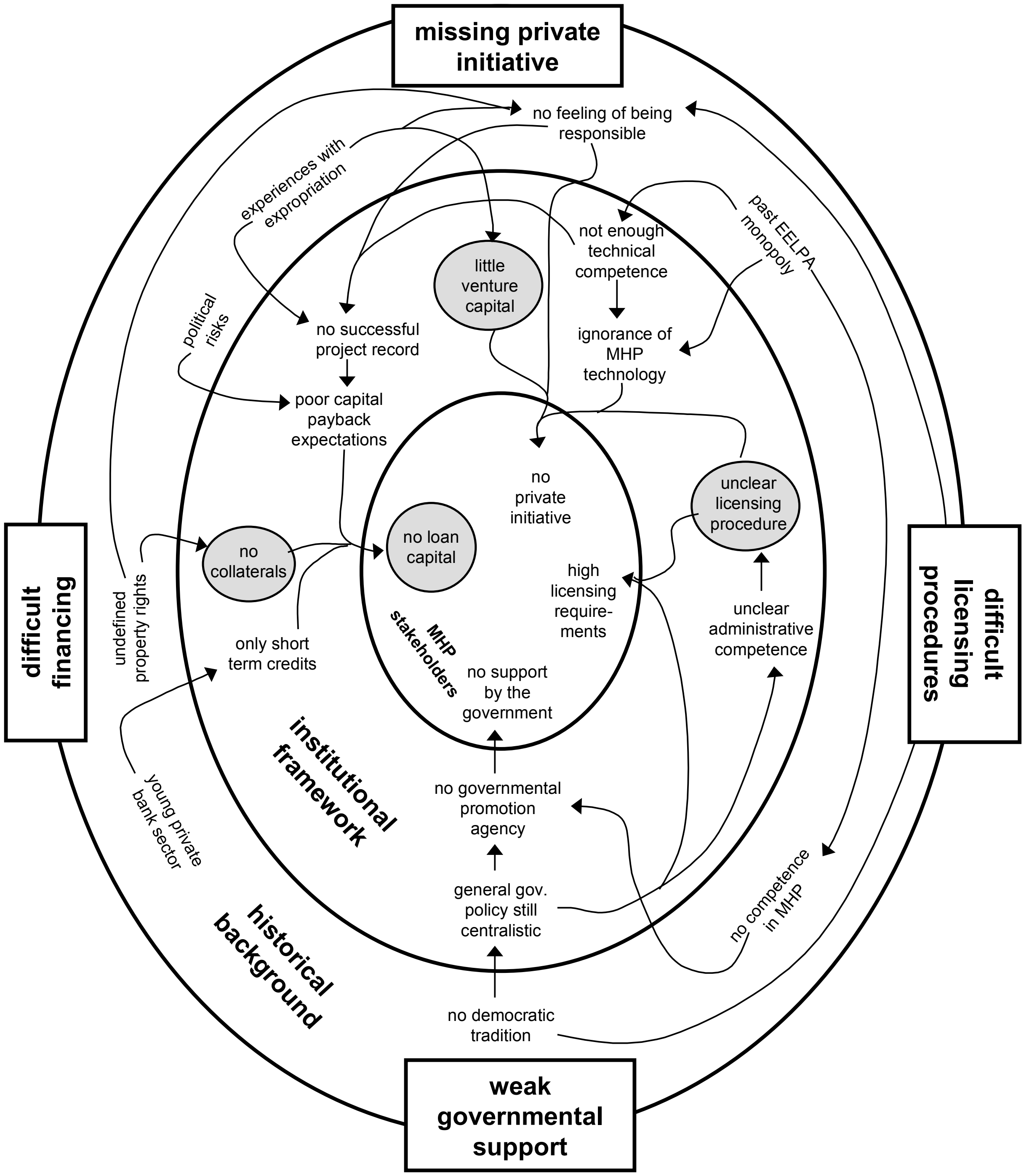


*Figure 3.2: Hindrances for MHP in Ethiopia*[55]

As substantiated above, of the manifold significant aspects for a decision support system the most relevant and tangible ones were selected according to their importance for the specific Ethiopian conditions. Thus the analysis aims to develop procedures to:

1. estimate hydropower **potential** at a specific site
2. estimate energy **consumption** as a function of population density, industries etc., daily and seasonal pattern, load factor...
3. make a rough technical **design** of civil engineering structures, as well as mechanical and electrical equipment
4. estimate investment, operation and maintenance **costs**

[55] Klein, 2000, p.6

5. compare MHP with other **alternatives**: diesel generator or connection to an existing grid (ICS or SCS)
6. identify **financing** possibilities, subject to financing volume, partners and instruments
7. define **organisational arrangements** and company types appropriate for financing, planning, implementation, and operation and maintenance
8. pinpoint **legal requirements**, e.g. licences and permits
9. propose an appropriate **metering, tariff and collecting system** considering ability and willingness to pay for electricity or mechanical shaft power

The study describes the theoretical background and analyses the essential aspects and their correlation and interdependencies. This step paves the way for the elaboration of program modules which can finally be integrated into a decision support system. Figure 3.3 proposes the basic structure of such a system.

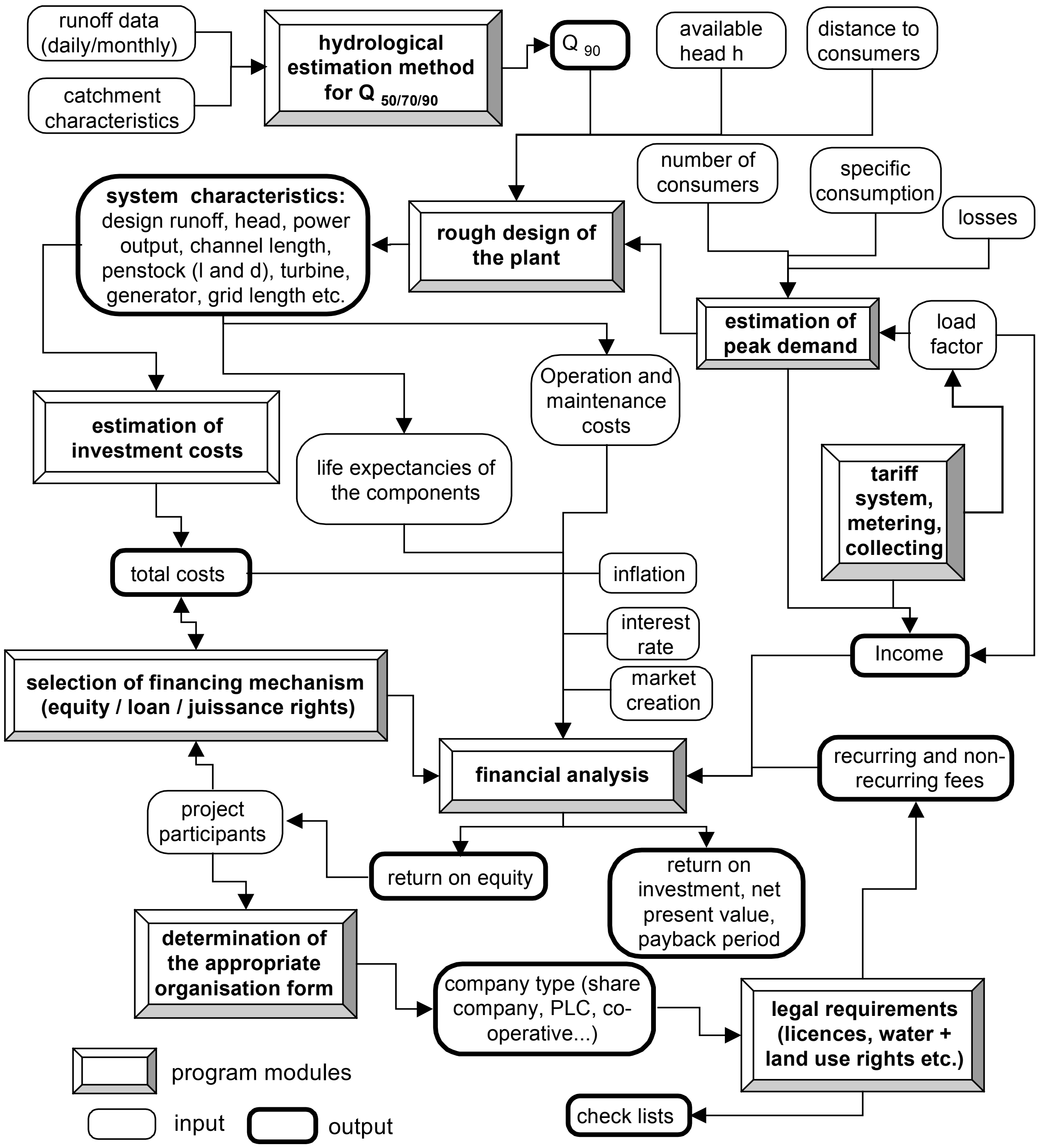


*Figure 3.3: Structure of a decision support system for development of MHP in Ethiopia*

### 3.2.2 Alternatives to MHP systems

The criteria influencing the choice of a supply system for electrical and / or mechanical energy are manifold and depend on the point of view of the respective decision-maker. As will be described in section 4.5 prioritising is mainly based on the following goals:
- reliability of the system
- low cost of the electricity supply
- profitability / economic efficiency of the whole system
- environmental aspects, giving preference to renewable energy sources
- general improvement of living standards
- independence from imported components / promotion of local market

Balancing these requirements in the present energy market, economic and political conditions, the most realistic alternatives for electricity supply in rural areas in Ethiopia are **MHP systems, diesel driven systems and connection to one of the existing grids (ICS or SCS)**. After some general comments on these three options the relevance of other renewable energy sources in the context of the present analysis is briefly analysed.

In some locations the potential exists for MHP systems to serve one or several communities. In other cases, an isolated diesel power plant, supplied with fuel oil from a central distribution depot, could be the only alternative. The third alternative is a more theoretical one. Firstly, generation capacities in the EEPCO system are not even sufficient to cover the current electricity demand, especially during peak hours. Secondly, as long as major urban centres are not yet supplied with electricity, their connection will remain of first priority for the supplier EEPCO, because of expected higher profit margins due to higher consumer density with lower specific infrastructure costs. Communities characterised by very small loads and extreme isolation make grid extension infeasible. Although both ICS and SCS are mentioned as potential bases for grid extension, in practice SCS in some cases already have operational problems and therefore do not offer a realistic option for connecting further consumers. Grid extension may play a complementary role in a few cases, but cannot be one of the feasible alternatives for rural electrification neither now nor in the near future.[56] So far, EEPCO's long term planning shows an unbalanced priority for increase of generating capacity, while it is under-investing in transmission and distribution lines.[57] Generation in the SCS so far is generally based on diesel generator sets. Capital costs for small diesel sets are relatively high, and fuel has to be transported over long distances, resulting in high generating costs in the SCS. In some cases diesel plants can only run during evening hours because high fuel costs prohibit continuous operation. Disregarding these aspects which might be killing arguments in the specific case the connection to one of these existing grids might reveal as the economically most viable solution. Within the present study it is examined up to which distance from ICS respectively SCS the construction of an additional transmission line could be a viable alternative to an MHP or diesel system. Further criteria such as availability of additional capacity, required substations etc. depend on the specific situation.

The **distance to the grid(s) operated by EEPCO** also plays a general crucial role with regard to tariff setting. Until now electricity from these grids is still heavily subsidised and this makes it almost impossible for another power producer intending to supply customers in the proximity, to charge tariffs exceeding the EEPCO tariff. Consequently, the success of an MHP system does not only depend on the theoretical economic profitability calculated by comparing the different technical options, but also on people's willingness to pay. This willingness is severely influenced by the knowledge about subsidised EEPCO tariffs. As soon as this option comes into consideration it raises doubts about the economically viable operation of any other system. Given the fact that ICS and SCS cover only a minor part of the whole country, in many cases the long distance to the grid allow other options for energy supply still to be interesting alternatives.

[56] Shewarega, 2000; p.18
[57] Fortune 18th March 2001 (Light Amidst Darkness...)

**Solar energy**
Ethiopia has a huge supply of solar radiation. It has been estimated that most parts of the country have over 3,000 hours of sunshine per year and receive solar energy in excess of 5.0 kWh/m²/day. The availability of this resource is particularly high in Tigray, Afar, Somali and Borana regions, where estimated annual solar energy is generally in the order of over 6.0 kWh/m²/day.[58] In these regions solar energy is a realistic alternative and can provide for considerable saving in biomass resources, thus alleviating environmental problems. The present study however focuses on West, Southwest and Southern Ethiopia, where solar energy potential is smaller, firstly due to higher annual precipitation, the latter entailing fortunately a bigger hydropower potential. Secondly, apart from the availability of the different resources, photovoltaics as a high-grade technology offer little prospect of building local capacity.[59] Estimations of unit cost for electricity production in Ethiopia based on different energy sources are given in Table 3.1.

| type of plant | electricity production cost in USD/kWh |
|---|---|
| large hydro, Ethiopia (>100 MW) | 0.03-0.096 |
| diesel (60-90 MW) | 0.09 |
| coal fired steam plants (60 MW) | 0.12 |
| geothermal, Ethiopia (5 MW range) | 0.07 |
| solar photovoltaics (10 kW range) | 0.30 |

*Table 3.1: Estimated unit costs for electricity production in Ethiopia[60]*

These figures reflect only the electricity production costs but not the transmission and distribution costs and can therefore not directly be applied to compare the competitiveness of different energy resources in rural areas. But they already indicate that although solar home systems might be an appropriate solution for decentralised supply in specific situations, the energy production cost is still quite high and thus often not competitive. Experiences in Zimbabwe, Kenya and Uganda showed that the costs of photovoltaic systems are between 0.5 and 1.5 USD/kWh. For instance, in "off grid systems" in rural Uganda the average cost using photovoltaics systems is about 0.5 USD/kWh compared to about 0.4 USD/kWh[61] for diesel generators.[62] Project evaluations from GTZ projects in 1993 - 1994 indicate for systems of 50 - 2,150 $\text{Watt}_{peak}$ that investment cost is as high as 8,000 - 11,000 $\text{USD/kW}_{el}$, which by far exceed investment cost for MHP systems (see section 6.2).[63]

**Wind energy**
The total wind resource of Ethiopia is estimated at 20.064 million TJ/year.[64] Wind energy is one of the resources which is virtually unexploited in Ethiopia. Only sporadic attempts have been made by a few organisations to harness this source of energy. Wolde-Ghiorgis made a wind energy survey using wind data collected by the National Meteorological Services Agency (NAMSA) which proved that mean wind speeds higher than 2.8 m/s are frequently found in Ethiopia, e.g. 3.5 - 5.5 m/s in eastern Ethiopia and central rift valley.[65] Especially for decentralised mechanical energy generation such as for water pumping, appropriate locally produced wind energy systems can offer a reasonable option. For electricity generation in small isolated grids, however, high fluctuations in wind availability generally raise technical problems. A promising and even economically viable future option is to feed wind energy into the ICS, where such fluctuations can be harmonised.[66]

[58] CESEN & ENEC, 1986
[59] Shewarega, 2000, p.18
[60] Mengistu Teferra, speech on "The Ethiopian Energy Scenario", held at the seminar "Energy in Ethiopia", 1999, p.3
[61] higher price for electricity from small gensets, compared to mentioned diesel systems of 60-90 MW with 0.09 USD/kWh
[62] ESD, 1998, p.5f
[63] Ökoinstitut (Institute for Applied Ecology), 1995 / 1999 ; p.26; available under http://www.oeko.de/service/em/index.htm
[64] CESEN & ENEC, 1986
[65] Wolde-Ghiorgis, W., 1974
[66] personal communication: Benjamin Jargstorf (Factor 4 Energy, Addis Ababa), 03/2000

**Geothermal energy**
Geothermal energy utilisation is also frequently mentioned in Ethiopian energy discussions, given a certain potential e.g. in the Langano[67] region. The technically exploitable potential was estimated at 700 MW.[68] This technology is still in the pilot phase in Ethiopia and additionally is no option for expanded decentralised rural electrification.

These arguments justify a concentration on the three options MHP, diesel and grid connection as mentioned before.

### 3.2.3 The scope of the study

Although alternatives to an MHP energy supply will be analysed, they will mainly be taken into account as far as economic comparison is concerned. The main focus of interest, however, are MHP systems.In this study MHP plants between 10 and 300 kW are considered. The definition of "micro" and "mini" hydropower varies in different publications. "Micro" in most cases refers to plants smaller than 100 kW, whereas "mini" is used for plants between 100 and 500 or even 1000 kW.[69] For the present study therefore the limit of 100 kW between "micro" and "mini" has been applied. Since only plants between 10 and 300 kW are considered the category of 10 - 100 kW has been used for micro hydropower and 100 - 300 kW for mini hydropower. For the whole range of 10 to 300 kW the abbreviation MHP is used.

The option of storing water by means of a reservoir was not taken into account, because reservoirs can lead to considerable cost increase.[70] They require additional sophisticated measures to avoid sedimentation since soil erosion and the resulting sediment transport are very severe problems in Ethiopia. Furthermore, they often rise the problem of water-borne diseases and can have several other negative impacts. Therefore only **"run-of-river" plants** are treated here. Figure 3.4 schematically illustrates the set up of an MHP scheme as run-of-river-plant. As discussed in section 3.2.2, only MHP plants supplying energy to **isolated grids** are of interest in rural Ethiopia. Plants feeding electricity into the existing ICS or SCS would have to compete with the cheap subsidised energy from big hydropower plants which seems to be impossible.

[67] EELPA / ACRES, 1983, p.18
[68] Bruke, 1995, p.8
[69] Fritz, 1984, p.1.5; Meyer 1981, p.17 and UNIDO, 1981, p.7
[70] Clark, 1982, p. 127

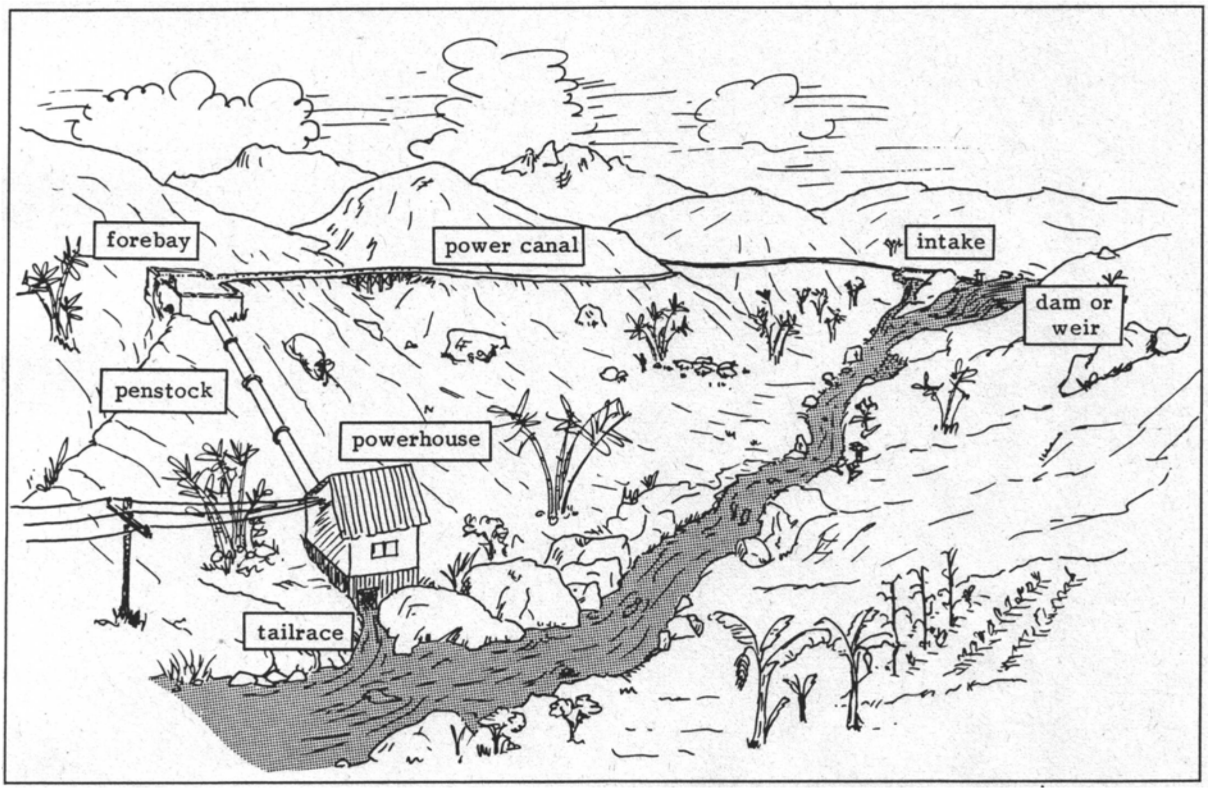


*Figure 3.4: Main components of an MHP plant*[71]

Given the fact that the highest potential for MHP is found in the mountainous and rainy **South, West and Southwest** of the country, mainly these regions, such as Oromia, "Southern Nations, Nationalities, and Peoples Region", and partly Amhara are taken into account. This mainly applies to the development of a hydrological estimation method (section 4.1) but also for the analysis of organisational (section 4.7) and legal (section 4.8) aspects. According to the National Atlas of Ethiopia[72] the southwestern and western highlands have a mean annual water surplus[73] of 300 - 900 mm. Based on this water surplus and the assumption of an overall efficiency of an MHP system of about 60 % and an available pressure head of 20 m, a catchment area of 50 to 150 km² would produce a runoff to drive a 150 kW plant (applying Formula 4-1).

The **ecological impact** was not taken into account given the fact that only systems without reservoirs are considered and that MHP has mainly positive environmental impacts. As MHP plants use a renewable energy source they contribute to the reduction of fossil energy exploitation, reduce carbon dioxide emissions and as an alternative to the consumption of different kinds of biomass it will in the long run reduce problems like deforestation[74], soil erosion etc.. Such effects have been demonstrated. An example is a rural electrification project in China, where 580,000 families in 100 isolated pilot-districts were supplied with 700 MW produced by small hydropower plants. This resulted in a saving of over 400,000 tons/year of fuel wood, due to the utilisation of small adequate electric stoves.[75] A noticeable positive impact however is only to be expected in case of extensive regional MHP-programs promoting and achieving far-reaching dissemination of the technology.
Despite numerous positive environmental effects, water abstraction for MHP plants always leads to a modification of the natural flow regime. Although all the abstracted water is returned to the river downstream of the plant, the river section between intake and the end of

[71] Inversin, 1986, p.63
[72] Ethiopian Mapping Authority, 1988, p.17f
[73] = sum of monthly excesses of rainfall over potential evapotranspiration when soil moisture storage is assumed to be at field capacity; considered to be approximately equal to surface runoff since the determination of the surplus is derived from the inflow-outflow hydrological equation.
[74] http://www.panasia.org.sg/nepalnet/icimod/mei97-5.htm ; Kamal Banskota Bikash Sharma, 1997
[75] Xiaozhang, 1990

the tailrace can be affected either by the reduction in flow or even by completely running dry. The more complete the water abstraction the more negative the effect on eco-morphology, including longitudinal connectivity, migration possibilities for fish, variation of width and water depth as parameters for habitat heterogeneity, substrate etc.. Additional analysis of such aspects would go far beyond the scope of the present study. Generally, the Ethiopian legislation requires that a minimum flow is maintained in the river to ensure the life and reproduction of fish and for miscellaneous water usage (see section 4.8.2). The determination of an acceptable minimum flow is a key issue in determining the economic feasibility of a scheme. In the absence of a universally adopted method of determining this flow to the satisfaction of all involved parties like project developer, regulator, electricity consumers etc. a case-by-case solution has to be found to reconcile the various interests.

Direct and indirect **social impacts**, such as health improvements especially for women cooking at present with open fires in their "tukul", education through the availability of electricity during evening hours, saving time that was previously used for collecting firewood, increased productivity in rural areas etc. are difficult to quantify objectively. Therefore, they are only mentioned here but not considered in the detailed analysis described in the following sections. However, social impacts must by all means never be ignored in an overall assessment.

### 3.2.4 Applied methodology

Points 1.-9. listed in section 3.2.1 are first treated successively. Most of the information was collected at different organisations and institutions in Addis Ababa during the various field trips in the years 1999 to 2001. The research work is mainly based on:

- the analysis of existing studies, reports, statistical material, hydrological data etc.
- the procurement of proclamations, regulations, the Civil Code and other legal provisions
- interviews with different resource persons such as bankers, consultants, officials etc.; for a comprehensive list of resource persons see Annex 1
- visits to existing mechanical MHP plants, isolated grids supplied by diesel generators and other small towns to analyse consumption patterns.

Table 3.2 shows in detail from which sources information has been collected.

| **information obtained** | **organisations and other sources** |
|---|---|
| hydrological data | Ministry of Water Resources |
| precipitation and evaporation data | Ethiopian National Meteorological Services |
| topographic and thematic maps | Mapping Authority |
| geological maps and studies | Ethiopian Geological Survey |
| studies on consumption patterns, tariff systems, unit prices for electrical equipment etc. | EEPCO |
| cost estimates and unit prices for civil structures, mechanical and electrical components, feasibility and final design studies | consultants, producers, suppliers and trading companies, NGO's and GO's |
| financing possibilities and conditions | banks, chambers of commerce, international funding organisations, NGO's, etc. |
| legal provisions and requirements, political framework etc. | administrations such as the regional government of Oromia, Ethiopian Investment Authority EIA, Ethiopian Electric Agency EEA |
| information on organisational arrangements and miscellaneous data | secondary literature, different NGO's |
| background information, references for publications, etc. | interviews with experts |
| publications, product prices for cost estimates | internet research |

*Table 3.2: Sources and information obtained*

The whole working procedure has been a process of continuous refinement, starting first with certain assumptions concerning hydropower potential, consumption, interest, inflation, credit funds etc.. For example, to find out information on financing possibilities rough estimations of investment cost and profitability were required to start interviews with bankers and other potential financiers. On the other hand the financiers' requirements regarding securities had to be known in order to analyse appropriate organisational forms etc..
The comprehensive data collection, the output of the stakeholder analyses, especially the numerous interviews and the above mentioned workshop have opened up to a broader view on relevant aspects and provided an insight into inter-dependencies between single aspects.
Despite several simplifications and generalisations, the procedure developed on the basis of the present analysis can help potential public or private investors to decide if an MHP system is the convenient option for a specific site and pinpoint which crucial aspects have to be taken into account. Yet, it can never replace a detailed planning procedure for the implementation of an MHP system.

### 3.2.5 Temporal aspects

The three main terms related to temporal aspects of the energy supply system used in the present study are the **lifetime of the system**, which is equal to the useful life expectancy or asset depreciation range, the **planning horizon** and the **project period**. The temporal aspects discussed here are of particular relevance for the financial analysis (see section 4.10.3) and are illustrated in the context of the investigation of case studies in Figure 6.2.

The **"lifetime"** is the average economic life or useful life of a system, meaning the life span of an asset over which it achieves the economic performance expected.[76] It is equal to the amortisation period, whereby the depreciation of assets based on their book value can be effected in a straight line or an accelerated method. The useful life of the whole system naturally depends on the lifetimes of the single components such as civil works, different mechanical and electrical equipment etc. and therefore has to be derived from those individual lifetimes. In general, the life cycle of the whole system is longer than lifetimes of most of the single components. The specific lifetimes being more or less unequal it is assumed that the "average" lifetime of the whole system expires, when major parts have to be replaced. Insignificant replacement costs incurring during operation are supposed to be regarded as operation and maintenance costs. Different figures concerning "average" lifetime can be found in the literature, mainly referring to systems in developing countries.[77] Examples are:

- 25 years for MHP plants (systems up to 15 kW); assumed by the Appropriate Technology Development Organisation (ATDO) in Pakistan which started its MHP activities in the mid-1970s[78]
- 30 years for MHP plants (10 - 800 kW) and 5 - 15 years for diesel plants[79],
- 15 - 20 years for MHP plants and 8 - 10 years for small diesel systems,[80]
- 20 years for MHP and 14 years for diesel plants (about 300 - 1000 kW); 20 years for a wooden pole transmission line, 35 years for a transformer[81]
- 35 years economic life for substations and power lines for grid connection and 30 years economic life for community distribution[82]
- more than 15 years for MHP systems[83]
- at least 25 years for MHP[84]

[76] Goldsmith, 1995, p.159
[77] in industrialised countries some MHP plants operate already more than 100 years.
[78] Inversin, 1986, p.259
[79] Clark, 1982, p.132
[80] Fritz, 1982, p.123
[81] Tropics Consulting Engineers P.L.C., 1998, p.15-2 (Daye Mini-Hydro Power Project, Draft Feasibility Report, Bonora)
[82] EELPA / ACRES, ENREP, 1994, p.8-7f
[83] Harvey et al., 1998, p.321
[84] Goldsmith, 1995, p.92

- 25 years for MHP based on weighted rate of depreciation, according to the different lifespans of the plant's components, such as civil-works, generating equipment etc. leading to an annual depreciation rate of 4 % of the initial investment and about 8 years for diesel sets (one third of the lifespan of MHP)[85]
- 35 years for MHP and 15 years for diesel plants (1000 kW system); rebuilding of the diesel engine every 5 to 7 years[86]
- two or three diesel life cycles should correspond to one hydro life[87]
- 10 - 20 years for MHP, lower value for generating units and the higher ones for civil works and services[88]
- about 6 years for gensets (with proper maintenance and care) in case of usage for prime or full-time power[89]
- economic life of 10 years for diesel systems [90]

Reviewing these figures, the present study proposes average lifetimes of **25 years for MHP systems** as well as for **grid connections,** but only **8 years for diesel systems**.

The basis for the technical design of the whole supply system is the so-called **"planning horizon"**. In general the forecast of energy consumption, including population growth, per capita consumption, industrial and commercial development etc., over the years is estimated and the design is effected with respect to this planning horizon. Nevertheless, individual components of the plant can be designed for a first phase and then upgraded to meet a subsequent increase of demand.

The planning horizon can be set according to the project and its context. The investor, the financing bank or even the political setting can limit this time span, subject to investment conditions, the life of a loan, the validity period of a licence etc.. To facilitate the comparison of different energy supply options a common **"project period"** applicable to all the alternative technical options must be defined. This period should encompass at least two or three "lifetimes" of a diesel generator in order to accommodate the advantage of the longer lifetime of an MHP system compared to a diesel plant. Accordingly, the average lifetime of an MHP system is chosen as the project period. Assuming a useful operation time of **25 years** for an MHP system, this time can be used as the period for the consumption forecast and also for the technical design. The design should provide sufficient capacity to satisfy the expected demand at the end of this time span. Strictly speaking, a continuous upgrading of the main components would in some cases be more economical. As discussed in section 4.3.4.8 the distribution grid could be constructed as a low-cost single wire earth return system (SWER), limiting loads to lighting and smaller handicraft machines. As soon as consumption exceeds a substantial level and connection of 3 phase motors require a higher voltage, the SWER which should meanwhile have been amortised must then be replaced by a more sophisticated 3 phase - 4 wire system. Another option is the combination of SWER and 3 phase system.

For the analysis of profitability **linear depreciation** is presumed, meaning that the initial value is uniformly distributed over the asset depreciation range (= useful life expectancy).[91]

[85] Meier, 1981, p.124 and p.133
[86] Fritz, 1984, p.11-4, p.11-10
[87] Fritz, 1984, p.11-9
[88] Chapallaz et al., 1992, p. 97
[89] http://www.allworlddieselgen.com/faq.htm; manufacturer of gensets
[90] EELPA / ACRES, 1994, p.8-5
[91] Wöhe, 1990, p.1063

# 4 ANALYSIS OF CRUCIAL ASPECTS INFLUENCING MHP IN ETHIOPIA

Referring to the research objective formulated in the previous sections 3.1 and 3.2, the following aspects will be treated successively:

1. hydrological potential
2. consumption
3. technical design
4. investment and operating costs
5. project participants
6. financing
7. organisation
8. legal aspects
9. tariffs
10. financial analysis

Most of these aspects are highly interrelated, except the estimation of the hydrological potential and the technical design which can be analysed almost independently. Although the hydrological potential as an "input variable" has to be the basis for the technical design, the way of estimation as such is not influenced by the remaining aspects.[92] The same applies to the technical design: even if e.g. the minimisation of investment and operating (= operation and maintenance O&M) costs is an underlying prerequisite for the technical design, most of the other aspects such as organisational form, legal requirements etc. do not affect the choice of technical alternatives directly and decisively.

The determinants are first treated in discrete sections, yet accentuating their respective relations to each other. In terms of a comprehensive view, chapter 5 summarises the most crucial interrelationships. Both the sections that analyse specific aspects and the "synthesising" section lead to the development of several flow charts displaying various kinds of decision trees. These decision trees are presented in view of the intended incorporation of the results into procedures applicable to a decision support system.

## 4.1 Assessment of hydropower generation potential

### 4.1.1 General procedure for potential assessment

To decide whether an MHP plant is a viable option for the energy supply of a community, the availability of flow and pressure head in the vicinity of the demand centre are the very first parameters to be checked.

The power which can be generated at a specific site is a product of flow, density, gravity, head and overall efficiency:[93]

$$\boxed{p = \delta \cdot g \cdot h \cdot Q \cdot \eta = 9.81 \cdot h \cdot Q \cdot \eta}$$

***Formula 4-1***

$p$ = useful power [kW]
$\delta$ = density of fluid (water = 1 kg/dm³)
$g$ = acceleration due to gravity = 9.81 m/s²
$h$ = head [m]
$Q$ = flow [m³/s]
$\eta$ = overall efficiency [ ]

To estimate the **head**, being available for power conversion, the difference in elevation between intake at the river and outlet at the turbine has to be measured. In case of a suction pipe downstream of the turbine, the suction head, in addition to the pressure head, has to be taken into account, giving special attention to probable tailback effects in case of floods.

[92] Solely, the profitability of the project can be associated with the availability of funds for a deepened hydrological study to ascertain the potential.
[93] Inversin, 1986, p.49

From this "total" head, the head loss along the power channel between intake and forebay has to be subtracted (see Figure 3.4). The remaining head between water level in the forebay and the turbine or the outlet of the suction pipe has to be reduced by the losses through pipe friction in the penstock, through turbulence at inlet and outlet and through bends of the pipe, finally resulting in the net head, which is available for power generation. The subtracting of losses assigned to the penstock pipe can alternatively be expressed as "efficiency", the latter being one part of the overall efficiency η of the total system. Methods to determine the available head in the field are described in detail in the pertinent literature.[94]

The overall **efficiency η** comprises efficiencies of penstock, turbine, gearing[95], generator, transformers and losses in the transmission and distribution lines. Usual values of these single efficiencies are given in the following Figure 4.1:

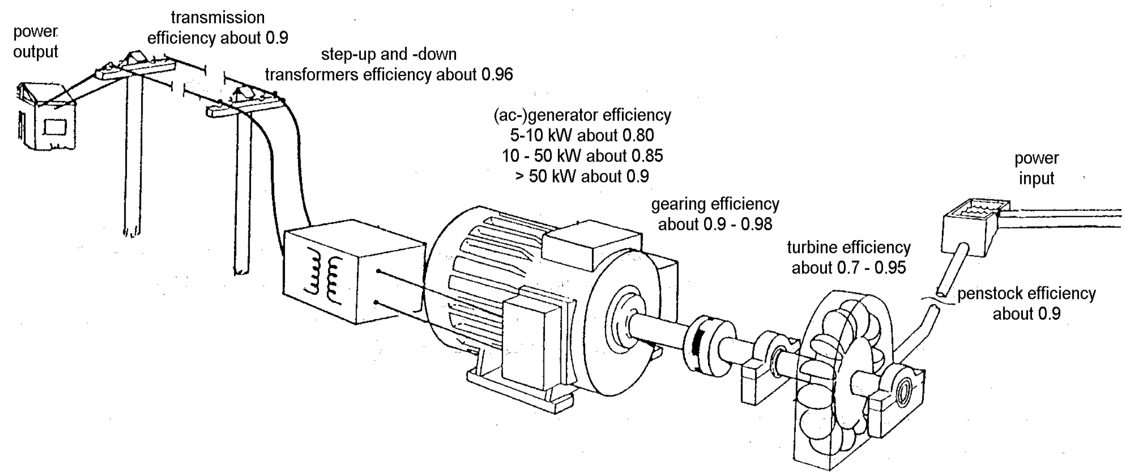


*Figure 4.1: Efficiencies of different system components[96]*

Provided a certain hydrological potential, rough estimates of efficiencies can give an idea of the energy output of the whole system according to the following equation:

$$P = 9.81 \cdot h \cdot Q \cdot \eta_{penstock} \cdot \eta_{turbine} \cdot \eta_{gearing} \cdot \eta_{generator} \cdot \eta_{transformers} \cdot \eta_{transmission} \cdot \eta_{distribution}$$ ***Formula 4-2***

Once head and runoff are known, the estimation of efficiencies facilitates the calculation of the energy potential finally available and its preliminary comparison with the forecast of energy demand. If significant discrepancies occur, other or additional sources must be sought.

Referring to decentralised, isolated systems, where energy shortages can in general not be compensated by other generation units, special attention has to be paid to the fluctuation of **runoff** over the year. If power should be available throughout the year round the MHP system should be designed for a flow which is available even during dry seasons. If the maximum continuously available runoff should be exploited, a flow value is selected which, on the average, is reached or exceeded in 85 - 95 % of the time in a year.[97] Once this so-called "design flow" for a system is fixed, it limits the maximum continuously available power output of the plant because the main power generating components, turbine and generator, will be

[94] Inversin, 1986. p.21ff and Harvey et al., 1998, p.43ff
[95] see also special remarks in section 4.3.3.9
[96] modified according to Harvey, 1998, p.4
[97] UNIDO, 1981, p.47 and Jackson, Lawrence, 1982, p.111

sized according to that runoff. In the present study the so-called **"Q(90,daily)"** is selected as the design value for the determination of the site potential. Q(90,daily) is the runoff which is reached or exceeded statistically in 90 % of the time, meaning in an average year at 90 % of 365 days (= 329 days). In some cases this runoff can exclusively be used for power generation; the assessment of the feasibility of an MHP plant has to consider potential water usage downstream in order to avoid conflicts. As a first approximation, it is assumed that the system is continuously operated with this runoff Q(90,daily) and consequently with an invariable general conversion efficiency. Under this assumption the available energy can directly be deduced from the integral of the duration curve. Yet, in reality the efficiency varies over the range of flows.

The value Q(90,daily) is obtained by means of the flow duration curve. The procedure is shown in Figure 4.2:

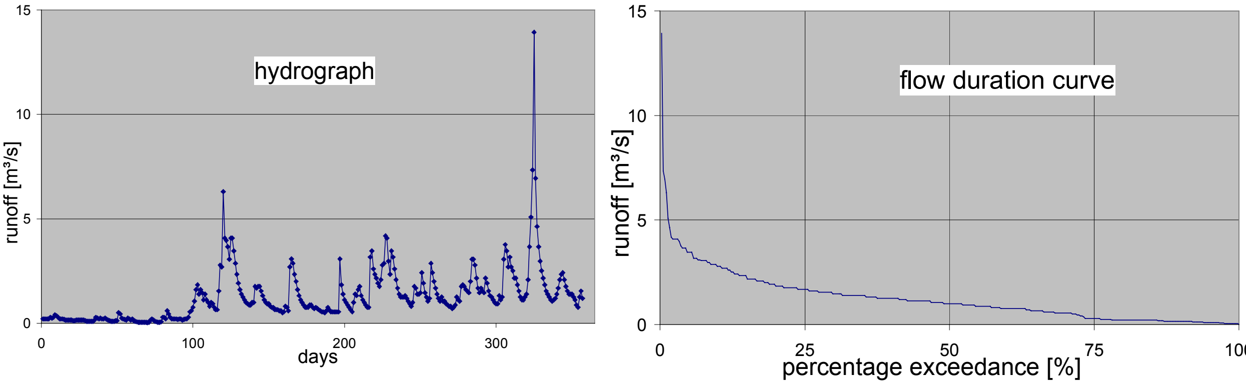


*Figure 4.2: Generation of flow duration curves*

This duration curve is obtained from one or several yearly hydrographs by sorting measured daily flows by size, from the largest to the smallest. The abscissa is scaled in terms of the percentage of the time that a flow is equalled or exceeded during the year(s).[98] Data of at least 8 - 10 years should be used to generate statistically reliable information. The same procedure can be applied to monthly data, which provides less detailed information of the runoff behaviour. Duration curves based on monthly data were used in the present study in order to find out how the "exceeding values" based on daily data, called **Q(x,daily)** correlate with those based on monthly data, called **Q(x,monthly)**. As soon as Q(x,daily) can be estimated by means of Q(x,monthly), more sites, namely also those with merely monthly data, can be integrated into the development of a regionalisation method (see also section 4.1.3). The variables Q(x,daily) and Q(x,monthly) are called **"runoff indices"** in the following sections.

### 4.1.2 Available estimation methods and their limitations

Only when long records of measured river flows are available at a potential site, the flow duration curve can be derived directly. However, at most sites the facilities for flow measurement are inadequate or completely absent. In such cases the flow duration curve and thus the runoff indices can only be estimated. Methods for estimation in such circumstances are given by Inversin[99] and Harvey[100]. Accordingly, an approximation for a flow-duration curve at an ungauged site is obtained either from the ratio of mean annual flows at ungauged and gauged sites, from the ratio of catchment areas or from the correlation of flows. Referring to the former method, it can be argued, that two rivers having similar mean flows might nevertheless have completely different low flow characteristics for example because of their respective geological or soil conditions. None of the methods mentioned above, explicitly takes into account the topography, lithology, soil characteristics, rainfall patterns and other specific

[98] Inversin, 1986, p.30f
[99] Inversin, 1986, p.32ff
[100] Harvey et al., 1998, p.41f

catchment characteristics. Taking such parameters into account is expected to provide a higher accuracy of low flow estimation.

The approach for the estimation of Q(90,daily), which is described in the following sections, tries to correlate this value with characteristics of the associated upstream catchment area. The desired result is the development of a technique which finally allows an estimation of the hydropower potential of an ungauged site, preferably with the minimum of effort, i.e. using limited and available input parameters.

### 4.1.3 The method applied: approach, requirements and validity

The technique applied is a **regionalisation approach**, by which flow characteristics are transferred from gauged to ungauged sites. By using a multiple non linear regression model, equations are developed which allow the estimation of the above mentioned low flow value Q(90,daily) and, if required, Q(70,daily) and Q(50,daily). These supplementary indices can furnish a rough idea of the general shape of the duration curve and allow a check on the plausibility of the results for example by verifying if Q(90,daily) < Q(70,daily) < Q(50,daily). For non-linear regressions the form of the regression curve is unknown. The basic equation for the **multiple non-linear regression** is:

$$v = a_0 \cdot u_1^{a_1} \cdot u_2^{a_2} \cdot u_3^{a_3} \cdot \ldots \cdot u_n^{a_n}$$

***Formula 4-3***

with: $v$ = dependent variable
$u_i$ = independent variables
$a_i$ = regression coefficients

The dependent variables are Q(90,daily), Q(70,daily) and Q(50,daily) and the independent variables are the different catchment characteristics, like area, precipitation etc., upon which the analysis is based. The *linear* multiple regression model is very well understood mathematically. Therefore, this nonlinear regression equation is transformed into a linear one by logarithmising both sides of the equation. Thus, also smaller values are given more weight and a more even distribution over the regression curve is achieved.[101]

$$\log v = \log a_0 + a_1 \cdot \log u_1 + a_2 \cdot \log u_2 + a_3 \cdot \log u_3 + \ldots + a_n \cdot \log u_n$$

***Formula 4-4***

With $\log v = y$, $\log u_i = x_i$ and $\log a_0 = b_0$, the simple regression model becomes apparent:

$$y = b_0 + a_1 \cdot x_1 + a_2 \cdot x_2 + a_3 \cdot x_3 + \ldots + a_n \cdot x_n$$

***Formula 4-5***

The unknown regression coefficients $b_0$ and $a_i$ have to be determined in such a way that the regression equation gives a "best fit" for the dependent variable. This means, that the sum of the squared deviations of the observed values for the dependent variable from those calculated by the equation must be minimised. With a partial derivative of this sum of squared deviations for every $a_i$, a system of n equations with n unknown coefficients $a_i$ is compiled and solved for $a_1$, $a_2$, $a_3$ etc.. To determine $b_0$ the calculated $a_i$ together with the arithmetic means of y, $x_1$, $x_2$ etc. are filled in Formula 4-5.[102]

[101] Maniak, 1993, p.211
[102] loc. cit. p.204f

A statistical index that is widely used to determine how well a regression fits is the **coefficient of determination r²**. It generally represents the fraction of variability in y that can be explained by the variability in x. In other words, the coefficient of determination explains how much of the variability in the y's can be explained by the fact that they are related to x, i.e. how close the points are to the regression function. When selecting independent variables the coefficient of determination is of outstanding importance. Firstly several single regressions are made between each independent variable $x_i$ and the dependent variable y (see Table 4.5). By calculating the coefficients of determination $r^2$ for each regression, the independent variables $x_i$ can be sorted by the magnitude of the coefficients and then **stepwise added to the multiple regression** in this order (see Annex 5). By this method it can easily be recognised, if the inclusion of the respective variable leads to an improvement of the regression, meaning of $r^2$. If the variable does not improve the regression it has to be left out (see sections 4.1.4.4 and 4.1.6.2).[103]

The catchment characteristics selected for application in the regression model have to meet several **requirements**:

1. explainable causal connection to the dependent variable(s)
2. area-wide availability for the regression analyses
3. variables should be independent of each other
4. available, accessible or easy to determine in any desired catchment area, for later application of the method that is developed

To examine expected and unexpected significant causal relationships, a common first step of data analysis that involve more than a very few variables is to establish a **correlation matrix** of all variables. Since significant results will be found surprisingly often due to pure chance, the expected causal, scientifically explainable correlations between the respective catchment characteristics and the runoff indices Q(x,daily) are analysed and illustrated in Table 4.4. The results of the regression analysis are screened on the basis of this table by verifying the physical coherence. For example, if a regression indicates a decrease in runoff with increasing precipitation or with increasing size of the catchment area, the regression is considered to be not reasonable and therefore eliminated. Thus, for every single parameter its logical consequence is checked (see section 4.1.4.3). Further aspects concerning the reliability of the results and how the above mentioned aspects are warranted are described in section 4.1.6.

The second and fourth point, concerning the availability of data, in this context means that the parameter should either be easy to measure in the field, to derive from a map or out of tables or to calculate by means of simple equations. If they are derived from maps, their accuracy should not be highly dependent on the scale of the map.[104]

The four selection criteria already exclude a substantial number of parameters which theoretically might be very useful and logically linked to runoff, but in practice are not available in the sense referred to above.

**South and Southwest Ethiopia** are the most promising regions for MHP systems, and so the study is limited to that part of the country. Other parts are less suitable for hydropower due to either lack of rainfall or relief energy. The regression model is being developed on the basis of data originating from South and Southwest Ethiopia, and therefore its applicability as a regionalisation model is limited to that area.

Summarising, the regression analysis is used to develop a method allowing primarily the estimation of Q(90,daily), but also Q(70,daily) and Q(50,daily), for a potential MHP site, where no runoff data are available at all. For the special case in which only monthly runoff data of

[103] Maniak, 1993, p.206
[104] Gebeyehu, 1989, p.36

the river of interest are available, but no daily flows, an additional linear regression model is established, directly providing the values for Q(90,daily), Q(70,daily) and Q(50,daily).

### 4.1.4 Database and procedure of analysis

#### *4.1.4.1 Availability of runoff data*

For the regression analysis carried out in the present research project, runoff data from 71 sites in South and Southwest Ethiopia were used. For 28 of these sites, only monthly data were available, while for the remaining stations daily data could be used. The 71 sites represent catchment areas between 5.5 km² and 1,975 km². The specific characteristics of the catchments used in the analysis are summarised in Annex 2.

To increase the number of applicable Q(x,daily) values, firstly linear regression analyses were carried out to identify linear relationships between Q(90,daily) and Q(90,monthly) respectively Q(70,daily) and Q(70,monthly) etc. as it is explained in the following paragraphs.

In general, for a specific site, a duration curve based on daily data, including extreme values of high and low flows, significantly deviates from a duration curve based on monthly data, which result from averaged and therefore less extreme data. However, in drier periods, a particular flowrate persists over a longer period and thus considerably affects the monthly mean. This mean is then relatively similar to the daily data of this period. High floods which take only a few hours or even minutes are hardly reflected in the monthly mean. Thus, in the range of higher runoff values, greater differences between the duration curves based on daily data and those based on monthly data occur.

Figure 4.3 depicts the higher conformity of duration curves established by means of daily and monthly runoff data in the low flow range, above 50 % exceedance. To highlight the low flows a logarithmic scale for the ordinate is chosen.

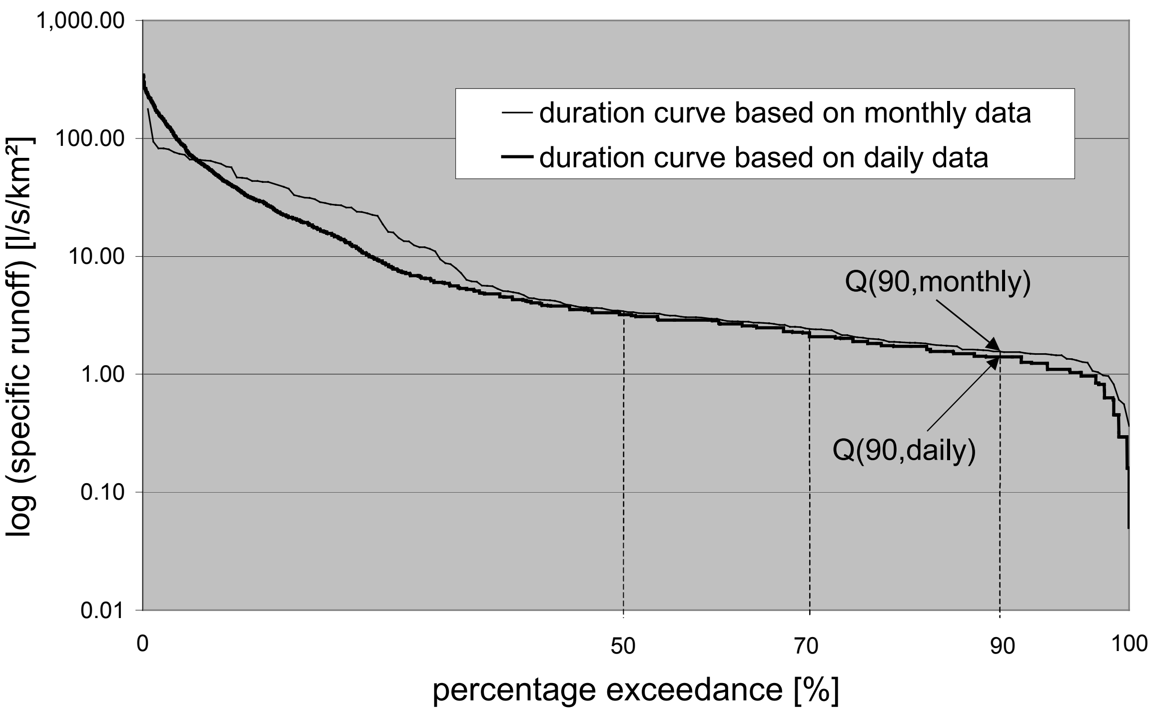


*Figure 4.3: Duration curves of the station AW1002: one based on daily and one based on monthly data, both on a logarithmic scale*

For all available stations the value pair Q(90,daily) - Q(90,monthly) was drawn out of the two types of curves and a linear regression analysis was performed, presenting Q(90,daily) as a function of Q(90,monthly). The same was done for the pairs Q(70,daily) and Q(70,monthly) as well as for Q(50,daily) and Q(50,monthly). Additionally, a linear regression analysis was effected for <u>all</u> pairs Q(x,daily) and Q(x,monthly), respectively for the different exceedance probabilities 90 %, 70 % and 50 %. Given the fact that the latter regression using all pairs of data together provides the best fit, it was adopted for further calculations[105]:

$$\boxed{Q\,(x, daily) = 0.9475 \cdot Q\,(x, monthly) + 0.0133}$$

**$r^2$ = 0.99** ***Formula 4-6***

*Q(x,daily)* = runoff, read from the duration curve based on daily data, statistically reached or exceeded for x % of the time [l/s/km²]
*Q(x,monthly)* = runoff, read from the duration curve based on monthly data, statistically reached or exceeded for x % of the time [l/s/km²]
*x* standing for the exceedance probabilities of 90 %, 70 % and 50 %.

The regression was effected by means of n=30 values from catchments with areas between 20 and about 700 km². The coefficient of determination of $r^2$ = 0.99 indicates that 99 % of the variance of the target figure Q(x,daily) can be explained by this regression. The correlation coefficient r being very close to 1, proves the close correlation between dependent and independent variables. In addition, the regression coefficient of 0.9475 shows that values with exceedance probabilities higher than 50 % (low flows), whether taken from daily or monthly duration curves, are very similar to each other.

This regression equation can be used for two purposes:
- to estimate Q(x,daily) for MHP sites, where only monthly runoff data are available
- to estimate the characteristic flows Q(x,daily) for the 28 sites with only monthly data in order to use them in the regression analyses

As a general rule synthetic data generated by statistical methods should not be used for further statistical procedures. However, due to the high coefficient of determination it is assumed that further analysis using the calculated values entails a negligible error. Thus for the 28 stations where only monthly means of runoff were available, the values Q(50,monthly), Q(70,monthly) and Q(90,monthly) are read from the duration curve based on monthly data and then converted into daily values by means of the above mentioned regression equation.

#### *4.1.4.2 Separation according to rainfall regimes*

The temporal distribution of rainfall in Ethiopia over the year is described in so-called "rainfall regimes". The seasonal variation of streamflows is strongly influenced by rainfall. This is especially true in the case of base flows, which are determined by the distribution of rainfall throughout the year, and influenced by the storage capacity of soil and aquifers. Because of these factors the regression equations are developed separately for the different precipitation regimes. The classification used in the present study is based on investigations by Daniel Gamachu.[106] He used monthly rainfall data from 67 stations and distinguished between 14 rainfall regimes, eight of them being the so-called "Type I" with one pronounced rainy season and six described as "Type II" with two distinct rainy seasons. The Type II regions are mainly in the Eastern part of Ethiopia. Almost all regions of interest for MHP, meaning with substantial hydropower potential, belong to Type I. According to Gamatchu a further sub-division into regimes I A, I B etc. can be effected according to the duration of dry and rainy seasons and the temporal distribution of rainfall. The spatial distribution of the different rainfall regimes is shown in Figure 4.4.

[105] Günther, 2001, p.21f
[106] Gamachu, 1976

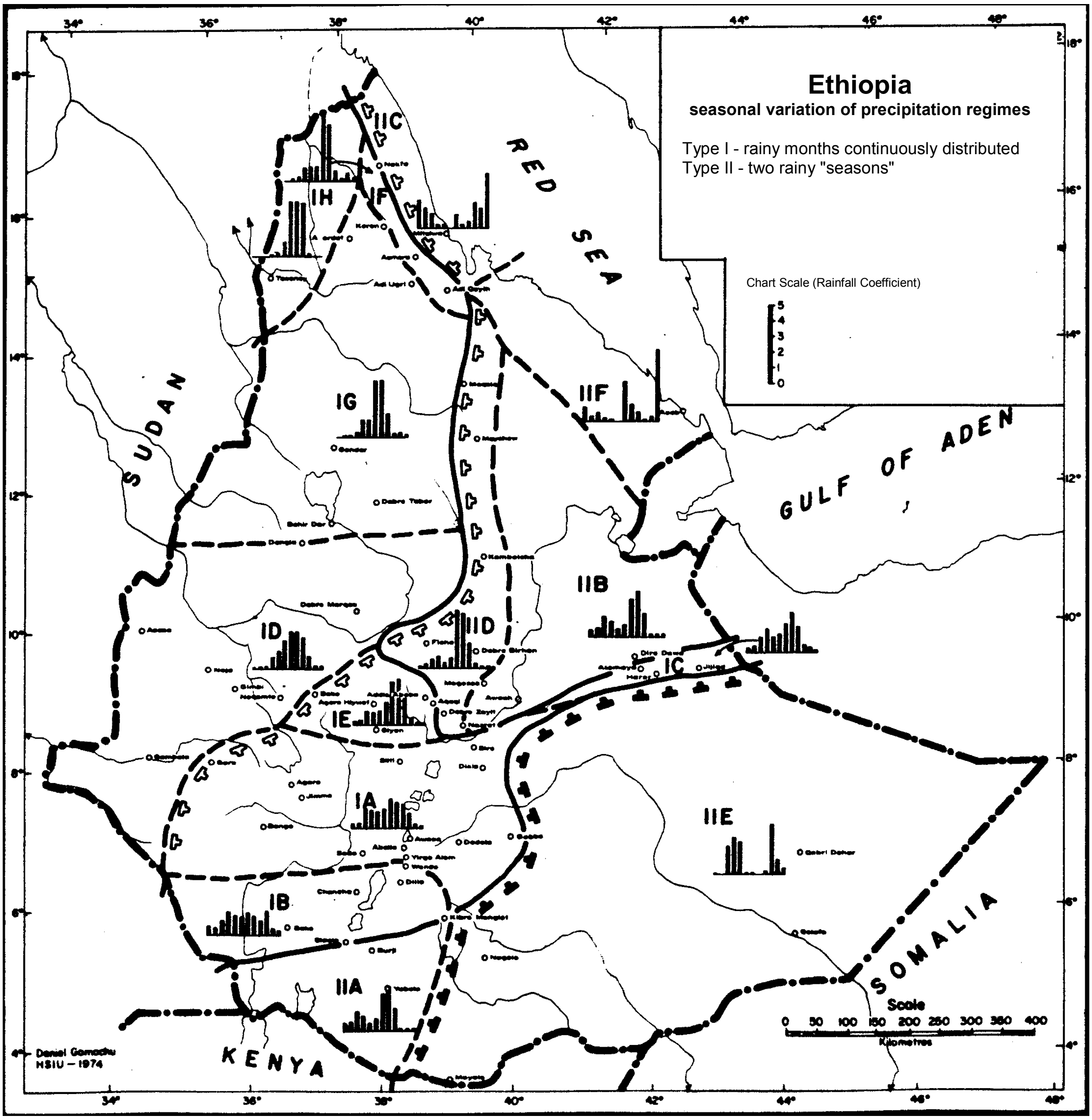


*Figure 4.4: Spatial distribution of rainfall regimes in Ethiopia*[107]

The 71 gauging stations with their associated catchment areas used for the regression analysis, were assigned to the different rainfall regimes. Separated according to their affiliation to a rainfall regime, the flow characteristics Q(x,daily) are then correlated with the catchment characteristics. Table 4.1 shows the number of available runoff stations in the different precipitation regimes.

| Rainfall regime | number of runoff gauging stations available in that rainfall regime |
|---|---|
| I A | 21 |
| I B | 9 |
| I D | 17 |
| I E | 16 |
| II D | 8 |

*Table 4.1: Number of gauging stations per rainfall regime*

[107] Gamachu, 1976

Information on the assignment of catchment areas to a respective rainfall regime is given in Annex 2.

#### *4.1.4.3 Catchment characteristics as explanatory variables*

Taking into account the selection criteria for explanatory variables mentioned in section 4.1.3, those in Table 4.2 were assumed to be useful for the regression model:

| **parameters** | **abbreviation** | **unit** |
|---|---|---|
| 1. mean annual precipitation | P | [mm/year] |
| 2. mean annual actual evapotranspiration | AET | [mm/year] |
| 3. hydraulic conductivity of the soil | HC | [m/day] |
| 4. mean slope in the catchment area | S | [%] |
| 5. size of the catchment area | A | [km²] |
| 6. specific capacity of the aquifer | SC | [l/s/m] |
| **auxiliary parameters** | | |
| 7. annual potential evapotranspiration | PET | [mm/year] |
| 8. mean altitude of the catchment area | h | [m] |

*Table 4.2: Catchment characteristics selected for the analysis*

The mean annual potential evapotranspiration (PET) [mm] and the mean elevation h of the catchment area in meters above sea level are called **auxiliary parameters** because they are only required in cases where no value for AET is available. Thus it had to be determined by means of further regression equations, requiring PET and h as input parameters, as shown in Figure 4.5 and
Figure 4.6. The mean elevation is determined from topographic maps (1:250,000) as the arithmetic average of minimum and maximum altitude of the river from the source to the gauging station. In the case of widely branching rivers, the lowest and highest points of the individual tributaries are specified for the calculation of the arithmetic mean.

Although land use in general has a strong influence on the overland flow and infiltration it is not considered here. Its extremely high spatial and temporal variability over the different seasons but also on a long run perspective, make land use a parameter which cannot be described and handled in one average, time-independent, "representative" parameter for the whole catchment area.

For the purpose of estimating the runoff at ungauged sites, the causal relationship between all these parameters and the dependent variable Q(x,daily) is examined. The following paragraphs analyse the general physiographic coherence between catchment characteristics and formation of runoff. Furthermore, they describe how the parameters are or can be determined, both for the actual analysis and for application of the method. The numerical values for the catchment characteristics utilised in the analyses are presented in Annex 2.

**Precipitation (P)**

Precipitation together with evapotranspiration are important input parameters deciding on the total quantity of water available for runoff or groundwater recharge. The mean annual rainfall for a particular catchment area can be identified either by using rainfall records from a station close to the area of interest or by taking the value from the map of mean annual rainfall[108], the latter method offering less accuracy than the measured and interpolated values in the table. The best but most unlikely option is that rainfall was measured in the area of interest and several years' data are available for direct calculation of the annual mean value. The selection of the appropriate Ethiopian rainfall regime can be done by reference to the map in

[108] National Atlas of Ethiopia, 1988, p.12

Figure 4.4. If monthly or even daily rainfall data are available they can be plotted, and the resulting curve compared to the curves of the well defined rainfall regimes in order to determine which regime is the most appropriate.[109]

*range of values for P: 600 - 2,500 mm/year*
*range of precipitation regimes: IA, IB, ID, IE and 2D*

**Potential and actual evapotranspiration (PET and AET)**
Evapotranspiration comprises transpiration from plants and evaporation from soil and free water surfaces. Except the latter, they are difficult to measure. Empirical and physical methods exist to estimate evapotranspiration.[110] Potential evapotranspiration PET is defined by climatic boundary conditions and assumes that sufficient water for transpiration and evaporation is available. The actual evapotranspiration AET takes into account that in reality evapotranspiration is limited by the availability of water. If precipitation is greater than or equal to PET and moisture storage in the soil zone is at maximum capacity, AET attains PET. Figure 4.5 illustrates the steps of analysis where the two parameters are required. The data for PET used in the regression analysis were taken from the "Oromia Study"[111], where they were estimated according to a modified Penman formula.[112] Figures for AET used in the "AET-regression" were calculated as difference between the mean annual precipitation and runoff (see section 4.1.4.4). Referring to the application of the regression equations to finally estimate Q(x,daily) (see
Figure 4.6, box 4) the mean annual AET is required as an input figure. Either this figure is known from measurement or estimation or it can be determined by means of the regression equations, developed for AET (see
Figure 4.6, box 3). If the site of interest is situated in rainfall regime 2D, this equation needs PET as one of the independent variables. In case that PET is not known, it can be estimated using one of the regression equations for PET (see

Figure 4.6, box 2), requiring only the mean altitude of the catchment area as input parameter. Annex 3 gives a list of values for AET and PET which can be applied for potential sites, as long as the sites are situated very close to the respective locations for which PET or AET values are available.

*range of values for AET: 100 to 1,400 mm/year*
*range of values for PET: 1,000 to 2,200 mm/year*

**Hydraulic conductivity (HC)**

The part of water reaching the ground either infiltrates or runs off superficially. Hydraulic conductivity (HC) and slope are essential factors influencing this division into infiltration and surface runoff. The less steep the terrain and the more permeable the ground, the more water can penetrate soil layers and flow underground to refill the aquifer. Water flow in the soil depends on the potential gradient and the hydraulic conductivity.[113]

$$\boxed{Q_{soil} = HC \cdot \frac{\Delta\Psi}{\Delta l}}$$ ("Darcy Equation") ***Formula 4-7***

where

$Q_{soil}$ = water flow in the soil [cm³/(cm² x s) or cm/s]
$HC$ = hydraulic conductivity [cm/s]
$d\Psi / dl$ = gradient of the potential [-]
$Q_{soil}$ is the quantity of water passing a "flow section" per time unit, given in cm³ per cm² and second, thus resulting in the unit of velocity, e.g. cm/s, although the hydraulic conductivity is no "real" velocity, which could be measured as such. "dΨ/dl" is the gradient of the potential

[109] Gamachu, 1976
[110] Baumgartner, Liebscher, 1990, p.335ff; Dyck, Peschke, 1989, p.125ff and Maniak, 1993, p.35ff
[111] Oromia Economic Study Project Office, 1999
[112] Günther, 2001, p.41f
[113] Scheffer, Schachtschabel, 1989, p.180

over a specific distance I, which is the driving force for water movement in the soil. Depending on pore size, particle-size distribution and stratification, HC is a specific characteristic of the soil and an important parameter for infiltration and percolation processes. HC also depends on the viscosity of the flowing medium and the saturation of the soil, whereby in the present context only water-saturated soils are considered. Generally spoken, a high hydraulic conductivity HC is associated with increased infiltration entailing increased interflow and groundwater recharge. Consequently the runoff pattern is more balanced between dry and rainy season, low and high discharges are less pronounced. Hydraulic conductivity (HC) values are needed in the regression equations in box 3 and 4 of

Figure 4.6, therefore a method for its determination is required if AET and Q(x,daily) are to be calculated. Since values for HC are not directly available, information from soil maps and a procedure of reclassification are applied as a "subsidiary method". Data on hydraulic conductivity are only available for *grain classes* like "sandy", "loamy", "clayey" but not for *soil types* like Vertisol, Fluvisol etc.. Soil maps with a scale of 1:50,000 and indicating the soil types are available for the region under investigation. These soil types are assigned to grain classes according to Annex 4 by which mean hydraulic conductivity values can be obtained. To determine one representative figure HC for the whole catchment area, the latter must be identified on the soil map, the soil types with their respective spatial occurrence as a percentage of the surface area are determined and the HC values assigned are read from the table in Annex 4. Finally, a weighted mean according to the occurrence of soil types in the area can be calculated. Alternatively, the hydraulic conductivity HC can be determined in the field (or in the laboratory) based on at least a few samples.

*range of values for HC: 0.06 - 3.5 m/day (values used for regression analysis: 0.1-1.2 m/day)*

**Slope (S)**

Steep terrain provokes high surface runoff and prevents the water from infiltrating and recharging the groundwater. Thus the slope of the catchment area is expected to be negatively correlated with the Q(90,daily), which is in general mainly fed by groundwater. As far as Q(70,daily) and Q(50,daily) are concerned the connection to the slope is more ambiguous. In case that Q(70,daily) and Q(50,daily) are mainly fed by groundwater, they are also negatively correlated with the slope; but in case that they are dominated by surface runoff it can be the direct opposite because steep slopes provoke high surface runoff.

The slope of a river channel normally follows the general topography of the area, i.e. the mean slope of the catchment area is similar to the channel slope.[114] As a matter of simplification it is supposed that the slope of river and neighbouring terrain, as far as the "catchment average" is considered, more or less coincide, even if they might differ on short specific sections. For the determination of the slope topographic maps (scale 1:250,000) are used, taking into account the tributaries and the main river by means of a weighted average over the whole channel length, meaning main river and tributaries. For every tributary in the catchment basin under investigation the following simple formula was applied:

$$\boxed{S = \frac{H_{\max} - H_{\min}}{L} \cdot 100 \quad [\%]}$$

***Formula 4-8***

where

$S$ = slope [%]
$H_{max}$ - $H_{min}$ = difference between highest and lowest point of the channel [m]
$L$ = channel length, between the points where $H_{max}$ and $H_{min}$ are determined [m]

The larger the scale of the map used for the determination of slope, the higher the accuracy. Therefore, when finally applying the regression equations, the scale should not be smaller than 1:250,000. A scale of 1:50,000 is recommended.

*range of values: about 0.5 - 25 %*

[114] Dyck, Peschke, 1989, p.170f

**Size of the catchment area (A)**

The size of the catchment area has an obvious influence on the runoff characteristics. In general it can be assumed that the larger the catchment size the more water is "caught" and thus the higher the runoff. The calculations in the present study imply that surface and groundwater watersheds are congruent. Although this assumption is a rough approximation, the lack of hydrogeological information usually does not allow a more sophisticated approach. Any discrepancy between the surface water catchment and the parallel underground area is unfortunately especially relevant for Q(90,daily), the latter being mainly influenced by groundwater fed base flow. The catchment sizes used to determine the regression functions were received from the Ministry of Water Resources. For subsequent application of the equations, topographic maps with preferably large scale, i.e. 1:50,000 or more, are required to determine the watersheds and thus the size of a potential catchment basin. These maps are available for the better part of South and South West Ethiopia[115] and can be obtained from the Ethiopian Mapping Authority.

*range of values for A: 10 - 2,000 km²*

**Specific capacity (SC)**

The specific capacity (SC) is the discharge of a well divided by the drawdown in the well. Note that specific capacity depends on the pumping rate and thus the aquifer's potential to store water. In other words SC is a measure of the number of litres per second pumped per metre of drawdown in a well at any point in time, expressed in l/s/m. Knowing the specific capacity of a well, the operator can estimate the drawdown that will be produced at different pumping rates. The specific capacity should not be confused with the specific storage[116] or the specific yield[117]. The so-called "base-flow", meaning the runoff during low flow periods, represented by Q(90,daily), is expected to be mainly fed by groundwater and therefore be strongly influenced by aquifer characteristics. In general an aquifer with a pronounced capability to store and to transmit water can theoretically contribute to a significant base flow. Whether the parameter SC is really of importance for the river runoff or not, depends on the specific situation, meaning if and how the aquifer and river are inter-linked. This in turn depends on the depth of the aquifer, its topographic position and recharge ability, siltation of the riverbed, etc.. The Geological Map of Ethiopia[118], although giving detailed information on the underground situation, does not provide a parameter quantifying the productivity of aquifers of the different regions as far as base flow is concerned. The Hydrogeological Map of Ethiopia[119] at least classifies five different groups of aquifers, but it distinguishes only three classes of productivity namely "high", "moderate" and "low". The aquifer classification is based on quantitative pumping test data. Indicative values of specific capacity are presented in Table 4.3.

| **productivity of aquifers** | **sample size (boreholes with data)** | **specific capacity [l/s/m]** | | | |
|---|---|---|---|---|---|
| | | range of sample, all known values | range, 80 % mean values | ***arithmetic mean*** | median |
| **high** | 106 | 0.03 - 40.5 | 0.2 - 7.6 | ***3.3*** | 2 |
| **moderate** | 116 | 0.02 - 13.5 | 0.05 - 1.1 | ***0.53*** | 0.13 |
| **low** | 15 | 0.001 - 3.4 | 0.006 - 0.5 | ***0.1*** | 0.04 |

*Table 4.3: Classification of aquifers according to the Hydrogeological Map of Ethiopia[120]*

Arithmetic means were used here. If different values for SC occur in the same catchment area, an area-weighted average was used. In general, rift valley and adjacent areas have

115 Ethiopian Mapping Authority, 1998, p.19f
116 = volume of water released per unit volume of aquifer for a unit decrease in hydraulic head [m$^{-1}$]
117 = volume of water, a saturated porous medium can yield by gravity drainage divided by the volume of the porous medium [-]
118 Merla et al., 1973
119 Ministry of Mines and Energy, 1988
120 loc. cit.

some of the best aquifers as a result of high degree of faulting and fracturing of the volcanic rocks and the occurrence of relatively permeable, unconsolidated sediments. In contrast, the highland volcanics of older age exhibit less fracturing and a higher amount of clay filling. Therefore they have moderate to low productivity aquifers.[121] Since only three classes of SC are registered on the map, and each of them representing a relatively large range of values, the output of this regression step was not very meaningful. Being nevertheless incorporated in the equations, for future application of the method, SC can either be determined via the mentioned Hydrogeological Map (as weighted average), by means of pumping test, or by analysing hydrogeological studies conducted for the area of interest in the context of other projects. According to Table 4.3 most of the values will lie between 0.05 l/s/m and 7 l/s/m. If an area-weighted average of the values in the Hydrogeological Map is used the span of values is even further restricted (0.1 - 3.3 l/s/m).

*range of values: 0.001 - 40.5 l/s/m*

**Synopsis of the catchment characteristics**

According to the background described above, Table 4.4 summarises the pursuant qualitative correlations between the different runoff values Q(x,daily) and the explanatory variables, expected from the regression analysis:

| | **Q(90,daily)** | **Q(70,daily)** | **Q(50,daily)** |
|---|---|---|---|
| **area A** | + | + | + |
| **precipitation P** | + | + | + |
| **actual evapotranspiration AET** | - | - | - |
| **hydraulic conductivity HC** | + | +/- | +/- |
| **specific capacity SC** | + | +/- | +/- |
| **slope S** | - | +/- | +/- |

*Table 4.4: Expected correlation between catchment characteristics and runoff indices[122]*

"+" stands for a positive correlation, between dependent and independent variable and thus a positive exponent in the regression equation. E.g., for a larger catchment area, a higher Q(90,daily) is to be expected. Whereas "-" means that an increase in the independent variable entails a decrease in the dependent variable, which is called inverse correlation. When the causal connection is equivocal, "+/-" is indicated.

#### *4.1.4.4 Steps of analysis*

Figure 4.5, shows the steps of analysis which finally lead to the regression model for the determination of the runoff characteristics.

The final target of the analysis is the establishment of the regression equations shown at the lower end of Figure 4.5, which are correlating the runoff indices Q(90,daily), Q(70,daily) and Q(50,daily) with the six catchment characteristics (in Table 4.4). These equations can be applied as soon as the coefficients $c_i$, $d_i$ and $e_i$ have been estimated. The left branch of the flow chart demonstrates the procedure for achieving the input data for Q(x,daily) (see section 4.1.4.1). The right branch summarises the approach leading to numerical values of AET, which are relatively difficult to estimate compared to the remaining ones.

The encircled numbering from 1 to 4, applied in Figure 4.5, corresponds to the numbering in Figure 4.6, e.g. the regression analysis number 3 in Figure 4.5 leads to the regression equations, also marked with number 3, in Figure 4.6.

[121] loc. cit.
[122] Günther, 2001, p.58

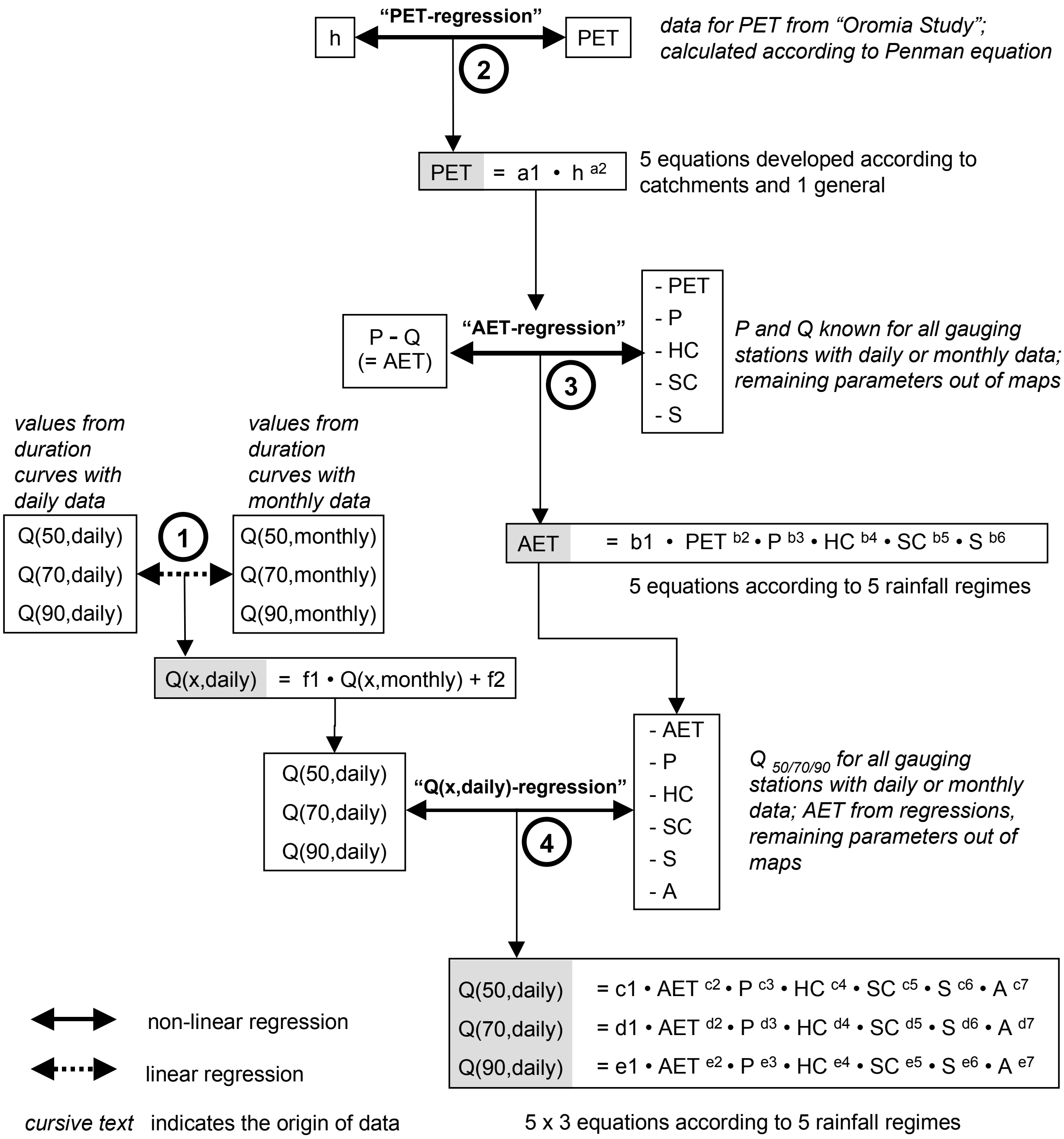


*Figure 4.5: Steps of hydrological analysis*

Given the fact that data for the mean annual actual evapotranspiration AET are not directly available, they are derived from another multiple non-linear regression procedure, the **"AET-regression"**. The purpose of that analysis is to find regression equations for the calculation of AET by means of the five catchment characteristics potential evapotranspiration PET, precipitation P, hydraulic conductivity HC, specific capacity SC and slope S. This approach suffers from the disadvantage that the parameters P, HC, SC and S are applied to estimate AET and then the resulting AET together with the same parameters is applied to estimate Q(x,daily). The "AET-regression" can only be conducted, separately for every specific rainfall regime, if values for AET are available. Due to missing measurements of AET, the values have to be estimated by means of the "water balance equation". Supposing that inter basin water transfer is excluded and long-term changes in groundwater storage are negligible, AET can be computed as the difference between the long-term averages of precipitation and runoff.

$$\boxed{evapotranspiration = precipitation - runoff} \qquad \textit{"water balance equation"}$$

Although, strictly speaking, part of the rainfall infiltrates and recharges groundwater, this portion will be lost to feed the runoff during dry periods as base flow. Thus, if mean annual values are considered, the effect of infiltration can be considered to be more or less compensated. This leads to the water balance equation in the presented abbreviated form.

This "AET-regression" requires values for the potential evapotranspiration PET in the catchment area, so a third regression analysis, the **"PET-regression"**, has to be conducted. PET is dependent on the temperature, which in turn is generally reciprocally proportional to the altitude, so this non-linear regression indicates that altitude is inversely related to PET. A regression equation is determined for each main catchment area, which are Awash, Baro Akobo, Genale Dawa, Rift Valley, Wabi Shebele, Abbay and Gibbe Omo, supposing uniform climatic conditions in the individual catchment basins. In addition one non-linear regression was developed, pooling together PET data from all catchment areas in the region of interest (South and South West Ethiopia) in order to verify if it delivers better results. This is the case for Abbay and Gibbe Omo catchment areas, i.e. the individual regressions deliver coefficients of determination inferior to those from the "general" regression using all data. Consequently, for these two catchment areas, the application of the general regression equation is preferred. The PET data required for this step of analysis were extracted from the Water Resources Baseline Survey conducted by the Region of Oromia.[123] In that study PET values had been calculated according to the Penman method.

The whole analysis finally delivers a method which basically consists of the following three steps: estimation of PET, estimation of AET, estimation of the flow characteristics Q(x,daily).

### 4.1.5 Resulting method for the determination of runoff characteristics Q(x,daily)

The method resulting from the steps described above is shown in Figure 4.6. This decision tree illustrates how values for Q(90,daily), Q(70,daily) and Q(50,daily) can be estimated depending on the availability of data. If daily or monthly runoff data are available for at least 5 years, the flow characteristics can either be determined directly using readings from the daily flow duration curve or by using values read from the monthly flow duration curve, together with the regression equation. If neither daily nor monthly data are available for a sufficient period, the values can be assessed by means of several non-linear regression equations, depending on the availability of AET and PET data, the rainfall regime at the potential site, the average altitude of the catchment area and the connection to one of the main catchment areas of the country.

The determination of the parameters required for the procedure is detailed in section 4.1.4.3. To facilitate a first approximation of the unknown parameters, the estimated range of values in the area offering potential MHP sites (South and South West Ethiopia) is appended at the end of every subsections. This range is also limited by the range of numerical values used in the regression analyses. For example a specific regression equation with certain regression coefficients $a_i$ (see Formula 4-3) developed using runoff data originating from small catchments of 10 - 2,000 km² cannot be assumed to be reliable for a catchment of 5,000 km².

[123] Oromia Economic Study Project Office, 1999

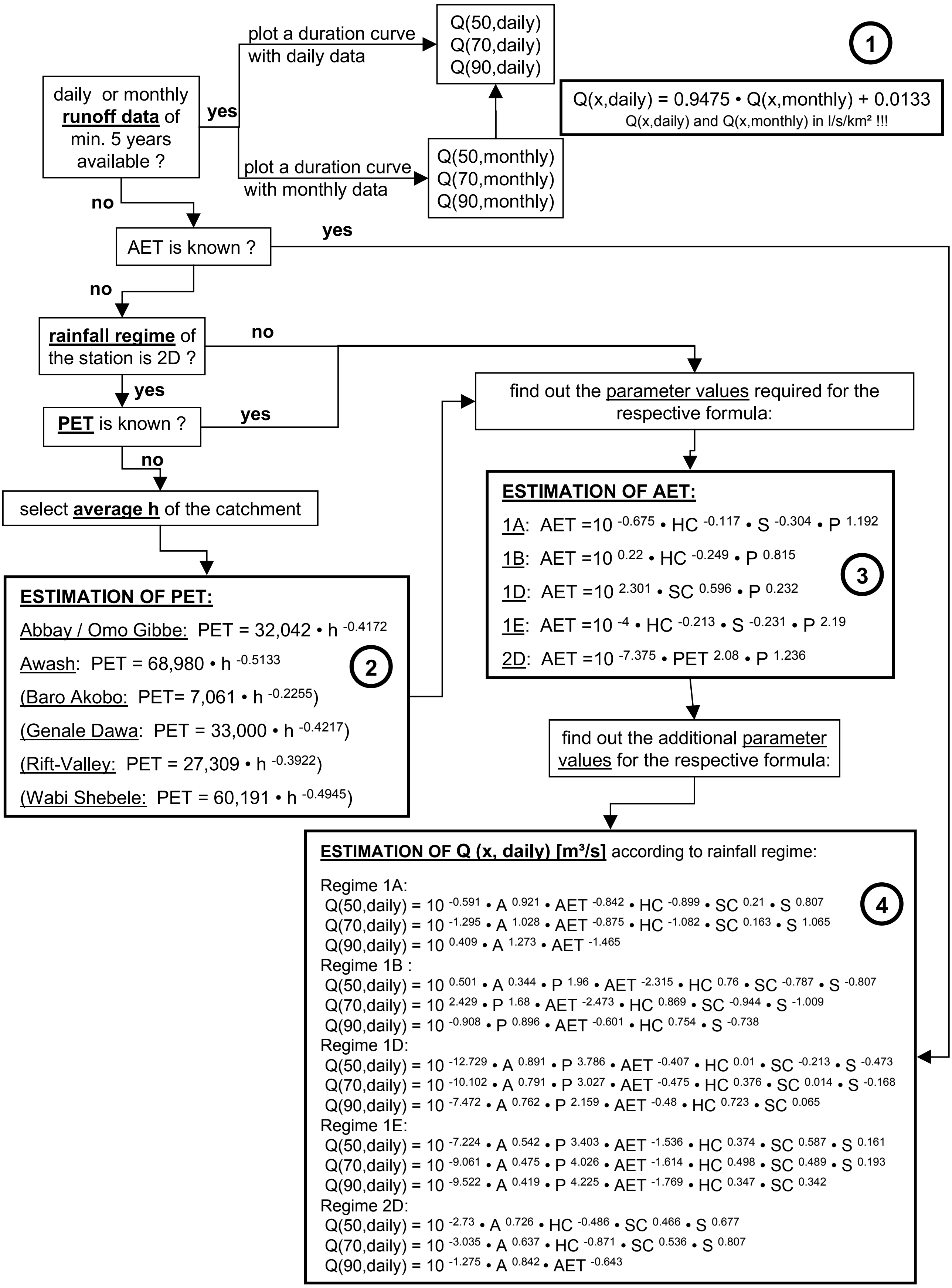


*Figure 4.6: Estimation method for Q(x,daily)*

### 4.1.6 Reliability of the results

The reliability of the new method described above can be evaluated according to the reliability (consistency and homogeneity) of the input data, the significance of the multiple coefficient of determination and statistical tests with regard to significance of the whole regression equation.

#### *4.1.6.1 Reliability of input data (consistency and homogeneity)*

Time series data, like runoff and to some extent rainfall, used for a statistical analysis had to be checked with regard to their consistency and homogeneity; whereby the consistency test must precede the homogeneity test. Measurements are consistent provided that they are not affected by their transmission or by errors of measurement due to defective instruments, error in reading etc.. Observed values are homogeneous if the regime observed is not disturbed by anthropogenic or natural impacts such as climatic change, hazards, rerouting of the river bed after floods etc.. In general a consistency test includes control of measuring instruments, calibration curves and rating curves, plotting water level versus discharge, etc.. Often these effects can be detected only by means of statistical procedures. Statistical tests are also an adequate method for identifying non-homogeneities.[124] When testing inconsistent and non-homogeneous data by means of statistical methods, consistency and homogeneity cannot be checked separately. In other words, if inconsistency cannot be removed, these two sources of error cannot be separated and the data should be checked with statistical tests.

Since most **runoff data** originate from the hydrological branch of the National Ministry of Water Resources, it is assumed that the data can be considered to be consistent. The data received for the regression analysis were selected according to the reliability of the gauging station.[125] The employee of the Ministry who is responsible for these data knows every single station and has explicitly chosen the stations with the highest data quality and with long data records. A further check of consistency has not been possible because of lack of additional information. For the check of homogeneity, the "double mass curve analysis" was applied. By plotting the sum of accumulated totals for each year at one gauge against those for the same year at the adjacent gauge, in case of inhomogeneity the duration and kind of "disturbance" can mostly be recognised. If the two series of data correlate well, a straight line will appear. The slope of this line corresponds to the factor for transferring one series into the other. A change in the slope indicates an inhomogeneity. According to the availability of data (time series over similar periods are required), runoff data from some gauging stations are correlated with runoff data from neighbouring stations and with precipitation data measured near the respective runoff station.[126] In the present study, checks using nearby precipitation data proved the homogeneity of the respective data. Of the runoff data which were checked by means of data from adjacent stations, only four showed slight inhomogeneities. In the analysis of these sites a change in slope of the regression line has been detected. The reason might be a change in rainfall pattern or land use in the catchment area. Seventeen sites could not be checked for homogeneity at all because neither precipitation nor runoff data, from an adjacent site and covering a similar time period, were available.

The homogeneity and consistency of **rainfall regimes** adopted from Gamachu[127] were assumed to be already checked.

For the **mean annual rainfall (P)**, data from 200 gauging stations and additional interpolations amounted to a total of 935 values for all of Ethiopia. These data were provided by the "Soil Conservation Research Programme" (University of Berne, Switzerland, in association with the Ministry of Agriculture, Ethiopia). For the regression analysis linking discharge

[124] Hofius, Liebscher, Löken, 1986, p.27ff
[125] personal communication: Mr. Deksios (Ministry of Water Resources, Addis Ababa)
[126] Günther, 2001, p.19f
[127] Gamachu, 1976

(Q(x,daily)) and rainfall, those closest to the runoff gauging sites were selected. Among the selected locations with available rainfall data, 16 are stations with directly gauged, not interpolated, data. For 11 of these 16, a double mass curve analysis was conducted by referring in each case to an adjacent site; this analysis proved the homogeneity of the data.

The **area (A) of the catchment** used for the regression analysis is indicated by the Ministry of Water Resources, which lists all gauging stations with their specific characteristics including the respective size of catchment area. Since Ministry staff are familiar with all the gauging stations, it is assumed, that the figures are correct.

As already mentioned, data for the **potential evapotranspiration (PET)** were taken from the "Oromia Study".[128] The Meteorological Institute in Addis Ababa also provides data. Measurements are made with so-called Class A pans, which measure the evaporation from a water surface and thus provide an indication of PET. In general these data are subsequently transformed using special formulae into actual evapotranspiration, taking into account parameters like land use. According to Meteorological Institute, these measured data are not at all reliable and therefore they have not been used in the present study.
PET data published in the "Oromia Study"[129] however were calculated with the Penman formula. It is assumed that the input data for this formula, including radiation, temperature and wind, were checked for homogeneity and consistency. Data for the **actual evapotranspiration (AET)** were calculated by taking the difference between long-term averages of precipitation and runoff. Thus the reliability of AET data depends on the reliability of those two "primary" input parameters, which were both checked for homogeneity, and, for the most part, found to be reliable.

Values for **hydraulic conductivity (HC)** were not available as such, therefore a procedure of reclassification, with the final objective of identifying <u>one</u> representative value of HC for the whole catchment area, was applied as "subsidiary method". This reclassification was based on soil maps (1:50,000), studies of the Ministry of Water Resources[130] and the Ministry of Agriculture[131] and the “DVWK Merkblatt 116/1982”[132]. The soil maps were used to determine the soil types occurring in the respective catchment area. The soil types taken from the maps were each attributed to one particular grain class, which in turn were assigned one numerical value of hydraulic conductivity (HC) obtained from the “DVWK Merkblatt 116/1982”[133]. The resulting classification is illustrated in Annex 4. Although soil maps with a relatively detailed scale of 1:50,000 were used, the series of simplifications, namely the assigning of one grain class to each soil type and of one value of HC to one grain class, and finally the calculation of an area-weighted mean, do not make allowance for the high variability of the values of the parameter HC. In reality each soil type can have a variety of representative grain sizes and consequently a range of HC values.

The regression relationship between the runoff and the **specific capacity (SC)** data based on hydrogeological maps gives only a vague idea of the influence of specific capacity on the runoff because, as mentioned above, only three classes of specific capacity are provided, each of them being described with a specific range of values. The scale of the map (1:2,000,000), the lack of precision of the data and the calculation of an average for the whole catchment basin substantially limit the reliability. Nevertheless this method is chosen because it is one of the few possibilities for determining an area-wide parameter.

The accuracy of the mean **slope (S)** used in the calculation is influenced by the scale of the map and the discrepancy between the average slope of the river and the neighbouring terrain. As long as a sufficiently detailed scale is chosen (1:250,000 or higher) and the mean

[128] Oromia Economic Study Project Office, 1999
[129] loc. cit.
[130] Ministry of Water Resources, 1999-2
[131] Ministry of Agriculture, 1995
[132] DVWK 1982
[133] loc. cit.

river and terrain slopes are relatively consistent, the error of slope determination can be contained.

#### 4.1.6.2 Significance of the multiple coefficient of determination

The equations resulting from the regression analysis effected between catchment characteristics and Q(x,daily) are shown in
Figure 4.6. The influence of the single parameters AET, P, SC etc. on the dependent variable Q(x,daily), called "runoff index", is expressed by the coefficient of determination $r^2$ of the single regression, this coefficient being defined as ratio of the explained variation to the total variation. If there is zero explained variation (i.e., the total variation is all unexplained), this ratio is 0. If there is zero unexplained variation (i.e., the total variation is all explained), this ratio is 1. In other cases the ratio falls between 0 and 1. The higher $r^2$, the better the regression.[134] The coefficients of determination resulting from the **single regressions** are listed in column 4 to 9 of Table 4.5. These $r^2$ are exclusively used to establish, for every particular runoff index, e.g. Q(70,daily) in rainfall regime 2D, a **ranking** of the parameters A, P, AET etc.. Pursuent to this ranking they are integrated stepwise into the **multiple regression** analysis to achieve a continuous improvement of the result.[135] This stepwise improvement of the $r^2$ due to inclusion of further parameters is illustrated in Annex 5. The last column of this table as well as the last column of Table 4.5 present the final, optimum value of $r^2$ achieved with the respective multiple regression. The coefficients of the multiple regressions between Q(90,daily) and the six parameters are unfortunately not very high, namely between 0.4 and 0.6. Since the $r^2$-values in these shaded cells result from multiple regressions, they have to be considered completely separate from the remaining $r^2$-values and "sums" of $r^2$-values, which all refer to single regressions.

| | | | **coefficient of determination r²** for the **single** regression with ... | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **rainfall regime** | **runoff index Q(x,daily)** | **num-ber of cases** | surface area **A** | precipi-tation **P** | actual evapo-transpira-tion **AET** | hydraulic conducti-vity **HC** | specific capacity **SC** | slope **S** | r² for the **multiple** regres-sion |
| 1A | Q(90,daily) | 21 | 0.424 | 0 | 0.008 | 0 | 0 | 0 | **0.549** |
| | Q(70,daily) | | 0.500 | 0 | 0.002 | 0.011 | 0.003 | 0.023 | 0.698 |
| | Q(50,daily) | | 0.533 | 0 | 0.005 | 0.013 | 0.013 | 0.038 | 0.752 |
| 1B | Q(90,daily) | 9 | 0 | 0.081 | 0.112 | 0.097 | 0 | 0.275 | **0.531** |
| | Q(70,daily) | | 0 | 0.285 | 0.010 | 0.091 | 0 | 0.316 | 0.977 |
| | Q(50,daily) | | 0.584 | 0.338 | 0 | 0.096 | 0.007 | 0.243 | 0.987 |
| 1D | Q(90,daily) | 16 | 0.482 | 0.040 | 0.076 | 0.009 | 0 | 0 | **0.592** |
| | Q(70,daily) | | 0.578 | 0.167 | 0.087 | 0.102 | 0 | 0.004 | 0.761 |
| | Q(50,daily) | | 0.555 | 0.314 | 0.096 | 0.266 | 0.004 | 0 | 0.882 |
| 1E | Q(90,daily) | 16 | 0.015 | 0 | 0.163 | 0.030 | 0.013 | 0 | **0.416** |
| | Q(70,daily) | | 0.016 | 0 | 0.184 | 0.040 | 0.034 | 0 | 0.567 |
| | Q(50,daily) | | 0.043 | 0 | 0.180 | 0.017 | 0.032 | 0.002 | 0.538 |
| 2D | Q(90,daily) | 8 | 0.508 | 0 | 0.028 | 0 | 0 | 0 | **0.530** |
| | Q(70,daily) | | 0.592 | 0 | 0 | 0.012 | 0.310 | 0.023 | 0.781 |
| | Q(50,daily) | | 0.733 | 0 | 0 | 0 | 0.392 | 0.004 | 0.866 |
| *sums of r²-values added up from those of the **single** regressions* | | | | | | | | | |
| *"sum"* | *Q(90,daily)* | | *1.429* | *0.121* | *0.387* | *0.136* | *0.013* | *0.275* | *2.618* |
| *"sum"* | *Q(70,daily)* | | *1.686* | *0.452* | *0.283* | *0.256* | *0.347* | *0.366* | *3.784* |
| *"sum"* | *Q(50,daily)* | | *2.448* | *0.652* | *0.281* | *0.392* | *0.448* | *0.287* | *4.025* |
| *sum of all regimes* | | | *5.563* | *1.225* | *0.951* | *0.784* | *0.808* | *0.928* | *10.42* |

*Table 4.5: Coefficients of determination r² resulting from the different regressions*

[134] Sachs, 2002, p.501f
[135] Maniak, 1993, p.206

The regression analyses show some particularities which are described in the following paragraphs:

**Regime 1A:**

The size of the catchment area and AET seem to dominate over other influencing factors and are the only parameters related to low flows, especially as far as Q(90,daily) is concerned. The soil parameters (HC, SC) as well as precipitation and slope are obviously not or only weakly correlated with the runoff indices.

**Regime 1B:**

Q(90,daily) and Q(70,daily), which in general are influenced by the so-called base flow mainly fed by groundwater, are not associated at all with the size of the catchment area, neither with SC, as demonstrated by the zero value of the coefficients of determination. The most obvious explanation for this phenomenon is the possible lack of congruence between the surface and subsurface catchment areas as discussed in section 4.1.4.3. Q(50,daily) however, which is in general dominated by surface runoff much more than by base flow, clearly shows a close correlation to the size of the drainage basin. The coefficient of determination for precipitation and the respective runoff index increases from Q(90,daily) to Q(50,daily), also supporting the above mentioned assumption. Q(50,daily), mainly influenced by surface runoff, is more closely related to the amount of rainfall.

**Regime 1D:**

In this rainfall regime all parameters, except specific capacity and slope, significantly contribute to the explanation of the dependant runoff variables. The size of the catchment area, precipitation, actual evapotranspiration and hydraulic conductivity influence the formation of runoff over the surface as well as subsurface flow. The assumption of congruence between surface and subsurface catchment areas is obviously justified.

**Regime 1E:**

Neither precipitation nor slope have a noticeable influence on the runoff behaviour. Even the remaining parameters lead to quite weak correlation (all coefficients < 0.2 !). A possible interpretation is that the processes leading to formation of runoff are so complex, that it is impossible to "map" them by means of a multiple regression including only six parameters.

**Regime 2D:**

In this precipitation regime Q(90,daily) is a function of the size of the catchment area and, to a smaller extent, of AET. In contrast, for the two other dependant variables, Q(70,daily) and Q(50,daily), besides the size of the drainage basin, the specific capacity yields a surprisingly high coefficient of determination. As described in section 4.1.6.1 the specific capacities of all catchment areas are placed into only three classes, each representing a range of values. As a result, the specific capacity of any catchment area is portrayed in a very superficial way, and the fact of a correlation with Q(50,daily) and Q(70,daily) but not with Q(90,daily) might be of little significance.

**Summing up the coefficients of determination** of the different rainfall regimes and considering separately the flows Q(90,daily), Q(70,daily) and Q(50,daily), illustrates the general strength of correlation between the respective catchment characteristics and the runoff indices. The catchment area is the parameter obviously closely linked to runoff. The size of the area under consideration determines the total amount of precipitation and therefore the quantity of water available for runoff. The three "coefficient-sums" in the rightmost column are the sums of added $r^2$-coefficients from the single regressions which are presented in the cells to the left. The "coefficient-sums" in the righmost column decrease from 4.0 for Q(50,daily) to 2.6 for Q(90,daily) thereby supporting the assumption of increasing importance of base flow, the latter probably originating from an underground catchment area which might differ from the surface catchment area. Consequently the correlation between runoff index and catchment area is expected to be closest in the case of Q(50,daily). This speculation is confirmed by the coefficients of determination ("sum") in the precipitation column, which are decreasing in the same direction, meaning that Q(50,daily) is the most closely related to surface runoff and thus to the amount of rainfall. Whereas, Q(90,daily) as a runoff characteristic that is dominated by baseflow is only weakly correlated to rainfall. It must be admitted that the influence of precipitation in the individual regressions is very inhomogeneous, in some it is relatively high and in others zero. The facts that the rainfall gauging stations are probably not representative of the whole of the particular catchment area and that part of the data are the result of interpolations might have contributed to the inaccuracy of the raw data. As far as AET is concerned, though the "sum of coefficients" is smaller, AET contributes to a certain extent to the explanation of the runoff behaviour in most of the rainfall regimes. Although the AET values used for the analysis are estimated by means of the water balance equation, which implies some rough simplifications, they are obviously sufficiently accurate to deliver relatively useful results. The overview shows that the multiple regressions for Q(50,daily) are superior to those for Q(70,daily) and Q(90,daily). This is probably because the parameters chosen for the multiple regressions are more appropriate for explaining surface runoff phenomena than the origins of base flow. The independent variables characterising the soil and geological situation are difficult to determine (see also sections 4.1.4.3 and 4.1.6.1).

#### *4.1.6.3 Test for significance of the whole regression equation*

r and $r^2$ values only give a guide to the "goodness-of-fit" and do <u>not</u> indicate whether an association between the variables is statistically significant. The statistical significance can be determined by statistical tests, which aim at the verification of assumptions, meaning the assessment of evidence in favour of some claim about the population from which the sample has been drawn. The methods of inference used to support or reject claims based on sample data are known as tests of significance. Statistics calculated from samples, in particular coefficients like r and $r^2$, are only estimates of parameters from the population the sample was drawn from, and there is always some probability that the sample statistic is different from the associated population parameter. Therefore statistical tests should be carried out to examine whether or not an observed value is in some sense compatible with a hypothesised value for a population parameter.[136] Correlation coefficients in particular are featured by more complex sampling distributions, therefore carrying out tests is more difficult. The only situation in which it is fairly straightforward to carry out a test is the one in which the null hypothesis that the correlation is 0 is tested against the alternative hypothesis that it is some other value.

The **F-test** with its test statistic $F_0$ indicates whether the multiple correlation coefficient significantly differs from zero or not.[137] The F-test for multiple regression is a test of whether or not the independent variables, taken together, explain any of the variance in the dependent variable. The null hypothesis, that they do not, is accepted when it appears that whatever variance in the sample dependent variable appears to be explained by the variance in the sample independent variable being attributable entirely to chance. The alternative hypothesis is accepted when the explained variance is too large to be attributed entirely to chance in the way the sample was drawn. Testing the null hypothesis means that all the coefficients were equal to each other with the value of zero, against the alternative hypothesis that at least one of them was not equal to zero. To conduct this statistical test, first the hypothesis is set up and the significance level is fixed. To test the hypothesis the test statistic $F_0$ is calculated from the available sample of data:

[136] Dyck, 1976, p.151
[137] Maniak, 1993, p.222 and Bortz, 1985, p.374

$$F_0 = \frac{r^2}{(1-r^2)} \cdot \frac{(N-(k-u)-1)}{(k-u)} = \frac{v_2}{v_1} \cdot \frac{r^2}{(1-r^2)}$$ **Formula 4-9**

where

$r^2$ = coefficient of determination
$k$ = total number of variables
$u$ = number of independent variables
$N$ = number of observations/cases
$v_1$ = k - u (degrees of freedom)
$v_2$ = N - $v_1$ - 1 (degrees of freedom)

This test statistic has an F distribution with $v_1$ and $v_2$ degrees of freedom. In the present case, $v_1$ = k - u is always equal to one, because the total number k of variables exceeds the number u of independent variables exactly by one, the dependant variable Q(x,daily)). Under the condition $v_1$=1 the F distribution shades off into the distribution of t², i.e. the square of the Student's t distribution.[138] The $F_0$ values calculated by means of Formula 4-9 reveal if the test statistic exceeds or falls below the critical value(s) for the hypothesis test. This critical value(s) is a threshold to which the value of the test statistic in a sample is compared to determine whether or not the null hypothesis is rejected. It depends on the significance level $\alpha$ at which the test is carried out, and the size of the sample or number of observations used for the calculation.[139] The significance level $\alpha$ of a statistical hypothesis test is a fixed probability of wrongly rejecting the null hypothesis, if it is in fact true.[140] Usually, the significance level is chosen to be 0.05 (= 5 %).[141] This indicates that in 1 - 0.05 = 95 % of the time, the variables selected will provide a good fit in the explanatory models for the runoff indices Q(x,daily). 95 % is the so-called "confidence level". This explanation shows that a statistical test does not give 100 % probability on the assumption, a certain error probability always remains.[142] If $F_0$ exceeds the respective value given in Annex 6, then the coefficient of determination is significantly different from zero at a confidence level of (1 - $\alpha$). The null hypothesis has to be rejected. If the calculated $F_0$ falls below the tabulated value, the null hypothesis has to be accepted, meaning that r² is not significantly different from zero and thus no statistical significance can be proved for a correlation between the dependent and independent parameters. The results of the F-test are listed in Table 4.6.

| rainfall regime | runoff index Q(x,daily) | r² for multiple regression | degrees of freedom v1 | degrees of freedom v2 | calculated value for $F_0$ with $\alpha$ = 0.05 | critical value taken from Annex 6 | r² significantly different from 0 |
|---|---|---|---|---|---|---|---|
| 1A | Q(90,daily) | **0.549** | 1 | 19 | 23.10 | 4.38 | + |
| | Q(70,daily) | 0.698 | 1 | 19 | 43.99 | 4.38 | + |
| | Q(50,daily) | 0.752 | 1 | 19 | 57.62 | 4.38 | + |
| 1B | Q(90,daily) | **0.531** | 1 | 7 | 7.91 | 5.59 | + |
| | Q(70,daily) | 0.977 | 1 | 7 | 293.23 | 5.59 | + |
| | Q(50,daily) | 0.987 | 1 | 7 | 527.35 | 5.59 | + |
| 1D | Q(90,daily) | **0.592** | 1 | 14 | 20.29 | 4.60 | + |
| | Q(70,daily) | 0.761 | 1 | 14 | 44.63 | 4.55 | + |
| | Q(50,daily) | 0.882 | 1 | 14 | 104.85 | 4.55 | + |
| 1E | Q(90,daily) | **0.416** | 1 | 14 | 9.97 | 4.60 | + |
| | Q(70,daily) | 0.567 | 1 | 14 | 18.32 | 4.60 | + |
| | Q(50,daily) | 0.538 | 1 | 14 | 16.30 | 4.60 | + |
| 2D | Q(90,daily) | **0.530** | 1 | 6 | 6.76 | 5.99 | + |
| | Q(70,daily) | 0.781 | 1 | 6 | 21.35 | 5.99 | + |
| | Q(50,daily) | 0.866 | 1 | 6 | 38.75 | 5.99 | + |

*Table 4.6: Results of the F-test at a levels of significance of 5 %*

[138] Sachs, 2002, p.127
[139] Dyck, 1976, p.152
[140] Sachs, 2002, p.90ff
[141] Dyck, 1976, p.153
[142] Lange, Bender, 2001

Since all calculated values for $F_0$ exceed the threshold to which the test statistic of the sample is compared to, the multiple coefficients of determination $r^2$ can be accounted significantly different from zero. The null hypothesis is abandoned and the equation can be applied on a 95 % significance level.

Applying the F-test to the multiple regressions established for the **estimation of the actual evapotranspiration (AET)** shows that the coefficient of determination $r^2$ of the regression equation is not significantly different from zero, at a significance level of 95 %. Consequently this equation has to be applied with care and if possible other estimation methods for AET should be used.[143]

#### *4.1.6.4 Summary evaluation of the method that has been developed*

In section 4.1.6.1 the reliability of the input data is illustrated in detail and the following weak points are revealed:
The size of the catchment area can be considered as one of the most reliable parameters, because it is easy and accurate to determine. The decisive constraint is the ignorance on the congruence of surface and underground catchment areas, which can be of great significance especially for Q(90,daily), since such streamflow is mainly fed by groundwater. Mean annual precipitation (P) is also relatively accurate to determine. An extensive list of gauging stations is available and further values are interpolated. The determination procedure for the hydraulic conductivity (HC) implies several simplifications and thus is more error-prone. For the specific capacity (SC), based on extremely rough original data, a very high risk of inaccuracy has to be accepted. Although information on geology is expected to be of significant importance for the base-flow dominated Q(90,daily), the geological characteristics of the catchment areas cannot be acquired to the desired extent because the lack of available input data for the areas concerned. The input parameter actual evapotranspiration (AET) in general has to be estimated with the help of "auxiliary methods", meaning, with a further multiple regression equation. When rainfall regime 2D is concerned and the potential evapotranspiration is not known, yet one more estimation step, more precisely a third one, is required. In this way the inaccuracies of the individual estimation methods accumulate, resulting in a considerable deterioration of the final result.

As shown in Table 4.5, the parameters explain at least part (40 - 60 %) of the variance of the low flow behaviour. Nevertheless, as a general conclusion it has to be stated that the method developed here, with the equations derived from the regression analyses, allows a rough estimation of Q(90,daily). The results should be treated with care and should preferably be rechecked and supplemented with the help of another methods, e.g. by random sampling of low flow measurements in the dry season.[144]

## 4.2 Consumption patterns and load forecast

### 4.2.1 Definition of terms applied

The **power demand** [kW] represents the instantaneous power required simultaneously by the various electrical devices connected to the system. The size of turbine and generator selected is determined primarily by this power demand. The **energy demand** [kWh], which is in the present context equivalent to **consumption**, additionally involves the length of time that the device is connected to the system.[145] The estimation of future consumption is a pivotal aspect firstly with regard to the design and size of the system and secondly in view of

[143] Günther, 2001, p.46
[144] further methods see: Inversin, 1986, p.37ff
[145] Fritz, 1984, p.7.27

electricity sales and consequently the income and economic viability of the system. The present chapter first describes the possibilities of forecasting an average total consumption, depending on population growth, specific consumption in different sectors and other factors. This average figure can refer to a daily or yearly basis. Figure 4.7 illustrates that this value is the basis for estimating the required system capacity in kW by taking into account the different loss rates respectively efficiencies (see Formula 4-2) and the so-called peak factor or the load factor. The consumption figures in kWh allow a forecast of the electricity sales.

Several terms applied in the present study require a preliminary definition, because their denotation is not consistent in the literature. The **penetration rate** indicates the percentage of the population (reference value "total population"), commercial establishments and other consumers which are connected to the system. In general only part of the population can afford a connection. The whole system is then designed with regard to supplying this proportion of the population at a planning horizon in year x, when the total of the installed loads on the consumer side is expected to finally reach the plant capacity. For the system design, not only the number and size of all installed loads need to be known but also the consumer behaviour in applying these loads, meaning at what time of day and in what combination the applications are used. The **peak factor** represents this "degree of simultaneous use":

$$peak\ \ factor = \frac{maximum\ of\ \ loads\ (really)\ switched\ on\ simultaneously\,[kW]}{average\ daily\ consumption\,/\,24\ h\quad [kW]}\quad [-]$$

***Formula 4-10***

Replacing the demand of loads "actually" switched on, in the numerator of the fraction, by the potential total load, meaning the "maximum possible", the result will be the reciprocal of the **load factor**. The load factor is the ratio of energy actually consumed $E_{act}$ [kWh] to the potential demand for energy if power were consumed continually at peak levels $E_{pot}$ [kWh]:

$$load\ \ factor = \frac{E_{act}}{E_{pot}} \cdot 100 = \frac{load \cdot (consumption\ time\,/\,day)}{maximum\ load\ installed \cdot 24\ h} \cdot 100 \quad [\%]$$

***Formula 4-11***

In general the peak factor is estimated with regard to the design of the system and the load factor is the parameter which characterises the plant utilisation. The load factor refers to the time aspect, according to the number of hours per day that the different loads are switched on. If all loads installed in the system were continually switched on 24 hours a day the factor would be 100 %. The reference value is the total kW load installed on the consumer side and not on the generation side since this would be the reference value for the so-called plant factor or plant utilisation.[146] The **plant utilisation** is the ratio of consumed kWh's to producible kWh's. It is affected by the load factor, the growth of population and consumption and the penetration rate. Among these factors, mainly the load factor is controllable, since it is influenced by the behaviour pattern of consumers. Therefore special importance is attached to this aspect. A high load factor entails a better plant utilisation and thus guarantees profitable operation. It should therefore be a design objective.

The following example illustrates the terms in the sense they are used in the present study:

**example:** simplified stationary view, without considering growth rates

- system which can supply 10 kW of loads
- 100 households
- only 50 households have a load of 100 W installed; one of the 50 households uses in addition a 3 kW stove
- the 3 kW stove is switched on only between 8 a.m. and 12 a.m.
- between 6 p.m. to 9 p.m. 50 households apply their 100 W loads
- between 9 p.m. and 12 p.m. only 10 households have their 100 W loads switched on.

[146] Harvey, 1998, p.8ff

**terms as defined above**:
penetration rate = 50 % (50 of 100 households are connected)

**peak factor** $= \dfrac{50 \cdot 100\ \mathrm{W}}{(3000\ \mathrm{W} \cdot 4\ \mathrm{h} + 5000\ \mathrm{W} \cdot 3\ \mathrm{h} + 1000\ \mathrm{W} \cdot 3\ \mathrm{h}) / 24\ \mathrm{h}} = \dfrac{5000\ \mathrm{W}}{30{,}000\ \mathrm{Wh} / 24\ \mathrm{h}} = 4$

**load factor**

$$= \frac{(3{,}000\ \mathrm{W} \cdot 4\ \mathrm{h}) + (5{,}000\ \mathrm{W} \cdot 3\ \mathrm{h}) + (1{,}000\ \mathrm{W} \cdot 3\ \mathrm{h})}{(5{,}000\mathrm{W} + 3{,}000\ \mathrm{W}) \cdot 24\ \mathrm{h}} \cdot 100 = \frac{30{,}000\ \mathrm{Wh}}{8{,}000 \cdot 24\ \mathrm{Wh}} \cdot 100 = 15.6\,\%$$

**plant factor**

$$= \frac{(3{,}000\ \mathrm{W} \cdot 4\ \mathrm{h}) + (5{,}000\ \mathrm{W} \cdot 3\ \mathrm{h}) + (1{,}000\ \mathrm{W} \cdot 3\ \mathrm{h})}{10{,}000\mathrm{W} \cdot 24\ \mathrm{h}} \cdot 100 = \frac{30{,}000\ \mathrm{Wh}}{240{,}000\ \mathrm{Wh}} \cdot 100 = 12.5\,\%$$

If the stove were also to be used in the evening hours between 6 p.m. and 9 p.m., at this time all installed load would be switched on simultaneously and the peak factor would be equal to the reciprocal of the load factor, i.e. 1/0.156 = 6.4 and thus an even higher generation capacity would be required ("worst case").

Applying the reciprocal of the load factor as peak factor corresponds to the **worst case scenario**, in which the generation unit has to supply as much energy as is required if all appliances are switched on simultaneously. As long as no detailed information on daily load patterns is available the following assumption is taken:

$$\boxed{peak\ \ factor = \frac{1}{load\ \ factor / 100} \quad [-]}$$

***Formula 4-12***

In most developing countries, especially in rural areas, the load factor tends to be very low; there is a large demand for power several hours each night, primarily for lighting, and little demand the rest of the day. In addition not all households are connected to the system from the beginning, bringing down the plant factor.[147] This demand profile requires a larger and costlier hydropower installation than is really necessary, and with a low load factor, the energy cost is high and so it usually has to be subsidised.[148] To optimise the economic viability of a system a relatively high load factor, at least close to 40 - 50 %, is aimed at.

With regard to the design layout of the system it is possible to estimate either:

1. which individual appliances summing up to a total load [kW] will be installed in the demand centre <u>and</u> which "diversity factor"[149] has to be applied **or**
2. the amount of energy [kWh] which will be consumed at the end of the planning horizon in year x on the daily or yearly average <u>and</u> which peak factor is to be expected; these two figures yielding the required peak power demand in kW.

In the present study the second way of calculation is chosen, because most figures are available as energy consumption figures [kWh]. In general in rural areas in Ethiopia, the daily peaks are more significant than seasonal peaks, so the daily peak factor is used.

[147] Harvey, 1998, p.8; plant factor = (power used x time power used) / ( power installed x period considered)
[148] Inversin, 1986, p.218
[149] Harvey, 1998, p.250; diversity factor = maximum demand [kW] / sum of all possible loads [kW]; the fact that not all connected loads draw power at the same time is accounted for by applying diversity factors to the loads (Jackson, Lawrence, 1982, p.110f)

### 4.2.2 Available data

A forecast of electrical demand for all existing and potential service areas is required for the layout and design of the power generation unit, the distribution networks, load flow studies, and finally economic and financial evaluations. Especially for small isolated grids, where only one generation unit, even without a storage device, is available, the demand and load forecast have to be carefully surveyed because production and consumption of energy have to be well matched. In isolated grids neither can any surplus be sold nor can missing capacity be added by an outside supply. Therefore an accurate assessment of the required capacity, according to the peak demands, and the daily and the seasonal load patterns, is an important precondition for the economic success of the whole electrification project.

The available data on electricity use in Ethiopia is inadequate, especially for small electrified population centres. The market penetration rate and consumption rates have historically been severely constrained mainly due to the low reliability of diesel generators, so that consumption data obtained for those systems might not be representative of systems where energy is available in a much more reliable way. Several studies on load forecasts and energy supply options in Ethiopia have been undertaken in recent years but some of them only adapted earlier forecasts. The most relevant ones, reviewed as part of the current evaluation, are:

- Ethiopia National Rural Electrification Project, Final Report, Acres International Ltd., 1994
- Power Sector Development Plan, Acres International Limited, 1995
- Ethiopia-Sudan Interconnection Study, IVO, 1995
- Load Forecast, EELPA, May 1996
- Forecast of EELPA Electric Energy and Peak Demand 1998-2016, World Bank/Applied Energy Group, January 1998
- Load Forecast of EEPCO System for Chemoga Feasibility Study, May 1998
- Ethiopian Power System Expansion Master Plan (EPSEMP), Acres International Ltd., 2000 - in the following called the "EEPCO-Acres study"[150]

In general, all forecasts are based on econometric models to establish a relationship between electricity demand, Gross Domestic Product and price. These basic models are then adapted to incorporate varying amounts of other information such as population growth, connection schedules by tariff category and regional developments. In the final report of the Ethiopia National Rural Electrification Project[151] it was already stated that the power sector demand forecasts have been prepared for the EELPA systems every 2 years since 1978. But rarely has a simple update been sufficient to incorporate the changing economic conditions and national development plans within the analysis. Most of the forecasts have exceeded actual sales figures within 2 or 3 years of their publication, because of revised development plans, lower-than-anticipated economic performance, project implementation delays or other unforeseen problems. The EEPCO-Acres study also reported that most of the models established in the past had been plagued by the impacts of external factors.[152] Structural changes in the economy through exchange controls and poor performance in the private sector, fiscal constraints brought on by civil war, and fluctuating weather conditions have all contributed to the divergence of forecasts from actual demand. These arguments show that the results of the studies listed above should be applied very cautiously. But if no better information is available, data from those studies based on electrified towns can be referred to. The more viable but also time consuming solution however is to take into account the specific characteristics of the town under study.

In the following section the **EEPCO-Acres study** will be the main focus for appraisal. This study has been chosen firstly because of its being the most recent and reliable study available in this field, secondly because its empirical approach towards forecasting rates of

[150] EEPCO / ACRES, EPSEMP, = "EEPCO-Acres study", 2000
[151] EELPA / ACRES, ENREP, 1994, p.6-5
[152] EEPCO / ACRES, EPSEMP, 2000, p.4-4

growth of energy consumption is the most appropriate and precise, and thirdly because it provides some justification of newly generated data, and also takes into account the experience from former studies. In addition to this EEPCO-Acres study, the load pattern of **five sample towns** was surveyed (November 2000). Although some specific restrictions have to be taken into account when evaluating the results of this survey, it gives a rough idea of possible consumption patterns, which are expected to be at least partly representative for other small towns with similar characteristics.

### 4.2.3 Available methods for forecasting consumption

For centres currently without an electricity supply, the forecast can be developed from:
1. estimates of actual population
2. expected population growth
3. household size and level of "interconnection"
4. percentage of people connected and
5. consumption per connection

The fourth point is the most complex and difficult one to determine and has therefore to be analysed in detail. Some of the methods generally available for demand forecast are described in the following paragraphs.[153]

***Time series methods***
They use historical consumption data to forecast the future development, by applying numerical analysis tools to identify trends, seasonal changes and other patterns. Thus patterns explaining previous behaviour are transferred into the future. New driving factors, such as changes in economic activity, cannot be incorporated. Time series methods are appropriate and deliver quite accurate results for short-term forecasts. However for newly electrified centres, where historical data are not available, and for long-term forecasts they are not the appropriate tool.

***Econometric methods***
Those methods try to estimate relationships between multiple variables. The basic assumption is that the behaviour of a dependant or "explained" variable, such as electricity consumption, can be described as a function of several independent or "explanatory" variables, including population, gross domestic product and electricity price:

*Consumption = function (population, gross domestic product, electricity price...)*

If sufficient data sets for all variables are available, the hypothesised econometric model can be verified. The aim is to find those data series and the form of equation which best explain the historical data and thus allow an optimised forecast. Here the same problem of availability of data sets arises. In towns which are not yet electrified, historical data sets for the explanatory data might exist but there is no information on the dependant variable, i.e. energy consumption, so that it will be impossible to find the relationship that provides a forecast.

***End use methods***
These methods start with the user, attempting to understand his behaviour concerning the usage of electrical devices. Although a very large amount of data, for individual users or at least representative user groups, is required, this method provides a deeper insight and a more comprehensive view, allowing a reasonable projection of the future demand.

[153] EEPCO / ACRES, EPSEMP, 2000, p.4-1ff

***Input / Output Models***
A very simple variant of this model is to estimate a linear relationship between electricity demand and production output, for example, of a factory. Then the expected output can easily be multiplied by the electricity consumption needed to produce a unit of output in order to determine the electricity demand of the specific factory.

### 4.2.4 Applied methodology

For the specific case of newly electrified areas, historic records of electricity consumption do not exist, so that any kind of forecast has to be based on what is known about consumption patterns in comparable areas, already electrified, and/or other information available on the area to be electrified. In general, population, population growth rate and household size are features which are known or can be estimated for the area under study. In contrast, the following parameters must be transferred from comparable electrified areas:

- **market penetration**: initial level, development and final level
- average **base consumption**: residential / commercial / industrial / street lighting
- average **growth rates**: residential / commercial / industrial / street lighting
- **peak factor**[154]: daily /seasonal

Given the fact that, for the load forecast model developed in the present study:
1. the parameters transferred from other areas are the result of econometric methods
2. specific characteristics of the area under study, for example daily load patterns, prevailing electrical devices etc. are also taken into account (see section 4.2.6)
3. the forecast for specific industries has to be done on the basis of an input/output approach

the method proposed here for newly electrified areas can be seen as a combination of the different methods described in section 4.2.3.

Some crucial aspects and figures are adopted from the EEPCO-Acres study. These were based on various surveys of towns electrified in the recent past. 16 towns were reviewed for the analysis of market penetration, 16 with regard to the base level of consumption and in 8 towns, which have been electrified for 10-15 years, growth rates of consumption were analysed.[155] Based on different surveys and examinations, national statistics and other studies the EEPCO-Acres report proposes the parameters listed in Table 4.7 for forecasting loads for rural electrification projects.

[154] strictly speaking, the peak factor is not required for average demand forecast [kWh] but to determine the required capacity [kW]
[155] EEPCO / ACRES, EPSEMP, 2000, p.8 (annex D)

| | parameter | proposed value | remarks | source |
|---|---|---|---|---|
| | population growth rate | **~4.9 %** | for urban centres outside Addis | Statistical, according to population census 1994 |
| | occupants per household | **~4.7** | | Statistical, according to population census 1994 |
| | development of "official" market penetration | Linear Increase from **10 %** in the 1st year to **40 %** in the 10th year | | empirical |
| **residential** | average base consumption | **303,7 kWh/oc*/year** | per official residential connection | empirical |
| | average growth of consumption | **~2.57 % /year** | | empirical |
| **commercial** | average base consumption | **175.8 kWh/oc*/year** | per official residential connection | empirical |
| | average growth of consumption | **~2.98 % /year** | | empirical |
| **small industrial** | average base consumption | **216.4 kWh/oc*/year** | per official residential connection | empirical |
| | average growth of consumption | **~1.65 % /year** | | empirical |
| **street lighting** | average base consumption | **6.4 kWh/oc*/year** | per official residential connection | empirical |
| | average growth of consumption | **0 % /year** | | empirical |

*) oc = official connection

*Table 4.7: Parameters for load forecast*[156]

Using the variables and parameters described above the total yearly consumption of a rural town in year x after the reference year can be estimated according to Formula 4-13.

$$aC(x) = \left[\left(\frac{pop}{shh}\right)\cdot gr_{(Pop)}^{X}\cdot pr(x)\cdot\frac{hh}{oc}\right]\cdot\left[resC\cdot gr_{(\mathrm{Res})}^{X} + comC\cdot gr_{(Com)}^{X} + indC\cdot gr_{(Ind)}^{X} + strC\cdot gr_{(Str)}^{X}\right]$$

*Formula 4-13*

where

*aC* = total average consumption [kWh]
*resC* = residential base consumption [kWh]
*comC* = commercial base consumption [kWh]
*indC* = (small) industrial base consumption [kWh]
*strC* = street lighting base consumption [kWh]
*pop* = population
*x* = number of years after reference year
*pr* = "official" penetration rate [-]; ≤1
*oc* = "official" connection
*shh* = size of household
$gr_{(...)}$ = growth rates (of population, residential consumption etc.) [-]; ≥ 1
*hh/oc* = number of hhs per official connection

This equation can be summarised as follows:

$$aC(x) = \lfloor number\ of\ oc\rfloor\cdot\lfloor total\ system\ consumption\ per\ oc\rfloor$$

***Formula 4-14***

[156] EEPCO / ACRES, EPSEMP, 2000, p.6-7ff and p.8 (annex D)

Formula 4-14 explicitly and even more apparently than Formula 4-13 illustrates that all consumption figures, residential as well as commercial, industrial etc. are referred to the population size, more precisely the number of "official connections", of the load centre.
The stepwise determination of the total average consumption in year x is illustrated in Figure 4.7. The figures are default values, which are selected to be appropriate for load forecasts in rural Ethiopia, according to the information available in year 2000.[157]

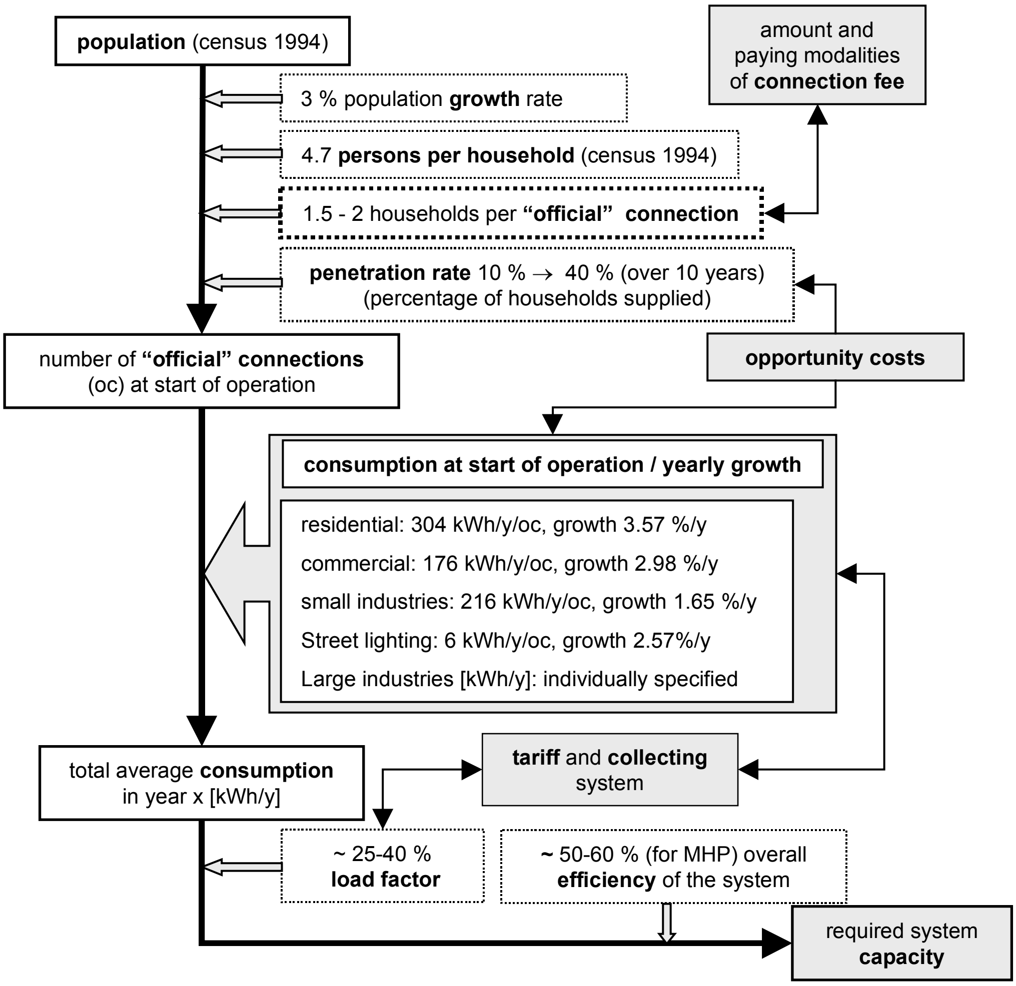


*Figure 4.7: Calculation of total average yearly electricity consumption and required system capacity*

The flowchart shows that load forecasting includes different aspects, like population growth, including migration, and the way in which users become accustomed to the availability of electricity and new opportunities for growth of economic activities, which are reflected in "market penetration" and consumption growth rates. In addition, interrelationships to other aspects like connection fees, tariff system and opportunity costs are indicated. The approach and the numerical data proposed in the EEPCO-Acres study of 2000 are based on the original analysis undertaken in the 1994 Rural Electrification Study[158] and were adopted by EEPCO in their current updates of their Corporate Planning and Power System Planning:[159]

- **population (pop)**: The yearly growth rate of the total population between 1994 and 2000 varied between 2.19 % and 3.15 %, the average during these years being about 2.9 % per year.[160] The last National Population and Housing Census of Ethiopia was taken in

[157] EEPCO / ACRES, EPSEMP, 2000, p.6-6ff
[158] EEPCO / ACRES ENREP, 1994
[159] EEPCO / ACRES EPSEMP, 2000
[160] Central Statistical Authority CSA, 2000, p.22 and 70-75

October 1994. The estimates up to 2000 are based on projections from the 1994 census. The latter provides a consistent database of population for all communities in the country. The growth rate of 4.9 % was estimated for urban centres outside of Addis Ababa, although a number of census references suggest a 3.95 % urban growth rate for the period 1994 - 1999. A rate of 4.9 % can be adopted as a first estimation in case of a really prospering centre. Otherwise an average growth rate of **3 %** seems to be most appropriate. As soon as more specific and detailed information is available the figure should be modified accordingly.

- **average size of households (shh)**: In the 1996 survey of household income for urban centres, the average household size was found to be **4.7** persons . By means of this figure the number of potential connections can be found from the population by dividing it by the number of persons per household.

- **“official” market penetration (pr)**: Areas receiving electrical power experience a large load growth during the first few years of operation. Then the growth slows down and becomes a function of the region’s population and economic growth. In general typical growth rates within the planning horizon vary from around ten per cent per year for the first five years to six per cent thereafter.[161] Studies specifically referring to Ethiopian conditions however indicate lower values of about 3 % linear growth during the first 10 years. The accelerated growth in the first years is called (“official”) market penetration, which refers to the number of households being connected directly to the EEPCO-system and possessing their own electricity meter. In fact the **real market penetration**, representing the number of households with access to electricity, in many cases tends to be as much as twice the official market penetration. Households whose incomes are insufficient to afford their own connection save costs by connecting to their neighbours' official connection.[162] This phenomenon was already mentioned in the EEPCO report 1994[163]: "The penetration rate does not include an allowance for the observed practice of connecting several houses to a single meter". Data attributed to the census and intercensus estimates for 1999 population and the number of people with access to electricity for 16 towns were reviewed and compared to the number of EEPCO connections for those towns in 1999. While the census data suggests that over 75 % of the population in the towns have electricity, the EEPCO figures would indicate that only approximately 39 % are connected to the system, based on the number of connections multiplied by the census average of 4.7 persons per household or connection. This means that a household according to the “census housing unit” cannot be considered to be equivalent to one customer connection. Rather, it is necessary to introduce the parameter "number of households per official connection" (see next paragraph). Based on the EEPCO analysis, the upper bound of the penetration rate has been estimated at 40 %, and taking into account that not all households will be connected within the first year of electrification, an initial connection rate of **10 %** was adopted, with an increase **over 10 years to 40 %**, corresponding to a linear increase of 3 % per year.

- **number of households per official connection (hh/oc)**: According to the explanation given above, the number of households connected to one official connection can be estimated to be **about 1.5 to 2**. When a new system is planned it is necessary to assess if the practice of “interconnection” will be followed or not. The forecast has then to be made accordingly.

- **consumption (resC, comC, indC, strC)**: The analysis of towns reviewed in the EEPCO-Acres study represents the basis for the determination of residential consumption and its growth rate. Furthermore consumption patterns in population centres with electrical supply were reviewed to determine the relationship between residential and non-residential

[161] Jackson, Lawrence, 1982, p.112
[162] EEPCO / ACRES EPSEMP, 2000, p.6-7 and appendix D-8
[163] EELPA / ACRES, 1994, p.6-19ff

(commercial, small industrial, street lighting) use. The forecast for commercial, small industrial and street lighting consumption, is based on the number of official residential connections and not on the number of connections of such kind, because there are no explicit forecasts available for the number of customers in each of these categories. This means that both residential and non-residential consumption are based on the number of households connected to the system. According to the EEPCO staff responsible for the study, this practice is based on the assumption that this non-domestic consumption depends mainly on the demographics of the town. This means that a more populous town is expected to host more commercial and industrial activities and, what is even more obvious, to have a wider network of street lighting.

The steps in Figure 4.7 are required to forecast the development of the total consumption of the respective load centre over the project time. This forecast gives an idea of the yearly **energy sales**, referred to in the financial analysis of the system. Finally, the electricity consumption at the planning horizon can be converted to the maximum **generation requirement** by taking into account the peak or load factor and the overall system efficiency, thus providing a pivotal basis for the technical design of the plant. Theoretically, in Formula 4-11 the load factor and the numerator of the fraction are known and the denominator, which is maximum load installed x 24 h, is calculated. Applying this approach for demand forecast results in a rapidly increasing "required system output-curve", especially during the first 10 years (see Figure 6.1). A plant which can cover the demand at the planning horizon is completely over-sized during the first years of operation (see also section 6.1.1).

### 4.2.5 Evaluation of the method for forecasting demand

As mentioned above, the energy demand in isolated grids should be forecast as precisely as possible in order to avoid excess capacities, leading to increasing costs. The EEPCO-Acres forecasting method, which uses a rule-of-thumb approach for forecasting energy demand and is the same for each town of Ethiopia, is suitable for the approximate forecasts needed for the selection of potential projects. When it comes to the detailed layout of a system, a more thorough approach must be chosen, and crucial specific characteristics of the location under consideration should be taken into account. If the number of households per official connection is taken into account, the specific consumption data in Table 4.7 correspond to data from other countries.[164] Yet, the EEPCO-Acres study shows several shortcomings, which are listed here in order to clarify the limits of application:

- The method is only applicable for **EEPCO tariffs**:
  The forecasting is based on the actual EEPCO tariff of about 0.5 ETB per kWh[165] and not on the tariff needed for full cost recovery. For cost recovery in MHP systems a charge of between 1.2 and 2 ETB per kWh would be needed in isolated grids.[166]
- **Household income** is not taken into account:
  Even though considered as an important factor, household income is not included in the calculation.[167] Calculating with an average residential base consumption supposes the same value for all customers.
- The cost of **alternative energy** resources, the opportunity cost[168], is not considered:
  The willingness to pay for electricity for particular applications like cooking also depends on the equivalent costs of alternative sources of energy such as wood and kerosene available for that purpose. Energy prices in Ethiopia are highly dependent on location and may be determined using the CSA-report on “Average Retail Prices of Goods and Services”.[169] The competition between different energy sources for specific appliances

[164] Baur, 2000, p.87
[165] EEPCO / ACRES, 2000, p.1-3
[166] Feibel, Collin, Scholand, 2001, p.106
[167] EELPA / ACRES 1994, p.6-19
[168] missing profit or benefit by renunciation of an alternative investment or in general: prevailing cost of raising investment capital in a particular economy (interest rate for capital investment in any sector of this economy)
[169] Central Statistical Authority CSA, 1999

must be taken into account (see section 4.9.4.5). As far as lighting is concerned, the efficiency of any energy source other than electricity is so low[170] that electricity is economically attractive.

- **Daily load patterns** are not considered:
  Daily load patterns are considered only via rules-of-thumb, even though they strongly influence the required generation capacity and profitability. They are reflected in the overall system load factor, which allows the estimation of the peak demand requirement from the energy forecasts.[171] In the EEPCO-Acres study the associated peak demand is determined using an average system load factor of 58.1 % for the ICS and an estimate of 40 % for SCS branches, corresponding to peak factors of 1.7 and 2.5 respectively. For newly electrified rural areas in Ethiopia, however, general daily peak factors of 2.5 to 5 should be assumed (see also section 4.2.7). The peaks are not the same all over Ethiopia, as shown by the EEPCO-Acres study of 1994[172], so a general factor can only be used as rough estimation.
- **Seasonal load patterns** are not considered:
  Seasonal load patterns in general might be less important in Ethiopia, especially relating to residential consumption. In some areas, however, with electrical agro-processing linked to harvesting times, the impact of seasons should not be neglected.
- The towns' **commercial and industrial characteristics** are not considered:
  Estimates of commercial and industrial growth are based only on residential connections. That might be reasonable as long as the non-residential consumption is used mainly for the supply of commercial and industrial services for the inhabitants of the town itself. As soon as additional "external" customers are served or manufactured goods are sold to neighbouring towns, an important additional demand might arise.

To overcome at least some of these deficiencies, an additional field survey has been implemented in some small towns. The approach and the results are illustrated in the following section.

### 4.2.6 Micro approach for analysing demand patterns in selected towns

The “micro approach” belongs to the so-called “end-use methods” mentioned above. It is based on the idea of estimating the kinds and numbers of electrical applications typically used in households, such as lighting, baking, cooking, refrigerator, radio, TV etc., commerce and small industries and the time of utilisation. A simple summation of the load curves of single applications then leads to the total demand curve of a town. The method starts from the assumption that typical consumption patterns or load curves for households, commercial premises, and small businesses like bakeries and joineries and other workshops in electrified towns can be transferred to towns where electrification is planned and where those consumption data are not yet available. An illustration of "typical" load curves of the different sectors is provided by the case study of Sebeta (see Figure 4.8). Because the socio-cultural conditions of such small cities in Ethiopia are relatively similar,[173] the characteristics traced out here can, as a first approximation, be transferred to other towns. Nevertheless the cultural dimension must be considered. To cite two simple examples, the attitude towards opening hours of shops, and the customary times for going to bed might be different. These factors can highly influence the load factor due to their influence on the load curve.

In five sample towns, a survey on daily load patterns has been implemented by means of interviews with a questionnaire. Two of these towns, Sebeta and Tefki, are connected to the national ICS grid and receive as a rule a 24 hour electricity supply. Three towns, Bale,

[170] Ethiopian Electric Agency EEA, 2000, p.17; Note: the efficiency of generating light by the usage of fuel wood for example is only 0.2 %, thus wasting 99.8 % of the primary energy applied for this purpose.
[171] EEPCO / ACRES, 2000, p.3-8
[172] EELPA / ACRES, 1994, p.C-6 to C-11; Note: within the towns studied some show clear evening peaks while others show clear morning peaks.
[173] personal communication: Eyob Deferra (Tropics Consulting Engineers), 11/2000

Dikses and Robe have a supply provided by their municipalities during evening hours. This restriction on consumption reduces the value of these load patterns as models to be used in other places. Since lighting is the declared goal of electrification in these towns, electricity is mainly used for that purpose. Moreover, tariffs fixed by the municipalities are too low to be cost recovering, so that the towns can only afford to operate the system for a few hours per day. Additional electricity generation during the day time might increase the financial deficit. Therefore a 24-hours supply is not in the interest of the operating entities.

The most interesting case being analysed more in detail is the town of Sebeta, about 20 km Southwest of Addis Ababa. It reflects quite typically the consumption patterns of an electrified town.

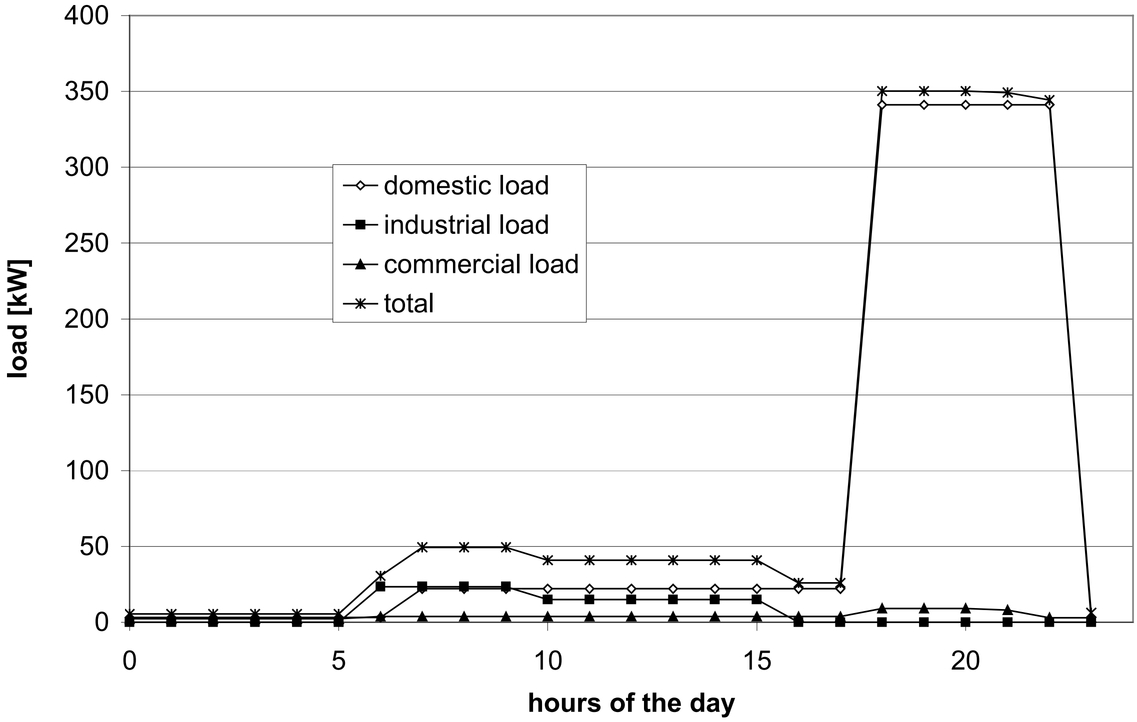


*Figure 4.8: Daily load curve of a small rural Ethiopian town (Sebeta)*

The load curve in Figure 4.8 is subdivided into domestic, commercial and small industrial consumption. The graph shows very clearly the evening peak caused by lighting and other domestic usage. The general predominance of domestic usage, with pronounced evening peaks starting with darkness at 6 p.m., is confirmed to be typical for most of the smaller towns in Ethiopia[174]. Commercial and industrial usage however are clearly different for each town, though the existence of industry is quite rare in the smaller towns in Ethiopia. If the big milk factory in Sebeta were taken into account, the consumption pattern would have been completely different. Therefore the milk industry is excluded from the survey to get a "typical" and more representative picture, transferable to other similar towns. In Table 4.8 the consumption figures obtained from the field survey in Sebeta are contrasted with the "theoretical" results from a forecast scenario according to the EEPCO-Acres approach and a so-called "modified" approach which takes into account the interconnection. The table is based on a population of about 20,000 inhabitants, a household size of 4.7 pers/hh and thus 4,255 households for the town of Sebeta in year 2000.

[174] according to statements in several interviews; personal communication: Wakjira Umetta, Eyob Defera (Tropics Consulting Engineers), 11/2001

| | **theoretically expected results according to EEPCO-Acres approach** | **results of field survey in Sebeta** | | **theoretical results according to "modified" EEPCO-Acres approach** |
|---|---|---|---|---|
| assumptions for the different calculations | penetration rate: 40 % and: 1 oc supplies 1 hh → "real" penetration rate of 40 % | figures directly from field survey | penetration rate: 80 % and: 1 oc supplies 2 hh's → 3,404 hh are supplied | consumption figures referred to oc's assuming: 1 oc supplies 2 hh's |
| | *[Wh/**oc**/d]* | | *[Wh/**hh**/d]* | *[Wh/**oc**/d]* |
| residential consumption | **833** | **579[175] [Wh/hh/d]** | **579** | **1,158** |
| commercial consumption | **482** | **101,000 [Wh/d]** | **30** | **60** |
| industrial consumption | **592** | **184,000 [Wh/d]** | **54** | **108** |
| street lighting | **18** | **-** | **-** | **-** |
| **TOTAL** | **1925** | | **663** | **1326** |

*Table 4.8: Consumption figures for Sebeta received by field survey and theoretical calculations (hh = household, oc = official connection)*

The survey conducted in Sebeta leads to an estimated average daily **residential** consumption of 579 Wh/hh/d, whereas the EEPCO-Acres study assumes about 833 Wh/oc/d. The common Ethiopian practice to use one "official" connection for more than one household can explain this apparent discrepancy. Calculating with 1.5 or 2 hh/oc would lead to 869 respectively 1,158 Wh/oc/d as residential consumption, thus proving figures relatively close to the field survey results and the figures assumed by the EEPCO-Acres report. General consumption figures for isolated rural areas, given in the pertinent literature, vary between 200 and 600 kWh per year and per customer.[176] Equating one household with one customer the figures correspond to about 540 - 1,640 Wh/hh/d, placing the average consumption figure of 579 Wh/hh/d of Sebeta at the lower end of the consumption range. As far as **commercial and industrial** consumption are concerned, they might probably not be completely recorded during the field survey. The levels registered for non-domestic consumption in Sebeta are quite low. One reason might be that the number of shops, commercial establishments and small industries was underestimated. According to the EEPCO-Acres approach, the commercial consumption should be 8 times higher and the small industrial consumption almost 6 times higher. Figures for **street lighting** were obtained in Bale, where 1,500 households are supplied with 22 street lights, each of 100 Watts. A usage of 6 hours per evening leads to 8.8 Wh/**hh**/d or 17.6 Wh/**oc**/d, assuming 2 households per official connection.[177] This figure confirms the EEPCO estimation of about 18 Wh/oc/d.

Taking into account the factors of uncertainty that have been mentioned, the EEPCO-Acres approach can, with certain reservations, be regarded as expedient.
When it is being applied two aspects merit particular attention:

1) the number of households connected to one official connection
2) the importance of commercial and industrial consumption compared to domestic.

The survey conducted in the 5 towns also gave an idea of the **load factors** representative for small rural towns:

[175] adding up of individual loads (lights, fridge, radio, TV etc.) and load times surveyed
[176] Chabot, 1992, p.179
[177] personal communication: Bale Municipality 11/2000

| town | load factor | peak factor (= 1/load factor) |
|---|---|---|
| Sebeta | 27 % | 3.7 |
| Tefki | 24 % | 4.2 |
| Bale | 21 % | 4.8 |
| Dikses | 25 % | 4.0 |
| Robe | ? | - |

*Table 4.9: Load factors surveyed in different small electrified towns*

The load factor in Bale, Dikses and Robe might be higher if electricity were available 24 hours per day instead of only 5 or 6 hours in the evening as is the case today.
The EEPCO-Acres study[178] mentions an average system load factor of 58.1 % for the ICS. For SCS branches an estimated load factor of 40 % is used. The existing SCS branches of EEPCO with their total installed generation capacity of about 30 MW, consisting of isolated hydro and diesel installations, are big systems where the variety of energy demands in an extended area leads to a much more homogenous load pattern over the day than might be possible in small isolated grids in MHP systems. This is even more pronounced for the ICS.

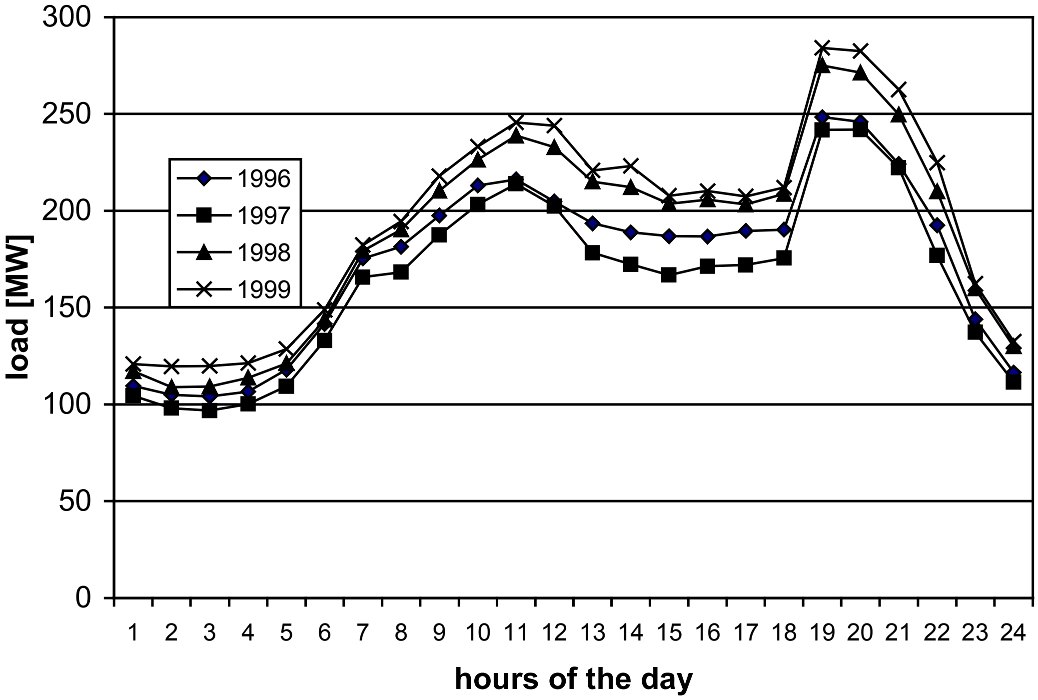


*Figure 4.9: Daily load curves – September Weekdays (MW)*[179]

Figure 4.9 shows the daily load curves for the ICS for September weekdays from 1996 to 1999.The typical load pattern has two distinct peaks, a morning peak between 8 and 11 a.m. and a higher evening peak between 6 and 10 p.m..[180] The same pattern was found for small isolated grids (see Figure 4.8) but in a much more pronounced way.

### 4.2.7 Conclusions for expected consumption and load factors in isolated grids

As far as consumption figures are concerned, the analysis in the previous section indicates that, on one hand, the assumption of a 40 % final penetration rate might lead to an underestimate of the domestic consumption. On the other hand, as the commercial, small industrial and street lighting consumption estimates are also based on the number of households, and

[178] EEPCO / ACRES, 2000, p.6-13
[179] loc. cit. p.3-2
[180] loc. cit. and EELPA / ACRES, 1994, p.3-16

those base consumption figures of 176, 216 and 6 kWh/year/oc (see Table 4.7) are quite high and probably overestimated, the total consumption calculated according to the EEPCO-Acres approach seems to deliver an acceptable estimate.

**These reflections support the use of the EEPCO-Acres approach (see Table 4.7 and Figure 4.7, with reduced population growth) as a first approximation for demand forecasting, but encourage the inclusion of further specific information as soon as it is available.**

This means that the specific consumption figures of the different sectors and a final penetration rate of 40 % can be applied as long as the number of households per official connection and the relevance of commercial and industrial consumption are taken into account. As soon as one of the figures is modified, all the others should also be reconsidered.

Particular attention should be paid to potential future industries that are expected in the town to be electrified. Commercial and industrial daytime loads are crucial with regard to project feasibility. Studies indicate that approximately 25 % of the load should be for commercial uses, making the plant financially viable.[181] Consequently, whenever the development of commerce or industry can be expected, their consumption should be analysed in detail with special regard to the design of the whole system, the tariff structure and incentives to stimulate this kind of consumption (see also section 4.9). In rural areas of Ethiopia important non-domestic electricity consumption is to be expected for coffee processing, grain milling, bakeries, wood working and carpentry, small hotels, bars, restaurants, shops (general merchandising and retail) and, in some areas, water pumping for irrigation.

Referring to the arguments listed above the following conclusions can be drawn and recommendations given:
- The **load factor** for small isolated grids can be estimated at between **25 and 30 %** and in special cases up to **40 %** (see section 6.3.5.1). It depends on the size of the grid and the variety of electrical applications. The more extended the grid and the more diversified the applications, the higher the load factor.
- The **daily load pattern** in general presents two peaks, a smaller one in the morning between 8 and 11 a.m. and a second much more distinct one between 6 and 11 p.m. Except where there are important industrial or commercial consumers, leading to a pronounced peak during the day, the evening peak provoked by domestic consumption is the more distinct one. As illustrated in section 4.2.1, the maximum possible peak load which decides on the system design can be approximated by multiplying the average power requirement, meaning the mean daily consumption [kWh] over 24 h, by the reciprocal value of the load factor, namely the peak factor (see also Figure 4.14).

## 4.3 Technical design with regard to investment cost

### 4.3.1 General remarks on "design objectives"

A technical design intended as basis for a comprehensive decision support system should mainly be conducted with the purpose of roughly estimating investment costs. Therefore it never replaces a detailed technical study but is rather understood as one of the facilitating elements integrated in the whole model. Consequently one of the main objectives of the present section is the development of **simplifying design procedures** for the different system components in order to finally quickly provide a basis for the financial analysis. The following sections illuminate aspects of crucial importance for the technical design of the three options MHP, diesel genset and connection to an existing grid with special regard to:

181 Jackson, Lawrence, 1982

- required standards
- potential for cost reductions
- reducing the complexity and cost of maintenance by preferring simpler equipment and systems
- local availability of the different components in Ethiopia

The procedure is based on the assumption that it is possible to cut costs by combining components purchased from manufacturers or suppliers and using locally manufactured components when possible, rather than purchasing the complete system from one enterprise. This is thought to be especially true for MHP plants. This potential for savings is more pronounced in the case of small plants, for which an individual design taking into account unconventional, locally appropriate approaches can significantly reduce costs. A simple scaling-down of large hydroelectric systems sharply increases costs per installed kilowatt.[182] The choice between imported and locally made equipment often revolves around the issues of efficiency and reliability. Although the latter reduces maintenance effort and expenses, the weighing up of the higher investment costs for imported components with probably better efficiencies often proves the locally produced equipment to be more cost-effective.

Since the whole research project is focused on MHP systems, the two remaining options, diesel genset and grid connection, are only briefly handled in sections 4.3.2.2 and 4.3.2.3, whereas the comprehensive sections on technical design concentrate on MHP. Diesel genset and grid connection are considered mainly with regard to cost comparison aspects.

### 4.3.2 Input data and features of the different options

Taking into account the three alternatives mentioned above, the following system components were identified as being relevant for a rough design:

| | **MHP** (see Figure 3.4) | **diesel genset** | **grid connection** |
|---|---|---|---|
| **civil works** | access road (optional) | | |
| | intake with weir | | |
| | settling basin and trash racks, inlet gate | | |
| | power channel | | |
| | forebay | | |
| | support/anchors (for penstock) | | |
| | powerhouse | powerhouse | substation (optional) |
| | tailrace | | |
| **mechanical equipment** | penstock and valves | | |
| | trashrack(s), inlet gate | | |
| | turbine | | |
| | coupling / drive systems | | |
| | | combustion engine | |
| | governor, control system | control system | control system |
| | optional: machines like grain mill, sawing machine etc. | | |
| **electrical equipment** | generator | generator | |
| | switchboard | switchboard | |
| | step-up and step-down transformers (optional) | | transformer (optional) |
| | transmission line (optional) | | transmission line |
| | distribution grid | distribution grid | distribution grid |
| | protection equipment | protection equipment | protection equipment |
| | electricity meters (optional) | electr. meters (optional) | electr. meters (optional) |

*Table 4.10: Relevant system components for the three technical options*

[182] Zoellner, 1982, p.150

For the technical design the required capacity in kW and the expected energy consumption in kWh are crucial **input parameters**. As far as MHP systems are concerned, available hydrological potential and energy requirements have to be matched. For the option "grid connection" the distance to an existing EEPCO grid, respectively a transmission line, and its voltage level have to be checked as crucial parameters.

#### *4.3.2.1 MHP option*

Especially for MHP plants, the costs for civil engineering structures are highly dependent on the local conditions in the field. Therefore, not only energy potential and consumption data, but also essential field data such as length of the power channel, distance between MHP site and load centre etc. must be known to roughly design the components. In the stage of feasibility, several assumptions and simplifications become necessary for a preliminary cost estimation. The design to be considered is the most simple set-up of a plant (see Figure 3.4): a weir to divert water from a river via a sluice gate and intake into the open channel, then to a forebay and then into the penstock, taking into account trashracks, optional at the intake and at the upper end of the penstock. The penstock guides the water onto the turbine, this flow being adjusted by means of a vane, as far as cross-flow turbines are concerned, or similar flow control devices. The powerhouse accommodates a turbine and either appliances like a mill, saw, or oil extraction plant driven by a shaft, or a generator or even both, generator and mechanical appliances. In the case of electricity generation, further electrical equipment, such as a switchboard, is installed in the powerhouse. Either electricity is directly distributed to the consumers if there is a short distance between electricity generation and consumption, or transmission by means of step-up and step-down transformers and a transmission line are required to limit electrical losses. In reality, additional civil works, for example two penstock pipes or two turbines, might be required, or the circumstances might necessitate a pipe instead of an open channel. All these ancillary cases cannot be taken into account. Also spillways, which are probably required at the intake, weir and forebay are neglected here as far as investment costs are concerned. If significant additional costs are foreseen, they should be taken into account as a lump sum or added to the contingencies. In general a continuous or stepwise extension is not possible for most of the system components. It would be too expensive, to buy a small turbine or penstock and to replace it for example every 10 years by a bigger one or to add a second one. Especially for civil works, such as power channel, tailrace etc. an extension according to the growing requirements is not worthwhile. Therefore the system is designed from the beginning for a demand which only occurs after 25 years, thus entailing high investment costs for a system size which cannot immediately be taken advantage of. Merely the distribution grid can be enlarged continuously. In every specific case, it should however be checked if any cost reduction due to continuous upgrading of civil works, mechanical or electrical components is possible.

#### *4.3.2.2 Diesel generator option*

As far as the electrical part of a diesel-driven generator system is concerned, it can be designed as for the MHP system. In general an internal combustion engine and a generator, together often called a "genset" are put up for sale as a combined unit. One of the pivotal advantages of the diesel genset is that it can be installed at any place as close as possible to the energy consumers. Consequently the transmission losses that occur with MHP systems do not pose a problem and transformation to a higher voltage level is not required. The main components are the engine combined with the generator, the distribution grid, and protection and control equipment.
The genset is designed according to the calculated peak demand. Gensets being characterised by shorter lifetimes than MHP plants their design capacity can be set closer to the current demand. As soon as the plant exceeds its economic lifetime it will be replaced by a bigger one, sized to meet the increased demand (see sections 3.2.5 and 6.1). Although the size

of the diesel system can be adopted to the requirements more continuously, still the problem of very low efficiencies at part load operation exists, thus increasing fuel costs.

#### *4.3.2.3 Connection to an existing grid*

This alternative applies to the option of extending the existing grid, by means of a 230, 132, 66, 33 or 15 kV transmission line starting from the nearest substation of the ICS. The costs thereby incurred must cover the following components, depending on the specific situation: an additional substation, a transmission line from the substation to the area to be supplied, step-down transformers and protection equipment.
For reason of comparability with the other technical options MHP or diesel genset, the benefits to other towns situated nearby and probably being supplied by the same substation and transmission line cannot be taken into account.

### 4.3.3 Design of civil engineering structures and mechanical components

Since systems based on gensets and grid connections do not require the structures discussed here, the present section is exclusively related to MHP plants. For simplification, the whole MHP system design is based on this average low flow Q(90,daily). This supposition assumes an "average capacity" for the whole energy generation and distribution system. Variations of runoff and utilisable energy potential over the year are not considered at this early stage of the decision-making process. The technical design leads to the cost estimation which is only one of the aspects in a decision support tool, albeit one of the most important ones, so this simplification is an acceptable assumption. In the appraisal of investment costs the crucial elements are listed in Table 4.10. If the forebay, powerhouse or other structures are exposed to excessive runoff which might endanger proper operation during heavy rains, they should be furnished with runoff interception and **drainage** facilities, which are not separately itemised in the following discussion.

#### *4.3.3.1 Access road*

In general, MHP sites are situated in more or less remote areas, but direct access to the site by any kind of road is usually not warranted. MHP projects in other countries have used a range of transport methods, from simple carrying by men or animal to helicopters. The maximum load which can be carried by men or animals is limited to about 400 kg.[183] Generators and control panels are difficult to disassemble, and dismantling and reassembly require experienced staff and transporting in this way entails the risk of damage. Helicopters are an extremely expensive option. Bearing these factors in mind, if there is a lack of suitable options, the construction of an access road should considered as a possible option for the transport of building materials, equipment etc.. For Ethiopian conditions, three different quality categories for road construction materials corresponding to respective unit prices are defined, as listed in Table 4.11.

| road quality | building materials and construction method | roughly estimated unit price (year 2000) |
|---|---|---|
| lowest quality | recycled bricks, applied non-compressed the road base | 150 ETB/m |
| medium quality gravel | applied and compacted on the prepared road base | 250 ETB/m |
| best quality gravel | applied and compacted on the prepared road base with additional drainage systems and fixing | 400 ETB/m |

*Table 4.11: Categorisation of road qualities and estimated unit prices*

183 Widmer, Arter, 1992, p.44

The construction of an access road can significantly increase the overall costs, depending on the remoteness of a specific site. On the other hand, these costs can be minimised by employing local labourers or even voluntary contributions of the community that will benefit from the electricity supply. Simple works like the tracing out of an access road or excavation for the power channel are most suitable for community participation.

#### *4.3.3.2 Weir, intake, power channel, forebay and tailrace*

As far as the weir, intake, power channel, forebay and tailrace are concerned, it is useful to differentiate between the various qualities of excavation work and building materials, considering their unit prices. The analysis of existing documents and similar construction works implemented in Ethiopia led to the estimates of unit prices as listed in Table 4.12.

| **excavation in:** | **roughly estimated unit price (year 2000)** |
|---|---|
| common/ordinary soil | 20 ETB/m³ |
| soft rock | 80 ETB/m³ |
| hard rock | 120 ETB/m³ |

| **building materials:** | **roughly estimated unit price (year 2000)** |
|---|---|
| masonry | 300 ETB/m³ |
| lean concrete | 500 ETB/m³ |
| concrete | 800 ETB/m³ |

*Table 4.12: Categorisation and unit prices of excavation works and building materials*

To estimate the dimensions of the weir excavation, the depth of the foundation, and the height, length and width of the structure have to be determined. Depending on the specific site conditions, it might be necessary to take into account the possible need for additional expenditure for river diversion during construction works. Similarly, for the intake, forebay and tailrace, excavation depth, height, length and wall thickness are required as input data.

#### *4.3.3.3 Power channel*

Regarding the intake or power channel, besides the building materials mentioned above, the option of an unlined channel is available. The following Figure 4.10 shows the procedure of designing the power channel based on several input parameters:

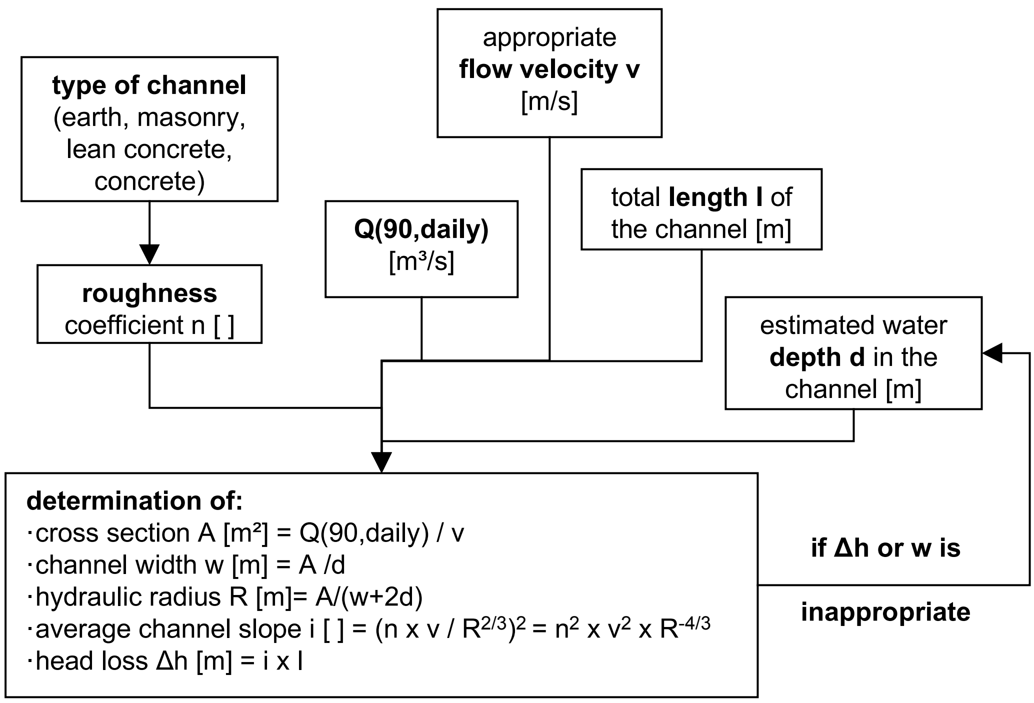


*Figure 4.10: Flowchart for channel design*

The roughness coefficient can be determined according to the kind of channel selected using Table 4.13. The flow velocity can be taken from Table 4.14. The value Q(90,daily) can be determined according to the method developed in section 4.1.5. The length of the power channel is estimated by considering the site conditions. Finally the channel depth as a variable is first roughly estimated and then iteratively changed to obtain reasonable results for channel width w and head loss Δh between intake and forebay. The head loss Δh is calculated from the slope i, the latter being determined by applying the Manning-Strickler-formula. To complete the calculation steps for the power channel, one further parameter, a value for the wall thickness, is required.

| type of channel | description of surface | roughness coefficient n [ ] | average values applied |
|---|---|---|---|
| **earth channel** | clay with stones and sand, after ageing | 0.02 | **0.04** |
| | lined with coarse stones, maintained with minimum vegetation | 0.04 | |
| | heavily overgrown, water depth 0,3 m | 0.15 | |
| **masonry channel** | normal masonry | 0.017 | **0.03** |
| | coarse rubble masonry, stones only coarsely hewn | 0.02 | |
| **concrete channel** | smooth cement finish | 0.01 | **0.02** |
| | tamped concrete with smooth surface | 0.016 | |
| | irregular concrete surfaces | 0.02 | |

*Table 4.13: Roughness coefficients for different channel types*[184]

| material | appropriate velocity [m/s] to avoid erosion and to prevent sedimentation | | |
|---|---|---|---|
| | < 0.3 m depth | 0.3 - 1 m depth | > 1 m depth |
| sandy loam | 0.4 | 0.5 | 0.6 |
| clay loam | 0.6 | 0.7 | 0.8 |
| clay | 0.8 | 1.8 | 2.0 |
| masonry | 1.5 | 2 | < 3 |
| concrete | 1.5 | 2 | < 4 |

*Table 4.14: Appropriate flow velocities according to channel material*[185]

#### *4.3.3.4 Penstock support facilities*

To prevent undesired movement of the penstock **support piers, anchors and thrustblocks** are used. To ensure low maintenance cost, special attention should be paid to the laying of the penstock. Support piers carry the weight of the pipe and the enclosed water and so are required to resist mainly vertical forces; whereas anchors, which are often used at horizontal and vertical bends but also at regular intervals along long straight sections, are designed to resist primarily the longitudinal forces such as friction, thermally induced stresses, and forces caused by changes of direction. The longitudinal forces can be reduced by using roller or rocker supports. A thrustblock, which is a specialised form of anchor, prevents a buried pipe from moving by transmitting the force or thrust, primarily caused by hydrostatic pressures, concentrated at distinct bends, to the surrounding soil.[186] A specific design of support piers, anchors and thrustblocks is neither possible nor required at the stage of the first rough design. Therefore the additional costs thereby incurred are expressed by simplified assumptions. Assuming that increasing pipe lengths and diameters entail higher costs for support facilities, the latter can be estimated as a certain percentage, e.g. 10 %, of the total cost for the penstock.

[184] modified according to Harvey 1998, p.105 and Inversin, 1986, p.97
[185] modified according to Harvey 1998, p.104 and Inversin, 1986, p.98
[186] Inversin, 1986, p.138ff

#### 4.3.3.5 Power house

The **power house** should enclose and protect the turbo-generating and associated equipment. Its design and equipment depends on the specific case, for example if block and tackle or cranes travelling on overhead rails are required. Since available information at the early planning stage is limited, a rough classification of different quality standards and the assignment of respective unit prices, as presented in Table 4.15, is useful.

| quality | description | estimated unit price (year 2000) [ETB/m²] |
|---|---|---|
| **lowest quality** | very simple construction; house without any foundation of lean concrete, only the machines being fixed to foundations; walls made of wood, for example eucalyptus; roof made of corrugated iron sheet | 2,000 |
| **medium quality** | house with foundation of lean concrete; some sections of the walls are made of masonry, but most parts made of wood, for example eucalyptus; roof made of corrugated iron sheet; including support, trolley etc. | 2,500 |
| **best quality** | house with foundation of concrete; walls made of masonry; equipment including support, trolley etc.; locally produced roofing tiles; metal framed door; walkway around the house; roof gutter; drainage | 3,500 |

*Table 4.15: Categorisation and unit prices of different types of power houses*

These categories correspond to specific unit prices per square metre [m²]. The plan area of the powerhouse, estimated according to the number and size of the machinery to be installed, is multiplied by the respective unit price and leads to a cost estimation for the powerhouse. Although the dimensions of turbines and accessories vary according to their capacity and the manufacturer's specific design, a surface of about 4 m² for every machine, for example turbine, generator, oil extractor, grain mill and other applications, can be assumed as a first estimation. For the system based on a diesel genset, the powerhouse is less costly because construction works for tailrace, valves, foundations etc. are not required. Total costs for the "diesel" powerhouse are about 2/3 of those assessed for an MHP powerhouse.

#### 4.3.3.6 Penstock

The penstock pipe generally matters a great deal concerning investment and maintenance costs.[187] Provided that they have the same capacity, high-head plants are in general less expensive than low-head plants, since the latter use a relatively larger flow, thus entailing higher cost for civil works like power channel etc.. When endeavouring to increase the useable head, special attention should be paid to the optimisation of the penstock pipe, in order not to nullify this cost advantage of a high-head plant by disproportionate penstock costs. Penstock optimisation tries to accomplish the following objectives:
- to minimise investment and operating costs
- to minimise head loss
- to minimise the penstock length for a given gross head
- to maximise stability (against pressure surges)

These conditions can be fulfilled by selecting the appropriate pipe material, diameter and wall thickness. For that purpose a "decision tree" in the form of a flowchart has been developed (see Figure 4.12). In the following paragraphs, the causal relationships are briefly explained.[188]

[187] Harvey, 1998, p.15
[188] according to Inversin, 1986, p.124ff and Harvey 1998, p.118ff

Commonly used **materials** for penstocks are steel, plastic, concrete and ductile iron. Advantages of plastic such as polyvinyl chloride PVC, high density polyethylene HDPE and medium-density polyethylene MDPE are its low weight, low cost and ease of installation. In general selection criteria for the pipe material are:

- operating pressure and surge pressure (in relation to selected diameter)
- method of jointing
- handling and accessibility
- maintenance and required lifetime
- nature of terrain where the pipe must be laid

The material for the penstock pipe can make a significant difference to the overall cost. For example, plastic penstock piping may be cheap but the joints may be expensive or not available in some regions.

Head **losses** in pipes are caused by friction between water and the pipe wall and depend on diameter and material of the pipe and turbulence created by changes in velocity at inlet, bends and valves. Except for very short pipes, losses caused by turbulence ($h_t$) are negligible compared to friction losses ($h_f$). The friction losses for the total pipe length can be computed according to Manning's equation:[189]

$$\boxed{\frac{h_f}{L} = 6.3 \cdot \frac{(n \cdot v)^2}{D^{\frac{4}{3}}} = 10 \cdot \frac{n^2 \cdot Q^2}{D^{5.3}}}$$

***Formula 4-15***

where

$h_f$ = head loss due to friction [m]
$L$ = length of penstock pipe [m]
$v$ = flow velocity in the pipe [m/s]
$Q$ = flow in the pipe [m³/s]
$n$ = roughness coefficient [ ]
$D$ = internal pipe diameter [m]

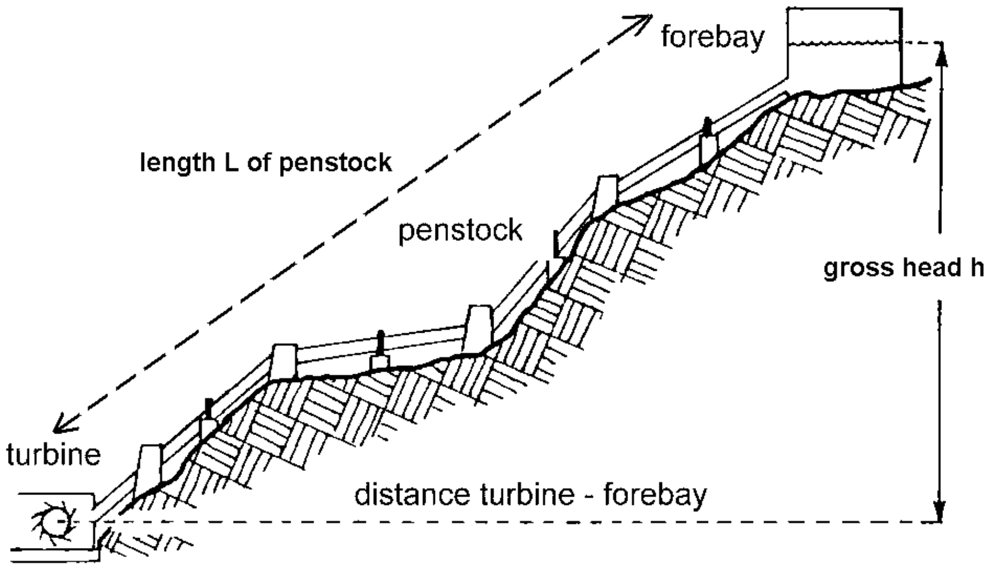


*Figure 4.11: Illustration of penstock length L and gross head h[190]*

Experience from different projects has shown that the required penstock length is about 2.5 to 3.5 times the net head available in the field.[191] Often not only the terrain slope but also obstacles must be circumvented, also increasing the pipeline length. The ratio $h_f/h$ should be in the region 0.05 < perc < 0.1, in other words the losses are 5 - 10% of the gross head h. To bring the losses down to near zero by choosing a very large diameter would entail exagger-

[189] Inversin, 1986, p.126
[190] modified according to Harvey, 1998, p.4
[191] personal communication: Valentin Schnitzer (hydropower), 04/2002

ated costs, whereas, losses of more than about 10 % of the gross head lead to a futile waste of available energy. The diameter appears in Manning's formula with the exponent 5.3, proving its strong influence on head losses. The absolute friction loss is proportional to the length of the penstock, and so the length should be kept as short as possible by selecting a site which allows the penstock to be as steep as possible. If "perc" is specified, D can be calculated according to:

$$D = \left( \frac{10 \cdot n^2 \cdot Q^2}{perc \cdot \frac{h}{L}} \right)^{\frac{1}{5.3}}$$

**Formula 4-16**

where: *perc* = percentage of losses, about 0.05 to 0.1 [ ], where: perc · h = $h_f$
*h* = gross head

n is taken from tables for different pipe materials[192], Q is the runoff chosen for designing the plant, "perc" is specified according to the acceptable losses and h and L are estimated from site information.

The pipe diameter affects the required **pressure rating** and therefore wall thickness. Smaller diameters lead to higher velocities and thus higher pressure surges, finally requiring increased wall thickness or strong pipe material. Water hammer is a pressure surge, occurring in the penstock, caused by rapid opening or closing of inlet gates, valves etc.. The velocity with which the pressure front moves in the penstock is described by the following formula:

$$a = \frac{1{,}420}{\sqrt{1 + \frac{1{,}000 \cdot K \cdot D}{E \cdot t}}}$$

**Formula 4-17**

where

*a* = wave velocity [m/s]
*K* = fluid bulk modulus = $2.1 \cdot 10^4$ kgf/cm² for water
*D* = internal pipe diameter [m]
*E* = modulus of elasticity of pipe [kgf/cm²]
*t* = wall thickness [mm]

The peak surge pressure is given by the formula:

$$p_s = \frac{a \cdot \Delta v}{g}$$

**Formula 4-18**

where

$p_s$ = maximum surge pressure [m]
$\Delta v$ = change in flow velocity in pipe [m/s]
*g* = acceleration due to gravity = 9.81 m/s²

The damping effect of friction within the pipe causes the kinetic energy of the flow to dissipate gradually and the amplitude of the pressure oscillations to decrease with time. If for example the valve in front of the turbine is opened or closed slowly, taking more time to open or close than is required for the pressure surge to travel to the forebay and back to the valve, peak surge pressures are reduced. The total pressure exerted on the pipe results from the head of water above that point and surge pressures arising from sudden changes of flow.

$$p_{max} = h + p_s$$

**Formula 4-19**

where $p_{max}$ = maximum total pressure put on the pipe [m water column]

[192]Inversin 1986, p.128

Figure 4.12 depicts and summarises the iterative calculation procedure developed to be applicable for a decision support tool.

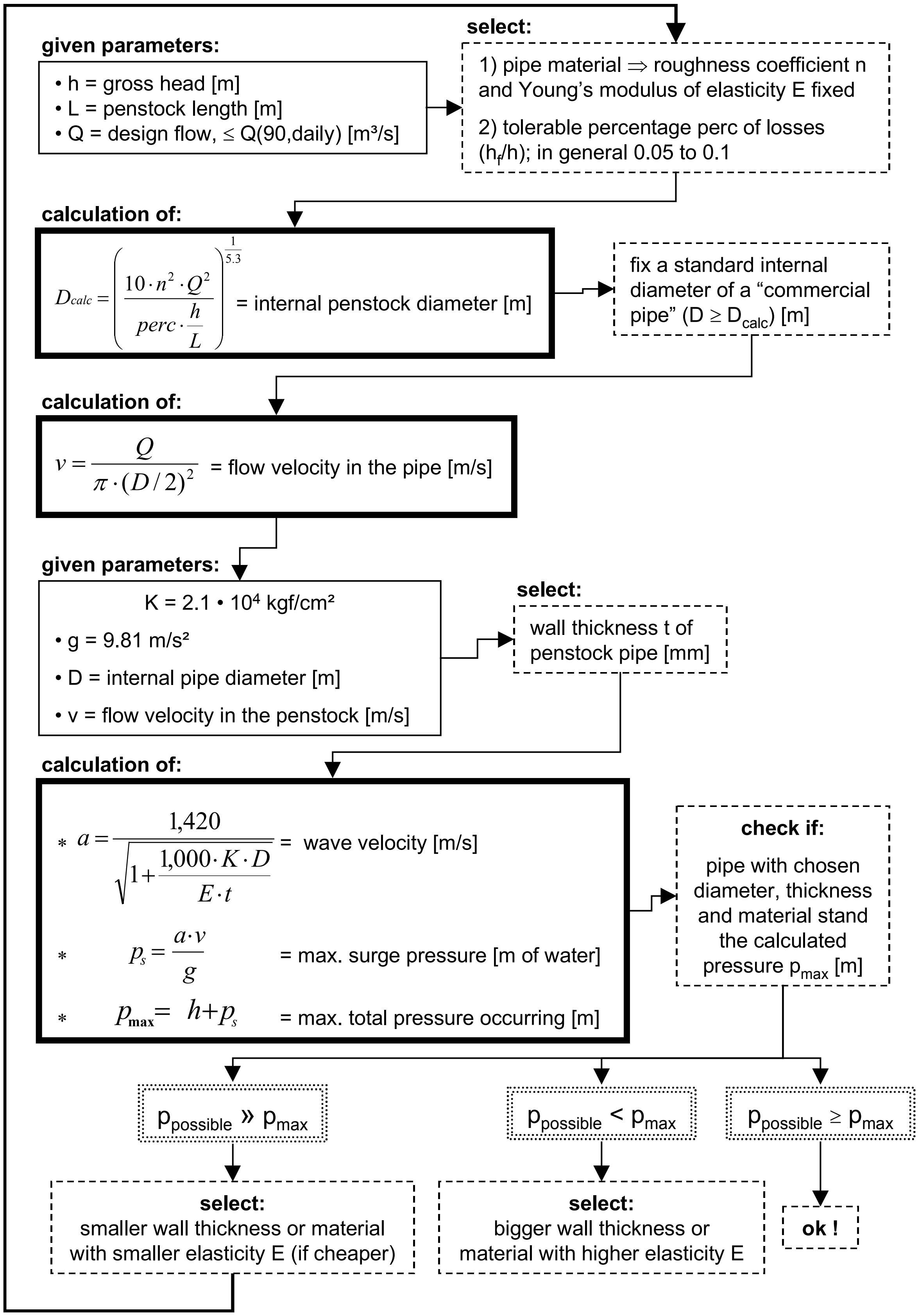


*Figure 4.12: Flowchart for the iterative calculation of diameter and wall thickness of the penstock pipe*

For bigger penstocks, **expansion joints** should be incorporated to reduce the size of the required anchors. These joints allow the pipe to expand and contract freely.[193] The unit price for a penstock pipe of a certain diameter should include the costs of the required joints.

#### *4.3.3.7 Further mechanical equipment*

If a **trashrack** is required to prevent driftwood, twigs and other floating material from entering the power channel or the penstock, the dimensions of the trashrack should be suited to the size of the power channel cross section. Supposing that the cross section of the channel is sized according to the maximum water depth, it similarly defines the size of the required **sluice gate/sliding gate**, a device regulating the flow into the power channel. If **valves** instead of or in addition to gates control the flow through water conveying structures, mainly butterfly and gate valves are used for MHP applications. While gates are used for open passageways and low-pressure applications, valves are used to control water flow through the penstock. In general a valve is provided at the base of the penstock for isolation of the turbine to permit its removal for maintenance or replacement. The valve diameter should be selected according to the calculated penstock diameter (see Figure 4.12). The costs of these valves, depending on the required diameter, can be substantial. A reasonable cost estimation for this item is **40 to 50 times the unit price** (e.g. in ETB per m) for the penstock.[194]

#### *4.3.3.8 Turbines*

Especially for large hydropower plants, manufacturers offer complete sets of turbines and generators, in which the runners are directly coupled to the generator and therefore designed to run at the speed of the generator. Experience has shown that purchasing separate units which have then probably to be linked with a transmission drive are often cheaper. For MHP systems it is generally more important to use less costly, standardised runners rather than custom-designed runners. Consequently the various components such as turbine, coupling, generator are considered separately here. There may sometimes be a need, depending on the specific case, for gearing between turbine and generator.[195] Crucial design criteria for the turbine are:

- available net head
- relationship between required power, depending on available flow, and head
- required speed for coupling to a generator or other machine

A turbine is characterised by its power-speed- and efficiency-speed- characteristics. This means that for a particular head, a turbine runs most efficiently at a particular speed and therefore requires a particular flow.[196] Under the given conditions in Ethiopia which mostly provide high heads, crossflow, Pelton and to some extent Francis turbines are most suitable. Compared to reaction turbines like the Francis **impulse turbines** like crossflow and Pelton offer the following advantages which make them more convenient for application under Ethiopian conditions:

- They are tolerant of sand and other particles in the water
- They allow better access to working parts
- They are easier to fabricate and maintain; crossflow turbines up to about 250 kW can be fabricated locally
- They are usually cheaper than reaction turbines because pressure casing and carefully engineered clearances are **not** needed
- They are less subject to cavitation, although at high heads, high velocities can cause cavitation in nozzles or on the blades or buckets

[193] Inversin, 1986, p.136f
[194] own calculation according to cost estimations of different projects
[195] Inversin, 1986, p.172 and Harvey 1998, p.153
[196] Harvey, 1998, p.153

- They offer flatter efficiency curves, especially if additional flow control devices are built in like for example variable cross section nozzles, spear valves, guide vanes, and devices to vary the number of jets or partition the flow[197]

Only for low head-to-power ratios, which fortunately are not common at potential MHP sites in Ethiopia, impulse turbines are not appropriate. Compared to Pelton turbines, which generally require casting facilities, crossflow turbines merely require simple fabrication techniques. In addition, the crossflow design is suitable for a wide range of heads and power ratings, because the shape of the turbine blades allows the runner length to be increased to any value without, in theory, changing the hydraulic characteristics.[198]
Crossflow turbines are locally produced in Addis Ababa by:

- the Selam Technical and Vocational Training Centre (for more than 5 years, mainly the models T205 and T12, up to 250 kW)
- the EECMY (mainly very small ones, up to about 15 kW)
- the Paradiso & Sons Engineering Workshop
- Akaki Spare Parts

With a given head and flow, reaction turbines like Francis turbines rotate faster than impulse turbines and can therefore often be directly coupled to an alternator without a speed-increasing drive system, thus leading to significant cost savings and easier maintenance. This advantage and, additionally, the high efficiencies are however offset by the sophisticated and expensive fabrication, susceptibility to cavitation and poor part flow efficiency characteristics. Compared to crossflow and Pelton turbines, Francis turbines are characterised by very steep efficiency curves. The local availability of cross flow turbines allows the purchaser to insist on a guarantee and ensures reasonable access to repair and maintenance specialists. These are crucial arguments in favour of crossflow turbines. Considering these arguments, the preference ranking of turbines established for Ethiopian conditions is: 1. crossflow turbine, 2. Pelton turbine, 3. Francis turbine.
The simplified turbine selection procedure, which is proposed in Figure 4.13 is oriented towards a rough cost estimation rather than on a technically precise design. The latter would require detailed information on part flow conditions, intended mode of operation etc..

[197] loc. cit., p.163
[198] Inversin, 1986 p.179

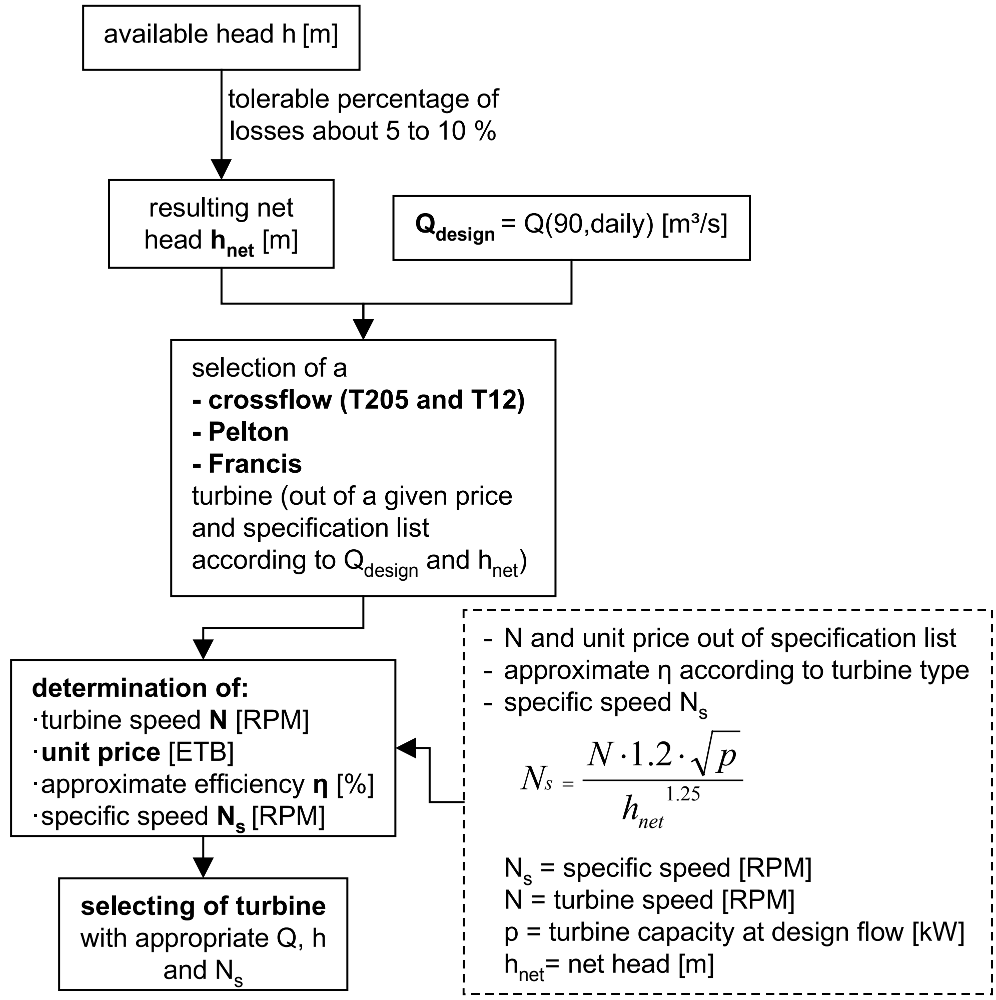


*Figure 4.13: Flowchart for turbine layout*

Although each turbine is characterised by a specific efficiency curve, the available literature suggests that the following figures can be applied as average values for the three turbine types:

| turbine type | range of efficiencies (Harvey) | range of efficiencies (Inversin) | selected average efficiency |
|---|---|---|---|
| crossflow turbine | 0.65 - 0.80 | up to 0.85 | **0.67** |
| crossflow turbine locally manufactured | 0.65 | 0.6 - 0.8 | **0.67** |
| Pelton turbine | 0.75 | 0.7 - 0.85 | **0.80** |
| Francis turbine | 0.8 | - | **0.75** |

*Table 4.16: Turbine efficiencies*[199]

To find out, which type of turbine is appropriate under the given site conditions, meaning available head and runoff, the specific speed $N_s$ is determined according to the formula:

$$N_s = \frac{N \cdot 1.2 \cdot \sqrt{p}}{h_{net}^{1.25}}$$

***Formula 4-20***

where

$N_s$ = specific speed [RPM]
$N$ = turbine speed [RPM]
$p$ = turbine capacity at design flow [kW]
$h_{net}$= net head [m]

Table 4.17 depicts appropriate specific speeds for different turbine types.

[199] Harvey, 1998, p.155f and Inversin, 1986, 174ff

| type of runner | specific speed $N_s$ [RPM] |
|---|---|
| crossflow | 20 - 160 |
| Pelton (single jet) | 10 - 30 |
| Francis | 50 - 400 |

*Table 4.17: Specific speeds of different turbine types*[200]

Once an appropriate turbine is selected, its speed should be reconciled with the speed of the generator, or with any other machine that is mechanically driven by the turbine. If the turbine and generator speeds are different, gearing, or a belt or chain drive between turbine and generator is required. The generator speed [rpm] is calculated according to:

$$\boxed{rev = \frac{120 \cdot f}{po}}$$

***Formula 4-21***

where

*rev* = revolutions per minute [rpm]
*f* = frequency [Hz]
*po* = number of poles

and in the case of induction generators (see section 4.3.4.3), the speed is calculated with respect to the slip according to:

$$\boxed{rev = \frac{120 \cdot f}{po} \cdot (1 - s)}$$

***Formula 4-22***

where *s* = slip [-]

For a commonly used alternator, for 50 Hz and with 4 poles, a speed of 1,500 rpm is calculated.

#### *4.3.3.9 Coupling / gearing*

In the optimum case turbine and generator or other machinery rotate at the same speed so that no gearing is required and thus losses, complexity and maintenance work are minimised. If the shafts of turbine and generator are colinear, then direct coupling is possible. But in general belt or chain drives are required to couple the components. A generator driven by the turbine shaft must run at a certain speed to produce electricity. For example, the recommended practical range for a turbine driving a 1,500 rpm alternator is 400 - 1,500 rpm. In general the **gearing ratio G** (= load [rpm] / turbine [rpm]) should lie **between 1:1 and 3:1**. To reduce costs and difficulties, the speed-up ratio should be less than 2.5. As far as efficiency is concerned, drive systems often lose a fixed amount of power, meaning that a drive with an efficiency of 95 % on a 50 kW scheme loses 2.5 kW. If the same drive is used to transmit only 25 kW, it will still lose 2.5 kW, resulting in an efficiency of only 90 %.

#### *4.3.3.10 Governing*

Modern MHP plants can be controlled by electronic load controllers which have superseded the **mechanical speed governor**, the latter being an expensive device requiring a high level of skilled maintenance.[201] Poor long-term reliability, slow acting characteristics and the danger of water hammer make the mechanical governor an inappropriate device for MHP. Therefore electronic load controllers (ELC) are favoured and mechanical governing is not considered further in the present study (see section 4.3.4.4).

[200] loc. cit., p.172 and Harvey 1998 p.155
[201] Harvey, 1998, p.167

#### *4.3.3.11 Machines (grain mills, sawing machines, etc.)*

Appliances like grain mills, hammer mills for corn, manioc, teff etc., sawing machines and oil extractors can be driven directly by the turbine. Transforming mechanical energy into electrical energy and back again into mechanical energy causes enormous losses and should be avoided if possible. Several manufacturing machines are produced locally in Addis Ababa. Given the fact that these machines are not necessarily operated by the same person as the energy supply system, the costs of such appliances are not included in the general investment cost estimation.

### 4.3.4 Design of electrical components

#### *4.3.4.1 General aspects*

The following paragraphs mainly refer to the MHP option. Well-defined technical standards apply to the alternatives, "diesel genset" and "grid connection", and so for these options attention is restricted to *economic* aspects relative to the MHP system (analysed in section 4.4). For the design of electrical components, the present study starts from the assumption that MHP plants for rural electrification in Ethiopia are always **stand-alone systems** because linking an MHP system to the ICS is not a realistic option, neither immediately nor in the medium term. As illustrated in section 3.2.2, the tariffs for electricity from the ICS are still heavily subsidised, so that an MHP system operated with cost-covering tariffs is far from competitive. In order to achieve a sufficient willingness to pay from the customer's side, it is important to implement the system at a certain **distance from the national grid** so that the low, subsidised tariffs are “out of reach".

The electrical part of an MHP system merits special interest for technical and economic reasons. From the **technical** point of view, the electrical equipment must guarantee an adjustment between energy potential, available as shaft energy from the prime mover, and the loads on the consumer side. Remembering that, for run-of-river plants, neither water nor electricity storage is envisioned, the balancing between available energy and consumption is of crucial importance. Since the rotational speed of the turbine is governed by the electrical frequency in the grid, either water flow or load must be controlled. In general, stand-alone systems must offer constant voltage and constant frequency independent of variations in the loads or in the water flow in the turbine.[202] Otherwise the electrical devices that are supplied may be damaged. The most sensitive types of equipment are those with inductive loads, like motors and transformers. As far as **cost aspects** are concerned, electrical components of MHP plants contribute a significant part, namely up to 30 %- 50 %[203], to total investment costs, so careful design can lead to enormous cost reductions. In Ethiopia, as in many other developing countries, most electrical parts have to be imported and are therefore adversely affected by the lack of foreign currency, by import taxes up to 30 %, harbour dues, freight and other transportation costs, by unfavourable exchange rates etc.. Only diesel generators and small motors are available off-the-shelf, whereas all other components must be ordered and imported.[204]

The main electrical **components** relevant for MHP plants are the generator, or an induction motor used as a generator, the electric load controller, the electric power network, including conductors, insulators, electricity meters etc., and the transformers.

The following system structure shows the basic elements:

[202] Elgerd, Puije, 1998, p.171
[203] Jackson, Lawrence, 1982, p.113, Chapallaz et al., 1992, p.97 and own calculations see section 6.2.3
[204] Fuhr, 2001, p.5

**one generator → one step-up transformer → transmission line → several step-down transformers → distribution lines**
Another possibility would be to use several generators for different load scenarios etc. and consequently also different numbers of transformers. In this way the overall efficiency and reliability of the system can be improved. However the consideration of a very simple system in the present study allows an easy preliminary rough design and a manageable cost structure.

Given the fact that **alternating current (AC)** can be transformed to higher voltage levels and then transmitted over longer distances at reduced losses, the use of direct current (DC) is not taken into consideration. The latter is only useful in very small systems of less than about 2 kW, e.g. for battery charging. But even in this specific case, short service life and the environmental hazard posed by batteries remain cogent disadvantages which should be weighed up carefully against possible merits. The arguments for the application of AC are[205]:

- most electrical appliances require AC and are cheaper than DC appliances
- synchronous and induction generators (for AC) are readily available and inexpensive
- AC allows use of transformers transmission at a higher voltage
- after rectifying, AC can also be used for battery charging
- AC generators are smaller, cheaper and more efficient
- AC allows lower power line and motor losses.

#### *4.3.4.2 Choice between single- and three-phase systems*

Once the choice is made for an AC system, it remains to be decided whether, in a specific situation, a three- or single-phase system is most appropriate for the distribution network. For low voltage distribution grids

1. the three-phase, 4 wire system and
2. the **S**ingle **W**ire **E**arth **R**eturn SWER system[206]

is suitable. A single-phase system, either “single-phase, 2 wire” or SWER, has one live and one return conductor, so that only one voltage level is available. The whole system operates at around either 220 V or 380 V. A three-phase, 4 wire system however uses three-phase wires and one neutral wire[207], the latter connected to the star point. Thus, different possibilities of connection, either star or delta connection, allow a choice of **two different voltage levels** for single-phase appliances: e.g. 380 V between the three phases and 220 V (=380V/√3) between any phase and the neutral wire. Today the 400/230 V system is the standard applied in Ethiopia, whereas 380/220 V was used in the past. Besides the two voltage levels, the three phases allow the operation of appliances requiring **rotating current**[208]**,** especially devices for productive applications, such as motors in manufacturing and processing machines. The decision between the two options, single-phase or three-phase, is influenced by cost comparison and load structure.[209]

**Single-phase systems** like SWER in general offer advantages for schemes of less than 10 - 15 kW. In such a case individual loads are probably a significant percentage of the total generator capacity, so balancing phases in a three-phase system would be more difficult. Pivotal arguments for single-phase systems in that range of capacity are:[210]

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205 Inversin, 1986, p.245

206 SWER = single wire earth return is basically a single phase supply with only one wire and using the earth as a return conductor; pole spacing of 150-200 m is possible; for more information see Widmer, Arter, 1992 p.65ff

207 Especially in small MHP systems with relatively few consumers, the loads on the three phases cannot always be completely balanced. A fourth neutral conductor is required to carry the current arising from this lack of balance.

208 = three phase

209 Harvey, 1998, p.248

210 Inversin, 1990, p.219, Harvey, 1998, p.249f

- cost savings through
  - switchgear and monitoring, control and protection equipment for only one phase
  - less expensive electric load controllers
  - generator size determined by maximum load
- less complicated wiring, insulation arrangements and switching.

Although in some cases, three-phase motors have been connected to a single-phase system by using capacitors to create a third phase[211], the connection of such appliances to a three-phase system is, as a matter of course, much easier.

As soon as the system size increases and more individual loads have to be satisfied, the balance between the three phases is easier to achieve and significant savings concerning the conductors are possible. The main arguments for the **three-phase system** can be summarised as follows:[212]

- up to 75 % of the expenditure on copper conductors can be saved compared to single-phase systems with equal line-to-neutral voltage, depending on degree of load balance achievable
- generators and transformers for a given power size are smaller, cheaper and more efficient
- three-phase generators and motors are more common, cheaper, smaller, resulting in less weight and lower transport costs, than their single-phase equivalents
- both single- and 3-phase loads can be supplied.

One of the disadvantages of the three-phase system is that normally generators with a capacity higher than the total maximum load are required (see also section 4.3.4.3, Figure 4.14). The economic viability of MHP systems in rural areas of Ethiopia depends on the promotion of productive energy uses. Rural Ethiopian villages that have recently been electrified have been quick to install machinery for motive power. Such machinery, like mills and oil extractors requires a three-phase supply. Therefore the saving of investment costs by installing a single-phase instead of a three-phase system can impede the introduction of production and manufacturing machinery. Consequently the implementation of three-phase systems is highly recommended. Only for systems with capacities of less than 10 kW should the application of a "pure" single-phase system be considered, with the expectation that such systems are justified only in exceptional cases.

Another possibility is to **combine three- and single-phase systems**. One or several transformer station(s) in the middle of the village or town can provide three-phase connections for this load centre, where the location of most of productive appliances requiring rotating current can be expected and where concentrated demand facilitates easier load balancing between the three phases. In contrast for remote consumers living in more scattered housing, the provision of single-phase connections can be advantageous and more economical. In general, significant standardisation benefits are available through the exclusive utilisation of either single-phase or three-phase transformers, related to quantity purchasing discounts and inventory costs for stocking spare equipment; especially if it is a matter of nationwide long-term planning. However, in cases where economic considerations may preclude immediate extension of three-phase supply to some smaller communities or settlements, it has to be verified if the layouts for interim single-phase supply systems should still be optimised for the ultimate adoption of a three-phase supply. When community load requirements have developed to warrant the additional cost of three-phase supply, the supply grid can be converted by replacement of transformers and addition of conductors.[213] A SWER system has a longer span between transmission poles and the poles are not as strong as those used for other systems, so it cannot be simply upgraded to a three-phase system. Consequently the SWER system should only be chosen if it is foreseen that the SWER system will pay for itself

[211] Widmer, Arter, 1992, p.68
[212] Fritz, 1984, p.7.14, Harvey 1998, p.249, 259
[213] EELPA / ACRES, 1994, p.5-2 and 5-3

during a first initial electrification phase, after which it will be completely replaced by a three-phase, 4 wire system.[214] Especially in rural areas in Ethiopia where scattered settlements are very common, the advantages of a combined three- and single-phase system should be carefully weighed up against the merits of standardisation.

The **combination of the three-phase, 4 wire system (in general 380 V / 50 Hz) with a SWER system (in general 220 V / 50 Hz)** is recommended as the preferred (final) solution. A SWER system should supply the consumers who are in more scattered locations and do not require three phases.

#### *4.3.4.3 Generator design*

The rating of a generator is based on some characteristics concerning the electricity supply process. The consumer loads in an electrical system can be subdivided into **resistive** and **inductive** loads. Resistive appliances are heaters, ordinary light bulbs, meaning incandescent filament lights etc., whereas partially inductive loads are induction motors, appliances incorporating motors, transformers like cassette recorders and TVs, fluorescent lights, etc.. The second group of loads cause current to lag behind voltage because of circuit inductance. This phenomenon is expressed by the **power factor**, characterising the relation of real power and apparent power.

$$\boxed{p = pf \cdot S}$$

***Formula 4-23***

where

$p$ = real power [kW] = $U \cdot I \cdot \cos\varphi$ = power which is consumed
$U$ = voltage [V], $I$ = current [A]
$pf = \cos\varphi$ = power factor [ ]; with $0 < pf < 1$
$S$ = apparent power [kVA] = $U \cdot I$ = power supplied by the generator

The power factor has the value of one, when resistive loads are connected. Inductive loads lead to a decrease of power factor. The so-called reactive volt amps, associated with the component of current completely out-of-phase with the voltage, are related to the **real and apparent power** as shown in Formula 4-24.

$$\boxed{S = \sqrt{p^2 + q_{el}^2}}$$

***Formula 4-24***

where

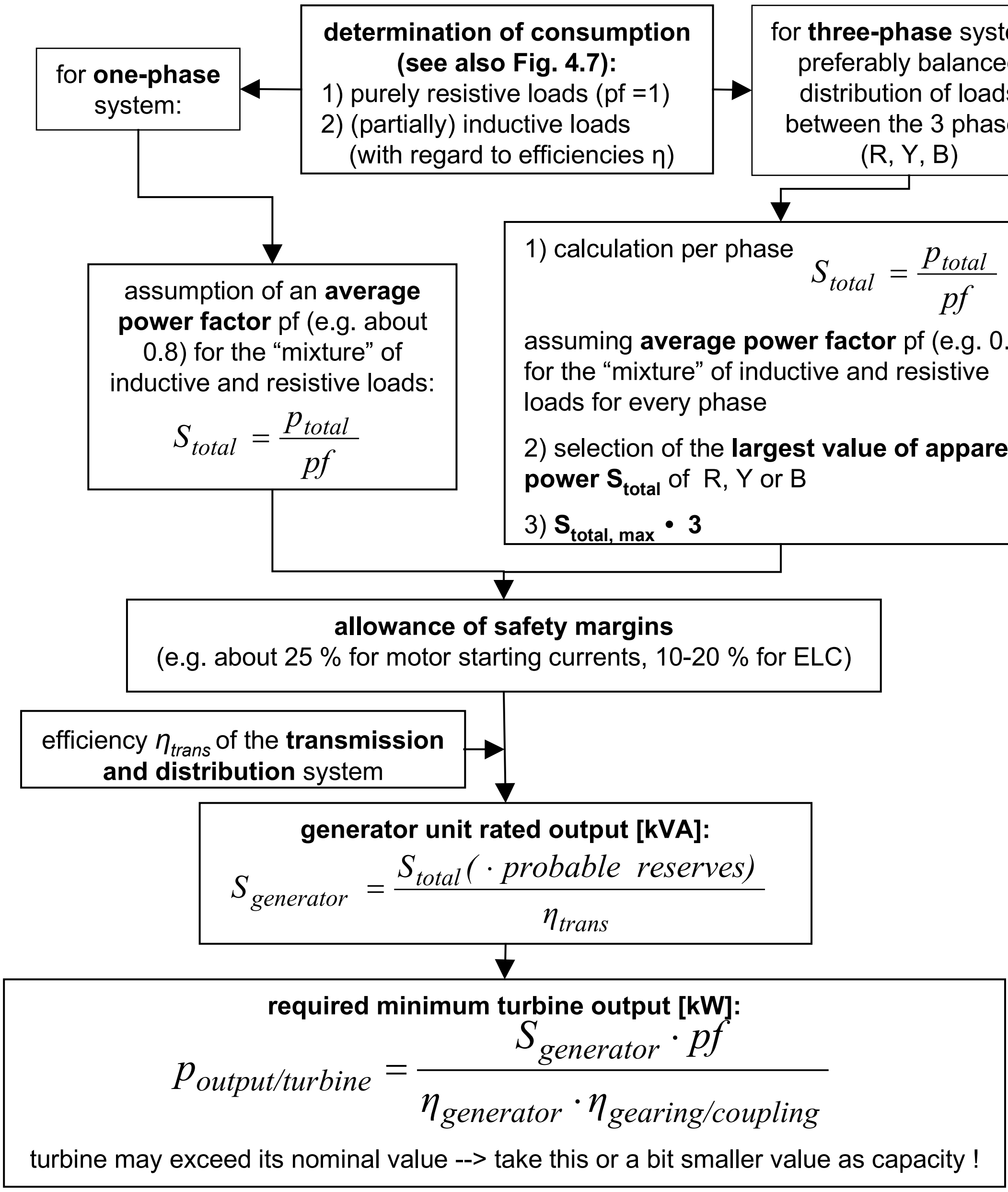
$q_{el}$ = reactive volt amps [kVAr] = $U \cdot I \cdot \sin\varphi$ = power which oscillates

To specify the rating of the generator, the apparent power required by the different loads of the community such as housholds, industry, commerce etc. must be determined. The size of any electrical machine is defined by its volt-amp-rating. In general, the following layout criteria have to be taken into account for the **output rating of the generator**:

1. total power required in the system at the planning horizon aimed at
2. load factor or peak factor
3. for three-phase system: distribution of the loads on the different phases
4. (average) power factor of inductive load(s)
5. momentary voltage reductions occurring when induction motors are started; in case that induction motors will be started "direct on line" it has to be checked if a capacity reserve has to be provided
6. efficiency of transmission system
7. efficiency of generator
8. heating of the generator (over-rated generators run cooler)

[214] Hosemann, Boeck, 1991, p.36

Figure 4.14 depicts the whole procedure for single-phase as well for three-phase systems leading to the determination of generator and turbine size.




where R, Y, B = three phases; p = real power [kW]; S = apparent power [kVA]; η = efficiency [ ]; pf = power factor [ ] = cosφ ; about 0.8 as average estimate

*Figure 4.14: Flowchart for the design of generator and turbine*

After using Figure 4.7 to estimate the total average consumption at the planning horizon [kWh/y], the layout of the generator and the turbine require some further calculation steps. In Figure 4.7 the general "system capacity" is estimated by taking into account the load factor and an overall efficiency of the system. Figure 4.14 which focuses on the layout of the two system components generator and turbine is based on more detailed following steps:

1. The consumption figure in kWh/y, resulting from Figure 4.7 is transformed into an estimate of the average load in kW connected to the grid. Multiplying this average by the peak factor (see sections 4.2.1 and 4.2.7) results in the maximum load to be expected:

$$\frac{\frac{kWh}{year}}{365d \times 24h} \times peak\ \ factor = required\ real\ \ power\ \ p_{total}\left[kW\right]$$

As a matter of simplification it is assumed that for a three-phase system the total load is equally balanced between the three phases: i.e. peak load per phase = $p_{total}/3$.

2. For this peak load (per phase) it is necessary to estimate which part of the load is purely resistive and which is inductive. For the latter, an average power factor must be estimated. In general this factor is about 0.7 - 0.8.[215]
3. The next stage is the calculation of the apparent power demand $S_{total}$ assuming an average power factor. If, in case of a three-phase system, unequal distribution between the phases has to be taken into account, $S_{subtotal}$ has to be calculated per phase, the highest value of $S_{subtotal}$ being then multiplied by 3.
4. $S_{total}$ is increased according to an appropriate safety margin, for example 10 - 20 % for ELC, 25 % for motor starting currents.[216]
5. Dividing the total power demand $S_{total}$ by the efficiency of the transmission and distribution system ($\eta_{trans} = \eta_{transmission/distribution} \cdot \eta_{transformers} \sim 0.9$)[217] yields the rated generator output $S_{generator}$ [kVA]
6. The turbine should be capable of supplying the total real power (= $S_{generator} \cdot$ pf) plus the losses of the generator and gearing/coupling. Finally, this *required* turbine capacity resulting from Figure 4.14 has to be compared to the maximum *available* turbine capacity resulting from Figure 4.13, which is limited due to the hydrological potential.

As technical options for MHP plants, **synchronous generators** and **induction generators** (IMAG = "induction motor used as generator") can be considered. Both can be wired for single- or three-phase. However single-phase induction generators are not normally manufactured in sizes above 2 kW, therefore they are not taken into consideration as a possible option.[218] For both types of generators the required output capacity can be calculated according to the procedure described in Figure 4.14. For IMAGs a simple de-rating rule can be applied, which is sufficient in many cases:

$$IMAG\ rating\ \left[kW\right] = \frac{required\ \ power\ \left[kW\right]}{de - rating\ \ factor\ \ of\ \ 0.8}$$

***Formula 4-25***

This allowance compensates for possible load imbalance in the case of three-phase machines but also winding imbalance in the case of single-phase machines.[219]

After a short discussion on governors and control systems the special features, pros and cons of the two categories of generators and suitable governors are illustrated in Table 4.19.

#### *4.3.4.4 Governors and control systems*

The interdependency between turbine speed, frequency and voltage is evidenced by the fact that controlling the turbine speed to keep it constant also keeps the generator rotating at a constant speed and thereby stabilises the line voltage and frequency.
The main control options are:

[215] Harvey, 1998, p.252
[216] loc. cit., p.250, 271 and personal communication: Valentin Schnitzer (hydropower), 04/2002
[217] Transmission system losses (mainly originating from losses in the transmission line; step-up and step-down transformer losses can be neglected) also have to be accomplished by the generator supplying the grid.
[218] Harvey, 1998, p.278f
[219] loc. cit., p.279

- governing the water flow (by means of manual or hydraulic valves or vanes, oil pressure governor)
- speed regulation for voltage control (automatic voltage regulator AVR)
- load regulation for voltage and frequency control (electronic load controller ELC or induction generator controller IGC)

Table 4.18 depicts the characteristics of different control systems.

| **control system** | **control device** | **governing the...** | **controlling the...** |
|---|---|---|---|
| speed control | mechanical governor | turbine | turbine speed → frequency |
| voltage control | AVR, IGC | generator | line voltage |
| frequency control (load control) | ELC, IGC | dump load | voltage and frequency |

*Table 4.18: Comparison of different control systems*[220]

Although one might expect mechanical governors to be simpler in structure, easier to maintain and even to be manufactured locally, they do not offer any of these advantages. In addition, although electrical governing systems are a bit more sophisticated, they are often cheaper than the mechanical ones and easier to maintain. This study therefore focuses on electrical governing devices, since they are considered preferable for the conditions of interest.

**Automatic voltage regulator (AVR)**
An AVR continuously checks the AC voltage and adjusts the field/excitation current so that the correct AC voltage is generated. In the case of small- and moderately-sized modern synchronous generators (up to 50 kVA), the AVR is usually an electronic unit built into the machine.[221] Otherwise an AVR has to be provided separately. In general AVRs can be used for single- and three-phase systems. The type of voltage regulation used in a generator determines the respective frequency-voltage combinations fed to the appliances used. Together with the type of governing system in use, life span and reliability of appliances can be affected, thus having also important maintenance and cost implications. Since AVRs are generally integrated into modern synchronous generators, it is not necessary to itemise an AVR as a specific cost element.

**Electronic load controller (ELC)**
The ELC is a turbine governor, which indirectly keeps the turbine speed constant, by means of an additional "dump" load, which absorbs any surplus available energy. The ELC ensures that the generator, either synchronous or IMAG, runs at constant frequency, and thus speed, by keeping constant the total resistive load. The most common type is a water-cooled dump load, which can in addition be a source of water heating. The ELC should provide a sufficient load on the generator such that when the user load is off, and the turbine is providing full power to meet the maximum expected demand, all the power can be safely absorbed by the dump load without the turbine and generator increasing speed.[222] The power dissipation capacity should be between 5 % and 15 % (= variable "reserve" · 100) greater than the usual expected maximum power output of the generator[223], as it is expressed by Formula 4-26.

$$capacity\ ELC = S_{generator} \cdot pf \cdot (1 + reserve) \quad [kW]$$ ***Formula 4-26***

where

$S_{generator}$ = generator unit rated output [kVA], estimated according to Figure 4.14
*pf* = average power factor [ ]
*reserve* = reserve for power dissipation capacity of the ELC [ ], between 0.05 and 0.15

220 modified according to Widmer, Arter, 1992, p.33
221 Harvey, 1998, p.263
222 loc. cit. p.274
223 loc. cit., p.271

The ELC senses frequency variations to activate the dump load. For example, if the power factor of the load decreases then the required generator current increases, even though the ELC ensures that the speed, and the power generated, remain the same leading to a decrease in the AC output voltage. ELCs offer a very convenient and reliable kind of governing and are available for single- and three-phase systems.

**Induction generator controller (IGC)**
The induction generator controller especially developed for MHP plants performs two functions in one, voltage control and speed (and therefore also frequency) control, thus replacing both AVR and ELC. The IGC makes use of the load-speed characteristic of the turbine driving the generator together with the generator's voltage-speed characteristic. It functions similar to an ELC; but instead of frequency it senses the generator output voltage. This voltage is controlled by diverting varying amounts of power to the dump load (see ELC).
IGC's can be applied to single- and three-phase systems.[224] Although the IGC is cheaper than the alternatives, the option of applying an IGC instead of ELC and AVR entails the possibly negative effect of frequency variation (5 - 10 %). The dump load for an IGC can, as for ELC, be estimated according to Formula 4-26.

The most suitable control system for a specific case can be selected using Figure 4.15.

#### *4.3.4.5 Survey on generators, governors and control systems*

Table 4.19 summarises the special features, advantages and disadvantages of the two categories of generators, which come into question for MHP plants in Ethiopia.

[224] Harvey, 1998, p.287

| | synchronous generator (alternator) | IMAG (= asynchronous generator) |
|---|---|---|
| **features** | - three-phase synchronous generator with higher power/weight ratio than single-phase synchronous generator<br>- electrical frequency and mechanical speed are synchronous $rpm = \frac{120 \cdot frequency}{number\ of\ poles}$ rpm = revolutions per minute<br>- requiring exciter feeding DC current into the field winding<br>- efficiency between 0.65 for 1 kVA and 0.9 for 20 kVA machines<br>- off-the-shelf models are normally 4-pole, producing 50 Hz at 1,500 rpm<br>- standard 4 or 6 poles | - more appropriate for three-phase than for single-phase systems<br>- frequency not directly proportional to shaft speed; changing slightly with load changes $rpm = \frac{120 \cdot frequency}{number\ of\ poles} \cdot (1-s)$ rpm = revolutions per minute s = slip (negative for generator)<br>- **less common** but increasingly used for MHP<br>- maximum mechanical <u>input</u> power must not be greater than the rated output power of the machine as motor<br>- any standard supply system voltage can be obtained<br>- for production of 50 Hz (neglecting s): 3,000 rpm (2-pole), 1,500 rpm (4-pole) or 1,000 rpm (6 pole) available → speed close to maximum power output speed of turbine can be selected |
| **suitable control mechanism** (see 4.3.4.4) | - **electronic load controller (ELC)** (automatic voltage regulator AVR already integrated into modern synchronous generators) | - electronic load controller ELC and voltage regulator AVR or better:<br>- **induction generator controller (IGC)**, which is also cheaper |
| **advantages** | - robust, simple to control and almost maintenance free in a brushless version<br>- at capacities > about 25 kW cheaper than IMAGs<br>- for medium range (> 100 kW) competitive because IMAG of this range not widely available<br>- large motors can be started<br>- in general in developing countries not readily available, must be imported | - easily and cheaply available as motors (easiest < 50 kVA)<br>- simply constructed and repaired<br>- reliable, rugged, require little maintenance (no brushes)<br>- withstand 100 % overspeed<br>- self-protecting<br>- easily used when connected to existing grid<br>- since 1985 increasingly used for < 50 kW with cheap induction generator controller IGC for voltage and speed control<br>- resistive loads can be supplied with only addition of capacitors, low cost ! |
| **disadvantages** | - in the case of 10-20 % oversizing (because of ELC) additional costs and reduction of part-load performance<br>- carbon brush types need more maintenance<br>- require frequency (ELC) and voltage regulator (AVR) | - stand alone self-excited option requires excitation capacitor and voltage regulation system or "controller"<br>- IMAG[225] with IGC: star-delta starters and power factor correction should be used to start large motors<br>- lower part-load efficiencies<br>- relative uncertainty of performance<br>- higher voltage and frequency variation even with IGC |

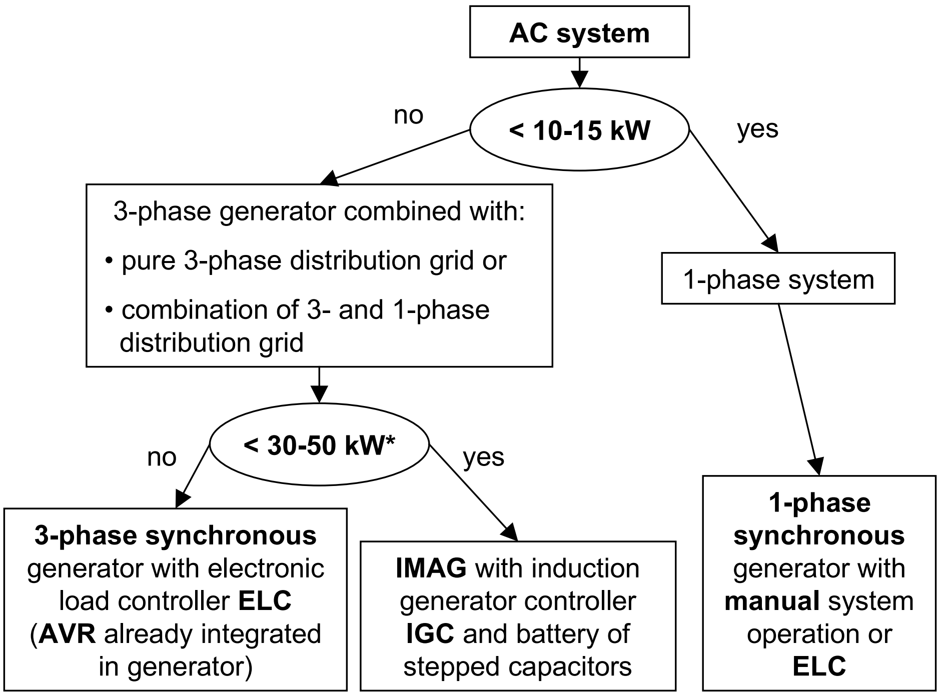
*Table 4.19: Comparison of synchronous generators and induction generators[226]*

[225] IMAGS are unable to deliver reactive power without special measures; their generation characteristics are sensitive to varying power factor, therefore the latter should be kept constant (power factor correction by means of capacitors)
[226] summarised from Harvey, 1998 p.256ff, Inversin, 1986 p.220ff and Widmer, Arter, 1992, p.23ff, Chapallaz et al., 1992, p.13

A standard squirrel-cage induction motor can be used very efficiently and without modification as a generator in **isolated schemes up to 50 kW**[227] **and up to 100 kW for parallel operation**.[228]

Summarising, the IMAG option for three-phase generation should be preferred to the synchronous generator if at least some of the following criteria are satisfied:
- the isolated scheme has a demand of less than 50 kW
- investment capital is limited
- the system should be as simple as possible
- experienced designers are involved
- the required IGC is available
- a connection to a larger grid is possible and economically viable, which is very improbable in Ethiopia, making the control system simpler.

The arguments listed and analysed in the three preceding sections 4.3.4.1 to 4.3.4.3 lead to the development of the "decision tree" illustrated in Figure 4.15.




*and sufficient power factor (> 0.8) and no heavier electrical motors to be started direct on line

*Figure 4.15: "Decision tree" for generator, control system and grid design*

For Ethiopian conditions a general recommendation is that designers should still aim at the utilisation of **synchronous generators**, because the IMAG is still not mass produced, so the provision of spare parts may pose a problem.

#### *4.3.4.6 Switchboard*

The switchboard devices measure and monitor electrical parameters and, by means of fuses, relays etc., protect the system against short-circuit currents, overcurrent and overvoltage. The switchboard allows the control of normal starting, shut-down and circuit opening in a minimum of time.

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227 Assefa, 1999, p.35
228 Chapallaz et al., 1992, p.14

In general the control panel should incorporate:[229]

- measuring instruments for: generated voltage and frequency, load current, ballast voltage or current or stepped indicators, a time counter and kWh meter

The switchgear shall comprise:

- a moulded-case circuit breaker MCCB or a miniature circuit breaker MCB for handling small currents for connecting or disconnecting the generator from the grid. The rated breaking capacity of the switchgear should be higher than the maximum possible fault current.

The measuring and protection equipment recommended for isolated MHP systems in the different ranges of rated outputs is summarised in Table 4.20.

| | **< 10 - 15 kW** | **15 - 50 kW generator output** | **50 - 300 kW generator output** |
|---|---|---|---|
| | **1-phase synchronous** generator with manual system operation or ELC | **IMAG** with IGC and capacitors | **3-phase synchronous** generator with ELC and AVR |
| **protection** | over-voltage relay | over-voltage relay | |
| | - | under-voltage relay | |
| | 1 circuit breaker per phase | 1 circuit breaker per phase + over-current relay | |
| | - | earth fault relay | |
| **instrumentation** | - | V-, A-, kW- and kWh-meters | |
| **specific characteristics** | only suitable for almost constant loads | tolerates moderate load changes | suitable for normally varying loads, increased safety |
| **accuracy of system control** | $\Delta$ U: +/- 5 %<br>$\Delta$ f: +/- 15 % | $\Delta$ U: +/- 2 %<br>$\Delta$ f: +/- (5-10) % | $\Delta$ U: +/- 2 %<br>$\Delta$ f: +/- (0-6) % |

U = voltage, f = frequency

*Table 4.20: Recommended measuring and protection equipment*[230]

#### *4.3.4.7 Transformers and transmission*

If the powerhouse with turbine and generator is remote from the load, a transmission line is required. A transformer at the start of the transmission line near the generator is used to step up the voltage to a higher value to minimise transmission losses and large voltage drops. Step-down transformers at the end of the transmission line provide a less dangerous lower voltage to the consumers. By comparing the investment and maintenance costs for transformers and high voltage lines, including accessories, such as more expensive insulators, with the costs of the power losses and the larger cable cross sections needed for low voltage (LV) lines, it is found that, in general, **LV lines** are more economical only for **distances of less than about 1.5 km**.[231] This is valid for three-phase 380 V lines. In that case a voltage of 480 V is generated in order to supply the load centre with at least 380 V (line to line) after a certain voltage drop. For distances of more than 1.5 km, to avoid large voltage drops on long LV lines, their cross section has to be increased significantly. Given the fact that the cost increases as the square of the transmission distance[232], smaller conductor cross sections, either accommodated by using transformers or acceptance of higher losses, should be chosen to avoid exaggerated costs. Because MHP power generation sites are often located on a low point, i.e. in a valley, whereas in general people in Ethiopia settle at higher elevations, this distance of 1.5 km is quickly exceeded, making the possibility of a purely LV option the

[229] according to guidelines from ESAP / AEPC Energy Support Assistance Programme / Alternative Energy Promotion Centre
[230] summarised and modified according to Widmer, Arter, 1992, p.41; Chapallaz et al., 1992, p.11
[231] Jackson, Lawrence, 1982, p.113
[232] Fuest, 1999, p.4; Harvey, 1998, p.296

exception in rural Ethiopia. In most cases, a **medium voltage system (15 kV)**[233] is expected to be the appropriate solution. Up to now the 15 kV level was the one mainly used by EEPCO for rural electrification starting from the national grid (ICS). The limited reach of a 15 kV system led to the requirement for a large number of low-rated substations, yielding high fixed cost per unit of energy supplied. Therefore EEPCO decided to switch to a 33 kV transmission system for new grid extensions. In areas which can be adequately serviced from the existing 15 kV supply, a new 33 kV supply would not deliver any net benefit.[234] The circumstances of MHP systems are completely different. In the ICS one substation should preferably supply a huge number of consumers, whereas the load centre to be supplied by the step-down transformer of an MHP system is clearly limited. **Up to transmission distances of about 20 km**, a 15 kV line with 3 wires is the adequate option for MHP systems, due to the cost reduction compared to transmission at 33 kV. This recommendation is in accordance with a rule of thumb for the choice of the transmission voltage level which advises "one kV for one km".[235] Concluding, the main arguments for the 15 kV system are, that it

- is sufficient to avoid excessive voltage drops in an MHP system
- is less expensive than a 33 kV system, having also regard to accessories
- was a national standard up to now, improving availability of spare parts
- offers the long-term possibility of inter-connection to existing grids.

The **step-up transformer** of an MHP system is designed to carry the generated real and reactive powers. The kVA rating chosen for the transformer should not limit the generator output under any credible operating condition. Thus the kVA rating of the transformer should be set at **105 %** of the total kVA rating of the generator[236].

The capacity of the **step-down transformers** should conform to the apparent power required by the total consumer load of the branch that the transformer is designed for. The capacity depends on the structure of the electricity grid.

#### *4.3.4.8 Wiring and conductors*

Concerning the **number of phases and wires** the following options are eligible:

- three-phase, 3 wire
- three-phase, 4 wire
- single-phase, 2 wire
- **S**ingle **W**ire **E**arth **R**eturn system SWER

***Transmission:***
For MV transmission lines a **three-phase - 3 wire** system[237] is recommended. The obvious benefit is that the use of three wires instead of four reduces the conductor costs by up to 25 %.

***Distribution:***
In general a three-phase, 3 wire system is only practicable for high and medium voltage transmission. For low voltage distribution grids however the **three-phase, 4 wire system** and the **SWER** system are suitable (see section 4.3.4.2).

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233 strictly speaking an even lower voltage (2.5-10 kV) would be sufficient but as it is not much cheaper, has higher energy losses, requires larger conductors (to distribute the same amount of power) and does not correspond to the national Ethiopian standard (leading to problems with spare parts and future interconnections), the national standard (of 15 kV) is much more advantageous; see also: Jackson, Lawrence, 1982, p.113
234 EELPA / ACRES, 1994, p.2-1
235 Spring, 1998, p.2
236 Tropics Consulting Engineers, 1999, p.4-15 (Feasibility Study and Final Design of 7 MHP Sites in Oromia, Final Design Report Dongage)
237 a three phase, 3 wire system operates at one single voltage

As a general rule, **conductors** in isolated grids should be designed for the maximum power that can be generated.[238] Important criteria for conductor design, i.e. material and cross section are:

- the desired voltage level and the power to be transmitted
- the acceptable voltage drop and resulting power loss
- maximum current density [A/mm²] at the prevailing ambient / atmospheric conditions; elevated temperatures and a small ratio of conductor surface to cross section reduce the dissipation of heat

In a three-phase system, power, voltage and current in every phase can be calculated according to the following formulas:

$$p_{per\ phase} = \frac{p_{total}}{3} \qquad [kW]$$

**Formula 4-27**

$$\left|U_{phase\ to\ neutral}\right| = \frac{\left|U_{phase\ to\ phase}\right|}{\sqrt{3}} \qquad [kV]$$

**Formula 4-28**

$$\left|I_{per\ phase}\right| = \frac{p_{per\ phase}}{\left|U_{phase\ to\ neutral}\right| \cdot \cos\varphi} \qquad [A]$$

**Formula 4-29**

where

$p_{total}$ = total power to be transmitted [kW]
$p_{per\ phase}$ = power per phase [kW]
$U_{phase\ to\ neutral}$ = line to neutral voltage [kV][239]
$I_{per\ phase}$ = current per phase [A]
$U_{phase\ to\ phase}$ = line to line voltage = phase voltage [kV]
$\varphi$ = phase angle between current and voltage ($\cos\varphi$ = power factor = about 0.7 - 0.9)[240]

The equations show that a higher voltage level necessitates a lower current flow (Formula 4-29), thus allowing a smaller conductor cross section.[241] Given the power that must be transmitted at a selected voltage level and the admissible voltage drop over a specific length of line, the total resistance can be calculated using Formula 4-30.

$$\phi = \frac{perc \cdot U_{phase\ to\ phase}^{\ \ 2} \cdot 1{,}000}{p_{per\ phase} \cdot l}$$

**Formula 4-30**

where

$\phi$ = (real) impedance per length [Ω/km]
*perc* = accepted percentage of voltage drop [ ]
*l* = length of line [km]

Once the expected impedance $\phi$ is determined its ohmic part $R_L$ can be estimated as shown in Formula 4-31, by subtracting the reactance $X_L$ which is taken from tables.[242]

$$R_L = \phi - X_L \cdot \tan\varphi \quad \approx \quad \phi \qquad [\Omega / km]$$

**Formula 4-31**

where

$R_L$ = ohmic part of the line impedance [Ω/km]
$X_L$ = reactance of inductive part of the line impedance [Ω/km]

238 Widmer, Arter, 1992, p.35
239 400/230 V and 380/220 V systems are commonly used
240 Harvey, 1998, p.242; Widmer, Arter, 1992, p.49, 55 and 72
241 Elgerd, Puije, 1998, p.191
242 Widmer, Arter, 1992, p.72-74

As a matter of simplification, the inductivity can be neglected, thus setting $R_L$ equal to $\phi$.
As soon as a conductor material with a specific conductivity g (see Table 4.21) is selected the maximum tolerable ohmic resistance per length determines the minimum required cross section A for the conductor.

$$A\,[mm^2] = \frac{1}{g\,[m/(\Omega \cdot mm^2)] \cdot R_L\,[\Omega/m]} \approx \frac{p\,[kW] \cdot l\,[km]}{g\,[m/(\Omega \cdot mm^2)] \cdot perc\,[] \cdot U^2\,[kV^2]}$$

***Formula 4-32***

where

*A* = cross section of the conductor [mm²] *g* = conductivity [m/(Ω·mm²]

The conductivity for different materials is illustrated in Table 4.21.

| conductor material | at 20°C | at 40°C | at 60°C | at 80°C |
|---|---|---|---|---|
| Al/St | 30.0 | 27.8 | 25.9 | 24.2 |
| Al | 35.4 | 32.8 | 30.5 | 28.5 |
| Cu | 56.3 | 52.1 | 48.5 | 45.4 |

*Table 4.21: Conductivity g [m/(Ωxmm²)] for different temperatures and different conductor materials*[243]

Once a standard cross section for the conductor has been chosen, the impedance $\phi$ can be re-calculated and the voltage drop and power loss can be determined in order to ascertain if the selected cross section meets the initial criteria. For example, in general the tolerable voltage drop should not exceed about 5 % for the whole system.[244] The whole procedure for the rough estimation of the conductor cross section is shown in Figure 4.16.

Strictly speaking the maximum **current density** to avoid melting should also be checked, taking into account the estimated cross section, A, of the conductor. The permissible current density depends on the cable material, the cross section and the ambient temperature, and it can be taken from tables.

The **conductors** most commonly used are *all aluminium conductors (AAC)* and *aluminium conductors - steel reinforced (ACSR)*. They have less weight and are cheaper than copper conductors. ACSR have approximately the same tensile strength as copper wires. In the special case of MHP systems, AAC for the LV distribution grid and the stronger but more expensive ACSR for the MV transmission system are recommended. The length of the transmission line is basically the distance between powerhouse and load centre. The distribution network can be radial as star grid, which is cheap and appropriate as long as the load density, which is the consumption divided by the supply area in km² is not very high. The advantage of a ring grid, which is in general more costly, is its moderate voltage drop and its reduced vulnerability to faults. In star grids a fault in one line simultaneously disconnects many more consumers.[245]

[243] Widmer, Arter, 1992, p.72
[244] Jackson, Lawrence, 1982, p.115
[245] Heuck, Dettman, 1999, p.52

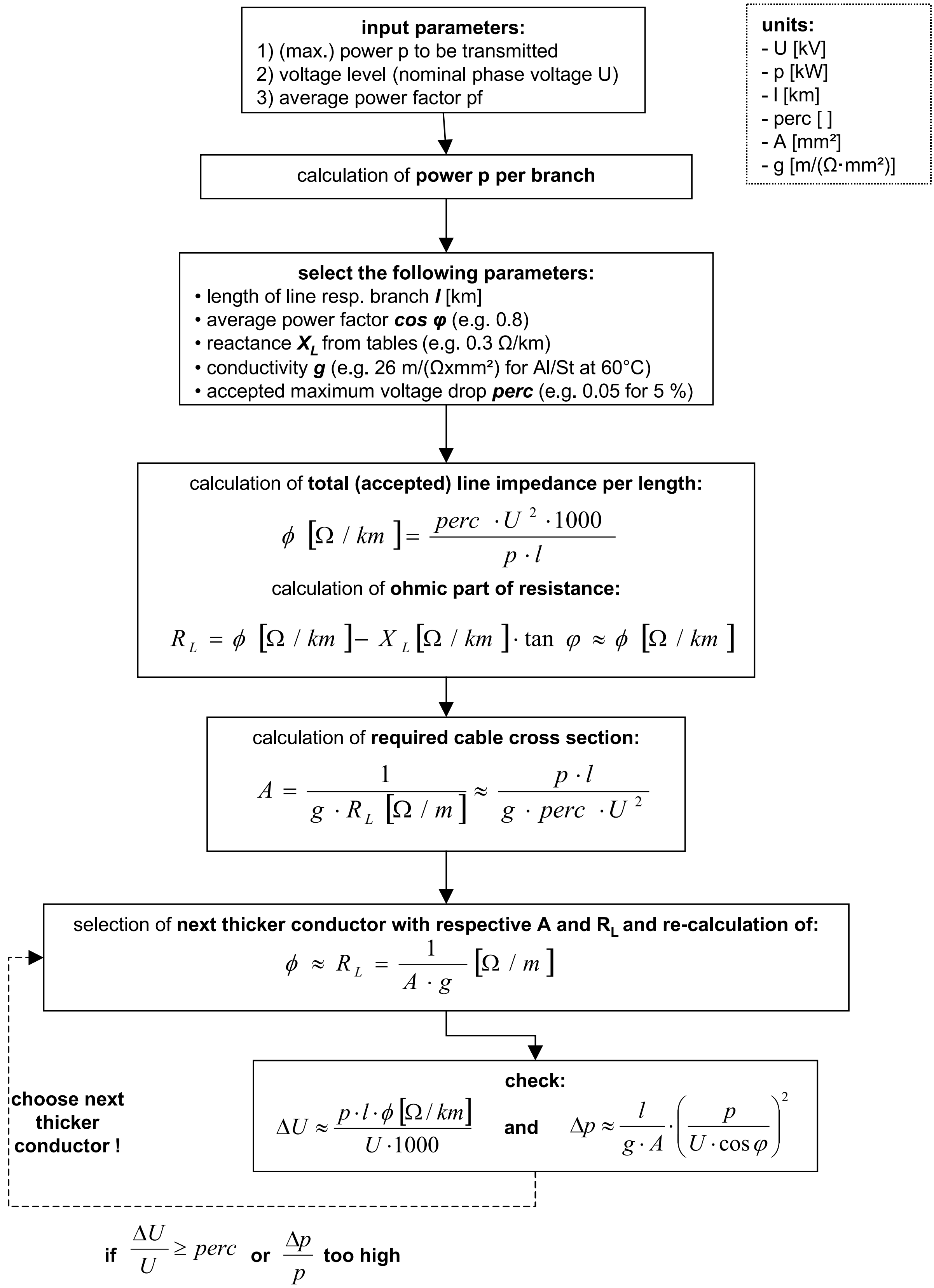


*Figure 4.16: Flowchart for the estimation of conductor diameter*

It is necessary to weigh up the pros and cons of the two position options for transmission and distribution grids, "bare conductor as overhead line" and "underground cables". **Overhead lines** as opposed to underground cables are characterised by the features in Table 4.22.

| advantages of overhead lines | disadvantages of overhead lines |
|---|---|
| - less expensive | - exposed to lightning, falling trees, wind and illegal tapping |
| - readily available | - land clearing required |
| - simple to install and to maintain; deterioration by ploughing, construction work, erosion etc. easier to control | - require poles and insulators; replacing of poles every 15 years, underground lines can last for more than 50 years |
| - easy to splice and tap as new loads develop | - for given conductor size less efficient than underground cable, since wide spacing of conductors cause inductive losses |
| - line faults easy to locate | |
| - no insulation required, as for underground cables | |

*Table 4.22: Pros and cons of overhead lines as opposed to underground cables*[246]

Since cost is a pivotal criterion, the option of **overhead lines** is recommended for rural Ethiopia. For MHP systems wooden **poles** of 8 - 9 m height for distribution and 10 - 11 m height for the transmission line of 15 kV are appropriate. Where suitable timber products are available, a full-pressure-treated wood pole may be produced for 50 % less than the equivalent concrete support structure, and it generally has half the weight and one third more tensile strength than the average concrete pole of comparable size. [247] The spans between poles vary from 30 to 60 m.[248] As a basis for a decision support model the following technical specification is recommended to achieve a preliminary cost estimation:[249]

- <u>transmission</u>: 15 kV line, three-phase, 3 wire; ACSR wiring of 20 mm², impregnated wooden poles of 10 m height at 50 m intervals; step-up transformers 0.4/15 kV and step-down transformers 15/0.4 kV with the required kVA ratings
- <u>distribution</u>: LV line, according to EEPCO standard: three-phase, 4 wire system with 400 V line-to-line and 230 V line-to-earth; 25 mm² AAC for three phases and 15 mm² AAC for neutral line; impregnated wooden poles of 8 m height at 30 m intervals; probably combined with SWER lines for distant scattered customers.

For more extensive distribution grids 50 mm² instead of 25 mm² AAC are recommended in order to avoid excessive voltage drops.

#### *4.3.4.9 Special aspects for grid connection option*

As far as the grid connection option as alternative to diesel and MHP system is concerned, it must be designed starting either from an existing substation with surplus capacity or from a substation to be specially constructed and fed by an existing high voltage transmission line. The feasibility of these options depends on the distance between the town or settlement to be supplied and the available capacities of existing lines and substations. The investment costs for the transmission line itself do mostly not depend on the capacity to be transmitted, because, generally, a standard type of wiring is applied which is oversized and thus also copes with stronger load increases.

In general, substations in Ethiopia are fitted with transformers working at voltages of 132, 45 or 15 kV, 15 kV having been the medium voltage level most commonly used in the country. As already mentioned in section 4.3.4.7 the reach of the 15 kV transmission line is quite limited. Although not yet implemented by EEPCO, the next economical and cost-effective voltage of 33 kV is envisaged for future extensions of the ICS. In general, the capital costs of constructing 33 kV transmission lines are only marginally higher than those of 15 kV lines, whereas a 33 kV system experiences lower losses and requires fewer substations. On the other hand, a widespread change in the standard system voltage imposes incremental costs

[246] Harvey, 1998, p.296f
[247] Jackson, Lawrence, 1982, p.113
[248] loc. cit. p.114
[249] EELPA / ACRES, 1994, p. 5-15

due to loss of volume purchasing discounts and increased inventory requirements for spare parts. There are also operational and even safety difficulties related to staff training and documentation requirements. Consequently, balancing the pros and cons, in areas which can be adequately serviced from an existing 15-kV supply bus with surplus capacity this voltage level should be retained, whereas in areas where a new substation or even an additional transmission line is required, the 33 kV system can deliver a net benefit.[250]

If a 132 kV line passes nearby but no substation is available, theoretically, a 132/33 kV step-down transformer would be needed, whereby the transformer should be of two-winding, three-phase type. In addition, one 33 kV out-going feeder bay is required in the substation in order to control and protect the supply system through the use of a 33 kV circuit breaker, lightning arrestors, etc..[251] The construction of an additional substation explicitly for the supply of a relatively minor load centre requiring less than 300 kW is quite expensive and not competitive with the MHP or diesel genset option. Since the implementation of a new substation entails disproportionately high costs, the option of grid connection is based on the assumption that a **substation with surplus capacity** exists and it is only necessary to extend the transmission line. Then, either

- a **15 kV** line for a distance up to 50 km or
- a **33 kV** line for distances exceeding 50 km

needs to be constructed. In chapter 6 there is an estimate of the length of transmission line of 15 or 33 kV which is still competitive in cost with the respective MHP option referring to costs in ETB per kW of required capacity. Based on the recommendations given by ENREP (Ethiopian National Rural Electrification Project), for a 33 kV transmission line an AAC conductor having a cross sectional area of 100 mm² can be used. For a 15 kV line a 95 mm² AAC or a 129 mm² ACSR line are required. The different technical options are specified in Table 4.23.

| | **15 kV level** | | **33 kV level** |
|---|---|---|---|
| **cross sectional area** | 95 mm² AAC | 129 mm² ACSR | 100 mm² AAC |
| **spanning** | 60 m | 50 m | 60 m |
| **height of poles** | 12 m | 12 m | 12 m |

*Table 4.23: Technical specification of different options for transmission lines*

#### *4.3.4.10 Electricity meters*

Different metering systems and their appropriateness for isolated MHP systems are illustrated in section 4.9.5. If electricity meters are required they can cause considerable cost, depending on the selected system. Taking into account the customers' limited capability to pay, especially as far as high initial costs are concerned, it can be advantageous to add the cost for metering facilities to the initial investment cost of the project. Subsequently they will be apportioned to the final tariff, which is set at a level that will cover all costs including initial investment, O&M cost etc.. Accordingly, the customer finally still pays for these costs but in smaller instalments. The alternative would be to consider the metering device as part of the investment to be paid by the customer as precondition for his connection. However, the additional cost might represent a barrier which restrains people from being connected.

[250] EELPA / ACRES, 1994, p.2-1f and 5-3
[251] Tropics Consulting Engineers PLC, 1999, p. 14-4 (Feasibility Study and Final Design of Daye Mini Hydropower Project)

#### *4.3.4.11 Summary on electrical components*

Table 4.24 summarises the results of the preceding paragraphs.

| **components** | | |
|---|---|---|
| | **for 10 - 50 kW** | **for 10 - 300 kW** |
| **generator** | IMAG of 50 Hz, 4 or 6 pole, 400 V, 3 phase[252] | synchronous generator of 50 Hz, 4 or 6 pole, 400 V, 3-phase |
| | **for IMAG** | **for synchronous generator** |
| **control** | IGC, voltage meter, ampere meter | ELC, voltage meter, ampere meter, frequency and rotational speed meter, kWh meter |
| | **for < 1.5 km distance** | **for > 1.5 km** |
| **transformer** | no transformer needed | step-up and step-down<br>0.4/15 kV and 15/0.4 kV transformer |
| **transmission** | - | 3 phase - 3 wire, 15 kV, 20 mm² ACSR up to 30-40 km distance, on impregnated wooden poles 10 m long at span of 50 m |
| **distribution (EEPCO standard)** | 3 phase - 4 wire (380/220 V); 25 mm² or 50 mm² AAC phase line,15 mm² respectively 25 mm² neutral line; on impregnated wooden poles 8 m long at span of 30 m | |
| **protection** | - earthing of all appliances in the power house through a buried grid<br>- over-voltage protection as minimum<br>- lightning arrestors | - earthing of all appliances in the power house through a buried grid connected to the penstock<br>- steel rod at the transformer<br>- lightning arrestors<br>circuit breakers<br>over- and under-voltage, over-current and under-frequency; < 30 kW under-voltage / under-frequency protection is not mandatory |

*Table 4.24: Summary on recommended electrical components and decision criteria*

#### *4.3.4.12 Neglected components*

The present study lays stress on, and proposes design procedures for, those components which are the crucial components of the investment cost. Therefore some components belonging to an MHP system were not studied in detail here, because they are relatively inexpensive. These less costly items include earthing, fuses, circuit breakers, lightning arrestors and other protection equipment, power factor correction by means of automatic power factor correction APFC or capacitors (induction generator excitation capacitance), and DC auxiliary batteries. The costs of the sophisticated calculations for their design are disproportionate to their more or less insignificant proportion of the total costs.

[252] only recommendable if commonly used in the respective country !

## 4.4 Determination of investment and operating costs

The present study provides a pool of information as data, decision trees, etc. that facilitate the implementation of a decision support model (DSM). In view of this objective, the following sections illustrate the importance of costs in a decision process, specify the available database, analyse crucial aspects for the estimations of investment and operating costs and give recommendations on how to structure and estimate investment and operating costs for a potential DSM. The illustration of the magnitude and lower and upper estimates of different cost items points out possible cost savings. Finally, since a DSM facilitates the investigation of different scenarios, it is useful for tracking the consequences of different cost modifications. The conclusions drawn here are applied to the case studies in chapter 6.

### 4.4.1 Costs as a crucial element in decision-making

Important decisions, influencing to a great extent investment but also operating costs, are often made in a very early planning phase, even at the conceptual design stage.[253] Paradoxically, at this stage, when special diligence in decision-making is required, only very little information is available to guide decisions. In general, the more definite the system configuration becomes, the fewer the opportunities for cost reducing measures. Most savings in operating costs depend strongly on decisions made during the investment phase. Savings are facilitated or obstructed by particular investment decisions, for example electronic load controllers which raise the investment costs but allow reduction of maintenance costs. A DSM can improve the situation by increasing the information density in various fields and by providing an instrument for sensitivity analysis.

A thorough analysis of investment and operating costs is required because the conclusions drawn from implemented projects are not uniform. For MHP plants there is considerable debate as to whether unit costs increase or decrease as plant capacity declines.[254] On the one hand, economies of scale can significantly reduce costs for bigger plants. On the other hand, the data from projects in Thailand, Ecuador, Nepal, Indonesia, Philippines and Pakistan show that the average installed unit cost for plants under 100 kW is approximately half that of the plants above 100 kW, because conventional engineering with sophisticated standards for design and construction is dispensable for very small plants. In particular, not only local contributions in the form of labour, material etc. in implementation and management but also unconventional improvisational technical approaches led to enormous cost reductions.[255].

### 4.4.2 Available data

According to the available information, apart from the EEPCO plants Yadot and Dembi and the recently implemented plant of Yayé (see section 2.2), no other hydropower plant with a capacity of less than 1 MW is in operation in Ethiopia. Even for those plants a detailed financial analysis is hardly possible because for the EEPCO plants only cost estimations from the feasibility study are available, but no detailed actual costs of the implemented systems. For Yayé MHP plant only subtotals of costs are available. Such conditions hamper the estimation of **investment costs**, because the evaluation of tenders is one of the most reliable methods to ascertain unit prices and to assess the importance of the different cost elements. The remaining major sources of data which are accessible are:

- studies recently executed by different consultants such as Tropics Consulting Engineers, Northwest Investigation, Design and Research Institute, Metaferia Consultants etc.

[253] Götz, 2000, p.295
[254] Clark, 1982, p.127
[255] loc. cit. p.128ff

- unit prices from construction enterprises, producers and trading companies such as ABB, Siemens, Selam TVC, Akaki Spare Parts, Ture P.L.C., Biselex International Trading, Reis Engineering, Elettromeccanica Santilli etc.

From 40 contractors approached for unit prices all over the country only three answered by sending a list of their prices.

The data is even more inadequate for **operating costs**, for which almost no information at all is available. The smaller EEPCO plants are subsidised and real operating costs for the individual systems could not be obtained. The MHP plant in Yayé started operation only in year 2002 so that no experience on operating has been gathered so far. Since expenditure on fuel accounts for a major percentage of operation cost for systems supplied by diesel gensets, SHELL and MOBIL have been asked to find out the local tariffs in the main cities all over the country. For the appraisal of annual wage expenses for operation and maintenance staff, the so-called "salary estimation manual"[256] was used.

The unit prices, salaries etc. used in the present study are rough cost estimates. They are based on figures originating from the evaluation of studies, cost estimate data manuals etc. mainly from the years 1997-2000. For reasons of comparability they are all **adjusted to prices for the year 2000** by means of an average inflation rate of about 5 % per year. The year 2000 is used as the reference year for all calculations effected here.

### 4.4.3 Breakdown of investment costs

Investment costs occur, as opposed to operating cost, at a single time, at the beginning of the project cycle. In general they can be divided into costs for **planning** and costs for **implementation**. The complete categorisation is depicted in Figure 4.17.

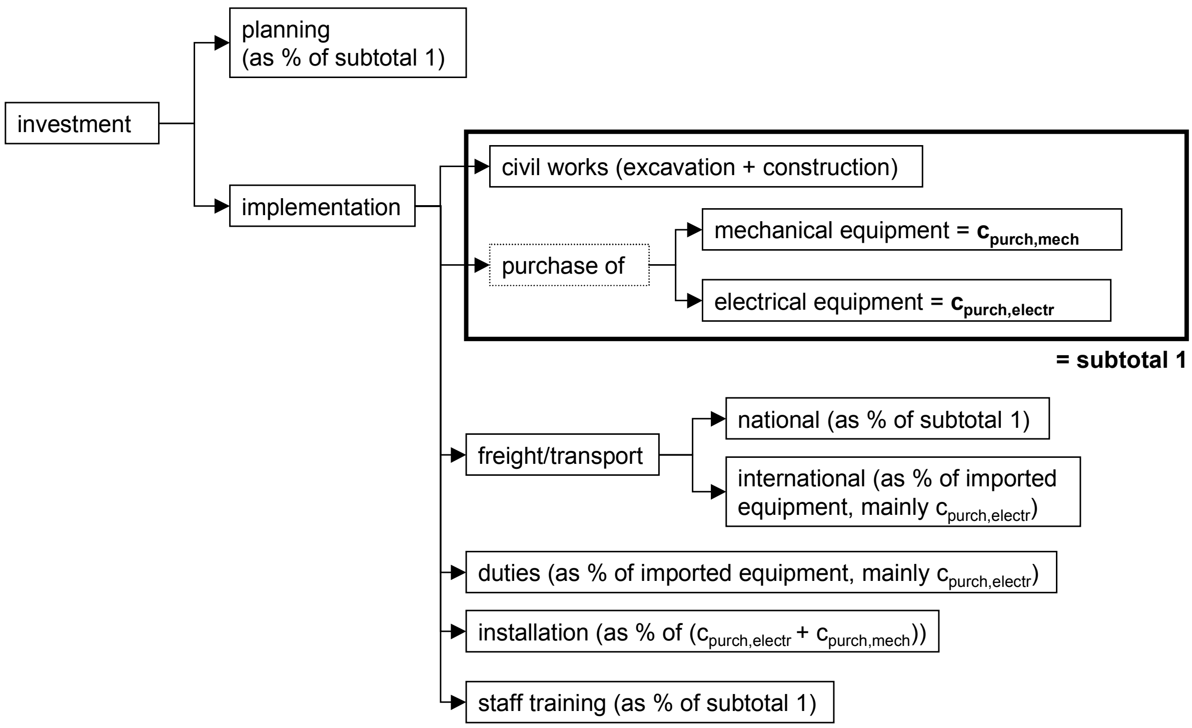


*Figure 4.17: Subdivision of investment costs*

The numerical contribution of these different cost types to the investment costs is summarised in Table 4.28. The planning costs are estimated as a percentage of the subtotal 1 implying the assumption that the higher this subtotal and in general the bigger and the more

[256] Ministry of Water Resources (Water Supply Development and Rehabilitation Project)

sophisticated the energy supply system the higher the required planning effort. The categorisation of implementation costs reveals differences between the relevance of the individual types of costs for civil works, mechanical and electrical equipment. Most of the civil works unit prices are specified as cost for "excavation" and "construction" and therefore they already include the costs of building materials and installation. Consequently, costs for civil works are considered only when calculating national transport cost, staff training and planning costs. Electrical equipment is not produced in Ethiopia and has therefore to be imported, either from other developing countries or from industrialised countries. Procurement from developing countries in general allows significant cost savings, albeit at the expense of failure to comply with technical standards, which are anyway probably too high for the particular project. Freight and transport costs as well as taxes and duties are of particular importance for these components.

#### *4.4.3.1 Planning cost*

The proportion of the total investment cost that is spent on planning is very difficult to estimate. For some case studies a percentage of 7 - 10 % of total cost is allocated to "engineering design and supervision".[257] For others planning even amounted 30 - 50 % of the total investment, which makes them become a high-risk investment in themselves, significantly increasing total investment and even leading to the absurd situation where their cost could seriously affect the project's feasibility.[258] Such disproportionate planning costs can often be attributed to uncritical transfer of terms of reference commonly used for large hydropower projects, difficulties in obtaining data like runoff, detailed maps etc., involvement of expensive foreign consultants instead of local experts etc.. In many cases pre-feasibility and feasibility studies never result in implemented projects or they have to be revised after several years of avoidable delay. In the past, energy supply systems in developing countries were often supported by loans or grants from donor agencies, and planning costs were often not included in the investment costs. The present case of EECMY plants, where planning and supervision cost are not recovered in user charges, supports this point. Consequently, information on planning costs is rare. In general, planning cost as a percentage of total costs decrease with increasing plant size and recommended values for **MHP systems** are:[259]

- 15 % for plants < 10 kW
- 11 % for plants 10 - 100 kW
- 8 % for plants 100 - 1,000 kW

The design of civil works and mechanical installations require relatively intense work due to analysis of runoff behaviour, flood forecasting etc., whereas the planning cost for **diesel plants or grid connection** are expected to be much lower. The planning costs for such installations are estimated using the following percentages of total cost:

- about 8 % for plants < 100 kW
- about 5 % for plants 100 - 1,000 kW

#### *4.4.3.2 Freight and transport cost*

As far as internationally furnished components are concerned, which is mainly the electrical equipment, the following terms are applied, describing limits of responsibility during acquisition and shipment:[260]

- "ex works": means that all costs and risks of bringing the goods from the factory to the desired destination, i.e. cost of transportation and insurance, are with the purchaser, entailing the minimum obligation for the seller.

[257] Meier, 1981, p.103
[258] UNIDO, 1981, p.58ff
[259] loc. cit., p.60
[260] Widmer, Arter 1992, p.83

- "free on board" (FOB): means that the goods are placed by the seller, free of cost to the purchaser, on board a ship at a port of shipment named in the sales contract. The remaining costs for transport to the construction site have to be borne by the purchaser.
- "cost, insurance and freight" (CIF): means that the seller pays the costs of freight to bring the goods to the named destination and effects insurance against the risk of loss or damage to the goods during carriage.

To generate a common unit price basis for electrical equipment an attempt was made to express all prices used for cost estimates as **"CIF-prices"**, the latter referring to a transport to Bole International Airport Addis Ababa or to Addis Ababa via the Port of Djibouti. After the outbreak of the border conflict with Eritrea, landlocked Ethiopia was forced to switch the import and export of its goods to the port of Djibouti. The formerly used ports of Assab and Massawa belong to Eritrea. Ethiopia is again looking for new alternatives after an unexpected increase of port charges in Djibouti.[261] The use of the Kenyan inland container depot[262], the port of Mombasa[263], or a rail link to Port Sudan[264] are some of the possibilities currently being discussed. The **transport situation** within Ethiopia is still unsatisfactory: in 1998/1999 only about 3,300 km of all Ethiopian roads were asphalt roads[265] and many roads and the railroad from Djibouti, the only one in Ethiopia, are not suitable for heavy transports.[266] Consequently the transport-related cost depends heavily on the distance to be covered and the quality of the roads. In general, cost estimations in Ethiopia, for example for civil works, are based on construction sites in Addis Ababa. The transport cost within Ethiopia can be adjusted by means of specific cost factors applied to civil works and the purchasing cost of mechanical and electrical equipment and depending on the **distance** between the construction site and Addis Ababa. The use of these cost factors, as suggested in Table 4.25, assumes that transport costs are proportional to the investment sum. This is a simplification which is not always reliable as expensive but small or light weight components are overrated, and vice versa.

| distance Addis Ababa - construction site | cost factor to be applied |
|---|---|
| up to 700 km | 1.03 |
| 700 - 1000 km | 1.05 |
| > 1000 km | 1.07 |

*Table 4.25: Cost factors to estimate transport costs within Ethiopia[267]*

Because the speed of a vehicle depends on the **quality of the road**, inland transport on gravel roads costs 1.5 times more than on asphalt roads and on unsurfaced roads 2.5 times more.[268]

***Example:***
cost for civil engineering structures and purchasing of equipment: 1 million ETB
distance from Addis Ababa to construction site: 1,000 km (900 km on asphalt, 95 km on gravel road, and 5 km on unsurfaced road)
resulting total cost: 1,000,000 ETB·(1.05·0.9+1.05·1.5·0.095+1.05·2.5·0.005)
= 1,108,000 ETB → *108,000 ETB is transport cost.*

If the existing infrastructure is insufficient and an additional access road is required, the cost associated therewith is considered as described in section 4.3.3.1.

261 The Daily Monitor, 29th January 2001: "Ethiopia, Djibouti ..."
262 Fortune, 21st January 2001: "Ethiopia Exploring Ways..."
263 The Reporter, 24th January 2001: "Mombasa Port ..."
264 The Daily Monitor, 24/25th January 2001: "Ethiopia, Sudan ..."
265 Central Statistical Authority CSA, 2000, p.195
266 Ostrowski, 1995, p.10
267 personal communication: Bekele Gadissa (Water Works Construction Enterprise Addis Ababa), 2000
268 standard values for inland transport

#### 4.4.3.3 Taxes, duties and licences

The most relevant **taxes** are income taxes (see section 4.8.4) which are counted among recurring costs and therefore are not considered for the investment cost estimation. The **licences** which have to be acquired are specified in section 4.8.1. They can be expected to cost in the region of 4,000 ETB for MHP systems and so they can in general be neglected compared to the total investment cost. **Customs duties** are payable on imports by all persons and entities which have no duty-free privileges. The main regulation on customs duty is Proclamation No. 38/1993. The rates are published by the Ethiopian Customs Authority.[269] The rates of customs duties for electrical equipment required for energy supply systems range between 5 % and 30 % and are summarised in Table 4.26.

| Item | Duty rate* |
|---|---|
| AC motor single-phase | 5% |
| AC motors multi-phase not exceeding 750 W | 15% |
| AC motors multi-phase exceeding 750 W | 5% |
| AC generators | 5% |
| DC generators up to 750 W | 15% |
| Diesel Gensets | 5% |
| Diesel spare parts | 15% |
| Transformer, capacity not exceeding 650 kVA | 5% |
| Batteries | 20% |
| LCD/LED | 30% |
| Capacitors | 20% |
| Fuses (<1000 V use) | 30% |
| Lightning arrestors | 5% |
| Automatic circuit breakers | 5% |
| Switch board | 5% |
| Switch board spare parts | 5% |
| Insulated cable of copper | 30% (imported by industries 5%) |
| Electrical insulators | 30% |

*10% reduction of duty rate for goods imported from COMESA (Common Market for Eastern and Southern Africa) member countries

*Table 4.26: Duty rates of imported components*[270]

Taking into account the individual duty rates and the contribution of different items to the subtotal of cost for electrical components, an average duty rate of **about 8 %** can be assumed. Possible **exemptions from custom duties** due to the acquisition of an investment license are dealt with in detail in section 4.8.1.2. A holder of an investment licence[271] is entitled to several incentives. He is exempt from payment of customs duty[272] on machinery and equipment necessary for the establishment of the respective enterprise.[273]

#### 4.4.3.4 Installation cost and staff training

Comparison of several project reports and studies offers a wide range of rates for **installation costs**. Heuck[274] estimates only 0.5 - 1 %; GTZ[275] applies 9 % of initial investment for installation. Completed projects and feasibility studies indicate at least 10 %.[276] These per-

[269] Ethiopian Customs Authority, July 2000
[270] loc. cit.
[271] minimum investment capital required see Table 4.41
[272] "customs duty" includes taxes levied on imported goods
[273] Investment Incentives Council of Ministers Regulations No 7/1996, Art.11(1)
[274] Heuck, Dettmann, 1999, p.540
[275] GTZ, 1987
[276] Note: Contract between Sidama Development Programme and Sigma Electric PLC for the installation of the Yaye plant.

centages presumably mainly refer to electrical installations. According to EEPCO[277], the installation cost, mainly wages, for the electrical part of a supply system, i.e. installation of 15 and 0.4 kV lines are in the range of 18 to 25 % of the material cost. As mentioned above, unit prices for civil works, including "excavation and construction", generally already include installation cost. For mechanical equipment the installation cost as percentage of the purchasing cost can be relatively high. For example for penstock pipes a percentage of 20 - 30 % is specified.[278] Installation costs for an MHP system as a whole are analysed in Table 4.27 which provides an approximate guide to the magnitude for the complete construction works. Manpower costs for the installation of MHP systems of different capacity ranges, including civil works, mechanical and electrical installations, are roughly estimated. Plants in the range of 5 - 20 kW are mainly designed to produce mechanical energy for mills and similar applications. Systems with capacities above 20 kW can deliver mechanical energy for agro-processing as well as electrical energy for households, commercial and industrial purposes.

| capacity range | roughly estimated system costs per kW [ETB/kW] [279] | investment cost for the named range [ETB] | average investment cost [ETB] | manpower | monthly salary [ETB] | required number | approximate construction period [months] | manpower costs [ETB] | percentage of investment cost |
|---|---|---|---|---|---|---|---|---|---|
| **5 - 20 kW** | 12,000 | 60,000 | 150,000 | unskilled labourers | 250 | 15 | 3 | 11,250 | |
| | | 240,000 | | skilled labourers (mason, carpenter, locksmith) | 400 | 3 | 3 | 3,600 | |
| | | | | experienced coordinator (e.g. operator of the mill) | 800 | 1 | 3 | 2,400 | |
| | | | | **total** | | | | 17,250 | **11.50%** |
| **20 - 80 kW** | 20,000 | 400,000 | 1,000,000 | unskilled labourers | 250 | 15 | 12 | 45,000 | |
| | | 1,600,000 | | skilled labourers (mason, carpenter, locksmith, electrician) | 400 | 4 | 12 | 19,200 | |
| | | | | MHP-specialist (engineer or turbine manufacturer) | 2,000 | 1 | 12 | 24,000 | |
| | | | | **total** | | | | 88,200 | **8.82%** |
| **80 - 300 kW** | 15,000 | 1,200,000 | 2,850,000 | unskilled labourers | 250 | 20 | 18 | 90,000 | |
| | | 4,500,000 | | construction enterprise or workshop with skilled labourers (masons, carpenters, locksmiths, electricians) | 400 | 8 | 18 | 57,600 | |
| | | | | engineers (civil and electrical engineers, coordinator) | 2500 | 3 | 18 | 135,000 | |
| | | | | **total** | | | | 282,600 | **9.92%** |

*Table 4.27: Manpower cost for the construction of MHP plants[280]*

Summarising, installation cost for *electrical* components are about 10-25 % of their purchase costs, and the installation cost for *complete* MHP systems is equal to about 8-12 % of the estimated investment cost. These figures show relatively higher installation costs for electri-

[277] Ethiopian Electric Light and Power Authority EELPA, 1995, p.47ff
[278] personal communication: Valentin Schnitzer (hydropower) 04/2002
[279] according to Table 6.2 and assuming investment costs of 12,000 ETB/kW for very small plants generating only mechanical but no electrical energy
[280] manpower requirements mainly based on personal communication information from Horst Höfling (GTZ), 06/2000

cal components. As an average proportion of the total cost for the installation of mechanical and electrical equipment for **MHP systems**, a percentage of **about 10 %** seems to be justifiable, even if it is at the lower limit. The proportion spent on electrical installation is higher for diesel plants. Therefore, they are supposed to require about 12 %. For the grid connection option an even higher figure of 15 % is introduced, due to the argument that labour-intensive electrical installation requires highly qualified staff. These percentages are applied to the total of purchase costs for mechanical and electrical equipment (see Table 4.28). It should be noted that the estimation of manpower cost is based on wages for **local experts and workers**. As soon as expatriates are involved, planning and installation costs are substantially augmented due to high travel cost and high international salaries. Percentages of 10, 12 and 15 %, which are anyway relatively low estimates, would not be applicable any more. However, the investigations led to the conclusion that well-trained local experts are available, at least in the capital Addis Ababa. With adequate payment they can be acquired for MHP projects in rural areas. The present study assumes that MHP systems are planned and implemented exclusively by local experts, which anyway is more sustainable than resorting to foreign experts. Costs for staff training (see next paragraph) account for additional requirements of funds, mainly for workers involved in implementation.

**Staff training costs** depend highly on the vocational education and skills of available persons. If skilled or semiskilled workers are not available in the area, local people must be trained in even basic skills,[281] or workers must be attracted from other areas. In any case, expenses for staff training must be added to investment costs because this indispensable training must be carried out during construction of the plant in order to guarantee that operations staff have the required technical skills. Because they depend on factors specific to the project, training cost are very difficult to estimate. As a first approximation they are fixed at about 3 % of the costs of civil works and mechanical and electrical equipment. In general, recruiting local people for skilled and unskilled tasks for civil works offers additional job opportunities and thereby increases acceptance of the system and helps to lower initial costs.[282] For the same reason, permanent staff required for operation of the plant after completion of construction works should as far as possible also be recruited in the project area. The costs for these permanent employees should be divided into single cost for initial training (as mentioned in Table 4.28) and recurring costs for regular salaries. The first item is added to investment costs and the second one to operating costs.

In the long run, it is not enough to train staff for a particular project but a sustainable network for local distribution and maintenance facilities must be established. Even if such accompanying measures cannot financially be added to the investment cost of single projects they must be considered as one of the crucial long-term tasks.[283] Otherwise the lack of stable supplier and maintenance structures will always remain a risk factor, and thus an impediment to a wider dissemination of the MHP technology.[284]

#### *4.4.3.5 Composition of investment costs*

The analyses in the preceding paragraphs and the comparison with different cost estimates of other projects result in the model of costs shown in Table 4.28.

[281] Zoellner, 1982, p.149
[282] personal communication: Horst Höfling (GTZ), 06/2000
[283] Kürsten, 1996, p.73
[284] VDI Gesellschaft Energietechnik, 1998; p.17

| costs | depending on: | range of proportion of cost according to literature etc. | costs assumed for the present study |
|---|---|---|---|
| ***civil works*** | specific site conditions | | $C_{civil\ works}$ |
| *purchase of* ***mechanical and electrical equipment*** | - manufacturers' prices<br>- local availability | | $C_{purch} = C_{purch,mech} + C_{purch,\ electr}$ |
| **"SUBTOTAL 1"** | | | $C_{purch} + C_{civil\ works}$ |
| ***freight / transport*** *from Europe to Addis Ababa via port of Djibouti* | - distance<br>- transport conditions<br>- insurance cost<br>- war risk... | 15-25 %[285]<br>60 %[286] | about 20 % of purchasing cost of imported components for MHP and 25 % for diesel systems →<br>- $C_{purch,\ imported} \cdot 0.2$ for MHP<br>- $C_{purch,\ imported} \cdot 0.25$ for diesel genset<br>- $C_{purch,\ imported} \cdot 0.25$ for grid connection |
| ***freight / transport*** *in Ethiopia* | - distance<br>- road conditions | 5 - 30 %[287]<br>3 - 5 %[288]<br>factors: 1.5 for gravel and 2.5 for unsurfaced road | according to distance, as percentage of "subtotal 1":<br>- < 700 km: 3 %<br>- 700 - 1,000 km: 5 %<br>- > 1,000 km: 7 %<br>factor 1.5 for gravel road and 2.5 for unsurfaced road<br>→ e.g. "subtotal 1" · 0.03 · 1.5 |
| ***duties*** | - legal provisions like customs regulations etc.<br>- nature of material | 5 - 30 % duty rate for electrical equipment | 8 % for electrical components<br>→ $C_{purch,\ imported} \cdot 0.08$<br>exemption from duties in case of acquisition of investment license ! [289] |
| ***installation*** *(of mechanical and electrical equipment)* | - salaries<br>- complexity of the plant<br>- availability and experience of staff | 0.5 - 25 % | as percentage of purchasing cost<br>- 10 % for MHP<br>- 12 % for diesel genset<br>- 15 % for grid connection<br>→ e.g. for MHP:<br>$C_{purch} \cdot 0.1$ |
| ***staff training*** | - availability and experience of staff<br>- complexity of the plant | | as percentage of "subtotal 1":<br>3 % roughly estimated<br>→ "subtotal 1" · 0.03 |
| ***study and planning*** | size and complexity of the plant; relatively lower percentage for bigger plants | < 10 kW: about 15 %<br>10 - 100 kW: about 11 %<br>100 - 1,000 kW: about 8 % | for MHP systems:<br>- < 10 kW: about 15 %<br>- 10 - 100 kW: about 11 %<br>- 100 - 1,000 kW: about 8 %<br>for diesel systems or grid connection<br>- < 100 kW about 8 %<br>- < 1,000 kW about 5 %<br>→ e.g. "subtotal 1" · 0.11 |
| **TOTAL** | | | $C_{total}$ |

*Table 4.28: Numerical contribution of different cost types to investment cost; grey rows are exclusively relevant for imported and thus mainly electrical components*

[285] own estimations according to oral information from Schenker Logistics / Kelsterbach, Germany
[286] GTZ values the transport cost Europe - Sri Lanka at about 80 % of the total investment cost. Based on the author's investigations (oral information Schenker Spedition / Darmstadt; May 2002) and the shorter distance to Ethiopia 20 % for transport of MHP equipment and 25 % for diesel system equipment are assessed here (CIF (Addis Ababa) = 1.2 or 1.25 · ex work European supplier prices). Investment costs for MHP equipment are higher than for diesel systems but the required transport capacity does not increase proportionally, therefore a lower percentage for MHP systems is justifiable.
[287] personal communication: Bekele Gadissa (Water Works Construction Enterprise Addis Ababa, Ethiopia), 2000
[288] standard values for inland transport
[289] Investment Incentives Council of Ministers Regulations No 7/1996, Art.9ff

In addition a percentage for contingencies can be introduced. Contingency allowances reflect physical and price changes that can be expected to increase the base cost estimate. The assessment of changes in quantities, methods and/or period of implementation, price escalation factors or other aspects may lead to additional costs, which can be "buffered" by including a certain percentage for contingencies. Since the costs applied here are anyway very rough estimates, serving mainly to allow cost comparisons, contingencies are not taken into account.

#### *4.4.3.6 Remarks on prices applied for investment costs*

Prices from or adjusted to the specific year 2000 are applied in the present study, especially in the case study analysis (see chapter 6). These unit prices constitute a useful current database, but cannot be kept up-to-date perpetually. In a DSM the data of the present study can either be used, extrapolated to the year concerned by means of a realistic inflation rate, or they can be replaced by more recent or more reliable data as soon as the latter are available. To allow such a flexible structure, the input fields should be provided with **"default values"** in order to assist the user, who consequently gets at least a rough idea of the magnitude of the required data.[290] As soon as the year for which the model is applied and an average yearly inflation rate are specified by the user, the default unit prices can be adjusted. The model should also offer the alternative of modifying the default values.

As far as imported components are concerned, the **currency exchange rate** should be taken into account. This mainly pertains to electrical equipment like load controllers, generators, transformers, cables and electricity meters. As already mentioned, all unit prices used in the present study refer to year 2000 and unit prices available in USD are converted at an exchange rate of **1 USD = 8.2 ETB (1 Euro = 7.1 ETB)**.[291] As most international distributors of these components invoice in US dollars or Euros it might happen that the exchange rate has a greater impact on the price increases than the national inflation rate, the latter, strictly speaking, being of no relevance for the world market price of imported goods.

The following aspects are recommendations for the development of a DSM and are applied in the analysis of case studies in chapter 6.
- To simplify a cost estimation as far as possible, for some items, such as an access road or a power house, the execution of the respective civil works is categorised according to quality classes (low / medium / high), the class influencing the price level (see section 4.3.3).
- For the estimation of investment costs it is necessary to assess which civil works, mechanical and electrical equipment make significant contributions. For example, since power channels are mostly long compared to the tailrace, more effort is devoted to the estimation of the cost of the power channel; the estimation involves a comprehensive design procedure.
- Cost estimates for unit prices of trashrack and sluicegate should be made in ETB per m².
- Cost estimates for valves etc. depend on their diameter. The sizes of valves are specified as DN 100, 150, 250, 300 etc. and are selected according to the size of the penstock.
- Restraining structures such as thrust blocks, slide blocks, anchors for the penstock cannot be designed in detail at such an early project stage. Therefore, as a matter of simplification, the costs are assumed to be a certain percentage of the penstock costs.
- As discussed in section 4.3.3.8, mainly crossflow, Pelton and Francis turbines are considered. Crossflow turbines up to 250 kW are locally produced and detailed price information is available from Selam TVC, Technical and Vocational Training Centre. Pelton and Francis turbines must still be imported. The cost estimates for these imported turbines are therefore not as reliable, numerous and detailed.

[290] this can be done not only for unit prices but also for other input data
[291] exchange rate according to http://www.oanda.com/convert/classic at 1st of December 2000

- As already shown in Figure 4.15, up to capacities of about 50 kW the IMAG can be used instead of the three-phase synchronous generator. This choice is confirmed by the fact that, up to 10 kVA output, the capital costs of an induction motor and capacitor battery are half the cost of a corresponding synchronous generator, and up to 25 kVA, the economic advantage is still about a third of the total investment costs.[292]
- Some electrical components, for example earthing and other protection equipment, power factor correction by means of APFC[293] or capacitors, DC auxiliary battery etc. must not explicitly be designed (see also section 4.3.4.12). They are simply supposed to be included in a lump sum percentage of about 30 % of the estimated cost, as a supplement for installation equipment (30 % of the cost of the distribution equipment).

General cost **correction factors** can be applied. For example if local skilled labourers/villagers are available and willing to participate in the construction works for an MHP plant the investment costs especially for civil works can often be significantly reduced. It has to be decided on a case-by-case basis, if such savings are possible or not.

For the **grid connection option** the investment cost includes the cost of extending transmission lines to the area to be served, the necessary distribution transformers and the distribution grid equipment, supposing that a substation with a power transformer of for example 132/45/15 kV with extra capacity exists. The distance to which a 15 kV line can technically and profitably be extended depends upon the cross-sectional area of the conductor and the acceptable voltage drop. If the next substation is too remote the extension of a 33 kV or even 132 kV line is required.

### 4.4.4 Breakdown of operating costs

Operating costs occur regularly during the whole operation period. In the present study, the expression **"operating costs"** is used synonymous with **"O&M costs"**. Although some authors distinguish between recurring costs and energy costs,[294] the present study employs operating or O&M costs as an umbrella term which comprises:
- **material** costs: for spare parts, additional electricity meters, lubricants, and energy costs such as fuel if required[295]
- **staff** costs
- regular **fees**, licenses etc.

Operating costs highly depend on the choice of appropriate equipment by the designer, the educational level and training of the staff, and also on the quality of the operation manuals. Due to the high fuel costs for diesel generator systems and the lack of energy costs for MHP systems, O&M costs are a decisive cost factor for diesel generation but extremely low for MHP. For the third technical option, connection to an existing grid, operating costs are also very low as they can be included in EEPCO's general O&M work, which is undertaken by already trained and experienced staff.

Operating costs can be subdivided into fixed and variable costs. Fixed costs are costs incurred irrespective of the amount of energy produced, whereas variable costs are proportional to the kilowatt hours generated. **Fixed costs** include personnel costs like salaries of staff, maintenance costs for repair works, purchase of spare parts and regular fees, for example for land leasing. Strictly speaking, maintenance costs are not really "fixed" but rather "variable" costs, because, in general, more operation hours entail higher wear and tear and thus more repair work. Taking into account that frequent shutdown periods might also negatively affect a system, maintenance can be assigned to the item of "fixed costs". **Variable or proportional costs** are mainly fuel costs for diesel generators and costs for lubricants. Lu-

[292] Chapallaz et al., 1992, p.12
[293] APFC = automatic power factor correction
[294] Clark, 1982, p.132; recurring costs are divided into O&M cost and energy cost
[295] modified according to: Götz, 2000, p.31

bricants are required in substantial amounts mainly for diesel generators and in relatively negligible amounts for MHP plants. For the sake of simplification it is assumed that proportional costs do not accrue for MHP systems. The third technical option "connection to an existing grid" implies that energy as kWh's is bought from the operator of the respective system, for example EEPCO. The higher the consumption in the new system, the more has to be purchased in bulk, and so these costs are counted as variable operation costs.

**Income tax** depends on the amount of energy sold and should therefore be attributed to variable costs. In order to facilitate the calculation, instead of adding them to operating costs they are directly subtracted from the income achieved (see section 4.10.3.2). Exemption from income tax payment is discussed in section 4.8.1.2.

**Financing charges** such as interest, loan repayment, etc. and depreciation are not counted among O&M costs but are rather treated separately in section 4.10.3.2.

#### *4.4.4.1 operating costs for MHP systems*

Since MHP systems incur no energy costs and the components are less susceptible to wear and tear, the O&M costs are very low. As noted above, they are more or less limited to fixed costs, and thus irrespective of the amount of energy produced. To give an impression of the O&M requirements for MHP systems, the most essential maintenance work is listed here:
- clearing of power channel, trashracks etc.
- greasing of shafts, screws etc.
- generator maintenance including checking of terminals, windings, bearings, and brushes[296]; IMAGs in general require less maintenance than other types of generator (see section 4.3.4.3)
- maintaining the water supply of the dump load of ELC if existing
- keeping overhead lines clear of tree branches, and inspection of insulators
- checking of protection equipment etc.
- inspection of loose connections, mainly at the switchboard
- replacement of fuses.

The number, qualification and working hours of the staff fulfilling these comprehensive tasks merit special attention. Personnel costs, occurring irrespective of energy production and therefore belonging to the fixed operating cost account for the crucial part of the latter. Once the persons are employed, their salaries must be paid monthly. Table 4.29 illustrates the figures applied in the present study.

| | **estimated monthly salary for year 2000 [ETB/month]** |
|---|---|
| operator | 400 - 800* |
| assistant | 200 - 500* |
| craftsmen | 500 |
| independent auditor | 320 |
| secretary | 300 |
| guard | 150 |

* depending on size and complexity of the system to be operated

*Table 4.29: Estimations of monthly salaries for different professions in year 2000*[297]

If maintenance know-how, metal workshops for making repairs etc. are available in the area these costs can be reduced by a certain percentage. A rough estimation of required staff is listed in Table 4.30.

[296] Fraenkel et al., 1991, p.120
[297] Ministry of Water Resources (Water Supply Development and Rehabilitation Project...) and EELPA, 1995, p.9 and 10

| plant capacity between... | investment cost[298] between... [ETB] | required specialists | salary during... [months] | number of staff | salary per month [ETB] | salary during 1 year [ETB] | percentage of invest-ment cost between... |
|---|---|---|---|---|---|---|---|
| 5 kW and 20 kW | 60,000 and 240,000 | operator | 10 | 1 | 400 | 4,000 | 8% and 2% |
| | | assistant | 2 | 1 | 200 | 400 | |
| | | craftsmen | 0.25 | 1 | 500 | 125 | **average:** |
| | | **TOTAL** | | | | **4,525** | **5%** |
| 20 kW and 80 kW | 400,000 and 1,600,000 | operator | 12 | 1 | 600 | 7,200 | 4% and 1% |
| | | assistant | 12 | 1 | 300 | 3,600 | |
| | | secretary | 12 | 1 | 300 | 3,600 | |
| | | guard | 12 | 1 | 150 | 1,800 | |
| | | auditor | 1 | 1 | 320 | 320 | |
| | | craftsmen | 1 | 1 | 500 | 500 | **average:** |
| | | **TOTAL** | | | | **17,020** | **3%** |
| 80 kW and 300 kW | 1,200,000 and 4,500,000 | operator | 12 | 2 | 800 | 19,200 | 3% and 1% |
| | | assistant | 12 | 1 | 500 | 6,000 | |
| | | secretary | 12 | 1 | 300 | 3,600 | |
| | | guard | 12 | 1 | 150 | 1,800 | |
| | | auditor | 1 | 1 | 320 | 320 | |
| | | craftsmen | 1 | 1 | 500 | 500 | **average:** |
| | | **TOTAL** | | | | **31,420** | **2%** |

*Table 4.30: Operation staff required for MHP systems of different capacities[299]*

The operator should be responsible for the technical equipment as well as bookkeeping. Additional external staff can be temporarily employed for non-permanent tasks, for example bricklayers, carpenters, locksmiths, and electricians for maintenance of power houses distribution grids etc.. In the case of 24 hour operation of bigger plants, two operators working in shifts are required. One should be a plant technician for maintenance, routine repairs, emergency repairs and operation; trained by the manufacturer delivering the equipment and thus competent to operate the plant.[300] The second one or the operator's assistant should be a line foreman in charge of distribution, line maintenance and operation, minor construction and meter reading. Furthermore, for more complex systems a secretary or treasurer must be hired for bookkeeping and billing.[301] The training level of the staff has to be appropriate to the complexity of the plant. This requirement is realised by applying various wage levels, as shown in Table 4.30.

#### 4.4.4.2 operating costs for diesel and grid connection systems

Although for **diesel systems** no civil works require maintenance, the total maintenance work, mainly for the engine and the generator itself, in general surpasses the requirements for the MHP system. In addition, the proportional cost for the fuel is a pivotal cost element in the operation of diesel gensets. The dependence upon shipments and transport of diesel or gasoline fuels over difficult terrain or poor roads, the need for foreign currency and the influence of the exchange rate USD to ETB, taxes and duties severely affect the costs. This is especially true for the more expensive middle distillate products other than crude oil, which have to be imported.[302] Since the fuel price depends on inflation in the world market, national subsidies, and the exchange rate between ETB and USD, a specific inflation rate, different from the national overall inflation, should be applied. The average diesel price in 2000 was

[298] according to Table 4.27
[299] modified according to Brunner, 2000, p.74; personal communication: Horst Höfling (GTZ)
[300] Joshi, Amatya, 1995, p.42
[301] Zoellner, 1982, p.146
[302] Ethiopia was reliant on Eritrea' refinery in Assab, which is one of the conflict points in the border conflict between the two countries.

about **2.1 ETB/litre**. Annex 7 gives an overview on the variety of prices in different towns of Ethiopia and shows a range of 1.8 - 2.57 ETB/litre.

For the **grid extension option** it is supposed that operating costs are more or less included in the usual maintenance work of the utility, undertaken by EEPCO. A very low percentage of the investment cost is sufficient to operate such an additional branch. The decisive part of O&M costs for the option "connection to an existing grid" is the (variable) price of the electricity [kWh] consumed in the new branch, which is purchased from ICS or SCS.

#### *4.4.4.3 Summary on operating costs for the three technical options*

The following estimations for **fixed annual operating costs** as a percentage of capital costs are drawn from a review of different literature sources; fuel costs are not taken into account and thus must be calculated separately:

- 1.5 % for MHP, 4.5 % for diesel systems, 0 % for grid connection option because these costs are already reflected in the long-term marginal cost[303]
- 6 % for MHP, 10 % for diesel systems[304]
- 1.5 % of total capital cost, for rural electrification based on renewable energy[305]
- 1.25 % for hydro and transmission works for MHP[306] and 4 % for diesel systems up to 1 MW[307]
- 5 % of generating investment cost for diesel systems[308]
- 4 % of investment for diesel systems with a capacity of less than 1 MW[309]

Chapallaz[310] appraises the yearly operating costs, covering costs of materials only, at 0.6 - 2 % of the electro-mechanical investment for an MHP plant. Salaries for operator and technicians must be added. It can be concluded from the figures from literature sources and the staff costs presented in Table 4.30 that about **3 % for MHP** plants and **5 % for diesel** plants can be reasonably assumed for the fixed O&M costs. As far as O&M costs for the **grid connection** option are concerned, they can either be taken as two per cent of substation and transmission line capital costs[311], whereby this figure refers only to fixed O&M costs and no variable costs. The second possibility is to suppose that the fixed O&M costs are 0 % because they are already included in the **long-run marginal cost (LRMC)** fixed for the respective extension by EEPCO who sells the required kWh's.[312] These LRMC therefore include fixed and variable O&M costs. For electricity produced by EEPCO, different estimations concerning LRMC were developed, yielding between 5 and 12 US cents/kWh corresponding to about 0.35 to 0.8 ETB/kWh.[313] Although these figures require further review, because they change dramatically according to crucial assumptions such as load forecasts, asset values, and required investment costs, a tariff of **0.8 ETB/kWh** is taken as a first approximation for the LRMC tariff for the ICS. Table 4.31 summarises the conclusions drawn for O&M costs.

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303 Clark, 1982, p.131f
304 Fritz, 1982, p.123
305 O'Sullivan, Krishnaswamy, 1992, p.202
306 Tropics Consulting Engineers PLC, 1999, p.15-4 (Feasibility Study Final Design of Daye Mini Hydropower Project); figure taken from EELPA / ACRES ENREP, 1994
307 Tropics Consulting Engineers PLC, 1999, p.15-3 (Feasibility Study Final Design of Daye Mini Hydropower Project)
308 EELPA, 1984, Yadot River Mini-Hydro Development
309 EELPA / ACRES, 1994, p.8-5
310 Chapallaz et al., 1992, p.99
311 Tropics Consulting Engineers PLC, 1999, p.15-4 (Feasibility Study Final Design of Daye Mini Hydropower Project), p.15-3
312 Clark, 1982, p.132
313 World Bank Report No. 17170-ET, 1997, p.33f; at that time 1 USD = 6.8 ETB

| | fixed annual operating costs | variable annual operating costs | total annual operating costs |
|---|---|---|---|
| **MHP system** | 3 % of total investment costs | negligible ! | 3 % of total investment costs |
| **diesel system** | 5 % of total investment costs | fuel costs per kWh consumed, about 0.8 ETB/kWh[314] | 5 % of total investment costs + respective fuel costs |
| **grid connection** | included in kWh-price | according to consumed kWh's, 0.8 ETB/kWh[315] | according to consumed kWh's 0.8 ETB/kWh |

*Table 4.31: Operating costs for the three different technical options*

## 4.5 Project participants

The analysis of investment and O&M costs should lead directly to the analysis of financing mechanisms, the latter being indispensable for the provision of capital. But before exploring the possibilities of *how* to obtain the required capital it is important to consider *who* is going to finance and operate the electricity supply system. Both the hydrological potential and the "human potential", meaning the interest and motivation, must be regarded as essential pre-requisites. If no-one is motivated, no MHP system or other technical option will ever be implemented. Different interested parties might have completely different motivations in participating, either financially or with their physical or intellectual manpower, in the project. The present section gives a short overview of potential project participants who have been identified, and their likely motivation. The issue of "project participants" is picked-up again in the sections 4.6, 4.7 and 5.3, where further aspects are analysed in detail.

### 4.5.1 Users

The future users of the energy supply system will profit from the operation of the system. They are expected to consume the energy put at their disposal and to regularly pay their electricity bills. If the electricity is used for certain applications, for example, mills, stoves and water pumps, users, especially women, might be released from heavy burdens like fetching water and wood and milling grain. Consequently the users in general are likely to be interested in the implementation and operation of an MHP system if they perceive that it would bring a personal advantage from the lightening of the burden of specific work tasks or any improvement in living conditions such as lighting, radio etc.. Because of this self-interest the users might be convinced to invest capital in the system, becoming shareholders. As will be amplified in section 4.6.3.2 the concept of juissance rights in particular is a possibility of appropriate financial involvement for customers. Depending on the chosen organisational form (see section 4.7.3), they might also be involved in management or operational tasks in connection with the system. But in whatever way they are involved, their main expectation is the successful operation of a system which guarantees an improved energy supply in households, workshops, enterprises etc. Compared to the concern that the energy supply is reliable, other interests like high rate of return and thus profit maximisation of invested capital may be less relevant in persuading users to invest in the system.

### 4.5.2 Investors

"Private investors" in this context are individuals or corporations, using capital which they aim to invest in promising projects. If they either live in a bigger city which is already connected to the electricity grid or they otherwise can afford a diesel generator for their individual energy

[314] based on the assumptions: 1 l diesel has an energy content of 10 kWh; efficiency of 32 %; fuel price of about 2.5 ETB/l diesel
[315] assumed LRMC in ICS system

supply, they do not depend on an improved MHP energy supply. Therefore "investors" are likely to be mainly profit oriented. Due to political risks, market risk etc. investors in Ethiopia tend to have high profit expectations like a return on equity of at least 20 %.[316] Therefore an MHP project must either meet these expectations or appeal to an alternative motivation of the investor. The latter might be a personal motivation, e.g. investment in his village or city of origin. A special case is the so called "self-supply" option (see section 6.3.5.2.1). This means that the investor implements the system for the energy supply of his own business, such as coffee processing or a factory and sells the surplus kWh's to a community.

### 4.5.3 NGO's

In general, private, church-related and other non-governmental organisations have specific directives or guidelines regarding their individual objectives, like poverty alleviation, support of women's concerns, education, covering of basic needs, environmental protection and religious or ideological mission. Normally, they are funded by members contributions, donations or governmental support. The origin of such foundations can be local, national, foreign or international, implying different sources and amounts of funds. Since NGO's are often involved in health, education and infrastructure projects for public benefit, they mostly do not attach great importance to cost recovery or even profitability of projects. Infrastructure projects in general do not directly generate added value and so do not offer big profit margins. Additionally, NGO's are often not allowed to make profits. As a result of the recent trend of decreasing funds, they are searching for innovative methods for project support in order to maintain or even improve project efficiency.[317] One possible source of additional funds is the free capital market, which is difficult for poor individuals to access but more easily tapped by reliable, creditworthy organisations. Therefore, an NGO might act as guarantor, standing in for the debtor in case of insolvency. This approach would lead to a shared sense of responsibility and therefore an enhancement of sustainability. MHP projects, though requiring high investment capital at the beginning, can be expected to show profitability after a few years of operation, so they are well suited to this approach, which can help to facilitate start-up financing. One option for alleviating credit conditions that are too strict would be to mix donations and capital from the free market in order to lower the burden of interest payments.

### 4.5.4 Public entities

Mainly due to lack of financial resources, public entities have little scope for becoming involved in the dissemination of new technologies like MHP. The most important player in the electricity sector is the formerly state-run authority (EELPA), which was transformed into a corporation (EEPCO) in order to achieve more efficient, profit-oriented operation. Urged on by World Bank policy, Ethiopia has tried to improve infrastructure development by means of privatisation approaches, at least at national level. Lower administrative levels however might still be interested in partial participation, for example in the form of public-private-partnerships. Although public institutions are perceived as a relatively weak stakeholder, their role has to be examined carefully for each specific case. In particular, strategic, legal and administrative aspects and the organisational structure should be arranged and harmonised with them.

### 4.5.5 Banks

Commercial credit institutions are mainly interested in maximising their profits. They are especially concerned with creditworthiness and guaranties, and ultimately profitability (see section 4.6.4.1). High-risk projects with long payback periods like MHP projects are not their priority. Several approaches for evading these limitations are illustrated in section 5.3. De-

[316] This is confirmed by the experience from other countries; see also Clark, 1982, p.133
[317] personal communication: Mr. Hess (BfW), 01/1999

velopment banks are an exception to this practice. According to their policy, they offer longer credit periods and lower interest rates. They generally look for an internal rate of return of about 10 %, although decisions to finance may rely on how well the MHP project complements other development goals in the area.[318] They can afford a less profit-oriented approach because they are refinanced by governmental institutions.

## 4.6 Financing instruments

This section first gives a general overview of different financing mechanisms and closely connected financing partners. Subsequently it focuses on those relevant to MHP projects in Ethiopia. It concentrates again on the MHP option and ignores the diesel and grid connection option because MHP is still in the centre of interest and also is the most problematic alternative because of its long repayment period and high risk characteristics.

### 4.6.1 General classification of financial instruments

Differences in financing mechanisms can be grouped according to the following aspects[319]:

1. source of financing capital (internal- or external-financing)
2. rights and legal liability of the financiers (equity or loan financing)
3. loan / financing period (short-, medium-, long-term)

Figure 4.18 shows which financing is in general of relevance for MHP under Ethiopian conditions (grey fields).

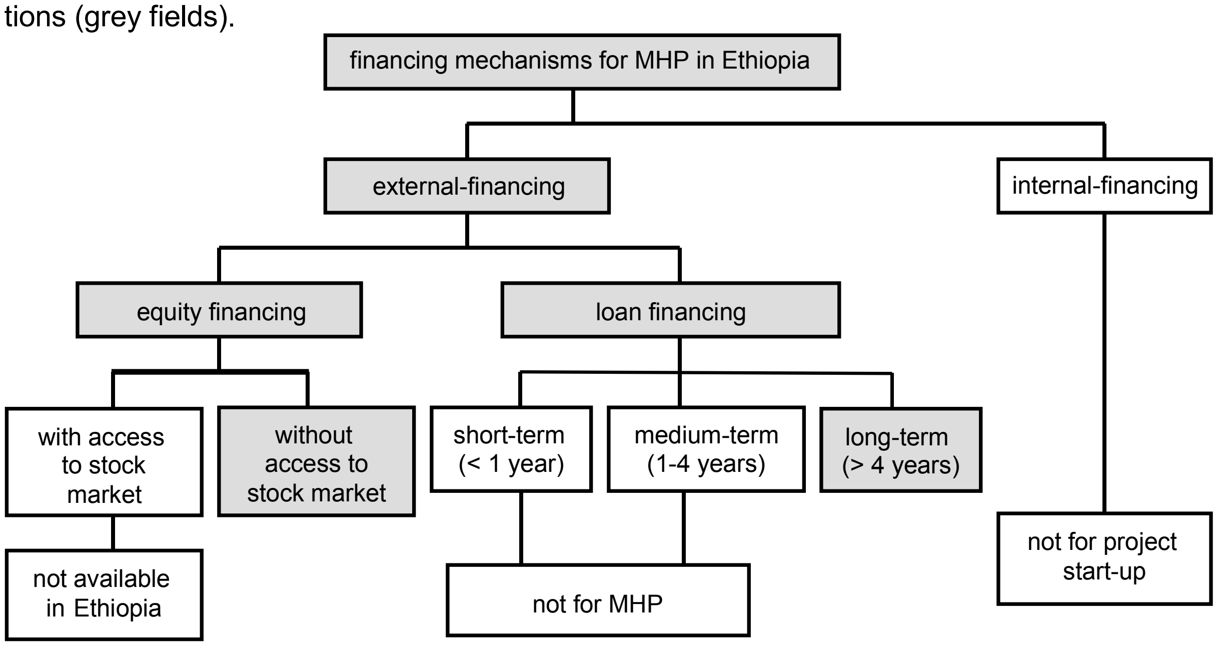



*Figure 4.18: Financing instruments for MHP in Ethiopia*[320]

Since MHP is considered to be a start-up project, the provision of additional capital from outside, either equity or credit, is indispensable. Internal-financing, out of the company's actual turnover, is not possible in this case. **Equity financing** is the provision of equity capital by means of profits carried to the balance sheet and the monetary participation of new and former owners. Equity capital allows for shares of the project's profits and value and is liable for losses. Ethiopia up to now has no stock market, so equity financing with access to a stock market is not possible. **Loan financing** is the provision of loan capital by creditors. The provision of loan leads to the right to charge interest, but does not lead to the ownership of the creditors. Loan capital is not liable for losses. Since the payback time for MHP systems is

[318] Clark 1982, p.133
[319] Perridon/Steiner, 1999, p.343ff
[320] modified according to Collin, 2000, p.15 and Perridon/Steiner, 1999, p.343ff; note: exclusion of financial instruments results from the argumentation above.

longer than 4 years, only long-term loans are considered for financing. Equity and loan are of decisive importance for MHP financing. The main differences, including the **rights and legal liability** of the financiers, are summarised in Table 4.32.

| ***criteria*** | ***equity capital*** | ***loan capital*** |
|---|---|---|
| **liability** | at least in the amount of the equity share, entails ownership | no liability, investor is a creditor with no rights of ownership |
| **income from capital participation** | share of profit or loss | interests at specified rate |
| **property rights** | share of value / debts | amount of loan (principal) and interest |
| **management** | usually some involvement | not entitled |
| **period of availability** | usually not limited | usually limited |
| **consideration for corporate taxes** | profit under corporate taxation | interest considered as corporate expenses |
| **capacity of financing** | limited by investor's private financial status | limited by securities requested by creditors |
| **risk for the investor** | high risk capital | comparatively low risk |

*Table 4.32: Fundamental differences between equity capital and loan capital*[321]

The financing mechanisms occur in the formal, semi-formal and the informal sector of the Ethiopian financing market.[322] The **formal** sector is controlled by the state credit laws and formulated by the National Bank of Ethiopia. The **semi-formal** financial organisations are outside the control of state credit laws, but under the control of other state institutions. The **informal** financial sector is not under the control of any governmental agency.

### 4.6.2 Financing mechanisms available for MHP in Ethiopia

Apart from the classification criteria mentioned above, the factors financing volume, provision of collateral and costs of finance are of special importance, when searching for appropriate financing for MHP in Ethiopia. In the context of the present research project, a comprehensive analysis of possible MHP financing sources in Ethiopia was carried out, taking into account the variety of crucial aspects. Summarising this analysis of appropriate financing mechanisms, the instruments and financing partners illustrated in Table 4.33 are identified as being able to offer adequate financial volumes at convenient financing periods.

| | |
|---|---|
| **(1) Limited anonymous equity by share issue and issuing house** | **equity** |
| **(2) Limited and liable equity by big investors** | ↓ |
| **(3) Donations from NGO's, bi- and multilateral organisations** | ↓ |
| **(4) Limited or liable equity by customers*** | ↓ |
| **(5) Juissance rights by customers and customer credit*** | ↓ |
| **(6) Equity and loans from NGO's, bi- and multilateral organisations** | ↓ |
| **(7) Long-term loans by Development Bank of Ethiopia (DBE) and Construction & Business Bank (CBB)** | ↓ |
| **(8) Medium- and short-term loans from banks** | **loan** |

*Table 4.33: Appropriate financing options for MHP under Ethiopian conditions*[323]

[321] Perridon/Steiner, 1999; p.344, modified
[322] Kropp et al., 1989, p.27ff
[323] modified according to Collin, 2000, p.42

The mechanisms marked with an asterisk might contribute higher amounts if several individuals manage to bundle their activities. As indicated in the right column of the table the different options are ordered by the degree to which they correspond to equity or loan. These eight options are arranged according to volume, partner and instrument of finance as shown in Figure 4.19.

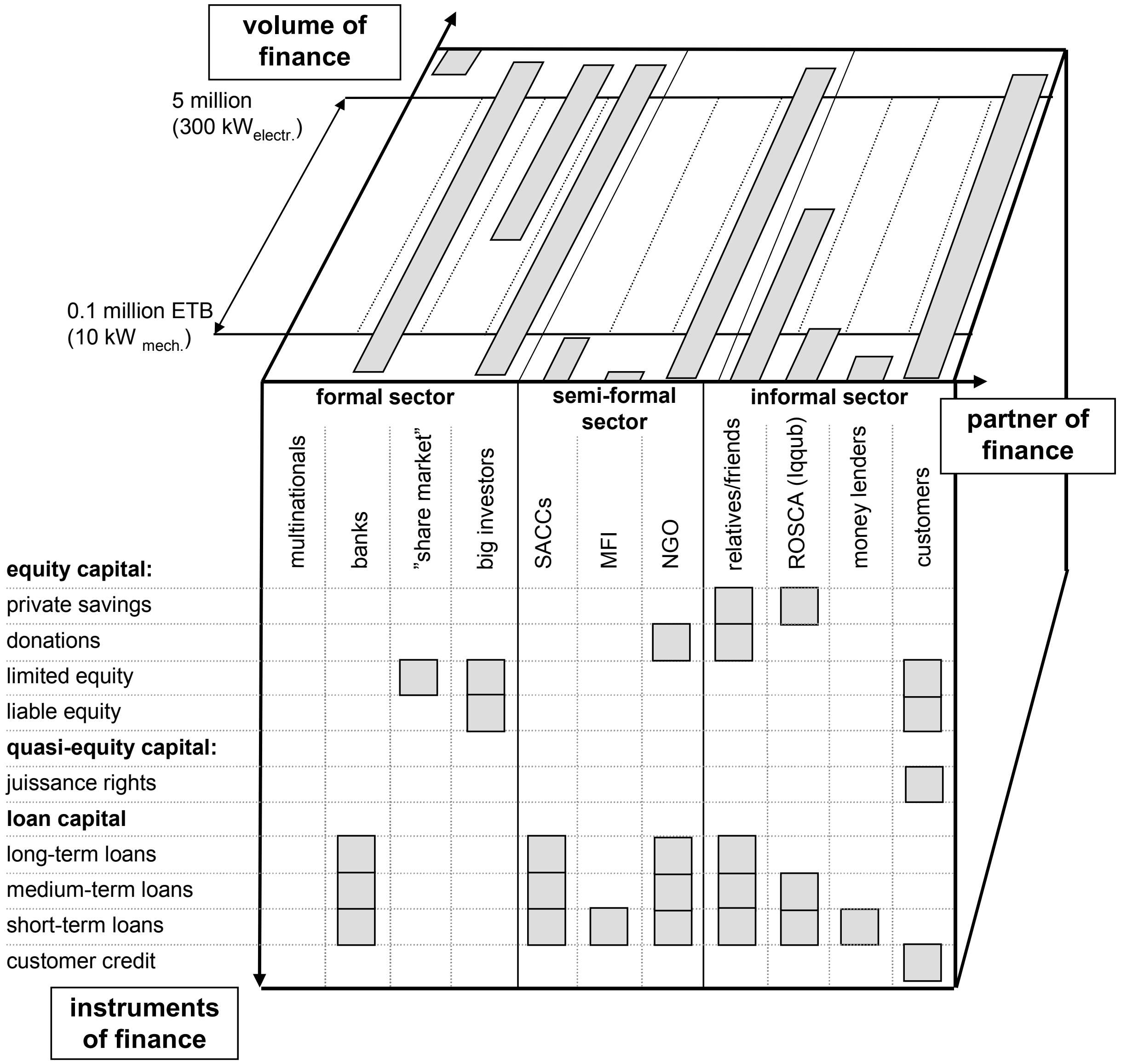



*Figure 4.19: Volumes, partners and instruments of finance and localisation of potential MHP financing*[324]

Considering MHP plants of capacities between 10 kW for mechanical energy and 300 kW for electrical energy the preferable financing volumes range between about 100,000 ETB and 5,000,000 ETB. The relevant financial partners can be found in the formal, semi-formal and informal sector. As far as the total of financial transactions in Ethiopia is concerned, the informal sector is estimated to be as big or even bigger than the formal sector.[325] In the formal sector several institutions like banks, share markets etc. or individuals like big investors and instruments based on loan or equity capital play a part with regard to MHP, whereas in the semi-formal sector only NGO's are of importance. Saving and Credit Cooperatives (SACC) and Micro Finance Institutions (MFI) do not offer sufficient financial volumes. In the informal sector mainly the future customers buying energy units should be mentioned, because, pro-

[324] modified according to Collin, 2000, p.43
[325] Ethiopian Economic Association, 1999/2000, p.342 and National Bank of Ethiopia, 1999-2, p.1

vided that they have a personal interest in energy supply, their individual contributions can be bundled together to realise substantial volumes. The remaining partners in the informal sector such as "professional" money lenders, relatives and friends and Rotating Savings and Credit Associations (ROSCA's) can contribute to the refinancing of the actual customers, mainly by means of borrowing. The instruments are classified into those relying on equity, quasi-equity and loan capital. Many of the relevant financial options (see Table 4.33) are linked to equity capital, which indicates the predominant relevance of the latter. As far as instruments with loan capital are concerned, several restrictions concerning loan period, guarantees, risks assessment etc. were revealed to limit their application. Long-term loan capital is particularly rare in Ethiopia and is linked to some severe prerequisites, whereas short-term financing of extremely low amounts in the informal sector is quite sophisticated having many forms.[326] The recommended eight financing possibilities mentioned above (see Table 4.33) are explained here in detail. Instruments number (1) to (4) are based on equity capital, (6) to (8) on loan capital and (5) is located somewhere in between. The following description is structured according to that distinction between equity and loan capital.

### 4.6.3 Instruments for equity and quasi-equity capital

To clarify possibilities of equity finance, Figure 4.20 first of all classifies different forms of equity and quasi-equity capital according to their **legal status**. Closely connected herewith, in a second step, appropriate organisational forms according to the Commercial Code and eligible financial partners are analysed in detail.

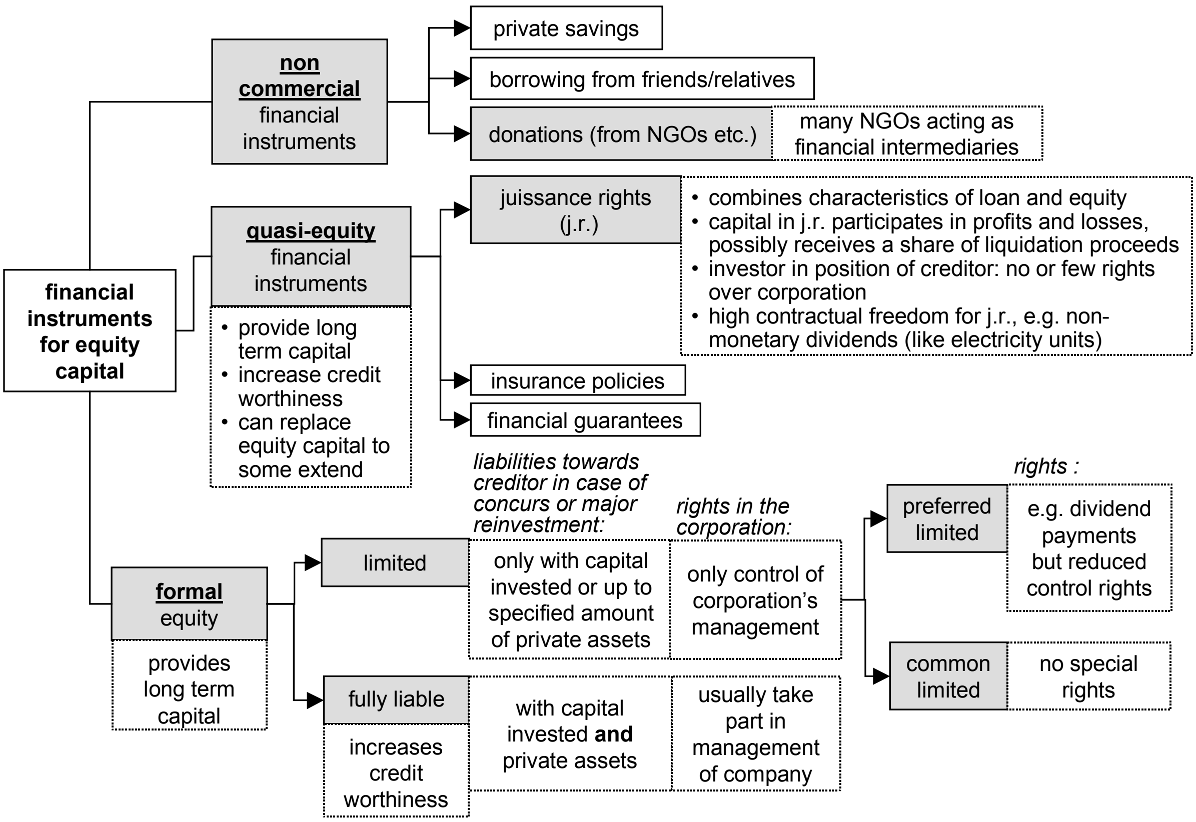



*Figure 4.20: Classification of different forms of equity according to legal aspects and their suitability for MHP financing*[327]

Those instruments, which are most relevant under Ethiopian conditions are marked in grey. The boxes with dotted frames present special properties of the different forms of equity.
In contrast to loan capital, equity usually is less time limited and does not require collateral, whereas profit expectations are mostly higher. Since profitability and cash flow of MHP

[326] Ethiopian Economic Association, 1999/2000, p.335ff
[327] Perridon/Steiner, 1999, p.411 and Ebeling, 1988, p.160 and 171ff

projects are only slightly below investors' expectations or may even reach them (see section 6.3.5.2), such projects might become a realistic option for equity investment. Depending on the future development of the price of diesel fuel, devaluation of the ETB against the US dollar and cost reductions from economies of scale in the MHP sector, profitability and competitiveness of MHP projects can even improve in the future.

#### 4.6.3.1 "Non commercial" equity

"Non commercial" financing instruments are defined here as those which are not associated with a particular legal form. According to the origin of a project sponsor's share, three different groups are displayed. In fact the category of donations from NGO's plays an important role in developing countries like Ethiopia. Since NGO's are concerned to support the poor in their development activities, hitherto, their main focus was put on grants. However, donations are becoming rare because of the shortage of funds and, further, often do not guarantee sustainability because they do not engender the feeling of responsibility or ownership. In the present study emphasis is put on is the private sector, which is expected to achieve widespread and sustainable dissemination of the technology due to cost-covering approaches.[328] To avoid dependence on subsidies, "pure" NGO donations should only be mobilised as a means of supporting the initial introduction of the technology, providing securities for venture capital, building up of know-how etc.. Apart from providing grants NGO's can yet also act as financial intermediaries in "real" equity finance, either in case of quasi-equity or formal equity, or as a provider of credit (see section 4.6.4).

#### 4.6.3.2 Quasi-equity financing instruments (juissance rights)

The most relevant quasi-equity financial instrument under Ethiopian conditions is the concept of **juissance rights** which are profit participation rights or **juissance shares** which are dividend right certificates. They both combine the characteristics of limited equity and loan capital and are quite flexible in their design. Juissance rights as well as juissance shares are property rights in an organisation / association and in general authorise the holder to share in profit. The juissance *share* is an equity certificate which certifies the juissance *right*. This securitisation or confirmation in writing of the entitlement to profit-sharing enhances fungibility. Since juissance rights do not confer any ownership rights, like for example voting rights, they bestow "loan character". Instead, they grant the holder the right to participate in the net profit and the liquidation proceeds, as well as the right to subscribe to new shares in the case of a rights issue.[329] This means that the juissance rights holder is in a position of a creditor and not of a partner. The possibility of participating also in losses and the subordinated liability bestows equity capital features to the juissance share although it is legally loan capital. The latter is circumstantiated by the holder having no membership rights and thus not being authorised to attend shareholder meetings. The dividend-right certificate may be in bearer or registered form. Compared to other forms of participation like "normal" shares, the pivotal **advantages** of juissances shares can be summarised as follows:[330]

- flexible design with regard to nominal value, interest, duration of the contract, terms of termination and possible liquidation claims because of missing legal provisions[331] allows adoption to entrepreneurial requirements, for example:
  - profit disbursement can be stipulated as a fixed or variable percentage of the nominal value (or combination of both: minimum interest in combination with a success-oriented component), thus resembling fixed-interest-bearing bonds in the first case and stocks in the second
  - repayment at issue price or depending on project performance

[328] Besant-Jones, 1995, p.1
[329] http://www.ubs.ch/e/index/about/bterms/content_d.html
[330] http://www.ey.com/global/vault.nsf/GERMANY/STH_Genussscheine/$file/Genussscheine.pdf
[331] Loritz, 1992, p.35 and Röder, 1987, p.802f

- independent of the legal form of the organisation, possible for both unincorporated and incorporated firms
- no stock exchange required for the allocation of juissance *rights*; issuance is cost-effective and not subject to authorisation; only juissances shares require a stock market or kerb brokers
- reinforcement of equity capital by means of juissances rights allows high-risk business[332]; mixed financing including juissance rights can improve profitability, thus attracting further investors, without relinquishing management control
- fiscal advantages: profit disbursement for juissance shares as an operating expense can lower the fiscal assessment basis for corporation tax as well as trade tax
- savings due to reduced interest payment, cheap issue etc. can improve return on investment for the juissance holder.

Investment in juissance rights involves a certain risk for the shareholder resulting from the possibility of sharing in losses, and subordination with regard to the refunding of claims. In the event of liquidation the juissance share value is repaid only when all other creditors are satisfied.

In conclusion, juissance rights are, in the specific Ethiopian case an appropriate means for customer participation, whereby the co-determination rights can be as limited as those of lenders. This restriction allows the decision-making authority of the main investor to remain undiminished, allowing robust management, which is a crucial pre-condition for MHP projects. Since juissance shares are ranked in terms of liability immediately after equity capital and before loan capital, they improve the creditworthiness of the project, thus facilitating the raising of loans for remaining capital needs at Ethiopian banks, which generally seek to avoid making loans that they perceive as high-risk. Juissance rights can be presented as a general **precondition for future customers** to get access to the electricity supply, the payment of **dividends** to participating customers being made in the form of **electricity units** rather than cash. These options offer the following advantages to the system operator:

- minimum obligation to pay dividends lowers **market risk**[333]
- acquisition of juissance rights as evidence for customers' **willingness to pay**
- security for the operator in case of **delayed payment.**

From the juissance holders' side, the essential advantages are:

- reduction of monthly electricity **expenses**
- capital investment **insured against inflation** due to fixed procurement quantity.

The implementation of this innovative means of financing can improve the profitability of MHP systems, but makes specific demands on the customers. With regard to general project financing it can be summarised that juissance shares can replace equity as well as loan capital to some extent. The owners of the shares, making available the value of their shares to the project, participate in profits and losses, but have no or few control rights over the corporation. Dividend payments are made according to a specific contract thus offering the possibility of paying it in electricity units, for example kWh or kW, or as other non-monetary disbursements. For MHP this instrument offers a promising integration of customers as financiers and will therefore be referred to in several steps of the present analysis (see sections 4.7.3, 4.9.6 and chapter 5).

[332] This feature makes juissance shares an interesting option for banks, who have high equity requirements to manage their substantial risks.
[333] In the present study, "market risk" is defined as the risk which is due to the uncertainties in electricity sales. Once the MHP plant is implemented, one can not be sure if and how much electricity will be sold during the operation phase.

### 4.6.3.3 "Formal" equity

"Formal" equity is subdivided into different forms of liability. Both forms, limited and fully liable capital, are of interest as far as financing of MHP projects is concerned:

1. partners who are **personally and fully liable** have rights and obligations with regard to management and participate in profits and losses. In addition, fully liable equity increases the creditworthiness of the corporation thereby facilitating the raising of loans.
2. the shares of **limited** partners only confer rights of management control, but not for day-to-day management, and rights of participation in profits and losses.[334] They extend the amount of available equity capital in the corporation.

### 4.6.3.4 Organisation structure for equity

The choice between different forms of equity is closely associated with the selection of a legal organisational structure according to the commercial code. Therefore some facets of organisational forms that are discussed on more detail in sections 4.7.2.3 and 4.7.2.4 need to be anticipated here.

For the realisation of formal equity investment in Ethiopia, all organisational forms, according to international standards, exist.[335] Table 4.34 gives a brief overview on these organisational forms and the corresponding legal status of equity. Further details are covered in section 5.3 and Table 4.37. Only those organisational aspects which are indispensable for the understanding of equity finance are anticipated in the following paragraphs.

| | **no access to stock exchange** | | | | | **stock-exchange** | **co-operative** |
|---|---|---|---|---|---|---|---|
| | **unincorporated firm** | | | **incorporated firm** | | | |
| **organisation form / partners' equity** | **one-man business** | **general partnership** | **limited partnership** | **private limited company (P.L.C.)** | **small share company (small Sh.C.)** | **share company (Sh.C.)** | |
| **common, limited** | | | limited partner's share | P.L.C.-shares | common stock | common stock | co-operative share |
| **preferred, limited** | | | preferred limited partner's share | | preferred stock | preferred stock | co-operative share |
| **fully liable** | no fixed equity | personally liable partner's share | personally liable partner's share | | | | co-operative share |
| | fully liable ←----------------------------------------→ limited | | | | | | |
| **participation of customers** | | | ←----------possible with juissance rights------------→ | | | | |

*Table 4.34: Organisational forms, respective liability and possibility of customer participation[336]*

Besides the different legal forms for the application of equity capital Table 4.34 shows which of the forms can be combined with the option of juissance rights. These are mainly the limited partnership, the private limited company (P.L.C.), the small share company, the share company (Sh.C.) and theoretically also the co-operative. As the concept of co-operatives follows the principle of common ownership, control and management, it does not seem to be useful to combine it with the issue of juissance rights, the latter conferring only the right to receive dividends. The organisational forms are ranked according to liability: from those

[334] Perridon/Steiner, 1999, p.354
[335] Proc. No.166/1960 (N.G.), Art. 227 to 554
[336] modified and extended according to Perridon/Steiner, 1999, p.351

based on fully liable capital in the column on the extreme left to those based on limited equity capital in the column on the extreme right. Fully liable equity is a precondition for unincorporated firms and an option for co-operatives, whereas limited partners' shares are an option for limited partnerships and co-operatives and are the unique basis for incorporated firms.

The combination of limited and full liability equity allows the project sponsor to add external equity capital to a project without giving up too much of his personal control.[337] A **limited partnership**, offering this arrangement, is recommended as one of the most appropriate organisation forms for the implementation of MHP in Ethiopia. A similar coexistence of different rights and liabilities is possible in **share companies**, because they allow common and preference shares. Common shares furnish all usual rights like that of participation at the general meeting, information, voting, dividends, and access to a share of liquidation proceeds.[338] Preference shares allow for special priorities or limitations concerning the above-mentioned rights (see section 4.7.2.3). Up to now no real stock exchange, and thus no official listing of shares, exists in Ethiopia. Shares can be made available via the issuing house "Commercial Nominees".[339] At a brokerage fee of 5 %, to be paid by the buyers, they offer an issuing service for shares, including evaluation of the project, and sales promotion by advertising. Issuing by Commercial Nominees requires a minimum equivalent value of the shares of about 0.5 million ETB and specific qualifications of the company. The shares can only be sold at a fixed price. Sale via book building is not offered. The underwriting risk is left to the issuing company.[340] Once the shares are issued, either via Commercial Nominees or via personal contacts to investors, they can be traded at the so-called "interoffice market", which is an informal arrangement used in the absence of a stock market.[341] In many cases, especially as far as small share companies are concerned, it is necessary to rely on personal and business-related contacts in order to raise equity capital.[342]

**Co-operatives**, mostly founded as groups of producers or consumers sharing the profits of joint activities, are owned by their members. These members are shareholders, though rights of management control are not affected by the number of shares, but follow the democratic principle of one vote per member.[343]

#### *4.6.3.5 "Origin" of financing partners providing equity capital*

Referring to the financing instruments based on equity capital (see Table 4.33 points (1) to (6)), equity capital can be procured from the following different sources or financing partners:

- share issue and issuing house, which means via the interoffice market or the Commercial Nominees
- big investors; in the context of the study also representing the interests of shareholders, company owners and potential future investment companies
- NGO's and bi- and multilateral organisations, often closely related to each other
- customers

Since there is no stock exchange in Ethiopia[344] **shares** have to be traded either directly between vendor and purchaser or in the interoffice market. Demand and supply are generated in Ethiopia by a small number of private large-scale investors and probably small retail in-

[337] loc. cit. p.353
[338] loc. cit. p.359
[339] personal communication: Molla Gessesse (Commercial Nominees), 03/2000
[340] Perridon/Steiner, 1999, p.365 and personal communication: Molla Gessesse (Commercial Nominees), 03/2000
[341] Meaning that special brokers manage the trade of shares by phone etc.
[342] Perridon/Steiner, 1999; p.357; Note: In this context also the lemon problem is relevant. Only corporations with high information flow and easy transactions of shares, such as share companies with access to the stock exchange, overcome the problem of actual investors being better informed than potential future investors.
[343] Routledge Dictionary of Economics, 1992, "Co-operative"
[344] The International Finance Corporation (IFC) has funded a technical assistance project aimed to set up a stock exchange in Ethiopia. An allocation of 200,000 USD has been made available for a Swedish Consultant, who started the project in February 2001; see also: http://www.worldbank.org/afr/et2.htm and http://www.ethioguide.com/aa-ethioguide/ethioguide/Fortune/Fortune%2041.htm#swedish

vestors. The business community in Ethiopia has instituted a regular "shares exchange forum" as a mechanism for facilitating the selling and trading of shares in Ethiopian companies.[345] Commercial Nominees, acting as issuing house, helps to evaluate the probability of success, set appropriate prices and may be in a strong market position for the primary trading.[346] In this context particular attention should be paid to the aspects of accessibility of the shares and costs of issuing them. Rural customers in particular are not at all accustomed to such an official procedure. They can only participate as shareholders if specific support is provided for. In addition, the involvement of the Commercial Nominees as evaluating agency and facilitator is only worthwhile when a certain project volume is concerned.

The market for equity from **big investors** is quite limited. The most important one is the Al Ahmudi family, representing approximately 70 % of foreign direct investment in Ethiopia and around 10 % of total private investment.[347] There are a few other well-known investors in Ethiopia having a more long-term and strategic approach than others.[348] Besides the Al Ahmudi family (with Saudi Arabian connections) there are also Kibur Genadesta (Head of the Chamber of Commerce of Addis Ababa); Roberto Jakano (with Italian connections); Captain Gezachew Wondirad (International General Systems) who are known to think this way and should be approached for pilot projects and first steps of private dissemination. Because Ethiopia is regarded as a high-risk country, Ethiopian investors expect high profitability and short pay back times of 2 to 4 years. An internal return on investment (ROI) of 20 % is not considered to be good, but just normal.[349] So far private implementation of hydropower plants has not been able to compete with such profitable alternatives for investment. In the rural energy sector, investment in diesel generators is preferred due to their short pay-back time and equal or even slightly better ROI, although in terms of net present value (NPV) the MHP option is more advantageous than diesel generation. Yet, NPV is a less favoured financial evaluation parameter under Ethiopian conditions, compared to ROI and payback time (see sections 4.10.3.3 and 4.10.4.1).

**NGO's and bi- and multilateral organisations** often simultaneously offer equity and loan capital (see section 4.6.4.2) but also donations (see Figure 4.20). Although, theoretically, equity from NGO's is imaginable, in practice some problems might arise. As non-profit organisations NGO's pursue specific development policies and are perceived in that way by the population. Therefore, it is difficult for such organisations to act according to principles of profitability or to impose at least cost-covering tariffs. Equity finance associated with profit expectations is rather accepted in case of individuals, who are interested in project success, either as consumers depending on reliable electricity supply or as profit-making investors. An important multilateral organisation, the **International Finance Corporation (IFC)**, which is one of the World Bank institutions, offers equity finance as well as loan disbursement. IFC loans are not issued in local currency. However, foreign currency loans are only allowed in Ethiopia in the case of export-oriented activities. Thus, IFC's involvement is limited to equity financing. In Africa the IFC provides equity for projects with minimum total financial volumes of 500,000 USD. In exceptional cases, the lower limit can be at 200,000 USD. This equity finance requires either foreign investors, foreign management or at least foreign education of investors.[350] In addition, the “renewable energy and energy efficiency fund for emerging markets (REEF)”[351], recently set up by the IFC, might also be useful for MHP in the future (see also section 7.2).

Sources of (re-)financing for private investors or future customers can be:[352]

- borrowing from relatives and friends

[345] http://www.telecom.net.et/~usemb-et/wwwhec35.htm
[346] Commercial Nominees PLC, 2000, p.1
[347] personal communication: Günther Schröder (DED), 03/2000
[348] loc. cit.
[349] personal communication: Molla Gessesse (Commercial Nominees), 03/2000;
[350] personal communication: Andrew M. Danino (IFC), 03/2000
[351] General-Anzeiger, 1999
[352] Aredo, 1993, p. 6f and EEA*, 1999/2000, p.337ff

- rotating savings and credit associations ROSCA, in Ethiopia: "Iqqub"
- group-based social security associations, in Ethiopia: "Iddir"
- moneylenders, in Ethiopia: "Arata Abedari"
- non-specialised financial intermediaries, and
- private savings.

As such, they are mentioned here as possible source of equity capital. As *exclusive* sources of financing for a whole MHP project, the financial volumes of these intermediaries are too small. In addition for some of them the loan periods are too short and the cost of finance too high. Only **Iqqubs**, which is an Ethiopian expression for Rotating Savings and Credit Associations (ROSCA) merit attention as far as very small plants for mechanical motive power for grain milling etc. are concerned. An Iqqub may be defined as a savings association for which each member agrees to pay periodically a small sum into a common pool so that each, in rotation, can receive one large sum.[353] From a financial point of view thereby all members switch at one point in the cycle from a position of net saver to a position of net debtor, except the first person to collect the "kitty" who is a net debtor throughout the cycle and the last one who is a net creditor throughout.[354] Some big trader Iqqubs are known to have collected sums of up to 85,000 ETB for distribution to the individual. The “kitty” volumes result from cycles of up to five years including several hundred members. These Iqqubs have semi-professional organisations at their disposal and tend to pay attractive salaries to the members employed by the organisation.[355] At the other end of the range are rural Iqqubs, whose members might save much smaller amounts of money. The two possible options for MHP would be either an interested individual, investing money, received from an Iqqub, or a whole Iqqub group using all the money that has been collected. The Iqqub itself is based on social ties and trust among the members, so no collateral is required. As soon as the savings of an Iqqub stop to be distributed among the members, but are rather invested into a joint project, it would cease to be an Iqqub and would have to be reorganised, e.g. as co-operative or corporation.[356]

### 4.6.4 Financial instruments for loan capital

As illustrated in Table 4.32, a provider of equity capital is more deeply involved in a project than a grantor of loan capital, given the fact that a creditor bestows the capital over a limited time frame, at a well-defined fixed or variable interest rate, claiming securities to limit his risks and assuming no liability for the project. He does not take part in the management and thus has no direct influence on operation and success of the project. Therefore, risk management and collateral are of crucial interest for a creditor. Loan capital relevant for MHP under Ethiopian conditions can be furnished either from specialised or non-specialised financial intermediaries.[357]

In the formal sector, banks act as **specialised financial intermediaries**. They offer:
- long-term loans for project implementation
- medium term loans for major repairs and replacements during operation and
- short-term loans for balancing of cash flow variations during operation

Volume of finance, maturity and interest rate have to be arranged between debtor and bank. The debtor must provide security for a loan to prove his creditworthiness. The Ethiopian governmental regulations seriously hamper the collateralisation (see also section 4.6.4.1). This might be one reason for short- and medium-term loans being widespread in Ethiopia, whereas long-term loans which require substantial securities being only offered by a very few intermediaries.

[353] Aredo, 1993, p.9
[354] loc. cit. p.10
[355] loc. cit. p.16f
[356] Collin, 2000, p.39
[357] personal communication: Fasil Osman (Chamber of Commerce), Andrew M. Danino (IFC), Franco Conzato (European Union, Ethiopia)

The most relevant **non-specialised financial intermediaries** are NGO's in the semi-formal sector and bi- and multilateral institutions in the formal sector. They usually have other political, humanitarian, etc. goals besides their financial interaction. The beneficiaries' payment can also be non-monetary, for example participation in project implementation with man-power, local construction material etc..

Two further instruments to be mentioned in this context are **supplier and customer credits**. A supplier credit is a short-term loan for the purchase of a product, provided by the supplier to the customer. It results from the timing of payment, meaning that the supplier delivers without immediate receipt of payment. This loan option is based on the supplier's interest in making a sale. For components like turbine, generator, ELC and other electrical equipment this option can be taken into consideration, depending on the specific loan conditions offered by the supplier. A customer credit is an advance payment by a future customer, required from the supplier side in cases of high investment costs. This instrument is of minor importance because MHP components do not reach financial volumes which would require such a "pre-financing" from the customer.

Financial instruments for short-term financing of extremely low, and partly also higher amounts in the **informal** sector exist in many different forms.[358] Due to their generally small volumes, short loan periods but also due to their unfavourable interest terms they are not appropriate for MHP financing.

Summarising, raising of loans is really restricted to banks and, to some extent, NGO's. Their opportunities, limitations and loan conditions are amplified in the following paragraphs.

#### *4.6.4.1 Loan capital from banks*

Financial instruments for loan capital are not well developed in Ethiopia. The main restrictions limiting the range of instruments appropriate for MHP are the required long **loan period** and the need for **collateral**. Loan periods granted by Ethiopian banks in general do not exceed 5 years, which does not meet the requirements of MHP, since payback periods for MHP plants are between about 12 and 25 years, depending on the size of the plant, load factor and other boundary conditions (see Table 6.9 and Table 6.10). Provision of collateral raises an even more crucial problem in Ethiopia. Most banks require tangible collateral exceeding the amount of loan disbursement. 125 % of the loan volume as collateral are quite frequent. The value of assets is estimated by the bank. As long as personal guarantees, e.g. from the project owner(s), are not available, one would expect that the MHP project with its plant components would be suitable as collateral. For that purpose a registration would be required. But, up to now no authority is in a position to register electrical and mechanical machinery and other MHP components as assets which could then be used as collateral for loans.[359] The country's legal framework provides neither for assignment[360] by way of security nor encumbrance on real property, in case of missing proof of registration by a governmental authority, so that the transfer of ownership[361] but also the garnishment of salaries[362] are rendered impossible. Thus the only possible collateral is vehicles, because they can be registered. Apart from very few exceptions, neither future cash flows nor former credit records are accepted to replace tangible collateral.[363] Furthermore, in some regions[364] it is not even allowed to transfer land-leasing contracts before maturity. This means that the plant itself may not be used as collateral[365] because, as long as the land cannot be transferred to an-

[358] Aredo, 1993, p.7ff
[359] personal communication: Hailu Legesse (CBE), 02/2000
[360] assignment = transfer of ownership of an asset from one person to the other
[361] personal communication: Mr. Shifferaw (Ethiopian Insurance Company) and banks executive managers, 03/2000
[362] personal communication: Ruth Erlbeck, Ralph Trosse (GTZ), 03/2000
[363] Collin, 2000, p.32
[364] Note: This is not relevant for the construction of MHP, because the Oromia State and the South Western Regions, which are most attractive for MHP, allow the transfer of land possession before the official end of leasing contracts.
[365] personal communication: Hailu Legesse (CBE), 02/2000

other legal person, the installations on it cannot be transferred either. Given the relatively high political and market risk[366] and the problem of collateral, governmental banks, as well as the newly established private banks in Ethiopia, are very reluctant to provide long-term bank loans. Yet, in terms of cash flow and return on investment, the analysis showed that MHP projects can be quite profitable, especially plants of about 150 kW or more (see section 6.3).

Nevertheless, as far as loan capital in the formal sector is concerned, banks are the most common partners for financing of MHP investment. Among the commercial banks, which work in a profit oriented way and usually require substantial collateral, especially the state owned **Commercial Bank of Ethiopia** (CBE) is of importance. With its 170 branches in Ethiopia, CBE can serve any region of the country. Though CBE loans are (still) being disbursed only at short loan periods, yet the bank is generally less risk averse, relatively open towards innovations and interested in the dissemination of sustainable technologies. In the long run, the **Construction and Business Bank** (CBB) might also become one of the players which can be convinced of MHP projects. In general CBB limits its sphere of activities on "construction projects" to which MHP projects, in a broader sense , can also be added. As soon as economic feasibility is proven, CBB seems to be interested in innovative approaches, as demonstrated by its cooperation with GTZ in a low cost housing project. As a conclusion CBE might be seen as a partner for the initial phase and CBB as a partner who gets in as soon as technical and economic feasibility are confirmed by independent experts. On the other hand the so-called development banks are specialised on loans with low interest rates. Their loans which are disbursed according to their development policy are refinanced by national or international institutions and not by customer deposits.[367] The **Development Bank of Ethiopia** (DBE) is one of the most promising credit grantors, because MHP projects excellently fit in their rural development policy. DBE explicitly expressed their interest to enter now into the field and they offer long loan-periods. Until now no bank ever invested in that field so that lack of experience explains their general reluctance. The DBE, according to their statement, would require a successful pilot project for the prove of technical and economic feasibility.[368] Advantageously, both, CBE and DBE, are also present in other towns apart from Addis and dispose of staff with high mobility, surveying project in a radius of about 100 km to the next branches.[369] In the long run the **Awash International Bank** (AIB), which already made an approach towards “project financing”, might become a possible partner. “Project financing” means that the performance of the project is the primary resource for the ability of debt service. Thus, the accomplishment of loan repayment depends on the project performance and thus on the expected future cash flow. Under Ethiopian conditions, an internal return on investment of at least 20 %, even for low risk projects, is required.[370] Among the **private banks** only the Bank of Abyssinia and Wegagen Bank declared that they can imagine to finance MHP in the near future.[371] Figure 4.21 depicts the market shares of loan disbursement of the mentioned banks in 1997/1998. It proves the still dominant position of CBE on the one hand, but a growing importance of private banks on the other hand.

[366] In the present study, "market risk" is defined as the risk which is due to the uncertainties in electricity sales. Once the MHP plant is implemented, one can not be sure if and how much electricity will be sold during the operation phase.
[367] Kropp et al., 1989, p.32f
[368] personal communication: Kidane Nikodimos (DBE), 03/2000
[369] personal communication: Hailu Legesse (CBE), Kidane Nikodimos (DBE), 03/2000
[370] personal communication: Solomon Awoke (AIB), 03/2000
[371] personal communication: Baissa Gemeda (Abyssinia Bank), Asfaw Alemu Tessema (Wegagen Bank), 03/2000

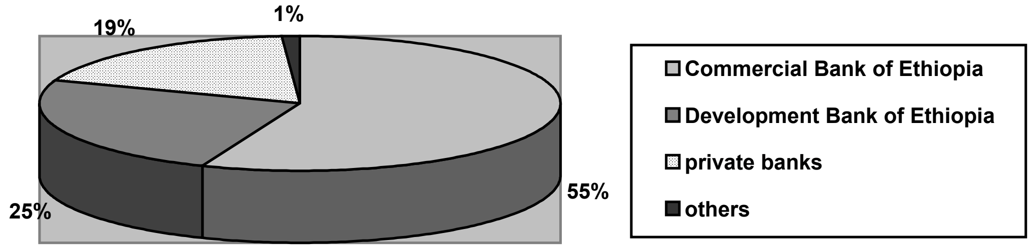



*Figure 4.21: Market shares of loan disbursement in fiscal year 1997/1998*[372]

One further possible partner, which can be addressed on international level is the **African Development Bank** with wide local experience.[373]

#### *4.6.4.2 Loan capital from NGO's, bi- and multilateral organisations*

As Figure 4.19 illustrates, in the semi-formal sector neither Savings and Credit Co-operatives (SACC's) nor Micro Finance Institutions (MFIs) in Ethiopia can presently procure the amounts of investment capital required for MHP projects, whereas NGO's at least punctually offer cheap credit services, often based on personal trust and group liability. According to a study of the Ethiopian Economic Association[374] (EEA*) volumes of credit from NGO's are in the range of 5 ETB up to 10,000 ETB for individuals.[375] In addition, according to a recently enacted regulation, NGO's have to be registered as "Micro Finance Institution" in order to be legitimised to offer credit services.[376] But, as soon as this requirement is fulfilled, NGO's can become important partners for a joint financing of MHP together with potential users.[377] They can offer bigger, long-term loans for groups or facilitate access to commercial loans by means of providing collateral, also on the long run. Since energy supply is a basic precondition for most income generating activities it empowers people on grass root level, a common approach of many NGO's. As mentioned in section 2.2 up to now especially EECMY and ERSHA were active in the field of MHP, mainly with 10 - 30 kW mechanical systems, used for grain milling. As for the existing EECMY micro hydropower plants, most of them were heavily subsidised. However, this practise was changed recently:[378]

- Referring to a church unit as applicant, the total investment costs, minus local contribution, such as sand, wood, stones and unskilled labour, have to be paid in two portions: 25 % of the required capital for hardware as down payment and 75 % interest free during the first 5 years of operation.
- If a peasant association, private investor or similar is concerned, 50 % of the investment costs have to be paid in advance and the remaining 50 % at commencement of operation.

Planning, transportation, training etc. remains financed by EECMY, which means that the service of EECMY personnel like consultant services is still for free for the users.[379] In several interviews some other NGO's like for example "Menschen für Menschen" expressed their interest for future activities in the MHP sector. Most of the local NGO's are supported by or even financially dependant on bi- and multilateral organisations, so that their activities and policies have to be viewed in close connection. Due to generally decreasing financial resources innovative concepts are envisaged by these organisations. Possible options are ei-

[372] NBE, 1999-1, p.33 and CBE, 1997, p.17 and Addison, Geda, 2002, p.5
[373] Collin, 2000 p.36
[374] to distinguish the Ethiopian Electric Agency EEA from the Ethiopian Economic Association EEA*, the latter is marked with an asterisk !
[375] EEA* 1999/2000
[376] personal communication: Mrs. Alewia (ERSHA), 03/2000
[377] Collin, 2000, p.37
[378] Feibel, 1999, p.104
[379] Workshop Proceedings, 2000, p.18ff

ther to switch from grants to low interest loans, at an interest rate below the one on the official capital market, or to guarantee as an intermediary for the provision of collateral for a commercial bank loan. This concept is on the way to be implemented for example by "Bread for the World"[380], a German protestant NGO, supporting EECMY.

As anticipated in Table 4.33, the profound analysis of Ethiopian financial intermediaries and instruments for loan capital proved the following three options to be realistic for MHP:
- loans from NGO's, bi- and multilateral organisations
- long-term loans by DBE and CBB
- medium- and short-term loans by (other) banks

The access especially to commercial bank loans depends on the provision of collateral. Therefore, the **legal status of the debtor**, be it an individual, group or any kind of company, and thus the liability of equity and other estates of the partners are of great importance. The legal status or organisational form on its part is chosen according to criteria like amount of equity and loan capital brought into the organisation and desired liabilities. Unincorporated firms like one-man business, general partnership and in some cases limited partnership include personally fully liable partners being responsible for payment of the debts. Incorporated firms like P.L.C., different types of share companies and in general also co-operatives consist of partners with only limited liability, meaning liable with their deposit capital. Although co-operatives theoretically also offer the possibility of fully liable partners, their reputation concerning reliability and repayment behaviour is historically impaired from banks' point of view (see sections 4.7.2.2 and 4.7.2.4).

The preceding section on financing mechanisms reveals the importance of organisational forms. These forms will be analysed in detail in the following section 4.7. Concluding recommendations on the closely inter-linked aspects of financing mechanisms, financing partners and organisational forms will be given in section 5.3.

## 4.7 Organisational forms

Since financing of MHP systems depends on the involved partners and thus the form of how they are organised, some crucial aspects concerning the legal company form already had to be treated in the preceding section. In many cases, economic indices of the project such as profitability, payback time etc. govern the interest of potential participants, like private investors, future customers, municipality and NGO's. Whichever of these groups or combinations of them takes part in project financing and management, decide on the selection of the organisational form. One pivotal question is, whether, how and to which extent responsibilities are delegated to local groups or to privates and to which extent state and parastatal utilities have to be involved. Utilities like EEPCO which was state-controlled until recently dispose of trained and experienced staff, so that their participation can be helpful in some situations. Local authorities and community based groups being in close contact to consumers and their needs can also provide benefit to the project. These examples illustrate that the project organisation during the planning, construction and operation phase is of importance for its sustainability and merits a profound analysis.

### 4.7.1 Requirements on organisational forms for successful MHP

Table 4.35 summarises the tasks to be fulfilled by the different actors during the specific project stages, namely planning, construction and operation.

[380] personal communication: Mr. Hess (BfW), 01/1999

<table>
<tr><th></th><th>tasks</th><th>prerequisites and required abilities</th></tr>
<tr><td rowspan="5">planning phase</td><td>promotion and information:<br>- initiate the project idea<br>- awake the interest of potential partners and the public especially on community level<br>- mediate conflicts arising during project preparation</td><td>personnel interest</td></tr>
<tr><td>identification of suitable site(s)</td><td>knowledge of terrain / technology</td></tr>
<tr><td>pre-feasibility, feasibility study, final design including<br>- assessment of the hydropower potential<br>- technical design and financial analysis of the system<br>- draft of a financial structure for proper operation (operating costs, pay-back etc.)<br>- draft of an organisational structure (participants, organisational form, required staff)<br>- elaboration of proper contracts between involved parties (by-laws, tariff system etc.) concerning financing, ownership, construction and management</td><td>ability to participate in or to commission the technical and financial planning</td></tr>
<tr><td>obtaining access to the following rights:<br>- water rights<br>- land use rights for construction works</td><td>access to relevant administrations and ability to negotiate with local representatives or “pressure groups”</td></tr>
<tr><td>obtaining the necessary registrations and licenses for:<br>- investment<br>- electricity generation and distribution<br>- grinding wheat (if required)</td><td>access to relevant administrations (EEA, Investment Authority etc.)</td></tr>
<tr><td rowspan="3">construction phase</td><td>procurement of required capital</td><td>equity capital and / or creditworthiness to obtain a loan</td></tr>
<tr><td>implementation and monitoring of civil works, installation of mechanical and electrical equipment, including:<br>- provision of skilled and unskilled labour, engineers, co-ordinators<br>- support with local material<br>- supervision of accounting<br>or delegation of these tasks</td><td>management and technical skills or ability to source out these tasks</td></tr>
<tr><td>training of operators and other staff</td><td>training capacity (or outsourcing)</td></tr>
<tr><td rowspan="3">operation phase</td><td>owner(s) has/have to control:<br>- operators (and their capacity building)<br>- instruction and payment of staff (incl. their capacity building)<br>- proper bookkeeping, like in-payments</td><td>ability and power to survey and control the project and possibility of penalising and fining; clear allocation of responsibilities</td></tr>
<tr><td>operator(s) has/have to:<br>- operate and maintain the system for proper output<br>- effect proper bookkeeping<br>- control users' tasks (tariff payment, no misuse nor manipulation of meters)</td><td>availability of qualified staff and endowment with responsibilities based on clear contracts, motivated users</td></tr>
<tr><td>formation of an arbitration committee</td><td>existence / creation of an impartial committee</td></tr>
</table>

*Table 4.35: Tasks and affiliated requirements during different project phases*[381]

Even in the case that by-laws and contracts are formulated unforeseeable conflicts or problems might arise. Therefore an **"independent arbitration committee"** should be nominated involving if necessary. Thus accompanying monitoring can continuously improve the implemented organisational structure.

[381] modified according to Brunner, 2000, p.14ff

### 4.7.2 Analysed organisational forms and their suitability for MHP projects

The term "organisational form" is defined here in a broader sense than in section 4.6.3.4. It does not only include the legal aspect, meaning the type of company according to the Commercial Code but also the comprehensive characteristics of structures accounting for a specific organisational form. Organisational forms relevant under Ethiopian conditions are community based mainly informal organisations, administrative structures, company types according to the Commercial Code and co-operative societies. These different types are analysed so as to result in recommendations concerning their appropriateness for MHP projects. A summary of recommendations is given in section 4.7.3.

#### *4.7.2.1 Community based organisations (CBO's)*

They are formed by the initiative of their members rather than being imposed by outside force. Thus, they serve the social, economic or development needs of their members. They are not necessarily registered at a government's authority.[382] Theoretically the responsible authority for registration is the Office of Associations under the Ministry of Justice.[383] However, some practical problems cause serious hindrances for registration of community-based organisations (CBO's) and additionally lack of legal privileges or support constrict the motivation to be registered. The registration may even result in suffocation of institutions through officialdom and subordination.[384] Nevertheless many of these organisations are actually functioning very well so that even the administrative structures use them to communicate and spread official information.[385] Table 4.36 summarises main characteristics and tasks of important CBO's in Ethiopia and indicates their possible role in an MHP project.

The features of these traditional organisational forms and their regional dissemination widely vary so that their possible role in MHP projects cannot be generalised. The existence of such forms and their potential involvement have to be **studied in every specific** case in order to define their possible role in project planning, implementation and operation.

[382] Molla, 1997, p.12 and Berhanu, 1997, p.36
[383] Molla, 1997, p.20
[384] Adal, 1998, p.12
[385] Adal, 1998, p.6 and Zewdie, 1996, p.8

| "organisation" | special features | main tasks | possible role in MHP project |
|---|---|---|---|
| **Elders** | one or several male persons, quasi legal institution | acting as mediators, solving conflicts, giving advice | - access to **water and land** use rights<br>- facilitation of **agreements and contracts**<br>- "social control" during MHP operation (payments, misuse of meters etc.) |
| **Iddirs (insurance association)** | informal financial organisation with a book keeping system and common fund deposited at a bank account | mutual help for funerals, wedding ceremonies, medical expenses etc., often involved in development activities | - access to **water and land** use rights<br>- facilitation of proper **by-laws**<br>- access to local staff |
| **Modiis / Golobees (insurance association)** | similar to Iddir | provide insurance service, mediate conflicts, taking part in social administration | similar to Iddir |
| **Iqqub (saving and credit association)** | very complex, formalised and institutionalised structure | members pooling their savings and receive money on lottery basis | - facilitate implementation of proper **by-laws**<br>- possibility for **refinancing** of MHP participants |
| **religious structures (Mahibers, Senbetes etc.)** | rural self-help institution | common help at cultural activities like weddings, funerals etc. | - access to **water and land** use rights<br>- access to **local staff**<br>- creation of **identification** with project<br>- spreading of **information** |
| **working parties (e.g. Debo)** | forum for voluntary collective labour and inter-household labour co-operation | temporary labour sharing arrangements to cope with high demand of labour during agricultural "peak periods" | - **identification** with project through participation in construction<br>- provide the project with **skilled and unskilled labour**<br>- procurement with **local materials** |

*Table 4.36: CBO's: features, tasks and possible role in MHP projects*[386]

#### *4.7.2.2 Administrative structures*

The original purpose of administrative organisations, like **Peasant Associations (PAs), Service Co-operatives (SCs) and Producer Co-operatives (PCs)** was to facilitate modernisation and nation building according to socialist policies.[387] After the political changes at the beginning of the 1990s, the so-called **Development Agents** were a new approach to establish institutions for the implementation of administrative and political goals.[388] Many **PAs** still exist in a reactivated way – without substantial changes in their organisation and decision-making structure – to administer efforts from the government's side.[389] Normally, they take care of all economic, administrative and political affairs of communities, under exclusion

[386] modified according to Brunner, 2000, p.40ff
[387] Adal, 1998, p.14
[388] Olana, Degefa, 1998, p.21
[389] Molla, 1997, p.18

of carrying out any kind of trade.[390] The **SCs** have originally been an instrument of the socialist transformation of agriculture. Their assignment was to provide crop production services, marketing of agricultural products as well as the provision of loans.[391] The problems of SCs were, and partially still are lack of autonomy, domination by government's rules, corrupt leadership as well as the feeling of incompetence for the demands and needs of the peasants.[392] Nowadays, many of the surviving former SCs are getting restructured to business organisations according to the Co-operative Societies Proclamation, often with the support of the Regional Co-operative Promotion Bureaux.[393] The most important prerequisite for that step are balanced accounts. Although, in a few cases, SCs seem to play an important role in the grain milling sector and in representing peasants interests, they generally still have a negative image due to their mismanagement during former socialist times. **PCs**, in the past, had the ultimate goal to establish collective farms in a socialist manner. Thus their characteristics are similar to those of SCs. The PCs channelled peasants production on lower prices than the market provided. They transferred agricultural surplus to industrial and urban sectors and involved farmers in all aspects of co-operative work without granting additional benefits to them.[394]

**Taking into account the exclusively administrative purpose of PAs and the relatively critical experiences with all three administrative structures, PA, SC and PC, and their negative image from socialist history, an MHP project should in general not be based on one of these structures.**

In every specific case the respective PA and SC can nevertheless be checked and its potential role be considered carefully. In general, the **Development Agents** as newer instrument of the government to collect taxes, to grant credits etc. have no well developed contact to community-members.[395] Therefore they do not seem to be appropriate to act a part in MHP-projects either.

#### *4.7.2.3 Business organisations according to the Commercial Code*

According to the Commercial Code of Ethiopia persons who professionally and for gain produce, distribute and supply electricity shall be deemed as *traders*.[396] And traders in that sense shall be registered.[397] In addition, business organisations shall be deemed to be of *commercial nature* where their objective is to carry out for example the above mentioned activity. Share companies (Sh.C.) as well as private limited companies (P.L.C) shall always be deemed to be of commercial nature.[398] All Ethiopian and foreign business organisations of this kind have to be registered.[399] Summarising, these provisions signify that a person or organisation who operates an electricity system in a profit-oriented way has to be registered. Sh.C.s and P.L.C.s have to be registered in any case. A conceivable case superseding the registration is an electricity supply system operated by a community or an NGO in a "non-profit-making" way. But, in most cases Ethiopian or foreign persons or business organisations involved in electricity production, distribution and supply shall be **registered**[400] according to the Code, because the system operation in order to sell electricity units has to be interpreted as commercial activity. Apart from sole traders ("one-man-business") different forms of business organisations are possible according to the Commercial Code[401]:

[390] Proc. No.166/1960 (N.G.), Art.25 (1)
[391] Adal, 1998, p.17
[392] loc. cit. p.19 and Olana, Degefa, 1998, p.22
[393] Proc. No.147/1998 (N.G.) and Proc. No.15/1997 (M.O.) amended with Proc. No.27/1999 (M.O.) and Olana, Degefa, 1998, p.22; personal communication: Oromia Co-operative Promotion Bureau (03/2000)
[394] Körner et al., 1997, p.17 and Pausewang, 1992, p.27
[395] Olana, Degefa, 1998, p.21f and Erenssa et al., 1998, p.10
[396] Proc. No.166/1960 (N.G.), Art.5 (13)
[397] loc. cit. Art.100 (2a)
[398] Proc. No.166/1960 (N.G.), Art.10 (1 and 2)
[399] loc. cit., Art.100 (2)
[400] loc. cit., Art.100 (1 and 2)
[401] loc. cit., Art.212 (1)

1. ordinary partnership
2. joint venture
3. general partnership
4. limited partnership
5. share company and
6. private limited company.

In general these companies are obliged to pay a **profit tax of 35%** per taxable income.[402] Possibilities of exemption from income tax are dealt with in section 4.8.1.2. Ordinary partnerships[403] are not authorised to undertake trade activities, the latter prevailing to consider them as general partnership.[404] Generation, distribution and sale of electricity being part of trade[405] ordinary partnerships are no suitable organisational form for MHP projects. The remaining forms with their specific features and resulting pros and cons with regard to MHP projects are described in the following paragraphs. According to the Commercial Code "special provisions applicable to co-operative organisations may be described[406]", which is done by specific proclamations and regulations. Due to their special status, co-operative societies are treated separately (see section 4.7.2.4).

a) Joint venture[407]

"A joint venture is an agreement between partners on terms mutually agreed and is subject to the general principles of law relating to partnerships" (Art. 271). It differs from the remaining business organisations in the following points:

- it is not made known to third parties
- it has not to be written down, registered, nor published
- it is no legal personality.

Every partner owns his contribution. A joint venture cannot issue negotiable securities and shares can only be assigned with the agreement of all partners. The management is obliged to all partners as long as no manager is explicitly appointed.

According to the Investment Proclamation, for a joint venture between foreign and domestic investor a minimum investment of 300,000 USD in a single project is required[408] to apply for an **investment licence** and thus to benefit from incentives (see section 4.8.1.2). The equity share of the domestic partners shall not be less than 2 % of the joint capital.[409] In the sense of the Investment Proclamation a foreign and a domestic investor can team up for a joint investment usually in the form of a partnership, private limited company or share company. If a foreign investor is willing to acquire an investment licence on his own account, without joint venture, a minimum investment of 500,000 USD is required. MHP systems in the range of 10 to 300 kW and estimated investment volumes of 15,000 to 550,000 USD will mostly not exceed this threshold. A foreign investor interested in MHP systems of this size should therefore strive for a joint investment with a local partner.

b) General partnership[410]

A general partnership consists of partners personally, jointly severally and fully liable. The partnership agreement, fixed in the memorandum of the association and approved by a public notary[411] may only be varied with the consent of all partners. Every partner has the right to check the firm's business, to consult the books and papers of the partnership and to draw up

[402] IMF, 1999, p.96
[403] Proc. No.166/1960 (N.G.), Art.227 - 270
[404] EIA, 2000, p.2 and Proc. No.166/1960 (N.G.), Art.227
[405] Proc. No.166/1960 (N.G.), Art.5 (13)
[406] loc. cit. Art.212 (2)
[407] loc. cit. Art.271-279
[408] Proc. No.37/1996 (N.G.), Art.11 (2)
[409] loc. cit. Art.8 (2) and Proc. No.168/1999 (N.G.), Art.2
[410] Proc. No.166/1960 (N.G.), Art.280 ff
[411] loc. cit. Art.284, 285 and EIA, 2000, p.3

a statement of the financial position. This means that every single partner has extensive rights but also duties. Every partner decides on the amount of money he wants to contribute.[412]

c) Limited partnership[413]

"A limited partnership comprises two types of partners: *general* partners in full liable personally, jointly and severally and *limited* partners who are only liable to the extent of their contributions."[414] Only the general partners may be appointed managers. Limited partners may inspect the books and call for the accounts. For the assignment of shares the agreement of the managers and the majority of the limited partners is required. In the written memorandum aspects like determination and follow-up of responsibilities, enforcing mechanisms in case of misdemeanour and auditing should be fixed.

d) Share company[415]

A share company's capital is fixed in advance and divided into shares. Liability is limited to the assets of the company, every member being liable to the extent of his share holding. The total capital must be at least 50,000 ETB and the number of members may vary between 5 and unlimited. The **founders** must sign the memorandum of association and subscribe the whole of the capital. Therefore, they have a special legal status. Their liability being stronger than that of other members, they may reserve to themselves a special part of net profit. In special cases the shares can be allocated exclusively among the founders. In general, after a valuation of contributions in kind and a notarised prospectus being made available to the public, the shares are offered for **public subscription**. A first subscribers' meeting will decide on the final text of the memorandum, setting up classes of shares with different rights, like common and preference shares, the articles of association and other items of the agenda. The Commercial Code of Ethiopia differentiates between preference shares and dividend shares. Holders of **preference shares** enjoy the preferred right of subscription in the event of future issues, or rights of priority over profits, or assets or both. Shareholders who have been given such rights of priority over profits and distribution of capital upon dissolution of the company may vote only on matters which concern extraordinary meetings. The number of these "vote-restricted" shares should not exceed half the amount of capital. As far as **dividend shares** (also called **common shares**) are concerned, the company may repay from profits or reserve funds, without reducing the capital, to shareholders the par value of their shares. In return, dividend shares however retain a right of vote. This means that dividend shares are built as voting shares and the preference shares, which receive higher dividends, not.

A share company is characterised by:
- the **general meeting of the shareholders**: managing body, being annually submitted the balance sheet, electing the directors and auditors
- the **general manager**: employee of the company, may not be a director, managing the operation of the company, being accountable to general meeting
- the **board of directors**: 3 - 12 members, electing chairman and appointing general manager, keeping records of management, accounts and books, submitting accounts to auditors, submitting annual report of company's operations to general meeting
- the **chairman**
- the **auditors**: elected by general meeting; auditing and controlling books and securities, verifying inventories, balance sheets, profit and loss accounts, commenting the directors' reports to general meeting etc.

The directors deposit as security a certain number of their registered shares in the company. Different classes of shares, set up in the memorandum of association, allow for preferred

[412] EIA, 2000, p.3
[413] Proc. No.166/1960 (N.G.), Art.296-303
[414] loc. cit. Art.296
[415] loc. cit. Art.304-509

rights, rights of priority over profits etc.. “The voting rights attached to ordinary or dividend shares shall be in proportion to the amount of capital represented” (Art. 407). “Dividends may only be paid to shareholders from net profit shown in the approved balance sheet” (Art. 458). Shareholders pay 10 % income tax on their dividends.

e) Private limited company[416]

The members of a private limited company are liable only to the extent of their contribution. The company shall have 2 - 50 members and the minimum capital is 15,000 ETB. All shares shall be of equal value and not less than 10 ETB, whereby a member can acquire several shares. The deed in the form of a memorandum of association has to be signed by all members. Public notification and application for registration in the commercial register are also required for this business organisation. The transfer of shares between members is not restricted, whereas the transfer of shares outside the company has to be approved by the majority of the members representing at least three quarters of the capital. In case of more than 20 members decisions shall be taken at members' meetings and a minimum of three auditors shall be appointed. Then general meetings should be held at least once a year. The number of votes entitled to depends on the number of shares held by a member. The management is taken over by one or more managers. Managers can be members, can be appointed by the latter or by the memorandum or articles of association. Thus ownership is an incumbency of the shareholders and management is the duty of the elected body. 1/20th of the profits should be transferred each year to the legal reserve fund of the company until this fund amounts to 1/10th of the capital. According to the Ethiopian Investment Authority, in these days, most of the companies established in Ethiopia by foreign as well as domestic investors are private limited companies.[417] As far as MHP projects are concerned especially the limitation of members on a maximum of 50 and the relatively complicated transfer of shares outside the company seem to be less convenient. Even in case of a few investors managing the system without consumer participation this organisational form restricts the loan raising possibilities because of the limited liability of the members.

#### *4.7.2.4 Co-operative societies*

The co-operative societies are formed by individuals with a common interest in creating savings and mutual assistance by pooling their resources, knowledge and property to actively participate in the free market economy and to share other advantages.[418] This includes the joint solution of social and economic problems to improve the living standard.[419] The national „Co-operatives Societies Proclamation“ of Ethiopia provides for the establishment of consumer co-operatives[420] whereas the Oromia Regional State allows the establishment of any kind of co-operative society.[421] Although electricity consumer or producer co-operatives are not explicitly mentioned they can be subsumed under "consumer co-operatives".[422] In any case these co-operatives, which are registered by the appropriate authority, for instance the Oromia Co-operative Promotion Bureau[423], have to be seen in strict delimitation to the former socialistic co-operatives with their enforced participation for the follow up of administrative goals (see section 4.7.2.2). In general after submission of an application for registration to the appropriate authority, in case of acceptance the society should be registered and receive a certificate within 15 days.[424]
A co-operative society consists of[425]

[416] loc. cit. Art.510-543
[417] EIA, 2000, p.5
[418] Proc. No.147/1998 (N.G.), Preface
[419] loc. cit. Art.2 (2), 4 (1), (4), (5); and Urban, 1993, p.16
[420] Proc. No.147/1998 (N.G.), Art.2 (1)
[421] Proc. No.27/1999 (M.O.) Art.2 (2)
[422] personal communication: Oromia Co-operative Promotion Bureau, 03/2000
[423] Proc. No.147/1998 (N.G.), Art.9 (1) and Proc. No.15/1997 (M.O.) amended by Proc. No.27/1999 (M.O.)
[424] Proc. No.147/1998 (N.G.), Art. 9
[425] loc. cit. Art.2, 6 and 20ff

1. at least 10 members
2. a **general assembly**, which is the meeting of the members and supreme organ, passing decisions, approving and amending by-laws, electing management and control committee, determining the amount of shares, deciding on annual net profit distribution,
3. a **management committee**, which is a body elected for a 3 year period, empowered by and accountable to the general assembly, managing the activities of the society like maintenance of the documents and books of accounts, preparation of annual work program and budget and implementation of the same upon approval etc.
4. a **control committee**, which is accountable to the general assembly, controlling the management committee, the utilisation of funds and property etc.

Important **characteristics** of the co-operative are:[426]

- democratic structure with equal voting right of every member (one member one vote)
- distribution of dividends from profits according to members shares and contribution; after deduction and setting aside an amount of 30 % of the net profit necessary for reserve, expansion of work and social services[427]
- liability of the society limited to its total assets[428]
- democratic control by the members and maintenance of autonomy
- engagement in production or service rendering activities determined by by-laws

Among others a member has the following **rights and duties**:[429]

- to become a member he has to pay a registration fee and the share capital
- to hold a share of not more than 10 % of the total paid up share capital
- transfer of share or benefit is only possible after at least one year of holding the share and approval by the management committee
- to obtain services and benefits according to his participation in the society
- participation in the meetings and elections
- to follow by-laws and directives

A special privilege of these societies is the exemption from income taxes provided however, members are obliged to pay ten percent income tax on their dividends.[430] In general, modern co-operatives can provide a suitable management structure for planning, implementation and operation of an MHP project. Either already existing co-operatives, especially saving and credit co-operatives and agricultural co-operatives, can be involved or a new co-operative society can be established explicitly for the purpose of an MHP project.

**Savings and credit co-operative societies (SCCs)** have a long standing history as semi-formal financial institutions in Ethiopia.[431] The first one was established by employees of the Ethiopian Airlines in 1964.[432] During the changeful history of Ethiopia since the 1960s, co-operatives were objects of different laws respectively proclamations.[433] SCCs' basic purposes are to promote thrift, to provide a source of credit at low interest rates and to teach people the intelligent use of their money and the efficient management of their limited accumulated resources.[434] SCCs are characterised by their shareholder-structure and ownership lies by all members. Lending is based upon the criteria of "character, capacity and collateral"[435] of each applicant thus taking into account good character and ability to pay when granting loans, whereas banks always ask for security and tangible collateral.[436] Lower inter-

[426] loc. cit. Art.5 and 7
[427] loc. cit. Art.33
[428] loc. cit. Art.10
[429] loc. cit. Art.13ff
[430] loc. cit. Art.31 (1a) and EIA, 1999, p.96 with reference to Proc. No.37/1996 (N.G.)
[431] also known as Credit Unions or Thrift and Credit Co-operatives. See: Aredo, 1993, p.36 and EEA*, 1999/2000, p.318
[432] EEA*, 1999/2000, p.318
[433] Aredo,1993, p.38
[434] loc. cit. p.37
[435] also called the "the three C's"
[436] loc. cit. p.37f

est rates and soft borrowing criteria confer primary importance to granting of loans within the SCCs.
Some of the well established and successful SCCs, as the above mentioned Ethiopian Airlines Employees' SCC, already started to choose several additional projects for income-generating activities, like the sale of tyres and distribution of petrol.[437] Prosperous SCCs are often interested in further income-generating activities, which might also be an MHP project.

Another option are the restructured former SCs or newly established **agricultural co-operatives (ACs)**[438], nowadays predominantly organised as agricultural marketing co-operatives. Given the fact that an already existing and well functioning management structure can easily be used for an MHP project, existence of ACs in the relevant region and its interest in being involved should be checked.

Recapitulating, MHP projects can be attractive either for SCCs as income generating ventures or for ACs as an option of electricity supply to process agricultural products with the far reaching consequence of an improved competitive position on national or even international markets, e.g. by means of coffee and other processing. Already **existing** co-operatives can

- mobilise investment capital, e.g. by means of equity capital of the co-operative society
- act as a source of re-financing for single investors, especially SCCs
- take over MHP project as additional task, in case of an already existing strong management structure (assignment of tasks, control of proper bookkeeping etc.).

In a co-operative society explicitly **newly established** for an MHP project by-laws, partition of responsibilities, distribution of shares etc. can be adopted to the requirements of the project. The management committee can consist of operators and treasurers contractually obligated to fulfil their tasks, like accounting to the general assembly, operation, maintenance and management of the MHP system including cashing of fees. Enforcing mechanisms like fines or dismissals in case of misdemeanour of the management committee should be introduced. The general assembly should decide on the management of financial resources. Elected auditors control the management staff.

### 4.7.3 Recommended organisational forms

In any case, **existing** organisational forms such as CBO's, co-operatives according to the new legislation, administrative structures like PAs, SCs etc. should be roughly surveyed to evaluate if they can bear the additional tasks of implementation and management of an electricity supply system. Even if a completely new organisation is required such an analysis reveals prevailing problems so that they can be avoided in new structures. If a business organisation according to the Commercial Code turns out to be most appropriate for an MHP system, in general, it has to be newly founded. The characteristics of business organisations and co-operatives, with regard to equity finance and liability, are listed in Table 4.34. A comprehensive overview is depicted in Table 4.37. Besides essential characteristics of the different forms, their impact on financing and organisational aspects and limitations of their applicability are illustrated.

[437] loc. cit. p.48
[438] Proc. No.147/1998 (N.G.) and Proc. No.15/1997 (M.O.) amended with Proc. No.27/1999 (M.O.); personal communication: Oromia Co-operative Promotion Bureau, 03/2000

| | unincorporated firms | | | incorporated firms | | | |
|---|---|---|---|---|---|---|---|
| | **1 man business** | **general partnership** | **limited partnership** | **P.L.C.** | **Small Sh.C.** | **Sh.C.** | **co-operative** |
| ***organisational aspects*** | | | | | | | |
| **number of members*** | 1 | 2 - unlimited | 2 (1 general + 1 limited partner) - unlimited | 2 - 50 | 5 - unlimited | | at least 10 |
| **structure** | | equal partners | general and limited partners | general meeting, managers, auditors | general meeting, board of directors, chairman, general manager | | general assembly, management and control committee |
| **voting right** | only 1 person | partners decide together | general partners decide together | in proportion to amount of capital (different numbers of shares) | in proportion to amount of capital (shares of different values) | | one share - one vote ! (shares of ≤10% of total share capital) |
| **liabilities in the structure of the organisation** | fully liable | <u>all</u> partners are personally, jointly and severally liable | - <u>general</u> partners: no limitation (personally, jointly and severally) - <u>limited</u> partners: only liable to the extent of their contributions | limited to the extent of the contributions of the partners | limited by the assets of the company (common and preference shares) | | limited to total assets of the society |
| | fully liable ←——————————————————→ limited | | | | | | |
| **control** | | control of books and papers by every partner at any time | control of books and papers by every partner at any time | control of the management by the general assembly | control of the management by the directors; control of the directors by the general meeting | | democratic control by members |
| ***financing aspects*** | | | | | | | |
| **participation of customers** | | | | ←———possible with (normal) shares———→ | | | |
| | | | ←—————possible with juissance shares——————→ | | | | |
| **acquisition of equity capital** | | | broad market | no access to anonymous capital | broad market ("interoffice market") | | only members' equity |
| **raising of bank loans** | ←——————————————— increasing credit worthiness | | | | | | difficult ! |
| **appropriate investment volume** | low ←————————————————————→ high | | | | | | no limits |
| **minimum capital** | | no limitation | no limitation | 15.000 ETB | 50.000 ETB | 50.000 ETB | no limits |
| **Commercial Nom. involved** | | | | if ≥ 15.000 ETB | if ≥ about 500.000 ETB | | |

* The number of members does not limit the number of juissance shareholders !

*Table 4.37: Characteristics of different organisational forms*[439]

[439] modified and extended according to Perridon/Steiner, 1999, p.351

Table 4.38 illustrates the results extracted from the comprehensive analysis of the preceding paragraphs, referring to their relevance for MHP projects.

| organisa-tional form | advantages | disadvantages | suitability |
|---|---|---|---|
| | **with regard to MHP projects** | | |
| **joint venture** | - advantageous when acquiring investment licence (see section 4.8.1.2) | - cannot issue negotiable securities<br>- shares can only be assigned with agreement of all partners | for co-operation between local and foreign investors |
| **general partnership** | - access to loan capital easier because of full liability | - every "participant" has to become partner with far-reaching liability<br>- not appropriate for consumer participation | for group of a few well funded or creditworthy business men |
| **limited partnership** | - more options of liability: fully, common limited, preferred limited<br>- combination with juissance shares useful<br>- relatively high contractual freedom of juissance shares compared to usual share in share company | - in organisation as such, without juissance shares, consumer participation not useful | for investors with different liabilities supplemented by consumers with juissance shares; with creditworthy general partners also access to loan |
| **share company** | - participation of big number of differently funded people possible<br>- access to broad capital market<br>- manageable by means of board of directors and auditors<br>- voting right according to value of shares | - less creditworthy for banks because of limited liability<br>- capital market limited to interoffice market, no official stock market | for big number of investors, consumers, NGO's etc.; different share values allow for different degree of participation |
| **private limited company** | | - max. 50 participants<br>- less creditworthy because of limited liability<br>- no access to broad capital market | only for group of several well funded investors; different number of shares allows for different degree of participation |
| **modern co-operative** | - user participation not only financially but also as decision makers<br>- more remunerative for public welfare | - strong democratic structure might be deterring for private investors | for well funded community which is independent of big investors and banks |

*Table 4.38: Advantages, disadvantages and suitability of different organisational forms for MHP in Ethiopia*

The fully liable partners of a **general partnership** are enabled to control the business by inspecting books and accounts and taking management decisions. Therefore the involvement of a huge number of electricity consumers as partners in a general partnership would make the organisation unmanageable. This business form has to be reserved to a smaller group of investors, who either procure the whole investment volume on their own or are creditworthy partners for a bank. In case of that smaller group of investors an alternative would be the limited partnership whose legal background is quite similar but additionally allows partners with different liabilities.

With a **limited partnership** as such, consumer participation is not useful either due to the same reasons as for the general partnership. As soon as this form is combined with the option of **juissance rights**, it offers a quite diversified organisational structure: partners willing to take higher risk become general partners, those who are more risk averse act as limited partners and customers can participate by means of juissance shares. Subsequently, both business forms, general and limited partnership, are appropriate for a few big investors, whereby the latter additionally allows for user participation by means of juissance shares.

In **share companies** management tasks are transferred to a board of directors and controlling is done by the auditors. The structures provide clear responsibilities. Ultimate decisions are still taken by the general assembly of all shareholders. This procedure allows participation of a huge number of consumers, investors etc., pursuant to their share value, but keeps the company still manageable.

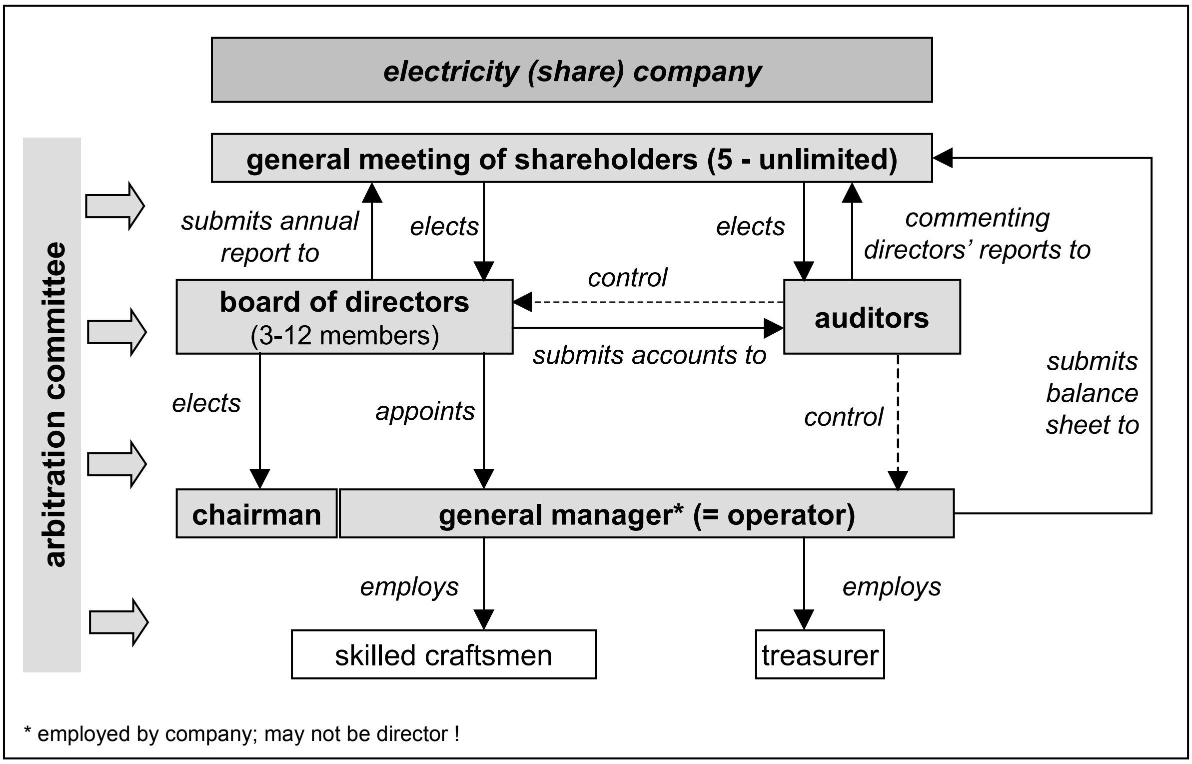



*Figure 4.22: Possible structure of an electricity (share) company*[440]

In contrast to the co-operatives, share companies are structured less democratically. Firstly because higher financial participation increases the influence in the general meeting and secondly because the general meeting delegates the management to a board of directors as representatives and the board assigns a general manager for proper operation. Thus between general assembly and management a further hierarchy level is introduced. The directors pay and control the manager and can apply enforcement mechanisms. Nevertheless the manager is also accountable to the general meeting, just like the board of directors, which must report to the general meeting. The manager employs and pays further staff. A right for termination of contracts can be granted for the case of misdemeanour of the manager towards the staff and the directors towards the manager. For conflicts which are neither regulated in the bylaws nor in the contracts, an arbitration committee of independent representatives like Elders, Iddirs, etc. can be nominated.

[440] modified according to Brunner, 2000, p.59

A **private limited company** allows a maximum of 50 project owners. Their registration is a relatively complicated procedure. The access to a broad capital market and to loans is limited. Due to these reasons, this organisational form is mostly not appropriate for MHP.

If a strong customer involvement is desired, a **modern co-operative** is a very suitable organisational form. Here, the decision-making process is not related to the amount of share participation. Everybody holding a share has the same voting right. This makes co-operatives less attractive for big investors, because they are forced to share management and control rights with a big number of users, who might as a whole be less profit but more service and welfare oriented than him. If such an investor needs equity input from the "public", but wants to exclude the public from system control, a limited partnership combined with juissance rights is more advantageous for him. From the point of view of the co-operative members, the acquisition of additional capital from "outside" is difficult either due to unattractiveness for big private investment volumes or lacking creditworthiness at banks. In general the amount of available capital of existing SCCs or ACs is by far not sufficient. In that case loans with soft credit terms, not requiring high collateral, from NGO's can be a solution. Yet, to ensure sustainability of the project, clear responsibilities for management tasks and loan payback must be defined. To check the appropriateness of a modern co-operative as organisational form, the following questions have to be asked:

- is a co-operative already existing ?
- how successful does it operate ?
- how much equity capital can it make available for investment ?
- which amount of collateral for loan raising is available ?
- how can the potential of the region develop in the near future, e.g. rich coffee region with low market risk guarantees energy demand for processing and lowers energy market risk

Figure 4.23 illustrates how an electricity co-operative can be structured.

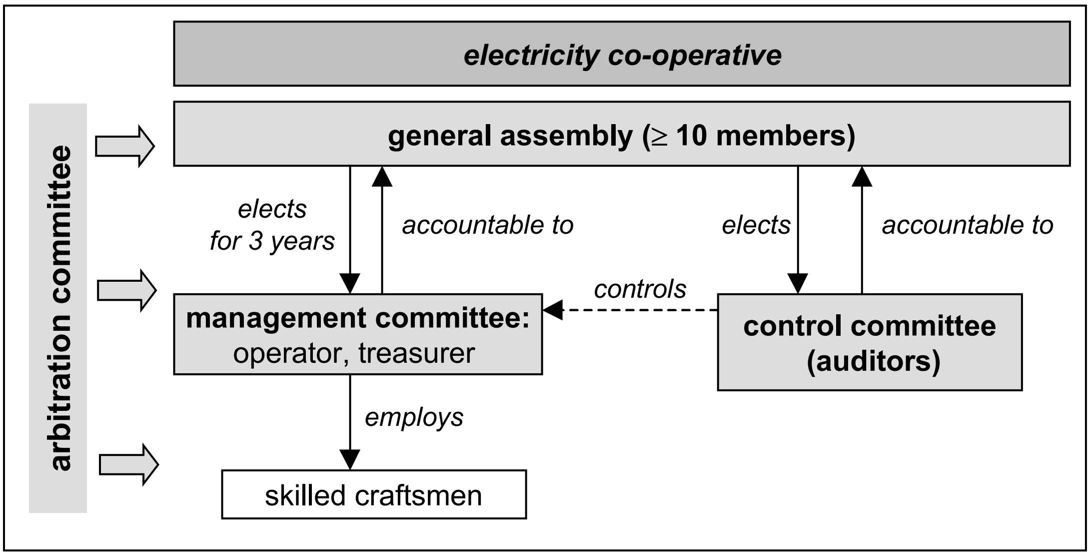



*Figure 4.23: Possible structure of an electricity co-operative* [441]

The general assembly is contractually obliged to assign and properly pay the staff and the management committee. The assembly supervises operator and treasurer with regard to management and maintenance. In case of misdemeanour it applies enforcement mechanisms. The management committee consists mainly of operator(s) and treasurer(s) and is responsible for technical and financial tasks and the collection of tariffs. Operator and treasurer should be granted the right for termination of their contract in case of misdemeanour of the general assembly.

[441] modified according to Brunner, 2000, p.55

Summarising, the most promising organisational forms for MHP systems are:
1. limited partnership combined with juissance rights
2. share company
3. modern co-operative

They warrant preferably high equity involvement from investors, customers and probably also from NGO's. A high portion of equity simultaneously improves the access to loan and customers' involvement improves the general acceptance of the system.

In general, the tasks to be fulfilled during the different project phases are either taken over by the project partners or will be sourced out. For very small plants of less than about 20 kW and preferably for mechanical use an implementation almost on own responsibility of the community, after initial and specific input from outside, can be envisaged.[442] For more sophisticated systems for electricity supply, external support for feasibility study, technical design etc. is required. Nevertheless, at least partial community participation is often useful for identification with the system and to reduce costs.

The organisation must in any case be established *before* project start in order to:
- draft **bylaws** for its own constitution, to assign responsibilities, powers and duties including enforcement-mechanisms, fines or punishments like exclusion of the users from the supply in case of misdemeanour
- conclude **contracts** to manage the financing, to oblige operator, treasurer etc.
- involve all **concerned parties**, for example the operator who imperatively must participate from the beginning and traditional authorities for arbitration
- define **external auditors**, evaluating the organisation and its work

## 4.8 Legal aspects

### 4.8.1 Required licenses

#### *4.8.1.1 Licenses for electricity generation, transmission and distribution*

In Ethiopia generation, transmission, distribution and sale of electricity is regulated by the different laws, proclamations and regulations and directives to be issued hereunder[443], namely the Electricity Proclamation[444], the Electricity Operations Council of Ministers[445] and the Investment Law. In addition, a specific regulation[446] provides for the establishment of the EEPCO, former EELPA, as a public enterprise. Amongst the three legal corpora mentioned above, priority is given to the **Investment Law** by Article 13 (3) of the Electricity Regulation No. 49 which states, that "no license shall be issued under these regulations unless the applicant is eligible to invest in the sector pursuant to the provisions of the relevant investment law."

The **Ethiopian Electric Agency (EEA)** as newly established control organ
- supervises the adherence to the mentioned legal framework
- determines and insures implementation of quality and standard of electricity services
- issues certificates of professional competence to electrical contractors
- issues, suspends and revokes licenses for the generation, transmission, distribution and sale of electricity

[442] personal communication: Horst Höfling (GTZ), 06/2000
[443] Proc. No.86/1997 (N.G.), Art.11 (1)
[444] Proc. No.86/1997 (N.G.)
[445] Reg. No.49/1999 (N.G.)
[446] Council of Ministers Regulation No. 18/1997

- studies, recommends and supervises implementation of tariffs
- collects license fees etc..[447]

An electricity license is needed as soon as generation, transmission, distribution and sale of electricity for **commercial purposes** is concerned; for non-commercial purposes the Agency (EEA) only has to be notified.[448] The general requirements for the application of a license are[449]:

- identity and address of the applicant
- **feasibility study** of the project, including social and economic impacts, estimated costs and returns of the project, duration of the project as well as the construction and installation program and the commencement date of operation
- **environmental impacts** assessment, including all potential damages to the environment along with mitigation, restoration or reclamation plan including resettlement program for displaced residents and estimated costs of implementation of the plans and programs
- documents showing the applicant's financial situation, technical competence and experience
- construction and installation designs, and other information which the agency may determine by directives.

Additional details for the acquisition of the different licenses, also required for MHP projects, are summed up in Table 4.39.

| | **generation license** | **transmission license** | **distribution and sale license** |
|---|---|---|---|
| | | | ***peremptory conditions[450]*** |
| **applicant** | for hydropower: possible for foreign and domestic investors without limitation of generation capacity | if the applicant is an investor, he has to be domestic | if the applicant is an investor, he has to be domestic |
| ***details to acquire the licenses*** | | | |
| **source** | source of electricity | | source from which the distribution system draws electricity |
| **maps[451]** | map of the project site at the scale determined by the EEA | preliminary route map of proposed main and alternative transmission lines | |
| **capacities** | total power capacity of the project | total length and maximum load of transmission lines | estimated number of customers and proposed price of each unit of power to be sold |
| **contracts and qualities** | power purchase contract where appropriate | standard of voltage and frequency | power purchase contract where appropriate |

*Table 4.39: Preconditions and specifications required for the acquisition of an electricity licence[452]*

Three working days after registration of an application by EEA, the latter will send notice of the request to the concerned publishers for **publication** on two successive issues of newspapers with wider circulation. In addition, the advertisement has to be announced on radio

[447] loc. cit. Art.3-6
[448] loc. cit. Art.10 (1), (2)
[449] Reg. No.49/1999 (N.G.), Art.3
[450] Proclamation No.116/1998 (N.G.), Art.2ff
[451] Copies of maps of the proposed area have to be deposited at the office of the EEA
[452] Reg. No.49/1999 (N.G.), Art.4ff

and TV for three consecutive days.[453] According to the general manager of the EEA, these duties are undertaken by the EEA[454], but the costs have to be borne by the applicant.[455] The whole procedure is illustrated in Figure 4.24.

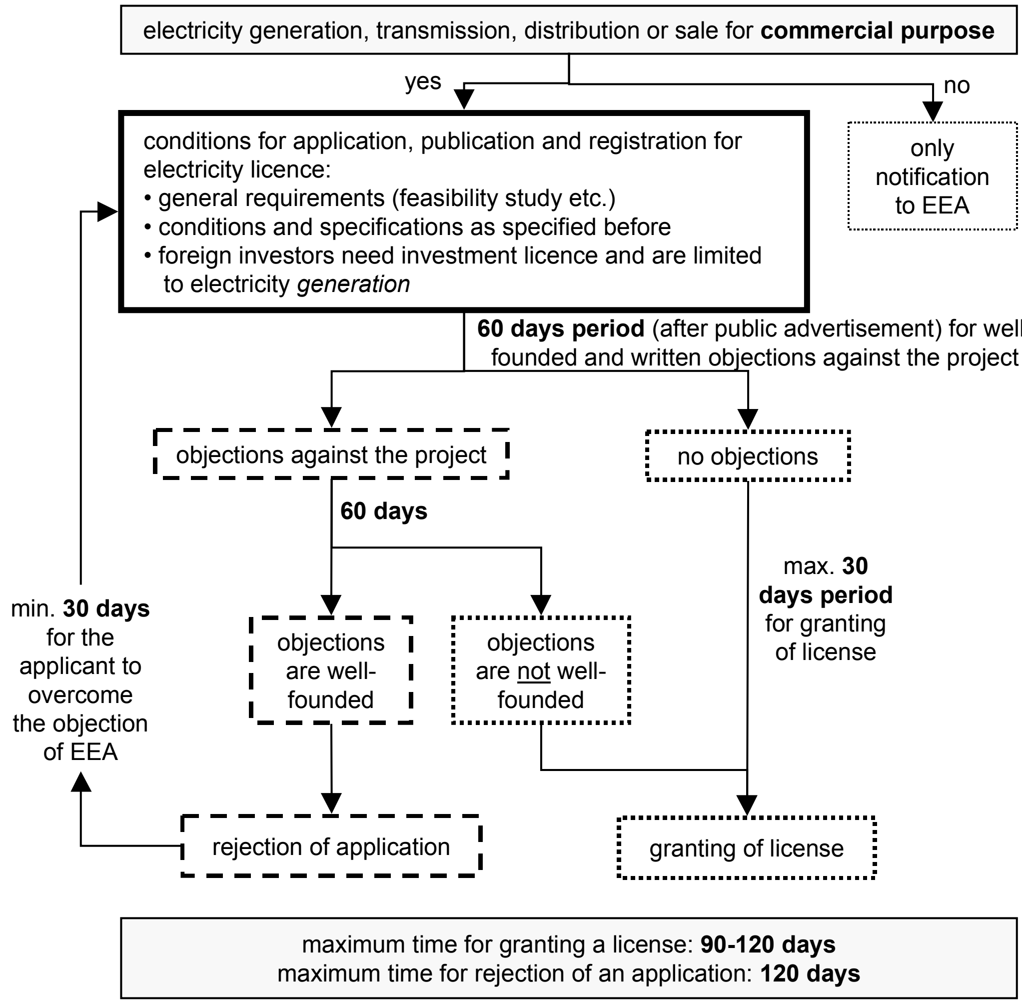



*Figure 4.24: Procedure and duration for granting or rejection of an electricity license for generation, transmission, distribution and sale[456]*

Table 4.40 summarises the fees to be paid for the different licences.

| | **specific fees** | **minimum fee** |
|---|---|---|
| generation license | 1 ETB / kW | 1,000 ETB |
| transmission license | 20 ETB / km | 2,000 ETB |
| licence for distribution and sale | 2 ETB / kVA | 1,000 ETB |

*Table 4.40: Fees for the different licenses[457]*

The fees for transmission license are referred to circuit kilometres and those for distribution and sale license are referred to kilovoltampere of transformer capacity. For MHP systems up to generation of 1,000 kW, up to transmission within 100 km and up to 500 kVA of transformer capacity the minimum amount of 1,000 ETB for generation, 2,000 ETB for transmission (if necessary) and 1,000 ETB for distribution and thus a total of 4,000 ETB has to be

[453] Reg. No.49/1999 (N.G.), Art.9
[454] personal communication: Gosaye Mengistie (EEA), 03/2000
[455] Reg. No.49/1999 (N.G.), Art.9
[456] Reg. No.49/1999 (N.G.), Art.13 and 14
[457] loc. cit. Art.21

paid.[458] 20 % of the fees have to be paid in advance; this payment is not refundable upon refusal of the license.[459]
The total of costs and fees incurring for the licensee can be summarised as follows:

- costs for the application, i.e. feasibility study, environmental impact assessment, construction and installation designs, which are in general no additional costs
- costs for advertisement
- costs for copies of maps etc.
- different license fees.

The **duration** of the licenses is based on the life of the project, whereby the maximum duration shall not exceed 40 years for generation, 50 years for transmission and 50 years for distribution and sale.[460] For amendment and renewal of a license, 50 % of the fee required for the issuance of the license are charged.

According to the legal framework, the general electricity pricing principles should take into account the efficient allocation of resources, where customers and producers receive the **true costs** associated with consuming and producing one additional unit of energy respectively.[461] The calculation of tariffs should be based on the system of **marginal costs** and consider the costs incurred by the total system, thus allowing continuing investments and sustainable services.[462] Outside the national grid the prices are determined on estimated or actual accounting costs and an acceptable rate of return on investment.[463] This "acceptable rate of return" is in the range of about **25 %**.[464]

Although the legal frame defines several obligations and limitations for the licensee it also concedes some rights to him. Among others the Electricity Proclamation regulates the **use of land and water**, allowing the licensee

- to enter land in order to undertake electricity operations[465] and to connect, repair, upgrade, inspect or remove electrical lines
- to cut and loop trees or to remove crops, plants and other things, obstructing construction or operation of electrical works or causing danger to electrical lines[466]
- to use water, free of charge, for generation of electricity
- to prohibit construction, farming, plantation or any other activity of a permanent nature within the clearance zone to be set, by regulations, adjacent to electric transmission stations or lines“[467]

Even if the realisation of these rights might be restricted in specific cases, where traditional rights have to be respected and conflicts of interest arise, the Electricity Proclamation and Regulations in general grant the licensee a relatively strong position.

#### *4.8.1.2 Investment licence*

The investment license is of importance for MHP in Ethiopia because firstly it is obligatory in certain cases and secondly can provide several incentives for the project. Table 4.41 summarises the legal framework for investment licensing, which is in detail regulated by:

- Proclamation No. 37/1996, Investment Proclamation
- Proclamation No. 116/1998, Investment (Amendment) Proclamation
- Regulation No. 7/1996, Investment Incentives Council of Ministers Regulations

[458] loc. cit. Art.21 (2), (3) and (4).
[459] loc. cit. Art.21 (1).
[460] loc. cit. Art.18 (1).
[461] loc. cit. Art.26 (1).
[462] loc. cit. Art.26 and 27
[463] loc. cit. Art.27-30
[464] personal communication: Gosaye Mengistie (EEA), 11/2000
[465] Reg. No.49/1999 (N.G.), Art.22 (1)
[466] Proc. No.86/1997 (N.G.), Art.20 (2), Art.21; in connection with Reg. No.49/1999 (N.G.)
[467] Proc. No.86/1997 (N.G.), Art.24

- Council of Ministers Regulations No. 35/1998, Investment Areas for Domestic Investors Council of Ministers Regulations
- Council of Ministers Regulations No. 36/1998, Investment Incentives Council of Ministers (Amendment) Regulations

| | | |
|---|---|---|
| - foreign national<br>- enterprise owned by a foreign national<br>- Ethiopian living abroad preferring treatment as a foreign national | | - foreign national permanently residing in Ethiopia<br>- foreign national, but Ethiopian by birth, desiring to be considered as a domestic investor<br>- Ethiopian national<br>- governmental and public enterprises |
| **foreign investor** | **joint foreign/domestic investment**[468] | **domestic investor** |
| investment licence is **obligatory** | | investment licence is **voluntary** |
| minimum investment:<br>- **500,000 USD** in a single investment project<br>- 100,000 USD for reinvestment in a new project and for engineering / consultancy | minimum investm.:<br>**300,000 USD** in a single investment project | minimum investment:<br>**250,000 ETB (31,000 USD)** to be entitled to incentives<br>below 250,000 ETB: registration with regional investment office possible, in general renunciation of national incentives[469] |
| buying of an existing enterprise or shares of it needs **approval** by the Investment Authority | | buying of an existing enterprise or shares of it needs **no approval** |
| investment in **hydropower generation** (shaft and electric energy) is **allowed** without limits | | |
| Investment in grinding mills, transmission, distribution and sale of electric energy is **not allowed** | | Investment in grinding mills[470], transmission, distribution and sale of electric energy is **allowed** |

*Table 4.41: Comprehensive overview on conditions requiring investment licensing*[471]

With regard to areas of investment and minimum volumes required for acquisition of a licence, the legal basis distinguishes between the categories foreign investor, investors in joint ventures and domestic investors. In all other respects, the law categorises all investors in the same manner during and after licensing.[472] The minimum investment can be in cash or in kind, in form of capital goods such as machinery, equipment or other tangible assets. In general investment may be effected in sole proprietorships, business organisations, public enterprises and co-operative societies.[473]

Whereby, business organisations have to be registered in accordance with the Commercial Code (see also section 4.7.2.3). An **application** for an investment permit shall use the right form[474] and shall contain the following details[475]:

- the project profile
- a list of the type and quantity of machinery and equipment intended to be exempted from import duties and taxes
- in case of a business organisation, the memorandum and articles of association

[468] Proc. 168/1999 (N.G.), Art.2 (2); equity share of the domestic partners shall not be less than 2 %
[469] Lemi, 1997, p.119 and Gavian, Degefa, 1994, p.149
[470] Reg. No.35/1998 Art.3
[471] Klein, 2000, p.16
[472] http://www.addischamber.com/ethiop/invst.htm
[473] Proc. No.37/1996 (N.G.), Art.10 (1), (2)
[474] EIA, 1998, p.23
[475] Proc. No.37/1996 (N.G.), Art.13

- in the case of expansion or upgrading, a brief description of the same and the implementation program
- in the case of planned employment of expatriate staff, a statement on the time schedule for their replacement by Ethiopians and the training program designed for such replacement
- power of attorney in the case of an application made through an agent
- other relevant information relating to the particulars of the project.

In the specific case of foreign nationals residing in Ethiopia and wishing to be considered as "domestic investor" several documents for the acceptance have to be supplied. The treatment as domestic investor lowers the required minimum investment volume. A holder of an investment permit has several advantages. He benefits from the **"One-Stop-Shop"** service of the competent executive body issuing the license. That means that either the Ethiopian Investment Authority (EIA) or the regional investment organ will not only take care of the issuance of an investment license but also of[476]:

- the issuance of **trade and operating licenses**, the latter theoretically including the **electricity licence**
- the granting of **work permits** to expatriate employees
- the **registration of business organisations** as required under the relevant laws
- the **allocation of land**[477] via the regional authorities and
- theoretically also the **water rights**[478]

The administration of investment in respect not only of foreign investors and joint investments but also investments made in areas eligible for incentives, by domestic investors who are required to obtain trade and operating licences from concerned federal organs is under the jurisdiction of the EIA. Other investments fall under regional investment organs' responsibility, whereby the granting of incentives such as exemptions from import taxes and custom duties is exclusively incurred by the EIA.[479] Subsequently foreigners <u>and</u> domestic investors dedicated to incentives should be attended by this institution. Although the Proclamation virtually not excludes domestic investors from the service of the "One-Stop-Shop", according to the information from the general manager of the Ethiopian Investment Authority this service is reserved exclusively to foreigners. Domestic investors would have to obtain the necessary licenses one by one.[480] The licensing procedures for an MHP project in Ethiopia, which depend on the investor, the project volume etc. are illustrated in Figure 4.25.

[476] loc. cit. Art.25
[477] loc. cit. Art.36 (1) and (4): "Where a Regional Government receives an application for the allocation of land for an approved investment it shall, on the basis of Federal and its own laws, deliver the required land to the investor within 60 days thereof" and "the appropriate investment organ shall, in co-operation with the concerned Regional Government entities, facilitate and follow up the allocation of land for approved investments"
[478] If the Investment Authority procures the electricity licence via the EEA and according to Proc. No.86/1997, the EEA may issue the required water use permit to the licensee in accordance with Proc. No.92/1994 (Water Resources Utilization Proclamation) and thus include it in the "One-Stop-Shop"
[479] Proc. No.37/1996 (N.G.), Art.24 (1)-(3)
[480] personal communication: Tadesse Haile (EIA), 03/2000

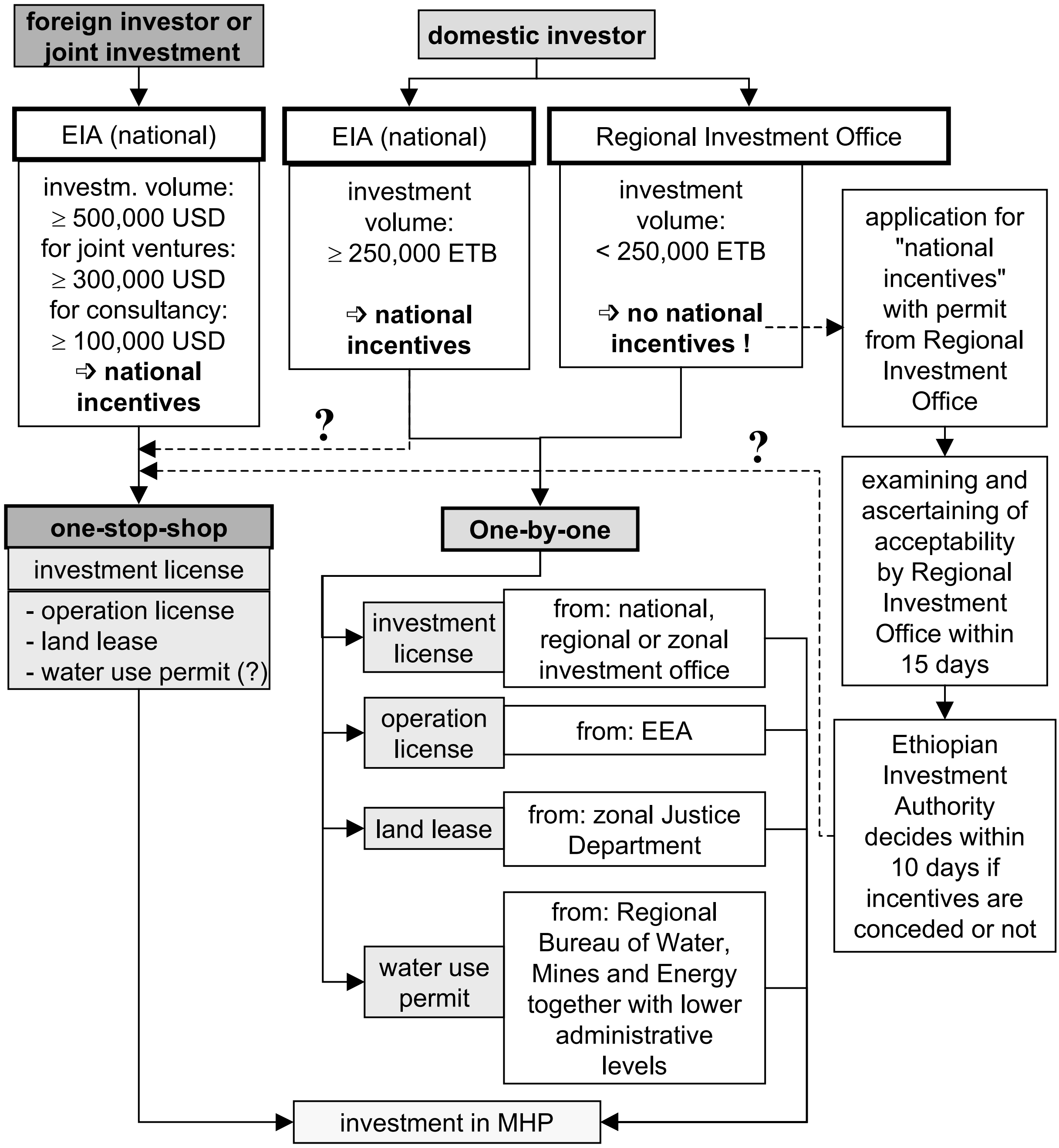



*Figure 4.25: Licensing procedure for investment in MHP in Ethiopia*[481]

According to the law, the investment permit has to be issued within **10 days** after receipt of the complete application[482] whereas the “One-Stop-Shop” service takes **30 days**.[483] In practice, however, more than ten days might be required. A recent review by the EIA of a sample of 15 applications indicated a mean processing time of 17 working days.[484] Given the fact that no experience has been gained with energy supply projects which require an electricity licence as "operation licence" the approval time for MHP projects is difficult to predict. Figure 4.24 indicates a maximum time for issuance of 90 - 120 days for an electricity licence. In case that EIA has to procure this licence at EEA and does not negotiate on a special procedure, the one-stop-shop service can most likely not be handled in 30 days. The EIA charges a fee of **30 - 100 ETB** for processing applications, depending on the amount of investment capital. A further expense of **300 - 700 ETB** resulting in a maximum total of about 800 ETB

[481] Proc. No.37/1996 (N.G.), Art.24ff
[482] loc. cit. Art.14 (1)
[483] loc. cit. Art.25 (3)
[484] http://www.ipanet.net/unctad/investmentguide/ethiopia/v.htm

may be incurred for stamp duties and the publication of an official notice.[485] It is assumed that additional fees for electricity licence etc. have to be subjoined. Compared to experiences, from the middle of the nineties, when the acquisition of an operation license could reach costs of about 44,000 ETB and could take as long as one year, because of the complicate administrative procedure, the present service is much more useful.[486]

Apart from the "one-stop-shop" service the holder of an investment permit is granted several **incentives**, whereby the specific entitlements described in Table 4.41 must be considered. "Production, collection and distribution of electricity" is appreciated one of the so-called “pioneer investment activities”[487], thus allowing

1. exemption from **income tax** for 3 up to 5 years, depending on the region, where the project is implemented[488]

Production and processing of oil crops, pulses, fiber crops etc., processing of forest and forest products also belong to this category of “pioneer investment”. If, in an MHP project mechanical or electrical drive of such processing machines is envisaged, these additional business ventures can also profit from tax relief. Manufacture of grain mill products, bakery products, sugar, macaroni, noodles, etc. and other food products however belong to the category of “promoted investment activities” allowing only 1 up to 3 years[489] of income tax exemption.

An investor or a business enterprise having incurred loss within the period of exemption from income tax can

2. carry forward his loss for 3 up to 5 years after the termination of the tax holiday, depending on the region and the “investment category”.[490]

In addition the following incentives are accorded with the issuance of an investment permit:[491]

3. expenditures for “research and training programs to upgrade or expand an enterprise shall be deductible for income tax purposes”
4. depreciation allowance can be calculated annually on the basis of straight line or accelerated depreciation methods
5. exemption from payment of **custom duty** on machinery and equipment necessary for the establishment of the enterprise. Even in case of an investment of less than 250,000 ETB this incentive is offered for other activities like manufacture of grain mill products, sugar, farinaceous products and other food products, which probably might be associated with MHP systems driving different machinery
6. capital goods which do not appear in a specific list of locally produced goods[492], can also be imported free of custom duty
7. machinery, equipment and accessories (together with spare parts up to 15 % of their value) necessary for generating, transmitting and distributing electrical energy as well as for certain agricultural, manufacturing and construction investment, but also electrical generators, machinery and equipment for installation of electrical supply lines are also exempt from payment of customs duty.[493] For machinery, equipment etc. for manufacturing purposes and those used for the construction of industrial buildings the exemption is only possible if this machinery is not locally produced. The Federal Investment Board may, by directives to be issued from time to time, prohibit the importation of such capital goods, which can be replaced by local products.[494]

[485] http://www.ipanet.net/unctad/investmentguide/ethiopia/v.htmloc. cit. and http://www.addischamber.com/ethiop/invst.htm
[486] Gavian, Degefa, 1994, p.154f
[487] Reg. No.7/1996, Schedule One (E)
[488] loc. cit. Art.3
[489] loc. cit. Art.4
[490] loc. cit. Art.8
[491] loc. cit. Art.9ff
[492] Reg. No.36/1998, Art.2 (4)
[493] Investment Incentives Council of Ministers Regulations No 7/1996, Art.21
[494] Investment Incentives Council of Ministers (Amendment) Regulations No 36/1998 Art.2(4)

The legal requirements under point 7 stress the political intent to support the national economy by promoting domestic products as far as possible. However, as long as no equivalent domestic product exists, the exemption from custom duties for the specific goods is applied as a means of investment promotion.

### 4.8.2 Water use permit

Though for the operation of run-of-river-plants (see section 3.2.3) a certain portion or even the complete runoff of a river has to be diverted, it is lead back to the riverbed downstream, meaning that MHP is a non-consumptive use. Water is not really lost for other purposes as it is the case for water supply or irrigation projects. Nevertheless, problems can result from competing water usage, either in the river section between the intake of the MHP plant and the tailrace, or due to water diversions upstream of the intake which disturb the operation of the plant. Therefore water usage for energy generation requires the respect of water rights and a contractual agreement between the different water users. Ownership and usage of water in Ethiopia is regulated according to

- the Civil Code[495] and additional laws or regulations[496]
- the „Water Resources Utilization Proclamation“[497] and
- traditional / indigenous rights and assignments orally handed down

A proclamation to provide for a Federal Water Resource Code[498] is in preparation by the Federal Republic of Ethiopia. However, at the moment, this outline is still very controversial, because it intrudes too much in regional competencies.[499] The authorities, which are or claim to be involved in water rights as far as hydropower is concerned, are

- Ministry of Water Resources
- Ethiopian Electric Agency EEA
- Regional Bureaux of Water, Mines and Energy
- several lower level structures like Peasant Associations, "elders" and other community based informal structures

The fact that various legal bases exist and responsibilities are not obvious, impedes clear statements with regard to MHP projects. The following analysis mainly refers to the obligatory Civil Code and the Water Resources Utilisation Proclamation.

The **Civil Code[500]** clearly states the priority of the community in the usage of all running and still water.[501] This article can be interpreted to prohibit a private person to use river water for power generation as long as <u>community interest</u> is averse to it. As far as the kind of water usage is concerned, highest priority is devoted to <u>domestic purposes</u> such as drinking, cooking, gardening etc. and watering of cattle.[502] Whereas the right to use water for irrigation may not be exercised to the detriment of those who, on the land downstream, use such water for domestic purposes or to water their cattle.[503] In a general way, Article 1242 expresses that the <u>owner of land</u> which is crossed or bordered by water may use such water for industrial or commercial undertakings such as water-mills. The question of land ownership is a very crucial one in Ethiopia. Hence, this article is quite ambiguous. The clearest statement is given by Article 1244, which is referring to hydraulic power, fixing that only those undertakings which have been granted a <u>concession</u> by the competent authority may do work on rivers with a view to distributing, carrying or selling hydraulic power.

[495] Proc. No.165/1960 (N.G.), Art.1228 - 1256
[496] loc. cit. Art.1230 (3)
[497] Proc. No.92/1994 (N.G.)
[498] Ministry of Water Resources, 1999-1
[499] personal communication: Prof. Gerd Foerch (WMERD, GTZ), 02/2000
[500] Proc. No.165/1960 (N.G.), Art.1228ff
[501] loc. cit. Art.1228 (1)
[502] loc. cit. Art.1237 (1)
[503] loc. cit. Art.1236 (2)

The **Water Resources Utilisation Proclamation**[504] gives more detailed information on application and issuance of a permit and the rights and obligations related to it. In general MHP systems exploit "regional water resources" so that the Regional Bureaux of Water Resources, Mines and Energy Development (former "Natural Resources Development and Environmental Protection Bureaux") are concerned as issuing "appropriate authority", and not the Ministry as it is the case for (big) transboundary rivers. For special water uses like hydroelectric power generation and irrigation a permit is required, whereas no permit is required for use of water by peasants.[505] Issuance is subject to the fulfilment of the following crucial conditions:[506]

- that the intended use of water is not detrimental to the interests of other water users
- that permits to investors do not adversely affect the interest of peasants in any manner whatsoever

After successful application the permit will be issued within 60 days. The duration of the permit depends on the nature of the project, including the option for renewal.[507] Article 10 specifies that according to directives of the authority concerned, fees for water permits and their renewals but also water charges can accrue.[508] These directives seem to be not yet formulated. On the other hand, the Electricity Proclamation regulates that the owner of an electricity license can use water for generation of energy free of charge.[509] Another important aspect is that of servitude.[510] Accordingly, a permit holder may construct water works, e.g. intake and power channel to abstract water for an MHP plant, on land under the possession of another person, the latter being adequately compensated by the permit holder. This regulation shall not apply to land under peasant holding unless the peasants themselves have given their consent.

The Regional Bureaux of Water Resources, Mines and Energy Development are assigned the authority to supervise the balanced distribution and utilisation of water resources on regional level, including the control of permits and licenses for use of local rivers both for mechanical shaft power use or for electrification.[511] As far as water rights for hydropower generation are concerned another authority on national level, the Ethiopian Electric Agency (EEA), claims the responsibility for the granting of these rights.[512] The Electricity Proclamation[513] states that „the Agency (EEA) may, representing the concerned authority, issue the required water use permit to the licensee in accordance with the Water Resource Utilisation Proclamation No. 92/1994". The outline of the new **Water Resource Code** evinces the attempt to establish water rights on an official legal level. Yet, this outline is still lacking the necessary assignment of competencies on either national or on regional level, thus provoking a controversial discussion which seems to be not yet decided. The new Code also specifies, that "The implementing organ may, by regulations, exempt designed persons from the payment of the charges whenever such an exemption will serve the Public Interest better".[514] Energy supply being of public interest, the possibility for water use free of charge would remain an option even under legal force of the above mentioned Code.

Apart from the "official water rights" issued by the authorities concerned, **traditional rights**, whether through local custom, tradition, practice or accepted religious belief for the use water up- or downstream a potential MHP site might exist. Often, these rights are only verbally handed down, bequeathed over generations, like indigenous rights, and therefore difficult to identify for "externals". The informal authorities on lowest administrative level, for example

[504] Proc. No.92/1994 (N.G.)
[505] loc. cit. Art.3
[506] loc. cit. Art.5 and Art.11
[507] loc. cit. Art.6
[508] loc. cit. Art.10 (1)
[509] Proc. No.86/1997 (N.G.), Art.26 (1)
[510] Proc. No.92/1994 (N.G.), Art.12
[511] Megen Power Ltd., 1998, p.4
[512] personal communication: Gosaye Mengistie (EEA), 02/2000; with respect to Proc. No.86/1997 (N.G.), Art.26
[513] Proc. No.86/1997 (N.G.)
[514] Ministry of Water Resources, 1999-1

the village-Elders might be helpful to give a historical overview on the development of natural and traditional aspects in their social environment[515] and thus also on water rights. Involvement of Elders and/or the community into the planning process for a prospective MHP plant facilitate negotiations concerning the transfer of water rights. In some cases, the *lease* of rights could be a possible solution.[516] As soon as an agreement is reached, it should in any case be fixed in a written contract between the involved parties. For smaller plants, in the range of about 10 - 50 kW, promising potential sites are those where traditional arab mills (water driven grain mills, see also section 2.2) were or still are operated. At those sites, water rights, but also land use rights, are most likely clearly defined and easier to be transferred to a new operator. Probably, the former operator or owner is even interested himself to restart the business, if he is given the necessary support. Apart from the access to water and land use rights, an additional advantage of such sites is the existence of an energy market due to grain milling activities. Certainly, it has to be confirmed if this is still the case.

With regard to MHP projects, the following **conclusions** are drawn:

1. Competing water usage, especially domestic use but also irrigation, have to be clarified and reconciled in time.
2. The different authorities such as EEA, Regional Bureaux of Water Mines and Energy, lower level and informal structures like Peasant Associations and Elders have to be involved in order to clarify competencies and find a common agreement on water rights.
3. Transfer of water rights, for example by lease of the rights, for a determined period of time has to be written down in a contract between the involved parties like owner of the MHP plant, Kebele or Woreda administration and Regional Bureau in order to guarantee a proper operation of the plant.
4. As part of the above mentioned contract (point 3) all existing and future water usage upstream the MHP system affecting the operation of the plant has to be agreed in a written form with the holder of the permit, i.e. either the owner or the operator of the plant
5. The contract between operator and owner should be based on the contract on the water right (point 3), because the operator needs the guaranty of clear water right as prerequisite for proper operation.

The water rights should finally, for a fixed period of time, be transferred by contract to the operator. The operator's employment contract should at least allow him to immediately terminate his contract and to claim for compensation, if the water for the MHP-plant was used unauthorised and affected the operation in that way that the operator was unable to fulfil his contractual tasks. Of course, the contract must oblige the operator to fulfil his tasks properly, but must also leave him of his liabilities for the cases of lacking water, e.g. also during periods of drought.[517]

### 4.8.3 Allocation of land and land use rights

The ownership of land on which the civil engineering structures, like intake, forebay, power channel, penstock and power house are built is of importance for the project, especially in Ethiopia, where land tenure is a very crucial question. The power channel and the penstock often extend over longer distances and make the problem even more relevant. As illustrated in section 4.8.1.1 the electricity license bestows legal security, especially with regard to land use for the installation of distribution lines etc.. Whereas, for the space for the mentioned civil works, land use must be contractually agreed in order to achieve legal security.

[515] Tolossa, Asfaw, 1995, p.45
[516] Brunner, 2000, p.24
[517] GTZ, 1999; lease act of Chinese GTZ project

Land tenure in Ethiopia has a specific history reaching from the feudal land tenure system[518] at the time of the emperor Haile Selassie I to common property of land according to the socialistic model under the Derg Regime starting in 1974, when, after every harvest, land was re-distributed by the Peasant Association for cultivation.[519] At the end of the Derg Regime life-long lease on peasant farmers was established and the leaders of the Peasant Associations were relieved from their responsibility of allocating land.[520] Today the legal framework of land tenure of the Federal Democratic Republic of Ethiopia is regulated as follows:

1. "The right to ownership of rural and urban land, as well as of all natural resources, is exclusively vested in the State and the peoples of Ethiopia. Land is a common property of the Nations, Nationalities and Peoples of Ethiopia and **shall not be subject to sale or other means of exchange.**"[521]
2. "Without prejudice to the right of Ethiopian Nations, Nationalities, and Peoples to the ownership of land, government shall insure the **right of private investors to the use of land on the basis of payment arrangements** established by law."[522]

These two aspects of the proclamation of the Ethiopian constitution puts up the full scope of user rights relevant for the implementation of an MHP system. The first point makes clear that the state has control over land as a trustee of the nations, nationalities and peoples of Ethiopia.[523] The expression „common property“ must presumably be understood in the sense of „res communes omnium“ from the roman law.[524] That means collective ownership in the way to use it in common with others in equality. In fact the present government is still against privatisation in general[525], but on the other hand, as the second point proves, land leasing understood as a right to use the land on the basis of payment arrangements is also possible. In general, the national law holds to account the Regional Governments for the allocation of land.[526] These Regional Governments shall:

- allocate land for investment activities
- in allocation of land give priority to approved investments
- facilitate and follow up this allocation in co-operation with the appropriate investment organ
- on the basis of Federal and its own laws deliver the required land for the approved investment within 60 days.

The regulations clearly demonstrate the preferential treatment of investors holding a license. For approved investment, at least as far as foreign investors are concerned, the EIA in co-operation with the concerned Regional Government entities, facilitates and follows up the allocation of land.[527] In case of foreign investors the allocation of land for an approved investment project is part of the one-stop-shop service, whereas for domestic investors it is referred to the responsibility on regional level, meaning the zonal justice department (see Figure 4.25). The national as well as the regional level legislation differentiated between urban land[528] and rural land[529]. The *Urban* Lands Lease Holding Proclamation, valid on national level, comprises a special article for the exceptional case of usage of urban land for common welfare: The government may grant freely or without public tendering urban land which is to be utilised for investment that the government encourages or for social services establishments or for other purposes which directly benefit the public.[530] The Federal *Rural* Land Administration Proclamation mainly refers to the regional legislation and only confines a land administration law enacted by each Regional Council to provide that demarcation of

[518] Cheru, 1992-1, p.1 and Tolossa, Asfaw, 1995, p.18, 32
[519] Cheru, 1992-1, p.1 and Proc. No.31/1975 (N.G.), chapter 2, (7.1)
[520] Tolossa, Asfaw, 1995, p.34; Mekonnen, 1999, p.4 and Cheru, 1992-2, p.8
[521] Proc. No.1/1995 (N.G.), Art.40 (3) and Proc. No.89/1997, Art.4
[522] Proc. No.1/1995 (N.G.), Art.40 (6); Proc. No.37/1996 (N.G.) (amended) and Gavian, Degefa, 1994, p.147
[523] Tolossa, Asfaw (1995), p.5
[524] Liebs, 1993, p.152 and Aredo, 1999, p.3
[525] personal communication: Dean of the Faculty of Law, Addis Ababa University, 03/2000
[526] Proc. No.1/1995 (N.G.), Art.52 (2d) and Proc. No.37/1996 (N.G.), Art.36
[527] Ethiopian Investment Authority, 1998, p.24
[528] all lands within the boundaries of towns; see: Proc. No. 80/1993 (N.G.), Art. 2
[529] all land outside the boundaries of a municipality or outside an area, which the respective Regional Council designates as a town; see Proc. No.89/1997 (N.G.), Art.2
[530] Proc. No.80/1993 (N.G.), Art. 13

land for social services and other communal use to be carried out in accordance with the particular conditions of the locality and through communal participation.[531]

The **Oromia Region** with its huge hydrological potential for MHP is one of the most interesting regions. Therefore, the main focus is laid here on its regional legislation, which is fixed in the so-called Megalata Oromia.[532] In the future, in Oromia, a legal framework for administration of land to provide for a modified system of land tenure will be set up and strategic land use planning at central and regional level will be established with the goal of lasting management of natural resources.[533] At the same time the national regional policy of Oromia stresses that „micro hydro and small hydro options should be explored as a generation source for rural and small town electrification" as an instrument of maximising the benefits of limited supplies, saving on investment magnitudes and reducing pollution.[534] Such statements substantiate a conducive political and legal environment for the dissemination of MHP technology.
Figure 4.26 gives an overview on the land leasing procedure.

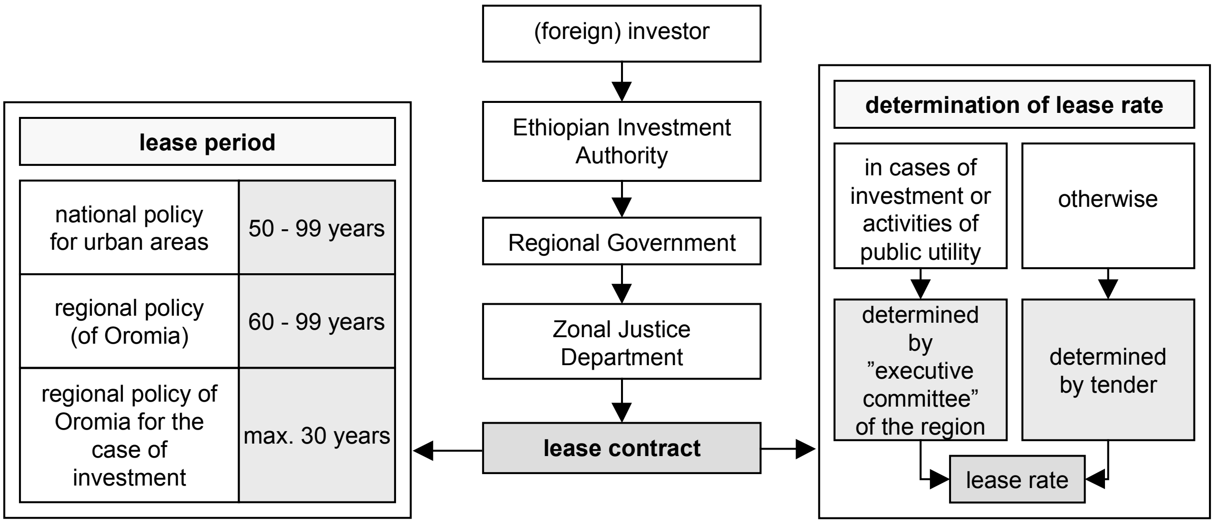



*Figure 4.26: Land leasing for investment projects; on regional level it is referred to Oromia*[535]

Land can be made available to investors on lease-hold-basis. A lease contract can be concluded between the investor and a representative of the Board at **zonal Justice Department**.[536] Lease-holders have a right of use over urban land for periods ranging from 50 to 99 years, depending on the type of usage. With respect to rural land, the rental value and the lease period are fixed by land use regulations of each Federal State.[537] According to the „Proclamation for the **Use of Rural Land for Investment in the Oromia Region**"[538], which shall give guarantees to investors in the region throughout their tenure of land[539], the duration of the contract of lease shall not exceed thirty years.[540] Beyond this, the size of land to be granted on lease shall be determined on the basis of the nature of the project and the amount of capital assigned for it.[541] Projects, which fall in the category of activities identified to be of top priority for the Region or those which have higher social significance shall be accorded preference in land allocation.[542] According to the political priorities of Oromia, which are orally confirmed by responsible stakeholders of its administration, MHP is defined as a

531 Proc. No.89/1997 (N.G.), Art.6 (6)
532 Proc. No.19/1997 (M.O.)
533 Oromia National Regional Government, 1996, p.4
534 loc. cit. p.27
535 Proc. No.19/1997 (M.O.)
536 loc. cit. Art.5
537 EIA, 1998, p.24; Proc. No.1/1995 (N.G.), Art.52 (2d); Proc. No.1/1995 (M.O.), Art.7 (1b); Proc. No.3/1995 (M.O.) Art.10
538 Proc. No.3/1995 (M.O.) (amended by Proc. No.19/1997)
539 Proc. No.3/1995 (M.O.), Preface
540 loc. cit. Art.8 (2).
541 loc. cit. Art.6 (1).
542 loc. cit. Art.4

priority investment. Lands can even be granted free of charge in case of projects deemed of special importance on the basis of their contribution to the promotion of public services.[543] In general, the lease rate per year for a hectare is at least around 100 ETB/hectare/year, depending on the area and the distance from the main road.[544] To close a leasing contract for a project of more than 250,000 ETB of initial investment an investment certificate is required.[545] Obstructive articles in the cited proclamation are the ones which verbalise that peasant holdings may not be let out for lease to investors and that a farmer shall have the right to lease (only) up to half of his holding for a period not exceeding three years.[546] Referring to the "Regulations on Lease and Rent Holding of **Urban Lands in the Oromia Region**" in general the lease rate shall be determined by tender and the highest bid shall be the lease rate applicable to the land.[547] This determination by tender, especially for urban lands, prejudices small enterprises having difficulties to compete against bigger ones.[548] However, in case of MHP projects it can be expected, that it pertains to land „utilised directly for activities of public utility“ or “desirable investment“, thus being granted without tender and allowing the determination of the rate on a basis “negotiated by the Executive Committee of the Region or by an organ to be delegated for this purpose“.[549] Unfortunately until now it is not yet clear which organ is referred to. The minimum lease rate fixed by this regulation on urban land lease is in the same range as the rate for rural land.

Apart from the “official” procedure to acquire land use rights, “informal” laws have to be taken into account. **Traditional rights** only orally handed down such as rights of passage, grazing or water use may interfere with official land use rights[550] and thus provoke conflicts. Such rights should therefore imperatively be considered at a very early project stage. These rights are very manifold and require a case-to-case analysis.

The most convenient approaches for acquisition of a land lease contract are:

a) for foreign investors: via the one-stop-shop service of the EIA
b) for domestic investors:
   if the investment capital exceeds 250,000 ETB: investment certificate probably allows the way via the one-stop-shop service; this is not clear in the legislation
   otherwise: attempt to declare the project as "public utility" to circumvent a leasing fee

In general, the implementation of a pilot project is expected to become a persuasive precedent, which can pave the way for a clearer legal modus operandi. The regional policy of Oromia, in particular, creates a very friendly environment for implementation of MHP systems. Here, it is possible to acquire land on lease-hold-basis for a suitable period up to 30 years and to fix a lease rate at regional level.

### 4.8.4 Taxation

The principal types of relevant taxes are:[551]

1) profit tax on business, for incorporated and un-incorporated firms
2) income tax from employment
3) income tax from dividend
4) sales tax
5) excise tax
6) customs duties (see sections 4.4.3.3 and 4.8.1.2)
7) royalties and stamp duties (see also section 4.8.1)

[543] loc. cit. Art.10
[544] loc. cit. p.10
[545] loc. cit. Art.8 (4)
[546] loc. cit. Art.5 (2) and 23 (2)
[547] Reg. No.1/1995 (M.O.), Art.6 and Reg. No.3/1997 (M.O.), Art.4 (amendment)
[548] Berhanu, 1997, p.34
[549] Reg. No.1/1995 (M.O.), Art.7 amended by Reg. No3/1997 (M.O.), Art.7(1b),(1e) and (5)
[550] Gavian, Degefa, 1994, p.156
[551] EIA, 1998, p.14

The first three types are all related to and depending on the amount of assessable earnings, i.e. profit and income. In case of unincorporated firms like general partnerships, the tax refers to the income of the partner as natural person or legal entity and therefore can also be termed as income tax. Whereas for incorporate enterprises like share companies and P.L.C.s, the profit tax is also characterised as "corporate income tax". Income tax from employment is only of importance for employed staff and income tax from dividend is relevant for shareholders. In Ethiopia, dividends distributed to shareholders are taxable at the rate of 10 % withholding tax. To simplify the calculations, it is assumed that stock dealing is not exercised during the operation time of the system, so that profitability of the system is not affected by these taxes. From the point of view of the owner and/or operator of an MHP plant mainly profit tax and sales tax are of relevance. Customs duties, royalties, stamp duties and possibilities of exemption from them are treated in the mentioned sections.

**Profit tax:**
The standard rate of corporate income tax in Ethiopia is **35 %**. Main earnings of an electricity generating system being the tariff payments, these taxes are directly subtracted from the customers' payments (see section 4.10.3.2).

**Sales tax:**
The Sales and Excise Tax Proclamation No. 68/1993 sets the legal basis for imposition of sales and excise taxes on goods produced locally, goods imported from abroad and services rendered locally. The rate of sales tax is 4 % for a selected list of agricultural and essential goods when either produced locally or imported while it is 12 % for all other products. Sales tax is paid by the producer. The consideration of sales tax can be avoided in investment appraisal, if net revenues and net expenditures are applied, thus excluding sales tax.

### 4.8.5 Consequences and conclusions for MHP

Before the coming into force of the new Electricity Proclamation, production and supply of electricity based on systems ≤ 25 MW of capacity was only allowed for Ethiopians and systems > 25 MW were even reserved to the Government. Today electricity generation and supply based on hydropower plants ≤ 25 MW of capacity is excluded from any limitation meaning that it can be effected by whatever (legal) person. Now, MHP projects and small diesel genset systems are an option for domestic as well as foreign prospects. Investment licence, electricity licence, water and land use permits are pivotal for MHP projects. The investment licence is of superordinate importance, since the one-stop-shop service of the licensing body provides several auxiliary services partly redundantising acquisition of further licences and permits. The most important legal aspects are summarised in Table 4.42.

As far as the engagement of foreign investors in MHP is concerned the threshold for minimum investment of 500,000 USD for the acquisition of an investment licence constitutes a problem, given the fact that MHP systems in general comprise smaller amounts. However, the EIA offers special support for foreign investors, like the one-stop-shop, and the general policy evinces an increasing interest to attract foreign investment. Thus, further improvement of the investment conditions is to be expected in the near future.

| | |
|---|---|
| **investment licence** | - special service by one-stop-shop<br>- conditions for the need of an investment licence see Table 4.41, displaying minimum investment of 31,000 USD for domestic investors, 300,000 USD for joint investment and 500,000 USD for foreign investors<br>- minor fees of maximum about 800 ETB<br>- specific requirements for application<br>- licensing procedure for application depicted in Figure 4.25<br>- allocation of investment licence associated with important incentives like tax holidays, exemption from custom duties etc. |
| **electricity licence** | - requirements for application see Table 4.39<br>- procedure of acquisition see Figure 4.24<br>- fees of about 4,000 ETB, see Table 4.40<br>- "acceptable" ROI of about 25 % allowed<br>- rules access to land and water |
| **water use permit** | no clear jurisdiction → involving all parties and stakeholders concerned in order to avoid conflicts of interest |
| **land use right** | easiest to achieve via investment licence |
| **taxation** | mainly income tax of 35 % of importance |

*Table 4.42: Summary on important legal aspects*

## 4.9 Tariff structure and demand side management

### 4.9.1 Experiences from other projects worldwide

Important conclusions drawn by a World Bank evaluation of renewable energy projects relevant with regard to tariff setting can be summarised as follows:[552]

- pricing policy decides on project viability; **cost recovery** principle, coupled with smarter ways of allocating subsidies where needed, is the most important factor; especially subsidisation of operating costs is counter-productive.
- full cost-recovery tariffs, appropriate legal framework and risk management facilitate **private sector attraction** even in a poor country
- initial connection charges are a greater barrier to rural families than the monthly electricity bill; extended financing arrangements, like spreading the costs of connection fees over an extended period, for affordability of connections can be helpful. In general, upper middle class and wealthy households are the first profiting by electricity supply; appropriate **connection policies** with low connection fees and lifeline rates facilitate significant electricity adoption rates for poorer households.
- any **subsidies** must be fair, equitable, and sustainable, enhance access for the poor, sustain incentives for efficient delivery/consumption, be practicable within the financial/human resource constraints of power utility and encourage the rural electrification business
- financial assistance for the **credit/hire purchase of electrical appliances** is often useful
- **involvement of local communities** is a crucial aspect

As an example, the tariff system of an MHP electrification project in Nepal is briefly sketched here.[553] The utility offers five levels of connection:

- level 1 limited to 100 W (lighting)
- level 2 limited to 500 W (also cooking with stoves)
- level 3 up to 2 kW

[552] http://www.worldbank.org/afr/findings/english/find177.htm
[553] Waldschmidt, 1992; DfID, 1999, p.11; Nepal, Vaidya, 1997, p.12

- level 4 up to 8 kW
- level 5 for commercials who negotiate wattage

During the peak times from 6 pm to 8 am only level 1 - 3 are available for all customers, level 4 and 5 are equipped with load control time switches and pay a fee for resetting of the switch. Level 1 and 2 pay a flat rate. Level 3 - 5 have a number of fixed charge units that have to be paid whether they are consumed or not and decreasing kWh tariffs (degressive tariff system). Customers profit of 5 % discount when they pay within the month of billing. When paying in the second month they have to pay a fine of 5 %, 10 % fine in the first 2 weeks of the 3rd month, 25 % fine in last 2 weeks of the 3rd month. After that the line is cut.

According to a comparison of energy costs drawn by the World Bank[554] the costs for electricity from micro-hydropower range between 0.2 and 2.5 USD/kWh (1.6 - 20 ETB/kWh in year 2000). Tariffs for profitable operation of MHP systems in Ethiopia are at the lower end of this range (about 1.5-2 ETB/kWh, see section 6.3.4). Yet, the consumers' willingness to pay does not only depend on this absolute value but rather on alternatives for energy supply.

### 4.9.2 Present EEPCO tariff setting, impact and conclusions

Although the government announced an electricity pricing policy eliminating all subsidies to EEPCO[555], the present tariffs, which are uniform in ICS and SCS are still not cost covering. Particularly the diesel systems, mainly in the SCS, cause enormous costs and have to be severely cross-subsidised. The costs to be covered by the customers include:[556]

1. a **one-off connection fee:** full labour and material costs for connection to the nearest power line, about 300 ETB or more depending on the distance from the grid[557]

and the fees, which have to be paid regularly monthly:

2. a **service charge** as base fee:
   for *domestic* consumers, only private households: 1.4 - 11.19 ETB/month depending on the purchased kWh's and 13.98 ETB/month for a 3-phase connection
   *other than domestic* customers: 43.91 - 44.27 ETB/month depending on the voltage level
3. the **electricity tariff** for consumed kWh's:

   "domestic": seven blocks with progressively increasing tariffs: **0.273 ETB** for the first 50 kWh, 0.2921 ETB for the next 50 kWh etc. **up to 0.569 ETB** for the kWh's consumed above the 500th kWh

   "general" (= commercial): 0.499 ETB for the first 50 kWh and 0.569 ETB above 50 kWh

   "industrial": depending on the voltage level

   "street light": 0.397 ETB/kWh

A minimum charge in ETB per kW and month has to be paid by customers with more than 20 kW installed capacity in case that their consumption is below 50 % of the maximum demand of the previous 12 months and if the decline can be paralleled by a corresponding similar fall in kWh consumption. A further fee is imposed to this customer group for power factor declension below 85 %. These two penalties are slightly higher in SCS than in the ICS and accommodate the additional costs attached to EEPCO by high demand variations and low power factors. In all EEPCO systems standard non-digital meters are used. They are EEPCO property and lent to the customers. Meter readings are effected only every four months, whereas invoicing and tariff collection is realised every month. The kWhs effectively consumed are balanced every 4 months. A cashier is responsible for 1,000 customers per week, which often seems to be not sufficient, as is circumstantiated by long time queuing. If the bill is not paid within 8 days, the customer can be disconnected. A charge of 15 ETB is imposed for re-connection, which by far does not cover the real costs.[558]

[554] http://www.worldbank.org/html/fpd/energy/off_grid/intro.htm
[555] World Bank, 1997, p.5
[556] EEPCO, 1998-1
[557] personal communication: Girma Biru (Central Regional Office EEPCO), 12/2000
[558] personal communication: Ato Tesfaye (Customer Service Department EEPCO), 11/2000

Apart from the level of tariffs, which does not recover the costs for EEPCO as a whole, the structure of the tariff system is too sophisticated for application in a small MHP system. However, three characteristics of the tariff system appear to be appropriate and transferable: Firstly the idea of setting incentives for **outbalancing the demand** merit special attention. If the electricity generating utility reserves specific capacities for single customers, especially high power consumers and industrials, they claim compensation for the (probably) escaped revenues because of the uncertainty to market the energy elsewhere. Secondly, the introduction of **collecting intervals**, which are shorter than the meter reading intervals, accommodates customers' general preference of smaller frequently charged bills instead of expensive bills in longer intervals. Thirdly, incentives for timely payment of bills and surcharges and / or disconnection for **late payments**, are transferable to MHP systems.

Depending on the location, electricity from an MHP system might have to compete with the subsidised EEPCO electricity. Especially large **industrial or commercial consumers** in contrast to households often have the possibility to choose a location, where they can get access to the subsidised electricity from the ICS. For their production processes they cannot afford expensive electricity which make their products too expensive and thus disabling them to persist on the market. To attract such important consumers, an MHP utility is forced to offer **attractive tariff structures**. Inducements for these consumers are all the more important as they generally require electricity at day-times, which are off-peak times for households requiring electricity mainly for lighting in evening hours. Thus industrial and commercial consumers tend to contribute to an increase and equalising of the system load over the day and are hence crucial for the profitability of the system.

### 4.9.3 Experiences from other isolated systems in Ethiopia

Table 4.43 gives an overview on some presently operated small isolated electricity systems, their collection and tariff system. The approximate EEPCO tariff is listed for comparison. Apart from the electrical MHP system supported by the EECMY, which is not operating any more, all others are provided with electricity from diesel gensets.

The information on municipality-driven systems has been received in interviews during a field survey in November 2000. The systems were implemented with the help of EEPCO but municipalities are in charge of operation. Since the villages are of manageable size and thus facilitate social control, the tariff system is based on a lump sum payment per bulb and month. None of the NGO- and municipality-driven systems is operated completely cost covering. Either investment, operating costs or even both are heavily subsidised. Therefore, the calculated tariffs are not sufficiently high for cost covering and sustainable electricity supply in isolated rural systems, but at least provide an indication of the willingness to pay. In contrast to these subsidised systems, the privately owned diesel gensets are mainly operated by business people, like hotel owners, who sell surplus electricity to neighbours. It is assumed that private systems are operated at least cost covering. Otherwise they were not installed, because one of the owners' main inherent interest is profit making. Even such elevated tariffs do obviously not completely deter people from electricity consumption. This fact is reaffirmed by the frequently apprehended public opinion, that NGO's as well as municipalities are expected to fulfil public tasks and encounter social needs, whereas it is a widely accepted fact, that private investors insist on cost covering or even profit making. Although the tariffs of the municipality-systems are relatively high, compared to EEPCO tariffs, the plants are used to capacity and in one case even 300 interested additional customers are enlisted, thus proving their general willingness to pay.

| operating utility: | | NGO-driven systems | | municipality-driven systems | | | privately driven systems | | | EEPCO [559] |
|---|---|---|---|---|---|---|---|---|---|---|
| | | EECMY | MfM[560] | Dikses | Bale | Robe | Alem Gebeya | Amaro Kelle | Borana | |
| **number of connected households** | | | 600 of 960 | 500 of 2,000 | 600 of 1,500 | 1,300 of 1,500 | | | | |
| **lightning** | | | | | | | | | | |
| | monthly per bulb charge [ETB/month] | 10 | 5 | 6 | 8 | 7 | | | 20 | *3.9*[561] |
| | wattage of bulb [W] | *60* | 60 | 60 | *60* | *60* | | | 25 | *60* |
| | hours of lighting [h/d] | *5* | 4,5 | 5 | 5 | *5* | | | 4 | *5* |
| | **charge [ETB/kWh]** | ***1.10*** | ***0.61*** | ***0.66*** | ***0.87*** | ***0.77*** | **5** | **3.33** | ***6.56*** | **0.273**[562] |
| **refrigerator** [ETB/ month] → resulting tariff[563] [ETB/kWh] | | | 10 **→0.68** | | | | | | | |
| **radio-cassette** [ETB /month] → resulting tariff [564] [ETB/kWh] | | | 10 **→0.68** | 1[565] **→0.07** | 0 | 1 **→0.07** | | | | |
| **battery** charging [ETB/kWh] | | | | | | | | 16.67 | | |
| **connection fee [ETB]** | | | | | | | | | | |
| | labor | | 0 | 10 | 10 | 10 | | | | 300 |
| | material | | 0 | 1,500 - 300 | 67 | 30 | | | | |
| **collecting system** | | | | | | | | | | |
| | payment period [d] | | | 5 | 5 | 5 | | | | 8 |
| | penalty for late payment (per bulb) [ETB] | | | 1 (5-15 days) | 2 | 1(after 5-15d), 2(after 15-30d)[566] | | | | |
| | disconnection after ...days | | "imme-diately" | 15 | no[567] | 30 | | | | 8 |

*Table 4.43: Overview on tariff levels applied in different systems (italicised figures are estimated)[568]*

[559] EEPCO, 1998-1 and EEPCO, 1999
[560] = Menschen für Menschen, German NGO
[561] including a service charge of 1.4 ETB/month (in the consumption class 0 to25 kWh/month)
[562] lowest tariff level applied
[563] assumption: 120 W refrigerator requires 10 min electricity per hour and thus 14.6 kWh/month; according to: Projektplanung Lauterjung / GTZ, 1990, p.10
[564] assuming operation time of 4 h/day
[565] 1 ETB per socket for radio or TV, only 1 socket per household allowed, no ironing allowed; tariff does not cover operating costs, rare disconnection
[566] No fuses for load limitation; in general about 50 customers pay the penalty and about 30 out of these 50 have to pay even the second penalty, 15-20 disconnection per month
[567] no threatening of disconnection as penalty; 50% of customers pay too late !

### 4.9.4 Conditions for pricing in isolated systems

#### *4.9.4.1 Legal requirements*

As illustrated in section 4.8.1.1 the Ethiopian legal framework[569] justifies a **true cost approach** for tariff setting, taking into account the costs incurred by the total system. The legislation in general refers to a marginal cost approach. In case of inapplicability of the marginal cost approach to pricing outside the national grid system due to technical reasons, a supplementing article stipulates to base the pricing on the average cost of supply and an "acceptable" rate of return on investment. This ROI is specified by EEA to be about **25 %**.[570] The total system costs include cost for generation, transmission and distribution as well as further charges for metering, billing, connection and reactive power consumption. The tariff setting should be based on the cost of supply, thus encouraging efficient energy use and contributing to financial viability of the system. Additional aspects emphasised by the law are simplicity and fairness of the tariff system.

#### *4.9.4.2 Market restrictions*

The market form rules the scope of pricing. In general, the latter is governed by the occurring costs and the customers' willingness to pay. Depending on the specific market situation competitive or monopoly pricing can predominate, entailing completely different consequences. Taking into account only comparable energy forms and starting from the assumption of an isolated grid, where no other electric energy is offered, the market situation most probably resembles the **monopoly pricing**. In reality, for several appliances, electricity from an isolated grid can be replaced by other energy forms: torches instead of bulbs, wood stoves instead of electrical ones, etc.. Thus, customers' willingness and ability to pay for other energy options, mainly reflected by opportunity costs, counteract the monopoly pricing. In addition, diesel gensets which can be easily and flexibly installed, either for singular appliances or to supply a small isolated grid, also affect the MHP electricity market. Therefore, specific long-term unit cost per kWh from MHP and diesel genset must be compared. Once the decision between the two systems is taken, the Ethiopian legislation provides a license for monopolistic power production. This means, that once a license for an area is issued, the respective licensee / operator of the system has the selling monopoly for electricity. In such a situation, the project structure and organisational form influence the pricing. In an isolated supply system with one single "bidder", who is a profit oriented investor, exploiting mechanisms can develop. Whereas a co-operative organisational structure as the inverse extreme is expected to promote social prices but might simultaneously endanger the profitability of the plant. In the first case, probably a commercial or industrial enterprise acts as a self-supply investor, who covers his own demand and only sells surplus energy, especially in the evening hours, to interested households. In the second case, households are the main target group, whereby attraction of commercials or industrials is required to run the system cost-effective.

#### *4.9.4.3 General tariff aspects for MHP*

In the present study exclusively **private costs** are taken into account, whereas those occurring on the level of political economy and external effects, like health improvement for women by avoiding open fire cooking, reduction of deforestation and thus degradation and erosion, $CO_2$-, $NO_x$- and $SO_x$-emission by diesel gensets, meaning all social and environmental costs,

[568] modified according to Kistner, 2001; data from interviews with Melessew Shanko (Megen Power), 11/2000 and from DfID, 1999, p.16
[569] Reg. No.49/1999 (N.G.), Art.26-31
[570] personal communication: Gosaye Mengistie (EEA), 11/2000

are extremely difficult to quantify and therefore not considered.[571] Solely in chapter 7, environmental aspects are of relevance with regard to international financing mechanisms in the context of the Kyoto Protocol.

As it is supported by World Bank experiences but also embodied in the Ethiopian electricity law, sustainability of the energy supply systems can only be warranted if tariffs reflect the real cost. Government subsidies can undermine long-term sustainability and lead to dependency. Especially enduring subsidies would have the effect of diverting the scarce government resources from the weaker non-electrified sections to the most fortunate electrified sections of the society. A full cost recovering tariff must take into account:

1. **capacity costs**, i.e. investment costs for generation, transmission, distribution
2. **energy costs**
   for MHP systems corresponding to O&M costs
   for diesel gensets corresponding to O&M costs + fuel costs
   for grid connection corresponding to costs for bulk purchase from an existing grid (and O&M costs)
3. **customer costs**: costs for connection, metering, billing, collection

Capacity and energy costs are already treated in section 4.4. The customer costs (see Table 4.44) can be subdivided into singular connection costs and costs resulting from metering, billing and collecting, which occur consistently in regular intervals. The latter are also called *"transaction cost"* because they do not add surplus to the customer but occur due to the exchange of goods and services at the market. They again can be subdivided into costs to obtain information caused by metering, meter reading etc. and enforcement costs due to issuing of bills, collecting, threat of penalties, disconnection etc..

| | | | |
|---|---|---|---|
| customer costs | initial connection (singular costs) | | |
| | metering | = costs to obtain information | transaction cost |
| | billing | = "enforcement" costs | |
| | collection | | |

*Table 4.44: Classification of customer costs*

Although, often singular connection costs are included in the initial investment costs and the transaction costs can be simply considered as part of operating costs, in the following section 4.9.5 customer costs are "detached" and analysed separately in order to compare the cost related to different tariff systems. To cover the total customer costs, they can either be prorated on investment cost and, even in case of different costs occurring for different users, be "homogeneously spread". Or, every single customer is charged according to his specific connection costs depending on his distance to the grid and initial costs of metering facility and his specific metering and billing costs in case that different systems are applied. In any case, to attract a maximum of customers, also low income households, market hindrances like excessive connection fees should be avoided. From an economic point of view it is not relevant if the **metering facility** belongs to the customer or the electricity utility, because finally all costs have to be covered by revenues. In the first case the customer pays directly and in the second case the costs are allocated to the tariff thus leading to higher kWh charges. If the meter belongs to the customer, it is more difficult to prevent him from destroying and manipulating the facility. But, on the other hand, it makes him feel responsible for his property which he will then take care of.

The tariff to be fixed is generally based on a discounted cash flow analysis. This implies several assumptions concerning load factor, tariff, etc. and yields an internal rate of return (see section 4.10.3.3). In case that this ROI exceeds the opportunity costs of money, for example the interest to be paid for a bank loan, the tariff applied does not only warrant cost recovery but even a certain return on investment. If calculated return and opportunity cost are equal, the applied tariff just permits cost recovery and thus stands for the **life cycle costs** without

[571] It is obvious, that MHP as a "clean" renewable energy source is absolutely advantageous compared to diesel generators.

additional profit. This tariff is the minimum amount which has to be imposed on customers in order to avoid bankruptcy in the long run. A comparison between the overall discounted costs of a kWh for diesel genset or grid connection on the one hand and MHP on the other hand has to be effected in the initial phase of a project. Since tariffs reflect real costs, they are expected to vary between different technical options but also between different potential MHP sites, due to the specific site conditions.

For MHP systems most of the costs occur whether electricity is produced or not. These so-called fixed costs mainly depend on the capacity of the system, due to investment cost and fixed operating costs and on the financing. Consequently, the more energy units are sold, the wider total costs can be apportioned and the more the unit price per kWh decreases. This makes the plant utilisation and thus mainly the average annual **load factor** the crucial parameter of the investment cost amortisation component of a delivered electric kWh. Production and consumption should be steered in such a way that an optimum load factor is obtained. Recalling the fact that life cycle costs or kWh unit costs are calculated on the assumption of a certain load factor, for example 30 %, these sold energy units already cover the complete capacity costs. Every additional energy unit, exceeding the preliminary assumed amount, can theoretically be sold at much lower cost, namely energy and customer costs. Presuming that operating costs do not increase significantly with the generation of additional energy units and can thus be neglected, the remaining costs for additional kWh's are those which are defined as variable costs, meaning fuel costs in case of diesel gensets and customer costs like connection, meter reading, and billing occurring due to the additional customer. The so-called **Long Run Marginal Costs (LRMC)** for energy units, which are sold in excess of the assumed load factor are much lower than those for the first kWh's which have to cover all costs or probably even to generate a profit. This is valid at least for off-peak hours, whereas in peak hours, especially at the end of the project period, the system is used to capacity and additional consumption requires an extension of the whole plant. As per definition, LRMC measures the opportunity cost to the economy of the resources consumed in the process of supplying an incremental unit of electricity to the consumers.[572] In case that the capacity costs are covered by the energy units sold within the scope of the expected load factor, further kWh's, additionally consumed during off-peak hours, do not require further generating, transmission or distribution investment, because the system is designed to meet peak demands.

#### *4.9.4.4 Objectives of tariff systems and of metering, billing and collection modalities*

Before different tariff models are discussed, their general objectives, as they are partly already adumbrated, are summarised here:

1. cost recovery or achieving of a certain return on investment ROI
2. generation of internal resources to finance system expansion
3. social equity by enabling the poor to have access to power
4. efficient use of power
5. demand stimulation to achieve a high penetration rate and a high load factor
6. load management aiming at preferably uniform system utilisation over day, week and season
7. concise, perspicuous and fair system, influencing willingness to pay
8. system acceptance by potential users
9. support of productive uses

The third objective can be achieved by introducing a "lifeline" block in the residential tariff so as to allow a necessary minimum amount of consumption at a cost which does not significantly exceed the sum previously paid for the same amount of energy derived from some other source. Supply of low income households and load management can be achieved by cross-subsidising. Point 5 and 6 are two ways to improve the load factor: On the one hand,

[572] O'Sullivan, Krishnaswamy, 1992, p.206

demand stimulation enhances the general consumption level and on the other hand load management simultaneously helps to shift demand from peak to off-peak hours in order to avoid even higher peaks caused by previous demand stimulation. Load management and load levelling techniques are used to build up energy demand during off-peak periods and reduce demand during peak periods, such as evening hours and meal times. Energy pricing policies may be used to penalise energy use during periods of normally high demand and reward energy use during times of low demand. Promotion of productive uses merits special attention. Electricity supply from MHP plants has to be reliable, quantitatively and qualitatively, in order to encourage commercial and industrial productive applications, manufacturing of agricultural products, production of fertilisers, irrigation pumps etc..[573] Such end usage has to be promoted in order to guarantee regular high income for the plant. Low load factors which mainly arise from pure usage for lighting in households have disastrous effects on the cost coverage of the system. Supplying energy to meet demand at peak load periods requires expensive additional capacities. By cutting off the excess demand at peak times by means of an appropriate tariff system incisively reduces the system size.

Despite this variety of objectives, the degree of elaborateness of the tariff system should not be as high as to exacerbate perspicuity with regard to customers' acceptance. Users' participation in decision-making can significantly improve the acceptance of a tariff system.

An appropriate tariff system, which already implies a certain way of metering, has to be implemented by **modalities of billing, collecting and paying**. The objectives of these modalities are in time payments and the minimisation unpaid bills and illicit connections.

Discount for early and penalty for late payments are approved methods. The introduction of such procedures is legally justified: The owner / operator of an MHP system who acquired an electricity license has the right to issue warnings and to disconnect customers, who violate any provisions or regulations (see also section 4.8.1.1). The licensee is legitimated to impose sanctions in case that a customer does not warrant access for meter reading or for checking of other electrical facilities, but also in case of delay or refusal of bill payment.

Most of the targets formulated so far arise from the operator's point of view, who is interested in successful system operation, which indirectly complies with the **customers' interest**. A more direct view on the customer however results in a focus on end uses thus bridging to the aspect of opportunity cost (in section 4.9.4.5). The customers confront the benefit of end-use to the cost occurring for him. Besides the amount of money, temporal availability of cash can be a hindrance to initial investment. In case that the electricity utility takes advantage of the customers having electrical appliances or energy saving devices at their disposal the utility can support them pursuant to its means. Provision of electrical appliances at attractive conditions such as low or subsidised prices, instalment payment etc. helps to improve the plant utilisation and to cut evening peaks by means of energy saving appliances like lamps. Even if such activities ostensibly require additional investment from users' as well as utility's side they can be profitable for both of them. A higher load factor and better plant utilisation reduce the required system size and thus the capacity costs and the tariff. As far as lighting is concerned, a possible option to alleviate the initial investment burden is to start with normal low-cost incandescent lamps and to **introduce compact fluorescent lamps as soon as the capacity limit of the plant is reached**. When market introduction has led to a consumption level close to the capacity limit, the investment in energy saving lamps temporarily supersedes an extension of the plant. Thus, objectives of users and the electricity utility have to be harmonised to a "win-win-situation".

[573] Goodman et al., 1981, p.9

#### *4.9.4.5 Willingness to pay*

Unlike "ability" to pay, users' "willingness" is a more subjective criterion, depending on:

- **income situation** as such
- **paying modalities**: income situation might lead to preference of regular small payments instead of high yearly payment
- **opportunity costs**: prices paid for biomass, batteries, kerosene and other fuels
- subjectively **sensed comfort**

Under the reserve that the income level is varying widely between different regions and population groups, the following figures give a general idea of the situation of rural households:[574]

| **yearly income [ETB/year]** | **% of rural population** |
|---|---|
| below 600 | 0.65 % |
| 600 - 2,000 | 14.5 % |
| 2,000 - 6,600 | 65 % |

Especially in rural areas the household income is mostly unequally distributed over the year. During harvest time, after the big rainy season, in the months of November until January households generate 95 % of their income.[575] According to the CSA report[576] the expenditures for **fuel and power** of Ethiopians living in rural areas lie between **120 - 160 ETB/person/year**. Based on current connection cost of EEPCO, a survey was conducted in a feasibility study for seven MHP sites in Oromia.[577] The responsible authorities and households were surveyed, making the following assumptions:

- standard metered connection at average costs of 780 ETB; client is owner of the meter
- alternative device with load limit at average costs of 100 ETB
- 6 month time for instalment payment of this initial connection fee
- payment of 12 ETB/month, assuming consumption of 280 kWh/year at 0.5 ETB/kWh

The results are summarised in Table 4.45.

| | **percentage of population [%] ready to pay...** | | | **present monthly expenses on lighting [ETB]** | | |
|---|---|---|---|---|---|---|
| town | **connection fee of 100 ETB** | **connection fee of 750 ETB** | **12 ETB/month (regularly)** | lowest income group | highest income group | average |
| Daye | 54 | 46 | 100 | 3 | 32.8 | 17.50 |
| Bensa | 48 | 52 | 100 | 6 | 45 | 20.16 |
| Werancha | 73 | 27 | 100 | 3 | 30 | 19.30 |
| Bona | 70 | 30 | 100 | 6 | 92 | 12.11 |
| | **connection fee of 100 - 750 ETB** | | | | | |
| Shenen | 83.3 | | 83.3 | 4 | 40 | 13.00 |
| Silkamba | 83.3 | | 92 | 4.5 | 42 | 16.00 |
| Obora | 90 | | 100 | 2 | 17.5 | 6.05 |
| Hindie | 80 | | 100 | 5 | 60 | 18.90 |
| Kachisi | 90 | | 100 | 3.5 | 50 | 17.40 |
| Solomo | 88.9 | | 100 | 5 | 18 | 11.55 |

*Table 4.45: Results of household survey on ability and willingness to pay*[578]

[574] CSA, 1998, p.171,
[575] Ankins, Shanko 2000, p.XV
[576] CSA, 1998, p.184f and p.173
[577] Tropics Consulting Engineers PLC, 1999-1, section 9 respectively
[578] Tropics Consulting Engineers PLC, 1998 and Tropics Consulting Engineers PLC., 1999-1, section 9 respectively

Taking into account what people declare to be able to pay and what they actually do pay for electricity, **10 - 20 ETB/month** seems to be a realistic figure. A **connection fee of 100 - 750 ETB** appears to be affordable for the majority of potential customers, provided the possibility of **instalment payment**. These figures from different surveys have to be evaluated critically because experience has taught that people often are reluctant to talk about financial affairs like income and if they do, they unduly understate income and overstate expenses.[579] Therefore, it is more promising to check the opportunity costs for households as well as industrials and commercials.

#### 4.9.4.5.1 Opportunity costs for household appliances

The opportunity costs[580] are an indication of customers' general willingness and ability to pay for electricity, assuming that they spend the same amount of money for the respective end-use, like electric lighting instead of kerosene lamps. For the user the costs for a specific end-use service is of higher significance than the costs for a delivered kWh.[581] In case that the energy unit in kWh is expensive, systems and appliances with lowest consumption for equal rendered services can be selected.
The most common use of electricity in newly electrified rural areas being lighting, the latter is applied here as one of the descriptive examples. Table 4.46 first of all contrasts the big differences between initial or purchase costs of frequently used lamp types.

| **type of lamp** | **initial costs** |
|---|---|
| usual bulb, incandescent with **40 - 60 W** | about 3 ETB |
| fluorescent lamp with 14 W | about 60 ETB |
| compact fluorescent lamp, Osram with **13 W** | 35 ETB |
| compact fluorescent lamp, Phoenix with 20 W | 65 ETB |

*Table 4.46: Initial costs for different types of lamps*

Since incandescent and compact fluorescent lamp deliver about the same luminous flux, the costs occurring are directly comparable as costs for the same end-use service.

| | **usual bulb, incandescent** | **compact fluorescent lamp** |
|---|---|---|
| **capacity** | 60 W | 13 W |
| **initial costs** | 3 ETB | 65 ETB |
| **lifetime** | 1,000 hours | 8,000 hours |
| **operation** | 5 hours/day | 5 hours/day |
| **assumed tariff** | 2 ETB/kWh | 2 ETB/kWh |
| **depreciation costs** | 0.46 ETB/month | 1.24 ETB/month |
| **energy costs** | 18.3 ETB/month | 4.0 ETB/month |
| **total costs** | **18.76 ETB/month** | **5.24 ETB/month** |

*Table 4.47: Cost comparison between incandescent and fluorescent lamps*

Table 4.47 shows that, despite higher initial costs compared to incandescent bulbs, fluorescent lamps significantly lower the energy costs for the same illumination output. By comparison, the luminous factor[582] of **kerosene lamps**, prevalently used in rural Ethiopia, is only about the one of a 15 W standard electric bulb.[583] At present kerosene costs for one month, assuming 5 hours of lighting per day, 2 ETB/litre of kerosene and 30 ml kerosene per hour is about **10 ETB/month**.[584] Thus, referred to the same end-use service, meaning the luminous

[579] Tropics Consulting Engineers PLC, 1999-1, section 9 respectively and Mekonnen, Shanko / GTZ, 1999, p.18
[580] In general: The cost of passing up the highest valued alternative when making a decision. This highest valued alternative must be sacrificed to attain something else or to otherwise satisfy a want. In other words, opportunity costs of a chosen alternative consist in the loss of use or profit of the best, but not chosen, alternative.
[581] Lovins, Hennicke, 1999, p.161f
[582] Note: The luminous factor is a measure for the brightness of a light source.
[583] EEA, 2000, p.11
[584] loc. cit. p.11 and DfID, 1999, p.16

flux of a normal 60 W bulb, the costs for lighting from a kerosene lamp exceed the electrical alternatives. In addition, electricity offers higher quality of lighting, higher convenience by avoidance of noise, smoke and danger of fire.[585]

**Preparation of injera[586]**, plays also a decisive role with regard to total energy consumption in Ethiopia. It is the most important end-use with the highest share of energy consumption.[587] 61 % of injera baking is based on use of fuel wood.[588] In an average household injera is baked twice a week[589] with 30 injera per baking session.[590] One household needs about 37 kg wood in a stove or 80 kg wood on open fire for injera baking per month. This leads to costs between **5 and 10 ETB per month**.[591] During the eighties low cost stoves were intensely promoted and subsidised so as to restrict further biomass depletion. This initiative was hampered by the fact that EECPO could not put sufficient capacities at the disposal.[592] Nevertheless, a slight decrease of deforestation was to be observed in this time.[593] Today, electric injera-stoves, so-called "Mitad", cost about 350 ETB and need about 0.24 kWh/injera , assuming 11 Ampere during 5 minutes and 4 kW load during heating up. The heat up time before usage is 17 minutes. 8 baking sessions per month and 30 injera per session require a total of about 64 kWh/month/household.[594] Only with an extremely low tariff of about **0.1 - 0.2 ETB/kWh**, costs of 6.4 - 12.8 ETB would occur, which could be competitive to traditional wood stove usage with 5 - 10 ETB/month, whereby initial costs of about 350 ETB for the electric injera stove are not even included. To avoid high investment costs one or several injera stoves could be shared within the community. A survey conducted in 1999 (see Table 4.48) proved that the preferred stove by almost two third of the population is electric, even though the most used one is open fire.

| Type of injera-stove | Open fire | Enclosed stove | Electric “Mitad” | Others |
|---|---|---|---|---|
| Owned | 75.8 | 4.3 | 22.7 | 0.3 |
| Preferred | 20.8 | 11.8 | 65.8 | 0.3 |

*Table 4.48: Ownership and preference of injera-stove types in % of households.*[595]

Thus, in case that *electric* injera baking reveals to be of relevance at a potential project site and people can afford to buy stoves, the alteration of the daily load curve due to injera baking has to be taken into account. In general, injera is baked twice a week for about 2.5 hours. Households in small towns usually bake injera in the afternoon or in the early evening.[596] In larger towns injera baking seems to be done mostly in the forenoon.[597] This requires no peak-time electricity and can significantly enhance the load factor. For cooking of meals other than injera only 6 % of the interviewed households expressed their wish to use electric appliances.[598]

[585] World Bank, 1988, p.31
[586] One of the most popular staple foods in Ethiopia is injera (household bread) which is a large flat pancake eaten by the majority of Ethiopians at least once a day. Injera baking is the most energy-intensive activity in Ethiopia. It accounts for over 50% of all primary energy consumption in the country and over 75% of the total energy consumed in households. Traditional injera baking needs a quick, fast heat, evenly distributed over a 60 centimetre ceramic plate called a mitad or mtad. The flat plate mitad is balanced upon three stones above the open fire and fuel is fed under the mitad from all directions. Energy consumption is highly inefficient - approximately 93% of the fuel is wasted. Injera baking is an unpleasant and dangerous activity. Highly flammable fuels, such as leaves and twigs, are used by cooks to achieve the high heat necessary to cook injera quickly and these often flare out as they ignite, causing injury through burns. Large amounts of smoke are produced by these fires and many women complain about stinging eyes and coughing. (information from http://www.tve.org/ho/doc.cfm?aid=240&lang=English downloaded 9/2002)
[587] EEA, 2002, p.6
[588] Mekonnen, Shanko / GTZ, 1999, p.22f
[589] Note: The frequency of baking depends on the climate and thus the storage life of the injera. Personal communication: Trudi Könemund (GTZ household energy project), 11/2000
[590] Lakew / GTZ / MoA, 1999, p.50
[591] loc. cit. p.51
[592] loc. cit. p.38ff
[593] loc. cit. p.66
[594] loc. cit. p.38
[595] loc. cit. p.60, note: some households own several types of stoves, therefore the sum does not equal to 100%
[596] Mekonnen, Shanko / GTZ, 1999, p.23f
[597] EEPCO, 1998-1
[598] Lakew / GTZ / MoA, 1999, p.60

#### 4.9.4.5.2 Opportunity costs for commercial and industrial consumers

A vague indication on commercial and industrial consumers' minimum willingness to pay for electricity can be derived from the EEPCO tariffs presently charged. They vary between **0.31 - 0.47 ETB/kWh** depending on the voltage level. The additional monthly base fee is **44 ETB**.

As far as **commercial injera production** is concerned a baker produces about 150 pieces per day.[599] Since commercial bakers purchase fuel wood in bulk, they avail themselves of lower prices than private households. The costs per injera, when fuel wood is used are estimated to be around 0.034 ETB per injera. If this is the maximum a baker would be ready to pay as energy cost for the production of one injera and if one injera requires 0.24 kWh a competitive kWh-charge could not exceed 0.034 ETB / 0.24 kWh = **0.14 ETB/kWh**. This is even less than the subsidised EEPCO-tariff. Given the fact that the exemplification on private and commercial injera baking even disregards the high purchase costs of an electrical stove, it proves that electrical injera baking can hardly compete with baking based on fuelwood. This especially applies to rural areas where fuelwood and other biomass is not as scarce and therefore still cheaper than in the adjacency of towns. Since baking requires high energy input in kWh, the conversion of "precious" electrical energy into heat energy is only a realistic option in case that either biomass becomes very expensive or surplus electricity is available in off-peak hours or electricity is subsidised for ecological or political reasons. The present situation in Ethiopia seems to set a better stage for the dissemination of energy saving stoves based on biomass.

Agricultural processing, like grain milling or oil extraction, is of special relevance in rural Ethiopia. As far as **milling** is concerned, at present 6 - 15 ETB/100 kg[600] of grain are paid. If a mill with a power output of 5 kW can process 150 kg/h, customers' present payment corresponds to **1.8 and 4.5 ETB/kWh**.

**Oil extraction** is still not practised so frequently for commercial purposes. The main oilseed in Ethiopia is noug (Guizotia abyssinica) but also rape seed and sesame are cultivated. The oil of the castor seed which is growing wildly lends itself readily for soap making and can be used as fuel in diesel engines. Usually farmers sell the different seeds to private millers, who process them with small scale oil presses. But often they are only used for self-supply or are sold unprocessed, then transported to the bigger cities and processed there. Yet, the results of field surveys showed that women give high priority to the introduction of oil extraction machines. Since oil seed processing is an additional source of income, women expect it to be a very promising activity. A survey showed, that they were ready to pay about 16 ETB for extraction of 100 kg noug seeds.[601] At an electricity consumption of 5 kWh/100 kg of seeds, the accepted tariff would be 16 ETB/5 kWh = **3.2 ETB/kWh**. Obviously, a very high expected profit margin leads to an enormous willingness to pay.

Variation of opportunity costs will be reflected in a likewise varying willingness to pay for different electrical end-uses. As long as much cheaper alternatives are available, e.g. biomass for injera baking, electricity usage is no realistic option. Electricity usage in such "non-competitive" cases requires a tariff structure, which is sufficiently differentiated to accommodate for these conditions, for example with usage-related charges.

### 4.9.5 Description of tariff systems and their impacts

Tariffs imposed are mostly divided into a fixed base charge and a consumption related charge. The appropriateness of this subdivision depends on the selected tariff system. In case of flat rates it does not make sense. In other cases, it can be applied as additional

[599] loc. cit. p.52ff
[600] Metzler, Gebre-Mariam, 1996, p.15
[601] Metzler, Gebre-Mariam, 1996, p.26ff

steering mechanism. If metered kWh's are sold, a **base charge lowers the market risk**, because it guarantees a minimum amount of revenues, even if no electricity is consumed. The **tariff system** comprises absolute level(s) of the charges to be paid but also the modalities applied for metering and collection of the charges. The first aspect is discussed in the preceding section 4.9.4.5. The different systems, their pros and cons, their interdependency and appropriateness for isolated MHP systems in rural Ethiopia are analysed in the following.

Criteria, which limit the level of detail of tariff setting are:
- the degree of **complexity** reasonable for the customers
- the **metering** system
- the **billing and collecting** system.

The metering method and its level of detail determine the collecting mode and the tariff system. The more detailed the individual consumption and temporal pattern are surveyed, the more sophisticated the tariff system can be. In general, a detailed registration of consumption increases the costs and thus the tariff to be paid, but on the other hand allows extensive demand steering. Expenses and benefits have to be carefully balanced. The collection mode, especially the frequency of collection and enforcing mechanisms have substantial influence on consumers' willingness and ability to pay. In general frequently paid smaller amounts are deemed to be covered easier, but might also cause higher collection costs. Contemporary or in-advance payments reduce the financing costs of the utility. Especially during the first year(s) of operation, high customer contributions in due time supersede challenging pre-financing by one or several plant owners.

As described in section 4.9.4.3, the tariff contributes to investment costs, operating costs and customer costs. The latter are subdivided into connection costs, which include purchase and installation of metering or limiting facilities and the transaction costs, which depend on mode and frequency of collection, billing, payment and enforcing mechanisms. Transaction costs mainly depend on the staff required to implement a specific system. In the following, **customer costs** are analysed with regard to comparing different metering systems. As it is referred to costs per connection they are called "specific".

Costs for the different tariff systems consist of manpower, facility and O&M costs. Monthly salaries, assumed for the estimation of manpower costs in year 2000, are about 400 ETB/month for a technician or assistant and 230 ETB/month for a bill-collector.[602] The staff costs for general O&M (see section 4.4.4.1) must be continuously paid as monthly salaries. Whereas, the technician, who installs meters, fuses etc. and the bill-collector are only required occasionally as part-time staff, the technician in irregular intervals and the bill-collector regularly. A skilled technician earns about as much as an "assistant" (see Table 4.29), whereas for the bill-collector a relatively low salary is, assuming that he pursues a further occupation besides bill collection. The costs are added up according to the working hours. Based on 160 working hours per month, 2.5 ETB/h have to be paid for a technician and about 1.5 ETB/h for a bill-collector. The installation costs comprise the device itself, i.e. the kWh-meter or load/current limiter, as well as staff costs. Since the staff cots range between 5 to 10 ETB/connection for about 2 - 4 working hours, they are negligible compared to the purchasing costs for the technical device.[603]

Advantages, disadvantages and costs of the different tariff systems are summarised in Table 4.49. Subsequent to this table, the systems are described in detail.

[602] personal communication: Robe Municipality staff, 11/2000; usual wages, not including social security contribution, vacation bonus, etc.

[603] note: To connect a household to the distribution grid costs about 300 ETB/connection according to EEPCO information. The exact amount- including labour and material costs (except for the electricity meter !) - depends on the distance to the nearest power line and can even exceed 300 ETB. However, these connection costs being equal for every metering system, they are not taken into account here.

| | advantages | disadvantages | initial cost | estimated "operating costs"[604] |
|---|---|---|---|---|
| | | | [ETB/cust.] | [ETB/customer/year] |
| **standard kWh meter** | - fair<br>- collection *at electricity office* less expensive<br>- less frequent reading than collection for cost saving | - meter reading required<br>- collection at households more expensive<br>- requires dis- and reconnection in case of late payment | **430 ETB** | - 2 h technician[605]<br>- 4 h bill collector (20 min/cust./month)<br>→ **11** ETB/cust./year |
| **digital meter** | - demand steering via sophisticated tariff system like amount or time related tariffs possible | - time consuming more complicated reading and billing<br>- requires dis- and reconnection in case of late payment | **1,140 ETB** | - 3 h technician[606]<br>- 8 h bill collector (40 min/cust./month)<br>→ **19.5** ETB/cust./year |
| **pre-paid with coins** | - fair<br>- no meter reading<br>- no overdue costs<br>- no costs for dis- and reconnection<br>- close to "ability-to-pay-variations" → can increase demand<br>- less costly than pre-paid cards | - less "forgery proof"<br>- costs for re-collection of coins | **400 ETB** | - 1 h technician<br>- 2 h bill collector (10 min/cust./month)<br>→ **5.5** ETB/cust./year |
| **pre-paid with cards** | - customer reloads the card himself → no costs for "re-collection" | - less "forgery proof"<br>- more expensive than coins | **600 ETB** | - 1 h technician<br>→ **1.5** ETB/cust./year |
| **current limiter** | - simultaneously protecting against over current<br>- delimiting peak demand<br>- no meter reading required → flat rates according to max. amperage | - danger of fraud and theft for switch fuses | **27 ETB** for low Amp fuse (15 kV and 5-10 A) | - 1 h technician<br>- 2 h bill collector (10 min/cust./month)<br>→ **5.5** ETB/cust./year |
| | | - additional costs for replacement of cut out fuses | **390 ETB** for high Amp fuse (100 A) | - 2 h technician<br>- 2 h bill collector (10 min/cust./month)<br>→ **8** ETB/cust./year |
| **time limiter** | - delimiting peak demand<br>- two options:<br>- time switch easy to handle<br>- multi-circle delivery system requires only 1 additional wire in distribution line<br>- no reading required | - reduced flexibility if different branches receive electricity at different times | **60 ETB** for time switch; costs for multi-circle system depending on length | - 0.5 h technician<br>- 2 h bill collector (10 min/cust./month)<br>→ **4.25** ETB/cust./year |
| **flat rates, based on "social control"** | - positive experiences in Ethiopia, not generally refused<br>- no metering or delimiting facility → cheap | - provoke electricity wasting<br>- no demand steering → peaks!<br>- no control → not fair | negligible costs for initial estimation of installed capacity | - 2 h bill collector (10 min/cust./month)<br>→ **3** ETB/cust./year |
| **any system combined with juissance shares** | - pre-payment by customers relieves financing<br>- customers receive inflation-free kWh's | - requires customers trust in MHP system<br>- high initial financial burden for customers | | |

*Table 4.49: Comparison of different tariff systems*

[604] operating cost = cost for technician (repair, dis- and reconnection) and bill collector (meter reading and collecting)
[605] including 1 h for dis- and reconnection on the average
[606] including 1 h for dis- and reconnection on the average

The **pre-paid systems** either operate with cards or coins, which are purchased in advance and contain a certain amount of kWh's, which can be consumed as soon as card or coin are inserted into the metering device. The coin unit has an electronic lock which can only be opened by the collector, so that the coins have to be re-collected. The card can be pulled out and either recharged or exchanged against new ones. Mostly, the number of kWh's per card or per coin is freely programmable by the electricity supplier.[607] As additional measure, the encouragement of local production of pre-payment meters in the long run lowers the facility costs and entails secondary income effects.

The **current limiter** interrupts electricity provision as soon as a maximum load in kW is exceeded. The user is authorised to connect only a limited total load simultaneously and is charged a lump sum for a specific "load level". Thus, the occurrence of peak demands can be restricted. This system implicates the benefit of protection against electrical hazards. The current limiter can be performed as cut out fuse, which limits amperage and burns through in case of ampere-exceeding but requires additional expenses for replacement. Switch-fuses can be reset by the customer himself and therefore must be accessible, even though this exposes them to fraud and theft. A combination with fusible cut outs with higher capacity for several customers, installed on the distribution line, inhibits manipulation, whereby accessible switch fuses on household level can offer additional convenience.

The **time limiter** or time switch restricts the time of consumption. It can be implemented as multi-circle system, which supplies different electrical branches at different times of the day. E.g. households can be provided with energy for lighting in evening hours and commercial and industrial consumers during daytime. If the distribution system is arranged accordingly from the outset, no additional costs occur. A system with time switches for every household or sub-grid necessitates higher expenditures. A **combination of current and time limiters**, even though it provokes higher investment costs, allows the energy utility to implement a more sophisticated demand steering.

A system **without any metering or load limiting** can simply base on the estimation of consumption, meaning number of consumers or number of appliances like bulbs and sockets per connection. It only requires a tariff classification at the moment of initial connection, but does not provoke any further costs. It is mainly based on mutual trust and social control. Fixed monthly payments or the use of load limiters or fuses avoid the costs of metering but encourages inefficiency and implies higher subsidies to large-scale consumers.

With **invariant** tariffs the kWh's consumed are simply multiplied by the fixed charge per kWh. As soon as amount and/or time of consumption are registered, **variant** tariffs can be imposed. The variation is generally defined in blocks. Progressive tariffs penalise high consumption and are useful during peak hours, whereas regressive tariffs, encouraging consumption, are of value for off-peak hours.

Unlike diesel gensets, which provoke additional fuel costs for every kWh produced, pricing strategies in MHP systems have to be designed to encourage electricity consumption up to the capacity limit. Higher load factors lower the costs per kWh. For MHP systems no energy costs occur, meaning that most of the costs are related to and depending on the capacity of the plant. As long as the capacity of the plant is not reached, increasing energy generation does not provoke additional costs. To ensure profitability the MHP system should, at any time, operate as close as possible at full capacity. Thus, **selling "capacity units" in kW** instead of energy units in kWh shifts the plant utilisation risk from the operator to the customer. If a certain capacity [kW] is allocated to the customer, he is relinquished the decision on the periods of usage. The more he uses the assigned kW-units the more lucrative for him. For the operator capacity requirement is much more calculable than power requirement. If in addition the capacities are sold for specific times of the day ("time-of-day subscription"),

[607] personal communication: Peter Bank (Energy Concept), 7/2001

homogeneous apportioning of different appliances over the day can be striven for. This combination of **"time and amount related flat rates"** extremely alleviates load management and counteracts against wastage of electricity. Load limiters are a cheap measuring facility, which, supplemented by time switches to control and limit the daytime of consumption, support this modus. The comfort of unlimited round-the-clock usage of all appliances is abandoned for the benefit of higher plant utilisation and consequently lower tariffs. For example high, consumption uses like injera baking and welding activities in a workshop are not mutually exclusive and do not require additional expensive plant capacity as long as welding is allowed between 8 and 11 a.m. and 2 and 6 p.m., whereas injera baking is effected from 11 a.m. to 2 p.m.. Especially appliances like electrical injera stoves, which can be replaced by cheap fuelwood stoves, can only be stimulated if very low flat rates at times with poor demands are offered. Higher tariffs at times of high demand attenuate peaks. Customers with very high and fluctuating consumption can buy **"standby capacities"** which are reserved for them. Thus the MHP operator is compensated for the unused capacity, which is only temporarily required.

One important approach for tariff systems is the **juissance rights model** (see section 4.6.3.2), which is based on the idea of "customers as financiers". Bonus shares can or have to be bought to get access to the system. The dividends of the shares are fixed and paid in form of electricity units during the whole lifetime of the plant or an agreed contract period. The disbursement can either refer to kWh's per month or year or to a specified capacity in kW. As a matter of course, additional kW or kWh exceeding the bonus can be purchased.

### 4.9.6 Recommended instruments

Any tariff system is only recommendable if it is accepted by the users. Therefore, it has to be fair and transparent, thus preserving social peace and minimising pilferage. Table 4.49 shows that measuring or limiting facilities can provoke high initial costs. Although, for example, the operating costs for pre-paid cards are much lower than for coins, the difference of 200 ETB/customer in investment costs are out of all proportion compared to the difference of 4 ETB/year/customer in operating costs. Expensive systems like digital meter and pre-paid card do not feature advantages which obviously justify such high initial costs.

For easily manageable small communities flat rates are the easiest and cheapest option. The rates can be fixed according to number and kind of appliances per connection or consumers per connection. As soon as the whole consumption patterns, e.g. of households, commercials and industrials, become more inhomogeneous, the tariff system has to provide for differentiation. Even if in many cases most households can afford to pay at least 10 - 12 ETB per month for electricity (see Table 4.45), mostly, still some are not in a position to cover this amount. If a substantial number of low income customers prefer to pay smaller amounts on daily basis, the coin system accommodates high "ability-to-pay-variations". Customers who can afford regular payments should either be offered standard kWh meters or the cheaper option of current and / or time limiter. In general, the relatively expensive standard electricity meters are only appropriate and worthwhile for high consumption. Since the price for time limiters being the double of current limiters it has to be checked in every specific case, if time switches can be replaced by simple (written) agreements to reduce expenses.

**Payments structure and the collection mode** are ruled by the utility's needs, like income requirements for quick loan payback, and customers constraints, like their solvency depending on income pattern. The crucial objective to maximise the number of connections, to achieve a high load factor, should on no account be lost sight of. Therefore appropriate and if necessary different paying modalities have to be offered. If the tariff system includes high **singular initial payments** such as juissance participation, connection fee etc., this might on the one hand be a barrier to market penetration and requires customers trust in succeseful system operation. On the other hand, high initial revenues lower the market risk for the op-

erator. To relieve customers' financial burden such payments should at least be encashed in high-income months, e.g. between November and January. For customers who in no way can afford such initial costs instalment payment should be offered. Credit schemes which allow consumers to spread initial connection costs over several years have been shown to significantly increase connection rates. The costs may also be built into the tariff structure.[608]
As far as **regular fees** are concerned, the tariff system should remunerate early and in-advance payment and accordingly impose penalties for late payments, according to the costs occurring, but within a scope which does not completely exclude low-income customers. Reduced charges as incentive for yearly in-advance payment or a combination of monthly and yearly payment, for those who can pay part of the tariff yearly in advance, can motivate people for opportune payment and improves the financial situation of the electricity utility. For cost saving reasons, payments should as far as possible be effected at the cashier's office instead of home collection. This anyway does not pose a problem in case of a flat rate system where no metering is required. With standard kWh meters the reading can for example be effected every 4 months and collecting every month, thus also economising employment of staff and simultaneously relieving customers' financial burden by means of shorter payment intervals.

Theoretically, **juissance rights** can be combined with all metering systems, even with flat rates, because, howsoever an electricity bill is paid, it can be reduced by the amount due to the holder of the juissance right. Although, substantial initial investment in juissance rights can often only be expected from well off customers (see also section 6.3.5.1), the adding up of smaller contributions from low-income consumers further reduce a probably required bank loan. To really lower the financing costs, and thus indirectly also the tariffs, the dividend payment for juissance rights should not exceed the interest rate of loans. An interest rate of for example 9 % for juissance rights by far exceeds the <u>real</u> rate of interest for savings of 2.5 %[609] (see also section 4.10.4.1). If these 9 % of the value of the juissance right, are disbursed as constant amount of kWh's or kW, it is not subject to inflation. Therefore, it is compared with the <u>real</u> interest rate of saving deposits. Thus, the shareholder benefits twice, by a dividend payment of 9 % on his juissance right <u>and</u> by receiving low-cost kWh's which do not increase their price due to inflation. Except for electricity units for juissance rights, the tariff is expected to increase according to the general inflation rate, which is about 4.5 % (see section 4.10.4.1). In addition to these direct financial advantages for juissance rights holders as well as for the electricity utility, customers who participate financially in the MHP system guarantee for less illegal connections, fraud, theft etc.. Even if only part of the customers participate that way, social control is highly strengthened.

### 4.9.7 Additional measures

Depending on its financial scope, the electricity utility can offer incentives or support for the purchase of **electrical appliances** especially for productive uses, like irrigation pumps, agro-processing machinery, commercial appliances, low-horsepower motors used in light rural industries, but also for incandescent bulbs or energy saving lamps and electrical stoves, in order to stimulate and / or steer the demand. Energy saving lamps are useful in case of low daytime demand and high evening peaks due to lighting. In that case, peaks can be smoothed and thus the totally required system size reduced. As far as stoves, mainly for injera baking, are concerned they presently are much to expensive to meet a broader diffusion. Even excluding investment costs, a tariff of 0.1 - 0.2 ETB/kWh would be required to compete with wood stoves. Only in case that no other daytime uses are expected to be performed, which offer higher revenues, e.g. due to higher opportunity costs, the introduction of an injera stove for common can be a viable option. With several individual electric injera stoves additionally the problem of high and severely varying electricity consumption accrues, especially if injera is prepared at very specific daytimes. Under the present conditions,

[608] O'Sullivan, Krishnaswamy, 1992, p.210
[609] subtracting about 4.5 % of inflation from about 6-7 % of interest rate for savings: 1.07/1.045 = 1.024

energy saving biomass stoves are the more realistic and therefore promising solution. The general problem of affordability of electrical devices as well as the initial connection to the system is also described by NRECA.[610] According to their experience, consumers need a source of credit to purchase the electrical devices that will make the system viable. If they have to pay household wiring and devices the implementing agency should support such ventures or identify sources of financing. Although selling electrical appliances at a reduced price or on credit implicates additional risk, this service is expected to extend the market, enhance demand especially in off peak hours and, in case of energy saving lamps, reduce peaks and thus the system size. Some potential consumers might not be in a position to pay high investment costs for electrical appliances but could pay the investment back in form of higher tariffs. An additional investment in subsidisation of electrical and efficient appliances to achieve a highly utilised system of smaller capacity has to be weighed up against possible far-reaching benefits. The customer is endowed with electrical appliances, which either indirectly have to be paid back through higher tariffs or can financially be compensated due the reduction of the system size. Here, a decision support model allows to manipulate different variables, like load factor, additional investment cost, tariff etc. while simultaneously retaining the remainder of conditions in order to reveal the potency of different measures.

### 4.9.8 Proposal on an appropriate tariff system

Based on four typical customer groups to be found in rural areas in Ethiopia the following tariff system is designed:

- <u>low income households</u>: can pay about **10 ETB/month**; pre-paid metering system with **coins** or simply **flat rates**; supposing 120 h/month (4 h/d) lighting result in:
  with 50 W bulb: 72 kWh/year and **1.6 ETB/kWh**
  with 14 W bulb: 20 kWh/year and **6.0 ETB/kWh**
- <u>medium income households</u>: **load limiter**, probably additional time switch for better load management, if many customers need electricity at the same time "time of day subscription tariff"; possibly participation via juissance shares; assumption: 2 bulbs à 60 W and 1 radio à 8 W, switched on 120 h/month (187 kWh/y); proposed payment:
  monthly after consumption: **144 ETB/y (12 ETB/month)** = **0.77 ETB/kWh**
  yearly in advance, reduction as incentive: **100 ETB/y (8.3 ETB/month)** = **0.54 ETB/kWh**
- <u>high income households</u>: number of appliances significantly exceeds the one specified above (2 bulbs + 1 radio), e.g. household with refrigerator, TV, radio, several bulbs..., metering by means of a **standard kWh meter**
  proposed tariff: at least **0.4 ETB/kWh**
- <u>commercial and industrial customers</u>: with **standard kWh meter**; additional **time switch** for cheaper commercial daytime tariff between 8 a.m. and 6 p.m. monthly payment more probable because of regular income situation;
  proposed tariff: **0.3 ETB/kWh**, reduced tariff to promote productive uses

Since generally high consumption is to be expected in the evening hours, tariffs should be higher then. Reduced charges at daytime enhance commercial and productive uses. The figures "invented" for this fictitious case give an idea of how a tariff system can be configured. The consumption of each consumer group then has to be multiplied by the specific kWh-prices in order to calculate total revenues, which finally enter into the financial analysis to prove or disprove financial viability of the project. For the comprehensive financial analysis (see section 4.10) it has to be decided, if the costs for the measuring facilities like standard kWh meters, load limiters etc. are borne by the users as part of the initial connection fee or if the investment is advanced by the utility and afterwards recovered by higher tariffs. From the point of view of the operating utility, in the first case the additional costs can be completely ignored. In the second case they are added to the general investment costs, which automatically implies a homogeneous apportioning on all customers irrespective of the metering system applied by the individual.

[610] Jackson, Lawrence, 1982, p.112

## 4.10 Financial analysis and profitability

### 4.10.1 Objectives and procedure

An internal financial analysis of the project is required from both, potential owners like investors, customers and NGO's but also from creditors like banks, bi- and multilateral organisations, for their decision-making and planning. While any kind of shareholders are mainly profit oriented, creditors are interested in solvency of the project. In the long run these two aspects are closely interconnected because only generation of surplus guarantees for maintenance of solvency. Its importance for project participants makes the financial analysis to one of the crucial elements of decision-making process.
The evaluation of commercial viability of a project involves all expenditures and revenues incurred. Since it provides information on the financial viability of a project, it is most meaningful if it is simultaneously carried out for different energy supply options. Thus, it exemplifies cost-competitiveness of different alternatives, assessing their relative attractiveness and creditworthiness with regard to their acceptance in capital markets. As far as electricity generation in rural areas in Ethiopia is concerned, the three relevant options taken into consideration in the present study are MHP, diesel and grid connected systems (see section 3.2.2). If different technical options are compared, the boundary conditions such as consumption figures, population growth etc. have to be kept constant. Scenarios based on different energy consumption, tariff systems, financing instruments, equity / loan ratios, interest rates etc. are contrasted by comparing resulting economic indicators. A financial analysis which compares the viability and financial performance of different alternative options comprises the following steps of calculation:

- determination of **investment costs**
- **cash flow** analysis
- determination of:
  a) **net present value NPV**
  b) **return on investment ROI (= internal rate of return IRR) and return on equity ROE**
  c) **payback period**

The tariff applied in a specific calculation reflects the energy production costs [ETB/kWh] under the conditions of a certain financing instrument (equity, loan etc.), interest rate, ROI, load factor, etc.. The calculation steps and their application on MHP projects and the two technical alternatives under Ethiopian conditions are explained in the following sections.

### 4.10.2 Required input data

Besides the project participants, their specific capital contribution and the loan conditions, meaning interest rate, redemption etc., the following input parameters are necessary for a financial analysis:

1. quantity structure and unit prices for the system components (see sections 4.3 and 4.4)
2. operation and maintenance costs (see section 4.4.4); including fuel price
3. overall system efficiencies (see section 4.1.1)
4. fees for licenses etc. (see section 4.8)
5. consumption, based on development of the population, market creation, load factor, operational hours of the system etc. (see section 4.2)
6. applied tariff (see section 4.9)
7. inflation rate, special rate for diesel fuel
8. percentage of juissance rights/ordinary shares and stipulated interest (see section 4.6.3)
9. tax holidays (see section 4.8.1.2)
10. lifetime of the system (see section 3.2.5)
11. loan redemption schedule, i.e. rate of repayment and possibility of bullet loan (see also sections 4.6.4 and 5.3)

The following sections clarify where and why these different parameters are required for the individual steps of calculation.

### 4.10.3 Description of the different calculation steps

#### *4.10.3.1 Investment costs*

Based on a very rough technical design of the respective energy supply system, the required components, their unit prices and quantities can be determined (see also sections 4.3 and 4.4). Besides specifications on the determination of investment costs, section 4.4 describes necessary assumptions and simplifications for that calculation. Having regard to additional singular costs, like e.g. license fees, the total investment costs can be calculated.

#### *4.10.3.2 Cash flow*

The second step, the cash flow analysis, allows a rating of solvency and an analysis of profitability of the project. The cash flow of a fiscal year is the difference between "effective" revenues and "effective" expenditures. "Effective" means that the revenues lead to cash-in of liquid funds, e.g. release of reserves are not included, and expenditures lead to real disbursements, e.g. depreciation and setting up of accruals are not included. The cash flow can be used for investment expenditures, debt redemption and profit distribution. It is distinguished between either pure equity financing or partly or even complete loan financing, considering interest payment and redemption. For both, the calculation of cash flow can be effected by two different methods, a direct and an indirect one. The formulas applied in the present study are summarised in Table 4.50.

| | independent from financing mode, corresponding to 100 % of investment as **equity** capital | with **equity and loan** participation, cash flow used for calculation of return on equity ROE |
|---|---|---|
| **direct** calculation of cash flow | **cash flow =<br>revenues<br>- (re)investments<br>- operating costs<br>- taxes** | **cash flow =<br>revenues<br>- (re)investments of equity capital<br>- operating costs<br>- taxes<br>- interest payment<br>- loan repayment** |
| **indirect** calculation of cash flow | **cash flow =<br>profit after tax<br>+ depreciation<br>- (re)investment** | **cash flow =<br>profit after tax<br>+ depreciation<br>- (re)investment of equity capital<br>- loan repayment** |
| calculation of **profit after tax** | **profit after tax =<br>(revenues<br>- operating costs<br>- depreciation)<br>· (1 - tax rate)** | **profit after tax =<br>(revenues<br>- operating costs<br>- depreciation<br>- interest payment)<br>· (1 - tax rate)** |

*Table 4.50: Formulas for cash flow calculation*

The formulas in the second and third row of Table 4.50 show that depreciation, though taken into account for the calculation of profit, is not relevant for the cash flow and therefore added and thus eliminated again. Formulas which refer to the equity part of capital invested in the project are relevant for the calculation of the so-called return on equity ROE (see section 4.10.3.3). Revenues and expenditures relevant for the cash flow of an energy supply system are individually specified in the following paragraphs.

The **revenues** result from customers' tariff payments. The total amount of revenues depends on the capacity of the plant, the energy sales and thus also the load factor, the amount of tariffs and the "market introduction". The concept of "market introduction" accommodates the fact of gradual development of both a clientele and its consumption (see section 4.2.7). Especially in rural areas, people are not accustomed to electricity use. They rather require a "phasing in" of different applications, whose benefit and convenience was not obvious before. The tariff system (see section 4.9) specifies the receipts of payments. Since the calculation is based on yearly revenues and expenditures, the payment interval, be it monthly or yearly, is of no relevance, whereas initial payments, like juissance shares and singular connection fees must be considered. From these revenues yearly **operating costs** are subtracted. Section 4.4.4 gives detailed information on the breakdown of O&M costs and their estimation for different conditions and technical options. The main **tax** load is due to income tax of 35 % (see section 4.8.4). In case that an investment licence can be acquired, the first five years of operation are exempted from tax payment. Taxes are not included in operating cost but separately calculated, subject to the amount of revenues. The amount of **interest payments** and the conditions for **repayment** depend on the amount of loan and the stipulated loan conditions. As soon as the term "interest" is used in the present context, it is equated with the "effective interest rate". This means that the disagio is already taken into account, unlike the nominal interest where the disagio is not yet included. The three most current repayment modes for long-term loans are[611]:

1. total repayment at the end of the credit period
2. repayment by equal instalments
3. **annuity redemption**

The second mode stands for a continually decreasing yearly burden because the repayment instalments remain equal, whereas the interest payment declines due to the reduced residual credit amount. The third mode implies a constant payment amount, the so-called "annuity", consisting of repayment <u>and</u> interest; the interest portion continually decreases and consequently the repayment portion continually increases. For MHP systems in Ethiopia the second and third mode are the closest to reality. Since the receipts of an energy supply system generally increase over the years, a decreasing total financial burden, as it is the case for the second mode, does not offer any advantage. On the contrary, the longer the plant is operating the higher profits can be expected due to growing market penetration, increasing consumption and tariff increase induced by inflation. In addition, especially MHP plants are not very susceptible to repair so that maintenance costs will not grow significantly. The third mode with a continuous total payment is most appropriate. The phenomenon of "market creation" or "market penetration" stands for minor receipts in the first years of operation. A repayment suspension during these few years would be an additional financial relief for the project. However, under the present conditions of the Ethiopian financing sector with restricted availability of capital, such a suspension period is not very realistic, at least as far as the private banking sector is concerned. Nevertheless, the option of a so-called **bullet-loan** should be kept in view as a possibility, for example for an NGO or other bi- and multilateral development organisations, to improve the profitability and thus attractiveness of MHP systems for the involvement of private investors. To integrate this option into the decision support model, the parameter of **"redemption-free period"** should be introduced. The parameter **(re-)investment** takes into account the investment costs at the beginning of the project and further reinvestments during the operation period. For the cash flow calculation, which is the basis to determine the **return on equity** (ROE), only the equity part of the (re-)investment is taken into account. The lifetime of the components and required system extensions rule the reinvestments. The average lifetime of an energy supply system can be deduced from the lifetimes of the single components of the system (see section 3.2.5). Assuming an

[611] Perridon / Steiner, 1999, p.412

"overall" lifetime for the whole plant and designing all components for the energy demand at the end of this period would make necessary only *one* initial investment and then *one* reinvestment for the replacement of the whole plant after the respective lifetime. If the replacement of every single system component such as penstock, turbine, generator, wiring etc. were taken into account according to its specific lifetime, the cash flow calculation would become extremely complicated. Simplifying, for MHP systems the average useful life is estimated to be about 25 years, meaning also for all components. The components are not at all susceptible to repair, so that required small reinvestments for spare parts etc. are considered to be part of the maintenance costs. For the most expensive part of the system, i.e. the electricity distribution grid, the consideration of a gradual extension, every 5 years, entailing regular reinvestment, is appropriate. For diesel generators an average life expectancy of about 8 years, depending on their performance and the provided maintenance, is assumed. This requires a reinvestment every 8 years for the purchase of a new electricity generation unit with increased capacity and for a simultaneous extension of the distribution facilities. The distribution facilities are supposed to outlast 25 year, just as it is assumed for MHP systems. For the third option under consideration, the grid connection alternative, a lifetime of equally 25 years is presumed, with gradual extension of the distribution grid. The lifetime of the MHP system of 25 years is fixed as reference period for the comparison of the three different technical options (see also 6.1.2).

#### *4.10.3.3 Net present value NPV and return on investment ROI*

The **dynamic** methods of investment analysis, net present value NPV and return on investment ROI, which is here equated to the internal rate of return IRR, take into account the variability of revenues and expenses over the time, based on the cash flow calculation. The cash flow for every single year is **discounted**[612] to receive the net present value:

$$NPV = \sum_{t=0}^{n}\left[\frac{revenues(t) - expenses(t)}{(1+ROI_{internal})^t}\right] = \sum_{t=0}^{n}\left[\frac{cashflow(t)}{(1+ROI_{internal})^t}\right]$$

***Formula 4-33***

The discounted cash flow analysis is often also referred to as "**life-cycle costing**".[613] It allows to compare projects with high investment costs but low operating costs and long useful lives like MHP plants with alternatives which have low investment costs but high operating costs and relatively short useful lives like diesel plants. For year n, which is the last one considered in this calculation, the liquidation profit has to be taken into account as revenue. In case that the NPV is calculated for the lifespan of the plant, the liquidation value, also called residual or salvage value, is zero. Return on investment ROI is the hypothetical interest rate, that equates the discounted cash outflows, i.e. expenses and cash inflows, i.e. revenues over the total operational time of n years. In other words, the internal ROI represents the interest rate earned on the capital invested in a project. It is calculated in an iterative way with the application of the following equation[614]:

$$\sum_{t=0}^{n}\left[\frac{cashflow\ (t)}{(1+ROI_{internal})^t}\right] = 0$$

***Formula 4-34***

Whether a rate of return is acceptable can be judged based on knowledge of the costs of raising funds in local and international capital markets and/or the earnings realised from in-

[612] "discounted" means that the "time value" of money is taken into account. The discounting process is needed to reflect the opportunity cost of capital, because the real value of an expenditure made in the future is (due to inflation) less than the real value of the same expenditure made today.
[613] Fritz, 1982, p.122
[614] van Horne, 1998, p.19f

vestments of comparable risk. The general rule to be applied is: Accept investments that offer rates of return in excess of their opportunity costs of capital and reject projects with an internal rate of return less than the market interest rate. In general, for the appraisal of project profitability absolute key figures and indices are less appropriate than ratios, because ratios can relate the calculated figure to the capital invested. Therefore, depending on which capital investment is used as underlying reference, it can be distinguished between return on *total* investment (ROI) and **return on equity (ROE)**. The ROE is the application of ROI-method on the equity part of investments. The cash flow equation as basis for the calculation of the ROI respectively ROE is shown in Table 4.50. Based on the cash flow equation, ROI and ROE are determined iteratively according to Formula 4-34.

#### *4.10.3.4 Payback period*

The payback period is the duration in years required to recover the initial investment out of the project's cash flow,[615] in other words the time taken to break even on an investment. The method takes into account cash outflows, i.e. (re-)investments, operating costs including taxes, and inflows, i.e. income from tariff payments. It assumes 100 % equity financing without capital costs. Starting with the year of investment the yearly in- and outflows are cumulated up to the year of amortisation, when the cumulated flows equate to the total initial investment. This method implies that the total capital reflux of the investment till the year of amortisation is exclusively used to cover the initial investment and after that for capital return.[616] Two different methods, a static or a dynamic one, can be applied. The static method, which is based on average in- and outflows, does not consider the time value of money. The **dynamic calculation**, however, which is applied here, calculates the period within which the invested capital, plus a return at the amount of the adequate target rate, is recovered. This is the moment, when the cumulated cash flow equals zero.

### 4.10.4 Limitations of financial analysis and resulting recommendations

The following section points out the limitations of the methods described and gives recommendations on future prospects and possible strategies.

#### *4.10.4.1 Appropriateness of NPV, ROI and ROE calculation under Ethiopian conditions*

To apply dynamic methods such as NPV, ROI and ROE the following boundary conditions have to be complied with in order to warrant for the validity of the results:[617]

- capital is a homogeneous good, which means that no differentiation is made between equity and loan capital and **saving and loan interest** are equal
- **capital** can at any time be acquired and deposited without limitation
- complete market **transparency**, meaning everybody can get all information

Although in practice these requirements are at most partly fulfilled, for the sake of simplification they are supposed to be accomplished. In general, only in case of high price stability a constant interest rate can be assumed and the market interest rate is used for calculations. For many developing countries, however, high inflation rates must be included to ensure accurate calculation. The calculation is effected according to Formula 4-35.[618]

$$1 + real\ interest = \frac{1 + market\ interest}{1 + inflation\ rate}$$

***Formula 4-35***

[615] van Horne, 1998, p.150
[616] Walther, 1998, p.17
[617] Walther, 1998, p.18
[618] All variables in the formula are absolute measures, no percentages.

The economic environment in Ethiopia is relatively stable. **Inflation** is at a low **4,5 %**[619] and did not reach values higher than 15 %[620] since the establishment of the new government in 1991. The interest rate for **savings** is between **6 and 7 %** in 1998 and 1999 for different Ethiopian banks.[621] Despite several measures of financial liberalisation in Ethiopia, a minimum floor on bank deposit rates of 6 % is retained so that deposit rates remain positive in real terms, i.e. after subtraction of inflation.[622] The interest rates for **loans** were decontrolled in January 1998. Rates of **10 - 13 %** in1998 and 1999 seem to be high, but reach moderate ~7,5 % after the subtraction of inflation.[623] As opposed to this, much higher returns in the range of about **20 %** (see section 5.4) can be achieved with investment projects in other sectors. As far as the assumption of a homogeneous interest rate is concerned, it can be applied as long as all surpluses out of the project are devoted to the redemption of the loan. But in the case of repayment by (yearly) equal instalments or annuity redemption (see section 4.10.3.2), revenues achieved do not exactly correspond to the fixed repayment rate thus provoking deficits or surpluses. Whereby surpluses are mainly achieved after some years of operation. The net present value method implicitly assumes that project surpluses are discounted at the "adequate target rate" defined in advance. This target rate corresponds to the minimum interest rate claimed by the investor, which is in general not below the interest rate required for capital acquisition at the bank. Likewise, the ROI calculation implies a reinvestment of capital at the internal rate of return achieved by the project. Between the interest rates of 6-7 % for savings, 10-13 % for loans and about 20 % for investment projects, a **discount rate of about 12 %** can be assumed thus containing the margin of error.

Though inflation affects the interest rate, it has no immediate influence on the net present value. The *real* net present value which takes into account the inflation is equal to the net present value calculated on the basis of discounting the (nominal) cash flows with the nominal interest rate.[624] However, investment costs, income and operating costs being subject to inflation, the cash flow and thus the net present value is indirectly affected by the inflation rate.

In general, the Ethiopian capital market is still not far developed (see section 4.6.2). The first private banks were established no more than a few years ago. Most banks have the majority of their branches in Addis Ababa and other bigger towns. These are only some of the reasons leading to the severe lack of **market transparency** and the lack of **capital availability**.

Even if the requirements cannot fully be complied, the feature of discounting in these dynamic methods makes them notedly advantageous compared to static methods. Therefore, they are made use of in the present study. Both methods, NPV and ROI, are based on the principle of time value of money. However, the methods may lead to differences, when comparing competitive investment projects[625], because they highlight different limiting factors of investments. The internal ROI maximises the return per monetary unit of investment, whereas the NPV maximises the total return. For this reason the **internal ROI has an advantage over the NPV when capital is limited, like it is the case in Ethiopia**, and vice versa the NPV is advantageous when there is a lack of investment projects.[626] The calculation of the ROI provides a relatively objective basis for evaluating investments. If this parameter is used, the acceptance criterion is an ROI, which is higher than the opportunity

[619] note: The figure is not taken from the statistical material of the National Bank of Ethiopia. It is specified by financial experts for Ethiopia, because the official data are not consistent with reality; personal communication information from: Conzato (EU), Danino (IFC), Gebreyesus (NBE), 03/2000
[620] personal communication: Gebreyesus (NBE) 02/2000 and National Bank of Ethiopia, 1999-2; note: officially and unofficially below 15 %
[621] International Monetary Fund, 1999, p.29
[622] NBE, 1999-1, p.33; CBE, 1997; p.17 and Addison, Geda, 2002, p.8f
[623] 1.12/1.045 = 1.071 rounded off to 7.5 %
[624] Walther, 1998, p.50f
[625] van Horne, 1998, p.153f
[626] Collin, 2000, p.9

costs of money.[627] Once the ROI is higher than the interest rate on loans, the leverage effect leads to an increasing ROE if the portion of loan capital increases.[628]

#### 4.10.4.2 Applicability of payback period

Although the method of "payback period" is easy to apply it does not give any information on profitability of the investment. The dynamic method takes into account the time value of money and thus overcomes at least one crucial weakness of the static method. Nevertheless, neither of them considers the cash flows after the payback time. The payback period even if it is based on a dynamic calculation can only provide a partial picture of whether the investment is worthwhile. It rather serves to estimate the duration of capital commitment and thus the effect on liquidity of the project. The payback period helps to answer the question if borrowings can be repaid in time by means of the surpluses. It characterises the time required to recover the total investment costs by means of the revenues lessened by operating costs and taxes. The investment is rated advantageous if the calculated pay-off-period is shorter than the one accepted by the investor, according to his risk assessment. The deficit of this method is the subjectivity of the payback period fixed by the investor as decision criterion. In practice, it often lies far below the economic lifetime of the project. The higher the investor assesses the risks of the project the lower he fixes the pay-off-time.[629] Especially in high risk environments like in Ethiopia this parameter delivers an interesting financial description of projects. Therefore, the method is applied from the side of investors.[630] For Ethiopian investment projects the high political risk led to ambitious expectations on payback periods in the order of two or three years. Even if such payback periods cannot be reached by MHP projects, the payback method allows at least a comparison between different options respectively different scenarios of electricity supply and shows which parameters are relevant, and to which extent, for the reduction of payback time.

[627] van Horne, 1998, p.150f
[628] Perridon / Steiner, 1999, p.473ff
[629] Wöhe, 1990, p.776f
[630] personal communication: Yilma Tekleyohannes (Ethio-African Export & Import), 03/2000

# 5 INTERACTION OF CRUCIAL ASPECTS

## 5.1 Steering consumption

The consumption patterns are closely linked to the tariff system. To a certain extent the behaviour of consumers can be directed: lower tariffs at particular times of the day promote consumption at those times, thereby **truncating peaks** and balancing demand over the day and night. Such financial steering mechanisms are limited, because some appliances are only useful at certain hours. For example, lighting in general is not required during the day, no matter how cheap electricity. Energy-intensive rural industries however can considerably be promoted by lower daytime tariffs. The **competitiveness** of production and manufacturing industries can be strongly influenced by energy costs and inversely industrial demands often decide on the profitability of the energy supply system as a whole. Since consumption and load pattern can be controlled and temporally balanced by means of an **appropriate tariff system** (see sections 4.9.6, 4.9.7 and 4.9.8), a forecast should take this into account.

## 5.2 Tariff system for cost-covering operation

Figure 6.1 depicts the continuous growth of the actually required system output for a typical despite fictitious case study. For **capacity planning** severe problems arise. If a medium value, like e.g. the required output after half of the project period, meaning in year 2013, is chosen for the system design, the plant is oversized at the beginning and overloaded at the end. The first years of operation are typically characterised by a very low initial demand due to slow market penetration and low load factors. As soon as consumption reaches or even exceeds the plant capacity, power cuts have to be managed. Generally spoken, consumption increases continuously, whereas the augmentation of generation capacity can only be realised in a stepwise way. Thus, the two curves will never be congruent. So the question arises, which demand should be taken into account for the design of the plant. Are there any approaches, such as special tariff systems, that can help to transform the continuous demand function into a stepwise one in order to adjust the demand patterns to the capacity of the supply ? In this way, the costs of energy production and hence of consumption could be reduced. One possible approach is to sell capacities instead of kWh's.[631] The questions, arising here, do not only concern the tariff system but also the financing mechanism. Investment costs are directly correlated with the capacity of the installed system in kW, and not directly with the produced electricity units in kWh. From this point of view it is much more profitable to **charge capacities**, as done by many informal power producers who operate small diesel gensets. This approach guarantees a stable and calculable income to cover the investment costs and allows a more stepwise way of increasing supply according to each new step of demand. It is an appropriate way to finance new electrification and further extensions of isolated systems according to the customers ordering of new capacities. This fits well to the idea of financing the system, at least partly, by means of juissance rights (see also section 4.6.3.2). Resuming, it becomes obvious that consumption patterns can be strongly influenced and even steered by a tariff concept that sells kW of capacity, instead of kWh's of consumption. Such a tariff structure offers possible links to an appropriate financing mechanism and finally also to the organisation, operation and ownership of the whole system, as it is illustrated in the following section.

[631] Feibel et al., 2001, p.106

## 5.3 "Who is how involved ?" - participating stakeholders

The comprehensive analysis in the different sections of chapter 4 allows conclusions on which financing mechanisms, financing partners and organisational structures are matching for a specific MHP project, depending on criteria like participants involved, size and thus investment costs but also operation and management requirements. These conclusions are presented in the following paragraphs.

The availability of financial instruments in Ethiopia and the application of different instruments in similar projects world wide show, that the dissemination of MHP technology requires **some non- or less-profit oriented capital**. In addition, the existence of specialised financing programs from banks and donors and / or a guideline for private investors or user groups are helpful.[632] Major financial partners for MHP-projects in other projects in Nepal, India, Peru and Ecuador etc. which can provide this "less-profit oriented" capital are identified as follows:[633]

- community co-operatives
- customers as shareholders
- development banks
- NGO's, bi- and multilateral institutions

These experiences from projects in other countries are in line with the results from the analysis of Ethiopian conditions. Under the assumption that a community has a strong interest in electricity supply, because no realistic affordable alternative is available, the general advantages of **customers as financiers** for at least part of the MHP plant are, that they accept:

- higher risks
- lower profitability and cash flow
- lower collateral
- longer financing periods.

Thus, consumers have to be looked upon as important equity or quasi-equity providers delivering a sound basis of financing. The different options are listed in Table 5.1.

[632] Collin, 2000, p.24
[633] Panasia, 1998, p.4,7,16 (http://www.panasia.org.sg/nepalnet/crt/); Renewing India, 2000, p.2 (http://www.renewingindia.org/); personal communication: Shiferaw (EECMY), 02/2000

| | characteristics, from the point of view of partici-pating customers | preferred organisational form | risks / chances for the project |
|---|---|---|---|
| **1. liable equity** | ownership with full liabilities | • co-operative society | management problems due to common responsibility, probably less professional, corruption...[634] |
| **2. limited equity** | issue of common or preference shares to custom-ers (and interested investors) | • share company | different "liability classes" possi-ble, responsibility with main proj-ect sponsor, influence on man-agement according to share value |
| **3. juissance shares (quasi-equity capital)** | juissance shares participate in profit (and losses), no or few rights over corporation | • share company<br>• limited partnership<br>• (co-operative society) | access to "quasi-equity" capital; customers have no or few rights over company; contractual free-dom for non monetary dividends (e.g. energy units in kWh or kW) allows<br>- in advance sales of electricity → reduced market risk<br>- in advance payment → reduced risk of customers' insolvency |
| **4. combination of different liabili-ties (common + preferred limited) and juissance shares** | participation with different types of liability possible | • limited partnership | same features as 2. and 3. |
| **5. long-term customer credit** | customer as loan financier | customers not necessarily part of an organisa-tional form | customers have no influence on management, bad creditor posi-tion of customers |

*Table 5.1: Different possibilities of customer participation*

Given the fact that in general the total amount to be invested for MHP systems can by far not be covered by the users, further contributions are required. Equity capital can also be acquired from private investors, whereby their more demanding profit expectation have to be taken into account. Further equity donors who also accept poorer dividends are bi- and multilateral organisations, NGO's etc.. Loan capital as second medium for financing must be furnished by conventional banks.

Main **restrictions limiting the loan portion** of MHP projects are:

1) the provision of collateral (requirement of around 125 % of loan volume; lack of legal means for transfer of ownership) and
2) the short loan periods of max. 5 years.

In general, Ethiopian banks require a minimum equity of around 30 % of total investment[635], thus releasing a loan of about 70 % of total investment. But, as far as MHP projects are concerned, no or insufficient outside collateral is available, so that bank loans are expected not to exceed **20 to 40 % of the project volume.[636]** Nevertheless bank loans are required in order to increase the ROE for the investors with the help of a **positive leverage effect**. The

[634] personal communication: Danino (IFC), 03/2000 among others
[635] personal communication: Kidane (DBE), Hailu (CBE), Tariku (CBB); Baissa (Abyssinia Bank), Mahmoud (NIB), Asfaw (Wegagen Bank), Solomon (AIB), 03/2000
[636] It is expected, that the collateralisation of the project (equipment etc.) is only sufficient to raise a loan for not more than 20-40 % of the total investment.

leverage effect describes the fact that the return on investment improves with increasing loan capital, if the internal rate of return of the project is higher than the interest rate for the loan (see also section 4.10.4.1).[637] As soon as the ROI exceeds the relatively low interest rates for loans of about 10 - 13 %, loans should be acquired in preferably high amounts. However, if about 30 % of the total investment should be covered by loan capital about 38 % (= 125 % of 30) of the total project value are required as collateral (see section 4.6.4.1).

The most appropriate way to finance and organise a specific MHP project is to combine different financing partners and different instruments, in order to gather their specific advantages in one structure. For example, the combination of equity and loan capital gives rise to the following benefits:

- equity improves access to loans
- positive leverage effect (increased ROE) by preferably high loan portion
- partition of liabilities and risks

Table 5.2 gives an overview on financing mechanisms and organisational forms, appropriate for different ranges of project size and combinations of project participants.

The summary illustrates that bigger plants due to their higher profitability can easier attract "anonymous" equity capital from investors, who are not directly involved in the project. An investor who contributes 70 % of project volume as equity capital must be financially sound and anyhow motivated, e.g. if his hometown is concerned. Whereas, a **self-supply investor** implements an MHP project in order to have electricity at his own disposal. Due to his own corporation or enterprise for which he initiates the energy supply project, he disposes of adequate collateral, enabling him to get access to loan capital. An **Independent Power Producer (IPP)** is a local or foreign investor simply interested in a profitable business. He benefits from the less profit-oriented equity capital contribution in the form of juissance rights and probably also donors and investment incentives, in case that the conditions for the acquisition of an investment licence are fulfilled. For the involvement of international institutions like IFC[638] or even multinational companies and to achieve investment incentives, either the project volume must be big enough or several smaller MHP projects must be bundled. A sufficient project volume at least about 500,000 ETB also facilitates the share issuing by the issuing house "Commercial Nominees".[639] The Commercial Nominees can evaluate the project and issue the shares via the fixed price method at a brokerage of 5 %. Depending on the amount and type of financial contribution, the various participants are assigned to a legal status in an appropriate organisational structure. Hereby, the organisation form must imperatively meet the control needs of those participants who contribute fully liable equity capital in order to minimise their risks.

[637] Van Horne, 1998, p.219f
[638] note: in Africa the IFC provides equity for projects with minimum financial volumes of 0.5 million USD; personal communication: Danino (IFC), 03/2000
[639] personal communication: Molla (Commercial Nominees), 03/2000

| size | participants | equity (% of total investment) | loan (% of total investment) | organisation | advantages / disadvantages | mainly appropriate in case of... |
|---|---|---|---|---|---|---|
| **10-80 kW** (200,000-1,600,000 ETB) | users + NGO | **25-30 %** as users' shares or juissance rights | **70-75 %** soft loan from NGO, development bank... | - modern co-operative<br>- share company | - broad equity capital basis<br>- identification with project<br>- cost cut in case of local contribution<br>- operational risk for co-operative organisation<br>- dependency from NGO | smaller plants with lower profitability; loan capital not available |
| | local investor/s + bank | **70 %** from investor | **30 %** medium term loan from bank; guarantee or collateral from project assets | - one-man-business for single investor<br>- limited partnership for several investors | - reduced risk and costs for operation | motivated, financially sound, local investor; for control local presence of investor required; more than 30% loan difficult due to collateral |
| **80-300 kW** (1,200,000-4,500,000 ETB) | self supply investor + bank | ≥ **30 %** from investor | ≤ **70 %** loan; corporation's assets as collateral ! | integrated in investor's existing corporation | - no market risk<br>- low operational risk | electricity for investor's needs (e.g. agro-processing), surplus sold |
| | IPP + users (+ donors + municipality) + bank | **33 % equity** from IPP, other individuals and customers;<br>**33 % juissance rights** (as prerequisite for connection) | **33 %** bank loan, with collateral of project | - share company<br>- limited partnership<br>- (modern co-operative) | - higher profitability for IPP and other equity donors due to participation of less profit oriented groups (lower dividends for juissance rights)<br>- major responsibility for operation should remain with (few) equity donors | local/foreign IPP sells electricity; investment incentives for foreigners with investment of ≥500,000 USD (~300 kW) or ≥300,000 USD (~170 kW) for joint investment together with a local |
| **150-300 kW** (2,250,000-4,500,000ETB) | IPP + users + e.g. IFC + bank | **33 % equity** from IPP(s), institutions like IFC and customers;<br>**33 % juissance rights** (as prerequisite for connection) | 33 % bank loan, with collateral of project | - share company with common shares for project sponsors preferred shares issued on interoffice market, and juissance rights for customers | - profitability for IPP and other equity donors raised by participation of less profit oriented groups; higher profitability compared to smaller plants, due to economies of scale<br>- access to "interoffice market"<br>- major responsibility remains with project sponsors | bigger profitable project; mixture of<br>- equity capital from IPP and IFC, for project volume of min. 0.5 million USD<br>- common shares (for project sponsors)<br>- preferred shares for interested investors<br>- juissance rights for customers<br>investment incentives see above |

*Table 5.2: Assignment of financing mechanisms and organisational forms to different project sizes and project participants*

## 5.4 Significance of profitability in the context of decision-making

Once the potential project participants (see section 4.5) and the amount and type of their financial contribution to the project are identified a financial analysis can be conducted. The financial situation of the participants, their investment motivation and **profit expectations** decide on the availability of equity and loan capital. Based on this causal relationship, a procedure of decision-making is elaborated which is illustrated in
Figure 5.1. The ROI which indicates the maximum interest rate to be received on the invested funds, still breaking even financially, is one of the decisive criteria for investors. Different project participants have different profit expectations. Future customers' or NGO's' equity capital is presumably invested under moderate or even no profit expectations, whereas "real" investors' equity has to meet return rates of about 20 - 30 %.[640] For them profitability is, besides payback time, the main exclusion criterion. In case that the ROE of the eligible energy supply project falls short of their expectations, they search for alternative investment projects. On the other hand, the ROE depends on the **equity to loan ratio**, which is an essential input parameter for the cash flow calculation. The required amount of loan and the loan conditions, i.e. interest rate and conditions of redemption, rule the capital cost.

Figure 5.1 visualises the correlation between project participants, financing instruments, economic parameters, especially the ROE, and organisational forms. It points out, in particular, the special feedback reaction between project participants and profitability. Due to this feedback the "decision loop" has, under certain circumstances, to be passed through two or even several times. First, the estimated investment costs are partitioned between customers, NGO's, bi-/multilateral organisations and banks according to the available information on their willingness and ability to participate in the project. In order to cover the total amount of costs, it is supposed, at this point of the procedure, that one or several potential private investors bear the remaining investment volume with their equity capital. Under these assumptions a financial analysis is started. One of the results of this first calculation of profitability is the ROE. The diagram indicates that in case of sufficient profitability (ROE ≥ 20 to 30 %) it can be concluded that a private investor will in fact participate in the potential project as it has already been presumed in the first step of the procedure. Otherwise either more quasi-equity or real equity capital from customers, NGO's etc. or a higher amount of loan from the bank must be contributed. Thus, in case of missing or deficient private equity investment due to a minor ROE, the dashed line in the diagram has to be traced. The capital contributions from the different participants in the form of equity, quasi-equity and loan capital have to be modified and the calculation of profitability repeated. Strictly speaking, the total contribution from the three participant groups in the upper part of the diagram must be increased in order to compensate the lacking participation of private investors. As soon as the participants and their specific financial contribution are ultimately defined, this result is used for the selection of an appropriate organisational form (see Table 4.38 and Table 5.1).

[640] Collin 2000, p.32f

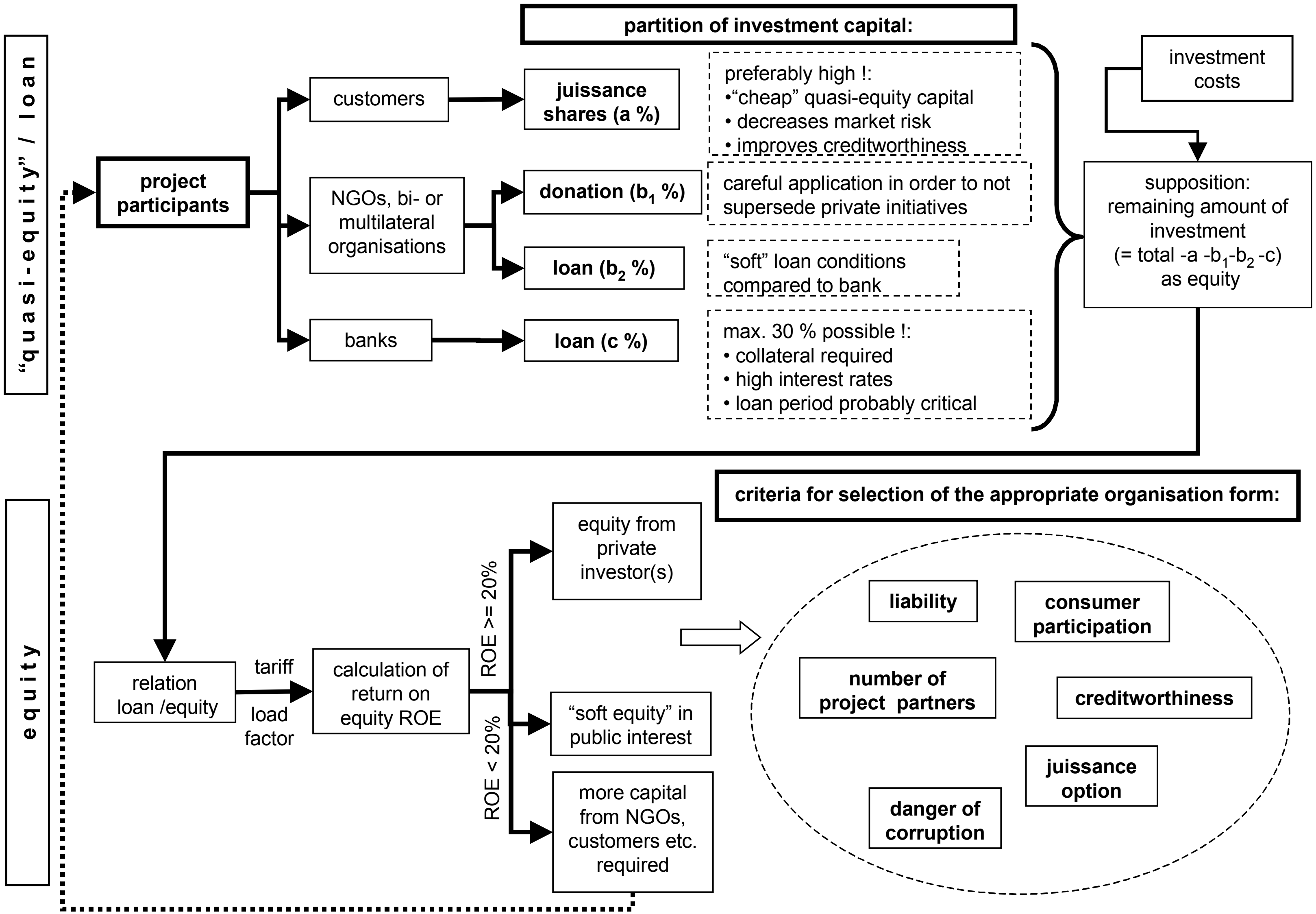



*Figure 5.1: Procedure of decision-making depending on participants, financial contribution and other crucial parameters[641]*

[641] Feibel, Collin, Scholand, 2001, p.106

# 6 ILLUSTRATING CASE STUDIES

To perspicuously and recapitulatory depict the analysis steps of chapter 4 and the comprising synthesis of chapter 5, two examples of energy projects, with capacities of about 50 and 150 kW, are presented here. The focus is put on:

- the forecast of electricity **consumption**
- a rough technical design, required for the estimation of investment and operating **costs**
- the calculation of **profitability** and **payback period**
- the proposal of a **financing structure** (depending on project participants) and an appropriate **organisational form**.

Investment cost estimation and profitability are compared for the three alternatives MHP, diesel genset and grid connection. Emphasis is again put on the MHP alternative. To start the analysis, several suppositions must be made, like the available head and runoff to drive the turbine, the distance between river intake and forebay for the length of the power channel, and between powerhouse and load centre for the length of transmission line and the population of the settlement. After a brief summary on the consumption forecast and the assumptions made (section 6.1), the results of the cost estimations are presented and compared to experiences from other projects worldwide (section 6.2). The profitability of the different options and a sensitivity analysis with regard to the specific assumptions are illustrated in the sections 6.3.1 to 6.3.4. In section 6.3.5 recommendations with regard to financing and organisation of the MHP systems are developed.

## 6.1 Selected approach

### 6.1.1 Forecast of electricity consumption

The supply systems considered here are based on consumption forecasts, which mainly apply the data presented in Figure 4.7. The population growth is fixed at 3.5 %, instead of 3 %, in order to allow for potential population movement due to the attractiveness of electricity supply. The results of the forecast are presented in Annex 8 and Annex 9. The factors which contribute to the unfavourable situation of poor plant utilisation at the beginning of operation are a slow market penetration and the growth of population and consumption. Figure 6.1 illustrates the influence of the market penetration which is assumed to grow linear from 10 to 40 % during the first 10 years of operation. After that, the curves slightly flatten because the penetration has reached its ultimate level and only the specific growth rates of population and consumption exert their influence. After half of the project time still a capacity of about 22 kW for the 50 kW system and 60 kW for the 150 kW system are sufficient for supply.

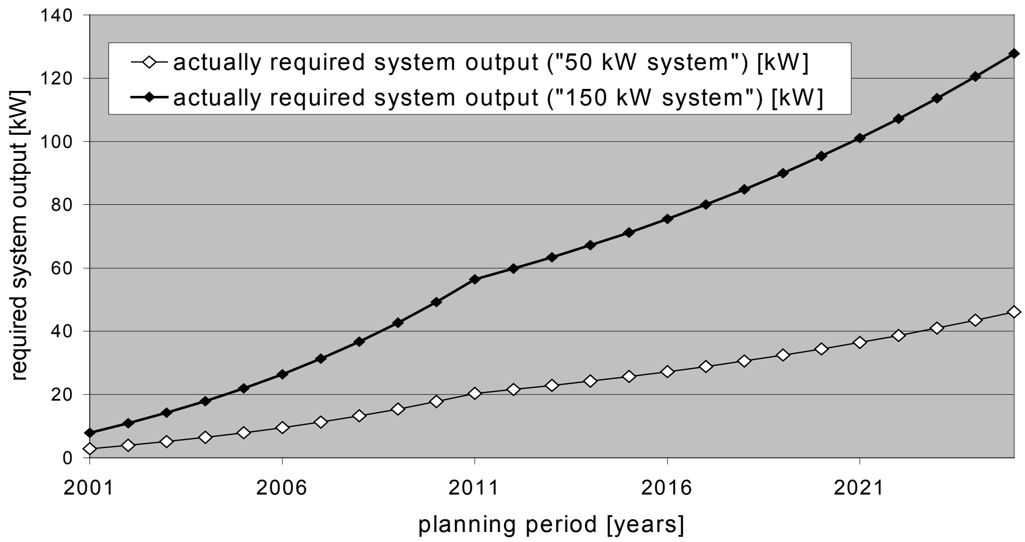



*Figure 6.1: Development of required system capacity during the project phase*

### 6.1.2 Assumptions made for the case study analysis

The main features of the case studies are summarised in Table 6.1.

| | unit | year of operation | 50 kW system | | 150 kW system | |
|---|---|---|---|---|---|---|
| | | | MHP | diesel genset | MHP | diesel genset |
| **project period** | [years] | | 25 | | | |
| **average economic lifetime** | [years] | | 25 | 8 (25)* | 25 | 8 (25)* |
| **planning horizon** | [years] | | 25 (5)** | 8 | 25 (5)** | 8 |
| **depreciation method** | | | linear | | | |
| **total consumption** | [kWh] | 1. | 7,470 | | 27,630 | |
| | | 25. | 121,060 | | 447,940 | |
| **available Q(90,daily)** | [m³/s] | | 0.50 | - | 0.75 | - |
| **required available net head** | [m] | | 20 | - | 37 | - |
| **overall system efficiency** | | | 52% | 32% | 52% | 32% |
| **length of power channel** | [km] | | 1 | - | 1 | - |
| **length of transmission line** | [km] | | 5 | | 5 | |
| **final length of distribution line** | [km] | | 8 | | 25 | |
| **final system capacity / generator output** | | 25. | 56 | 53 | 156 | 147 |

* 25 years for the distribution grid

** 5 years for distribution lines

*Table 6.1: Main features of the selected case studies*

As far as the option grid connection is concerned the assumptions are equal to those made for the MHP systems, except the length of the transmission line. The length of the transmission line for the grid connection is determined in such a way that the investment costs of that option, in ETB per installed kW, correspond to the costs of the MHP system of the same size. Thus, it becomes obvious up to which distance from an existing substation with assumed excess capacity the grid connection option is still as cost-effective as the implementation of an MHP system.

A rough **technical layout** is effected for the power channel, penstock, turbine, generator respectively diesel genset, electric load controller, transmission line and distribution grid, because these components revealed to be deciding for the **investment cost estimation**. Design and investment cost estimation for the MHP-, the diesel-system and the grid connection systems of 50 and 150 kW are illustrated in Annex 10 to Annex 15. All unit prices applied are related to year 2000. Prices for electrical equipment are CIF prices (Addis Ababa), except the electric load controller which, in the specific case, is supposed to be imported from New Zealand. Therefore, additional transport costs are taken into account for the ELC. Duty payment for imported electrical equipment is not taken into account, because it is assumed that the investor is holder of an **investment licence** and exempted from such payments. The calculations are based on an initial fuel price of 2.5 ETB/l at start of operation. The development of this price over the project period depends on the special inflation rate applied on fuel (see 4.4.4.2).

Figure 6.2 illustrates a **time schedule**. The whole design of the MHP system is adopted to cover the energy demand at the end of the planning horizon after 25 years, except the distribution lines, which due to the relatively high costs are extended stepwise every 5 years, according to the growing demand. The diesel systems are designed with regard to their average lifetime of only 8 years, meaning that the first plant must cover the demand expected at the end of the eighth year and is then replaced by a system with a higher capacity planned according to the energy requirements of year 16 after project start and so on. This means, that only the third diesel genset will have the same capacity as the MHP plant, which is designed for 25 years of lifetime. Strictly speaking, a project period of 25 years for the diesel genset option implies a final very high reinvestment in the last year (year 25, see dotted cell in Figure 6.2). Proceeding in that way would have an unduly negative effect on the profitability of this alternative. Therefore, this reinvestment is neglected and omitted. The electricity grid is supposed to be extended, simultaneously with the replacement of the genset, every 8 years and not every 5 years, as it is the case for the MHP option. The amortisation period for the electricity grid, meaning the successively implemented sections, is fixed at 25 years in all cases. For the grid connection option the required transmission line is designed for the end of the project period of 25 years, again with stepwise extension of the distribution grid every 5 years. Although, to minimise costs, smaller conductor cross sections could be selected for the transmission line to carry a capacity of 50 or 150 kW, the standard described in section 4.3.4.9 is applied. It would not be realistic to assume that a transmission line is explicitly constructed for such small loads. It rather has to be designed to serve further future customers along the line. Therefore it is adhered to the mentioned common standards.

The depreciation period corresponds to the lifetime of a machine, building etc.. For all system components **linear depreciation** is implied. For diesel systems a depreciation period of 8 years and for the distribution grid as well as for the whole MHP system 25 years are assumed. Consequently, at the end of 25 years of operation a certain liquidation value of the electrical installations remains. From the point of view of a conservative and risk averse bank this remaining economic value can only be capitalised under the condition that the system is further operated. However, it can be assumed that the abandon risk after 25 years of successful operation is negligibly small and, in addition, participating private investors are disposed to take higher risks. The depreciation instalments do not enter directly into the cash flow calculation but only the part which is subject to tax via profit calculation.

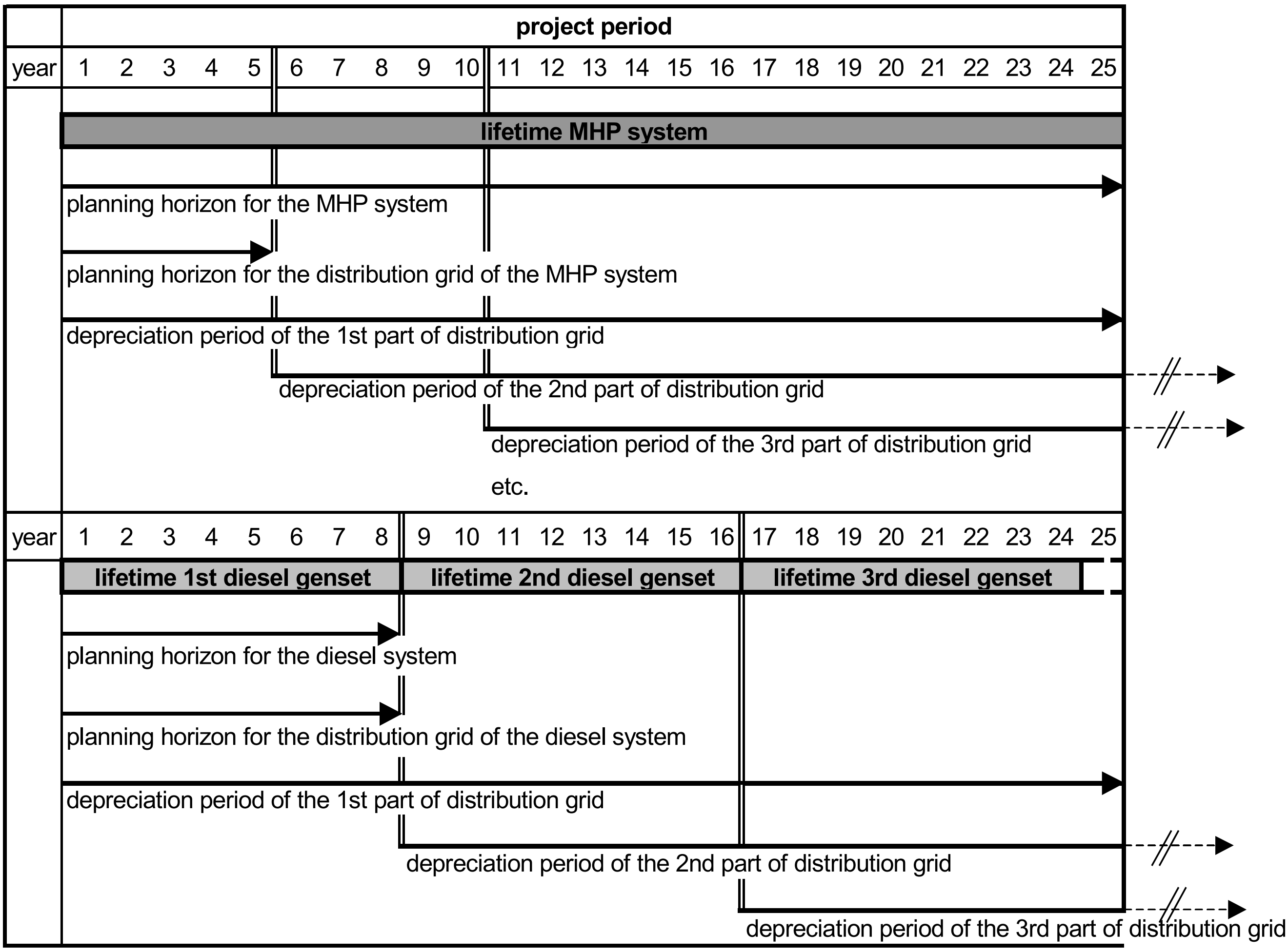



*Figure 6.2: Time schedule for the case studies*

As already mentioned, for the option grid connection the same assumptions as for the MHP system are made.

For the estimation of profitability, the cash flow is calculated according to Formula 6-1.

$$\begin{aligned} \textit{cash flow} = {} & \textit{revenues - running costs - taxes - (re)investments of equity capital} \\ & \textit{- interest payment - loan repayment} \end{aligned}$$ ***Formula 6-1***

The net present value, based on payments-in and -out resulting in the cash flow, is calculated under the assumption that all payment transactions take place at the end of a period meaning at the end of the specific year. Furthermore, it is assumed that **interest payment and loan repayment** are effected by means of annuity redemption with fixed constant instalments. The rate of annuity redemption is fixed according to the amount of interest to be paid and the remaining liquid surplus funds available at the moment of raising the credit; whereby liquid funds are defined according to Formula 6-2.

$$\textit{liquid funds} = \textit{income - running cost - interest - tax}$$ ***Formula 6-2***

Investments and potential loan raising is relevant every 5 respectively 8 years. At this moment the appropriate instalment rate is (re-)defined. This rate must at least be as high as the interest to be paid on the present credit volume. The maximum rate is the sum of actual interest and liquid funds as defined above. Especially in the first years of operation, when energy consumption is still low it can happen that the liquid funds do not even cover the interest to be paid. Then, additional refinancing by means of equity capital or a grace period or bullet loan are required to bridge the low-income years of continuously increasing market penetration (see also section 4.10.3.2).

**Taxes** are subtracted from the profit. If the investor(s) holds an investment licence, awarding 5 years of tax holidays, profit reductions due to taxes are abandoned for the first 5 years of operation. In case of negative profits, these losses can be carried forward for 3 up to 5 years after the termination of the tax holiday.[642] Carrying forward losses has a positive effect on the cash flow. As a matter of simplification, although it is quite an optimistic assumption, the amount of taxes saved is added to the cash flow in the year of occurrence.

## 6.2 Resulting investment costs and comparison with projects worldwide

### 6.2.1 Costs per unit of generation capacity

The results of the investment cost estimation are summarised in Table 6.2. For the diesel systems the different extension steps, every 8 years, are considered. The diesel genset itself as one of the system components is counted among mechanical equipment.

| | **MHP system** | | | | **diesel system** | | | | | | | | | | | | **connection to existing grid****** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **50 kW system** | | **150 kW system** | | **50 kW system** | | | | | | **150 kW system** | | | | | | **50 kW** | **150 kW** |
| | | | | | | | | | | | | | | | | | assumed length of transmission line: | |
| | | | | | **(step 1)** | | **(step 2)*** | | **(step 3)*** | | **(step 1)** | | **(step 2)*** | | **(step 3)*** | | **25 km** | **33 km** |
| capacity [kW] | 56 | | 156 | | 16 | | 33 | | 53 | | 45 | | 92 | | 147 | | 56 | 156 |
| total cost [ETB] | 1,167,000 | | 2,164,000 | | 177,579 | | 209,269 | | 269,590 | | 476,034 | | 554,295 | | 677,784 | | 1,184,000 | 2,143,000 |
| **cost per kW [ETB/kW]** | **20,727** | | **13,850** | | **10,982** | | **6,292** | | **5,077** | | **10,609** | | **6,006** | | **4,600** | | **21,029** | **13,716** |
| **cost per kW [USD/kW]** | **2,528** | | **1,689** | | **1,339** | | **767** | | **619** | | **1,294** | | **732** | | **561** | | **2,564** | **1,673** |
| **thereof...** | [ETB] | [%] | [ETB] | [%] | [ETB] | [%] | [ETB] | [%] | [ETB] | [%] | [ETB] | [%] | [ETB] | [%] | [ETB] | [%] | **costs exclusively for transmission line:** | |
| **civil** works | 336,915 | 29% | 396,664 | 18% | 27,200 | 15% | 27,200 | 13% | 27,200 | 10% | 34,000 | 7% | 34,000 | 6% | 34,000 | 5% | 31,070 ETB/km | |
| **"mechanical"** equipment** | 174,057 | 15% | 275,689 | 13% | 40,000 | 23% | 70,000 | 33% | 120,000 | 45% | 90,000 | 19% | 160,000 | 29% | 270,000 | 40% | 3,789 USD/km | |
| **electrical** equipment*** | 434,541 | 37% | 1,104,141 | 51% | 76,292 | 43% | 74,156 | 35% | 72,791 | 27% | 256,952 | 54% | 249,049 | 45% | 250,225 | 37% | | |
| additional cost: transport | 28,649 | 2% | 53,828 | 2% | 4,348 | 2% | 5,192 | 2% | 6,666 | 2% | 11,543 | 2% | 13,424 | 2% | 16,793 | 2% | | |
| additional cost: installation | 60,860 | 5% | 137,983 | 6% | 13,955 | 8% | 17,299 | 8% | 23,135 | 9% | 41,634 | 9% | 49,086 | 9% | 62,427 | 9% | | |
| additional cost: staff train. | 28,365 | 2% | 53,295 | 2% | 4,305 | 2% | 1,714 | 1% | 2,200 | 1% | 11,429 | 2% | 13,291 | 2% | 16,627 | 2% | | |
| additional cost: planning | 104,007 | 9% | 142,119 | 7% | 11,479 | 6% | 13,709 | 7% | 17,599 | 7% | 30,476 | 6% | 35,444 | 6% | 27,711 | 4% | | |
| **TOTAL** | 1,167,395 | 100% | 2,163,718 | 100% | 177,579 | 100% | 209,269 | 100% | 269,590 | 100% | 476,034 | 100% | 554,295 | 100% | 677,784 | 100% | | |

* without consideration of inflation
** for MHP system: mechanical equipment; for diesel system: genset
*** for MHP systems total costs for electrical equipment are considered; for diesel systems only those which are relevant for the respective phase (step)
**** option with ACSR conductors of 129 mm²

*Table 6.2: Overview on capacity costs and repartition of costs for the options MHP, diesel and grid connected system*

The unit costs per kW of installed capacity decrease with increasing system size, due to **economy of scale**. Especially for MHP plants the unit cost reduction from a 50 kW to a 150 kW system is remarkable. For smaller MHP plants, aspects like local contribution and unconventional or improvisational technical approaches are crucial for cost reduction as amplified in section 4.4.1. Since such aspects heavily depend on the specific situation, they can not be taken into account in a general fictitious case study, as it is considered here. For diesel systems the cost reduction due to economy of scale reveals when step 1, step 2 and step 3 are compared. The reason for this is that the costs for the distribution grid of the diesel system are split on the specific extension steps. Thus, the bigger the diesel system the lower is the percentage of electrical equipment at the total of costs and the lower is the unit cost per installed kW. The percentage of the costs of the diesel genset itself becomes more important

[642] depending on the region and the "investment category", see Reg. No. 7/1996 (N.G.), Art.8

from step 1 to step 3, whereby the absolute costs for a diesel genset do not increase proportional with its capacity. Referring to the costs per kW, diesel gensets of high capacity are much cheaper than smaller ones. Therefore, the unit costs for step 3 of the 50 kW diesel system are as low as 619 USD/kW which is close to equally low costs of 561 USD/kW for step 3 of the 150 kW diesel system. Although the low unit costs of step 3 suggest to implement a high capacity diesel plant immediately, the specific costs per consumer would be extremely high thus foiling profitability due to low consumption and low income. Table 6.2 does not allow for a direct cost comparison between MHP and diesel system over the whole period of 25 years, because the inflation is not taken into account. Based on a review of literature, Table 6.3 gives an overview on costs per kilowatt of installed capacity for projects world wide.

| **project reference / country** | **size [$kW_{electrical}$]** | **investment costs [USD/ $kW_{electrical}$]** | **comment** |
|---|---|---|---|
| India, 1 unit | 350 | 1,770 | |
| India, 3 units | 350 | 1,173 | |
| India, 1 unit | 650 | 1,285 | |
| India, irrigation project | 1,000 | 713 | |
| India, irrigation project | 1,250 | 453 | |
| India, irrigation project | 2,000 | 402 | |
| India, irrigation project | 2,500 | 440 | |
| Philippines | 500 | 2,295 | |
| Philippines | 700 | 1,517 | |
| Burkina Faso | 15,000 | 5,837 | |
| Togo | 22,000 | 4,192 | |
| Benin | 41,000 | 3,209 | |
| Mali | 78,000 | 2,691 | |
| Senegal | 87,000 | 2,556 | |
| Liberia | 146,000 | 2,836 | |
| Ivory Coast | 166,000 | 1,480 | |
| Ghana | 169,000, | 1,739 | |
| Sierra Leone | 228,000 | 2,298 | |
| EM** | < 1,000 | 3,500 | determined by EM |
| EM** | 1,000 - 10,000 | 3,000 | determined by EM |
| EM** | 10,000 - 100,000 | 2,500 | determined by EM |
| EM** | > 100,000 | 2,000 | determined by EM |
| Ethiopia | 54 | 1,285 | costs from study; project not implemented [643] |
| data from the EEPCO ACRES study[644] | < 400 | 2100 | estimated capital costs **for diesel genset systems** |
| figures estimated for Rwanda[645] | 15 - 850 | 1,000 - 3,660 | not mentioned if transmission and distribution are included |
| figures from workshop presentation in 1982[646] | 7.5 - 800 | 270 - 2,850 | not including transmission and distribution costs |

* = additional fixed annual costs of 264 $/(kW x year) for social activities
** EM = Environmental Manual for Power Development[647]

*Table 6.3: Investment costs per installed kW for different systems world wide[648]*

[643] Weber, 1996, p.69f; note: repartition of costs: 33 % construction works, 54 % electromechanical equipment, 12 % additional costs
[644] EELPA / ACRES, 1994, p.4-4
[645] Workshop Proceedings, 1983, p.193 (case study Rwanda), summary on undeveloped potential small hydropower sites
[646] Clark, 1982, p.106
[647] The EM website is an activity developed and maintained by the German Government via GTZ, and a group of donors, with scientific support from Öko-Institut; see http://www.oeko.de/service/em/index.htm
[648] Apart from the last four rows of the table, all data are from: Ökoinstitut, 1995 (http://www.oeko.de/service/em/index.htm)

Given the fact that hydropower plants are built with or without reservoirs, as run-of-river systems or barrages for whole valleys, as multi-purpose facilities which are additionally used for irrigation, flood control, drinking water storage, etc., under different geo- and hydrological conditions the cost parameters are extremely site-specific. Thus, the figures in the table give a broad range of specific capacity costs. Whereby, no clear correlation between capacity and unit costs per installed kilowatt is identifiable. Other studies circumstantiate a cost-function of head and size, calculating total costs between 1,825 USD and 8,750 USD per kW for heads from 2.3 to 13.5 m and 1,000 USD to 3,000 USD for heads between 27 and 350 m.[649] The capital costs of 16 micro hydro plants[650] in Peru, Nepal, Sri Lanka, Zimbabwe, Mozambique range from 714 to 5,630 USD per installed kW in constant 1998 prices, whereby plants for shaft power range between 714 and 1,233 USD/kW and those for electricity generation range between 1,136 and 5,630 USD/kW.[651] Two major reasons which contribute to the high cost variability are:

- the difficult-to-value labour provided by the local community
- the lacking consistency in defining system boundaries (distribution grid, house wiring etc.)

Referring to these comparable figures, the investment costs of **2,500 USD/kW for the 50 kW** case study are fair average and the **1,700 USD for the 150 kW** are even at the lower limit.

### 6.2.2 Costs for grid connection

According to the results shown in Table 6.2, the investment cost estimation for the **connection to an existing grid**, more precisely to an existing substation with excess capacity, is a competitive to an MHP system for distances of **up to about 25 - 35 km**. As described in section 4.3.4.9, the costs to connect a community to an existing grid heavily depend on the remaining surplus capacity of existing substations and additionally required transmission lines. In case that only a high or medium voltage transmission line, e.g. 132 kV, passes but no substation or only a substation already operating at full capacity exists, the costs for an additional substation have to be taken into account. If neither transmission line nor substation are available close to the project area, which is the most probable case in rural Ethiopia, the costs for an additional transmission line and a substation have to be considered. In 1994, it was found that very little room for expansion exists on the complement of 15 kV supply stations. The feeders emanating from these stations have generally been extended to the limits of acceptable voltage drops, and, in most cases, further expansion would require additional line exits and express feeders with very large conductor size. Thus, most cases necessitate substation construction or even extension of 33 kV, 66 kV or 132 kV transmission lines.[652]

The costs, exclusively for the transmission line, are estimated at almost **3,800 USD/km**, supposing ACSR conductors of 129 mm². This figure is very close to a cost estimation effected in a feasibility study of the year 1999, which specifies the figures presented in Table 6.4.

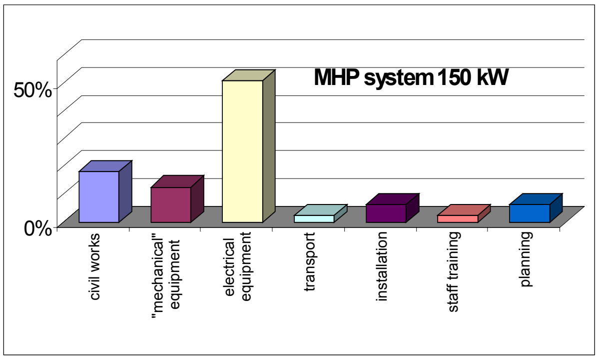
| **technical specification** | 95 mm² AAC | 129 mm² ACSR |
|---|---|---|
| **estimated unit price for 15 kV transmission line in USD** | 4,900 USD/km | 3,300 USD/km |

*Table 6.4: Unit prices for 15 kV transmission lines*[653]

[649] Meier, 1981, p.119f
[650] 10 to 100 kW
[651] Khennas, Barnett, 2000. p.9ff
[652] EELPA / ACRES, 1994, p.2-3f
[653] Tropics Consulting Engineers, 1999-2, p.14-4

### 6.2.3 Breakdown of investment costs

For MHP systems as well as for diesel systems, Figure 6.3 clearly reveals the predominant part of electrical equipment in total costs.



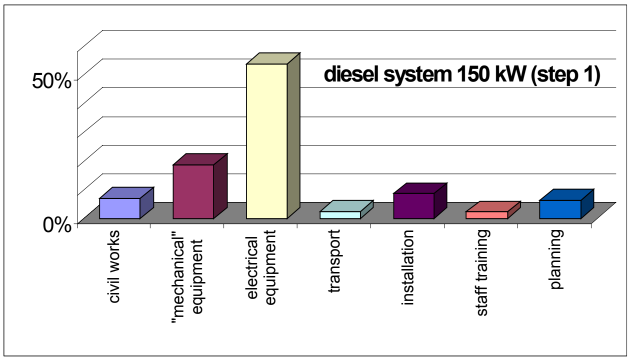




*Figure 6.3: Breakdown of investment costs for the different options*

The second important cost element are civil works as for MHP systems and mechanical equipment (including genset) for diesel systems. For both technical options the percentage of civil works decreases with increasing system size (see Table 6.2). Since electrical components constitute a crucial expense factor, the **cost reduction potential of electrical equipment** becomes essential. Electrical system parts are mainly imported and in that case have to be paid in hard currency. Savings by means of procurement on the local market are mostly impossible. One promising option to significantly reduce investment costs is to search for second hand electrical equipment from industrialised countries. The often cited importance of civil works in total MHP investment costs[654] has taken a back seat here, because expensive electrical equipment dominate the costs. For smaller plants without electrification, exclusively utilised to generate mechanical energy, the share of civil engineering in total project costs can increase to somewhat above 50 %. Nevertheless, for electrical as well as mechanical systems, effective cost reduction in civil engineering still has a greater impact on overall costs than mechanical equipment. In general, use of too much concrete and cement can lead to enormous needless cost increase. The comparison with cost figures in the literature proves a similar ranking order. Table 6.5, which depicts a breakdown of costs of MHP plants implemented in Pakistan, shows that electrical equipment is the decisive cost factor. Civil engineering construction costs still account for a fifth of total investment costs. Cost reduction by increasing local contribution or by preferring sites with high heads instead of high runoff (see section 4.3.3.6) is worthwhile to be considered.

| **capacity of the plant [kW]** | 5 | 7.5 | 10 | 12 | 15 |
|---|---|---|---|---|---|
| **mechanical equipment: turbine and accessories** | 6% | 5% | 6% | 5% | 5% |
| **civil works** | 21% | 20% | 20% | 21% | 20% |
| **electrical equipment: generator and distribution** | 57% | 63% | 64% | 65% | 67% |
| **technical assistance** | 15% | 12% | 10% | 9% | 7% |

*Table 6.5: Breakdown of costs of MHP plants in Pakistan[655]*

[654] Meier, 1981, p.81
[655] Inversin, 1986, p.258

## 6.3 Analysis of profitability and sensitivity to other project parameters

### 6.3.1 Remarks on the parameter variation for sensitivity analysis

The profitability of an energy supply project is influenced by different parameters. Some of them are directly interconnected among each other, like for example fuel price, inflation and interest rate. Others are of importance only under specific boundary conditions. For example, the influence of the interest rate mainly appears with a high ratio of loan to equity. In the present section, the most probable variation of parameters, meaning within realistic limits, is considered. The sensitivity analysis reveals which of the parameters are the most crucial for the project profitability. The following parameters are considered:

1. load factor (important for plant utilisation)
2. ratio of equity - loan - juissance capital
3. interest rates for loan and juissance rights and inflation rate ruling the discount rate
4. loan conditions: possibility of redemption free and/or interest free loan periods
5. energy costs:
   a) fuel price and its inflation for diesel systems
   b) bulk purchase tariff and its inflation for electricity bought from a neighbouring grid
6. operating costs
7. tariff (selling price)
8. rate of taxes and tax free periods

### 6.3.2 Importance of the multiple of contribution margins relative to the multiple of investment costs

Tariff level, investment costs, fixed and variable operating costs have to be considered in very close correlation as illustrated with a simplified sample calculation in Table 6.6.

| | | MHP system | diesel system | relation MHP/diesel |
|---|---|---|---|---|
| | **investment costs** | 1,000,000 ETB | 250,000 ETB | 4:1 |
| | **fixed operating costs [ETB/kWh]** | 0.1 | 0.1 | |
| | **variable operating costs [ETB/kWh]** | 0 | 0.7 (mainly for fuel) | |
| **case 1** | **tariff [ETB/kWh]** | **0.9** | | |
| | contribution margin[656] [ETB/kWh] | 0.9 | 0.9 - 0.7 = 0.2 | |
| | relation contribution margin to fixed operating costs | 0.9/0.1 = 9 | 0.2/0.1 = 2 | 9:2 = 4.5 |
| | contribution margin relation to investment costs relation | | | 4.5 / 4.0 = **1.1** |
| **case 2** | **tariff [ETB/kWh]** | **1.5** | | |
| | contribution margin [ETB/kWh] | 1.5 | 1.5 - 0.7=0.8 | |
| | relation contribution margin to fixed operating costs | 1.5/0.1 = 15 | 0.8/0.1 = 8 | 15:8 = 1.9 |
| | contribution margin relation to investment costs relation | | | 1.9 / 4.0 = **0.5** |

*Table 6.6: Ratios between contribution margins and investment costs for MHP and diesel systems*

[656] contribution margin per unit = unit price minus variable costs per unit. The contribution margin corresponds to the amount of the tariff contributing to cover the fixed operating costs. As long as the unit price exceeds the variable costs, at least part of the fixed costs are covered. If the sum of earned contribution margins corresponds to the sum of fixed costs the "break even point" is reached.

The sample calculation in Table 6.6 is based on an MHP and a diesel system with the same capacity producing the same amount of energy units per year. It illustrates the importance of the "contribution margin relation" to "investment costs relation" by applying different tariffs. For the MHP plant the variable costs can be neglected compared to relatively high fuel costs for the diesel system. Consequently with a tariff which is close to the **contribution margin** as in case 1, the multiple in the contribution margin of 4.5 is still higher than the multiple in investment costs of 4.0. As soon as the first relation, the multiple in contribution margins, becomes smaller than the second one, the multiple in investment costs, MHP systems loose their competitiveness. If the tariff is further increased the contribution margin of diesel and MHP system increase the same amount whereas the relation between the margins becomes smaller. This can be explained by the fact that the return on investment always includes the division of the profit by the capital invested.

Capital costs as such are meaningless in the determination of delivered energy costs unless the degree to which the plant is used is also considered. The lower the load factor and thus the plant utilisation, the higher are kWh-costs.[657] In general, diesel-driven generators may be more cost effective if use rates are low. Increasing load factors normally improve the competitiveness of MHP systems. However, as explained in the previous paragraph, beyond a certain threshold tariff, the load factor looses its positive effect. Consequently, the higher the tariff the less the advantageous effect of high load factors for MHP systems. Thus, to compare the competitiveness of MHP and diesel systems, **load factor, tariff and investment costs** have to be analysed considering their interdependence. The analysis of different scenarios (see section 6.3.4) exemplary illustrates the interdependence of different parameters and, for the specific case, reveals the extent of such effects.

### 6.3.3 Repartition between equity, loan and juissance capital

The involvement of project partners, and thus the mixture of equity, loan and juissance capital, is determined by the characteristics of the different resources of fund raising (see Table 6.7).

| | |
|---|---|
| **loan capital from banks** | limited by collateral requirements, payback periods, high interest |
| **equity capital from investors** | limiting by required profitability (≥ 20 %), risk averseness, project term and control needs; but: equity important as collateral<br>*preference shares*: higher dividends<br>*common/voting shares*: more influence, majority kept by project sponsor, same volume sold on anonymous capital market |
| **"quasi-equity capital" (juissance rights) from customers** | "cheaper" than loan, with positive influence on ROE, but limited by customers financial resources; no interference by capital donors; dividends in kind, kWhs not subject to tariff inflation; reduction of market risk and payment guarantee as insurance for power producer; since even in low income periods electricity consumption possible also insurance for customer |

*Table 6.7: Summarised characteristics of loan, equity and quasi-equity with regard to MHP financing*

It is optimistically assumed that at least the mechanical and electrical equipment of the energy system can be applied as tangible collateral to raise a bank loan (see section 4.6.4.1). Based on Table 6.2, Table 6.8 sums up the percentages of electrical and mechanical equipment in total investment costs for the different technical options.

[657] Clark, 1982, p.131 (table 3)

| technical option | capacity | | % of mechanical and electrical equipment |
|---|---|---|---|
| MHP system | 50 kW | | 52 |
| | 150 kW | | 64 |
| diesel system | 50 kW | step1 | 65 |
| | | step2 | 69 |
| | | step3 | 72 |
| | 150 kW | step1 | 73 |
| | | step2 | 74 |
| | | step3 | 77 |
| grid connected system | 50 kW | | 83 |
| | 150 kW | | 83 |

*Table 6.8: Portion of costs of mechanical and electrical equipment*

About 50 - 80 % of the total investment costs can be used as collateral. If 125 % of the loan volume have to be covered by collateral, not more than **40 to 65 % of the total investment** can be financed by means of a bank loan.

Given the fact that real equity, common and preference shares are summarised as equity capital, the **ROE** calculated here is an **average figure** which refers to this "mixture" of equity capital. In reality, especially preference shares are provided with higher dividends than common shares. In contrast to these types of equity, the return on juissance rights is fixed in advance and not part of the ROE.

### 6.3.4 Results of the calculations and sensitivity

#### *6.3.4.1 Profitability of a 50 kW system*

For the 50 kW system three different financing options are considered:
1) 100 % equity capital
2) 50 % equity capital, 50 % loan capital
3) 30 % equity capital, 30 % loan capital, 40 % capital from juissance rights

The three diagrams Figure 6.4, Figure 6.5, Figure 6.6, which relate to projects fully equity financed, indicate that MHP systems of this size require a high load factor, a high inflation rate and long-term exemption from (income) tax to reach a profitability of more than 10 %. The grid connection option, with a length of 25 km for the transmission line, does under none of the analysed conditions reach the profitability of the MHP system.

Financing with 100 % equity capital is only possible in case of a well-off single investor, for example motivated because of self supply requirements for his own business. Figure 6.4 shows that beyond a threshold tariff of about 1.5 ETB/kWh the profitability of the diesel system outruns the one of the MHP system. The competitiveness of MHP systems is improved by an extension of the tax exemption period, which is presently 5 years for holders of an investment licence, and in case of higher fuel inflation.

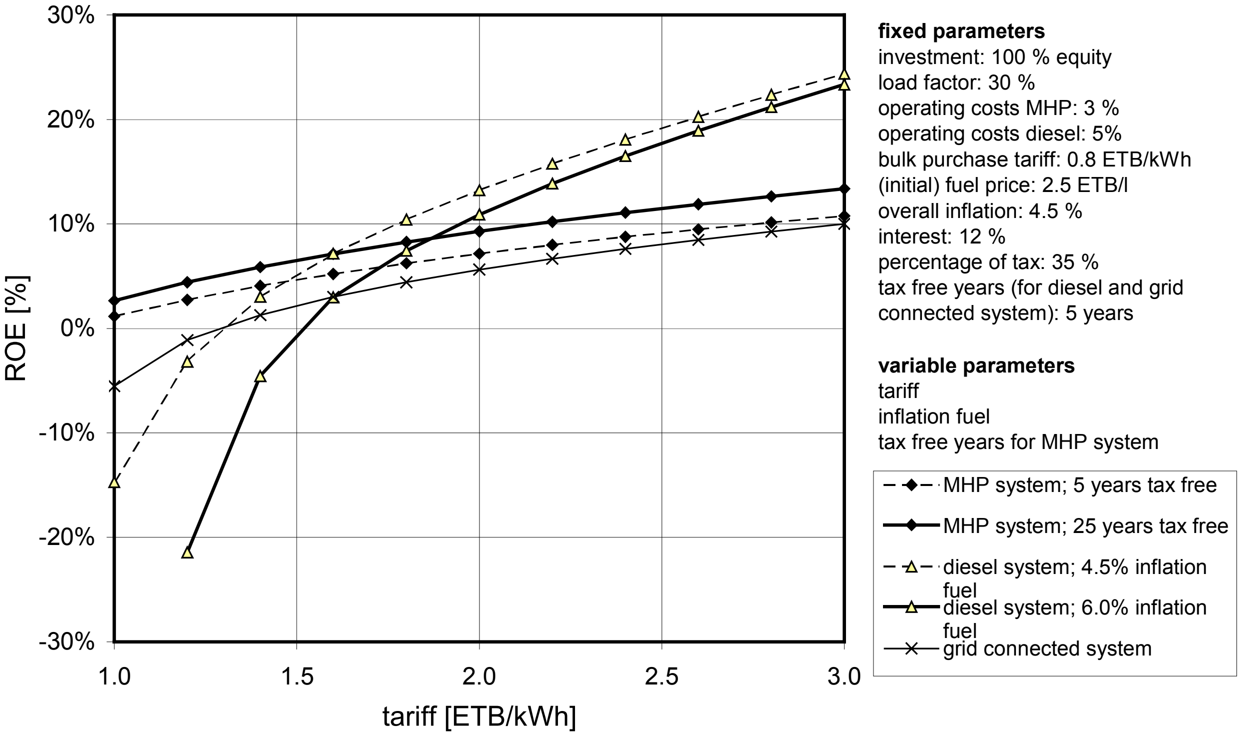



*Figure 6.4: Return on equity for a 50 kW system with 100 % equity finance, depending on tariff, tax free years and inflation of fuel price*

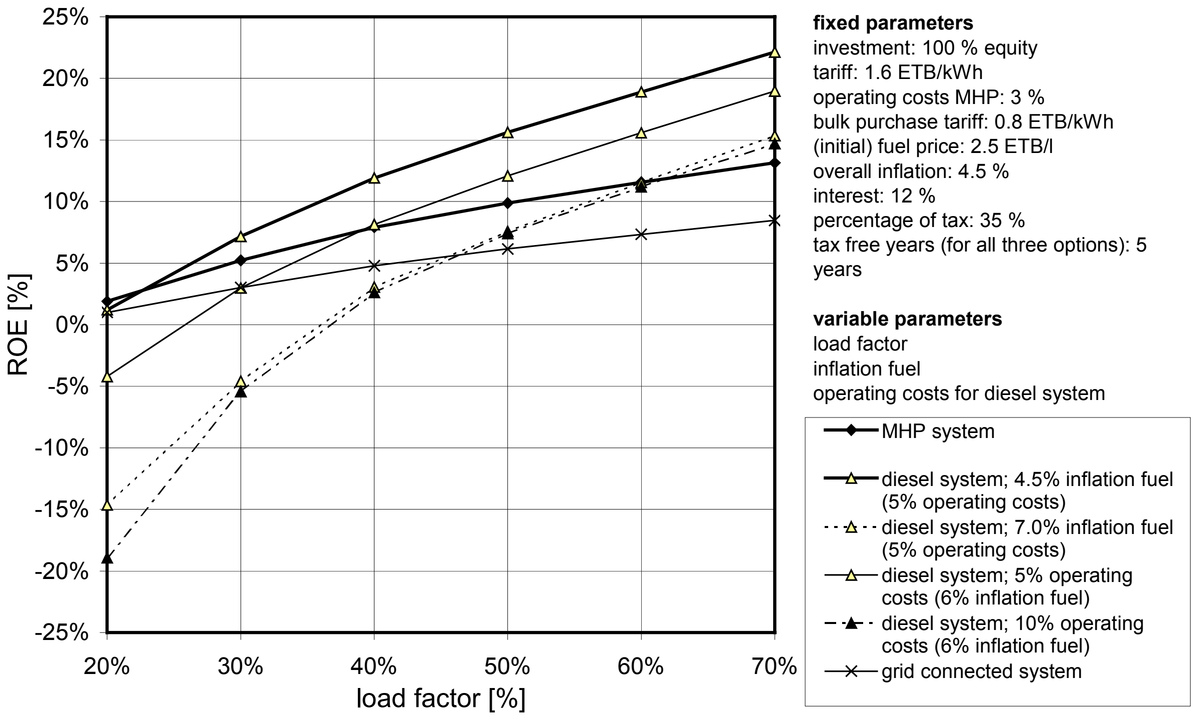



*Figure 6.5: Return on equity for a 50 kW system (100 % equity finance), depending on load factor, fuel price inflation and operating costs for the diesel system*

In Figure 6.5, the tariff is fixed at 1.6 ETB/kWh and the load factor is varied between 20 % and 70 %. An increasing inflation of the fuel price affects the profitability of the diesel plant more severely than an increase of the fixed operating costs. The curves prove competitiveness of the MHP system compared to the diesel system, up to a load factor of 40 % in case of a fuel inflation rate of 6 %, and even up to a load factor of 60 % if the fuel inflation rate is

7 % or if the operating costs of the diesel system are as high as 10 % of the investment costs.

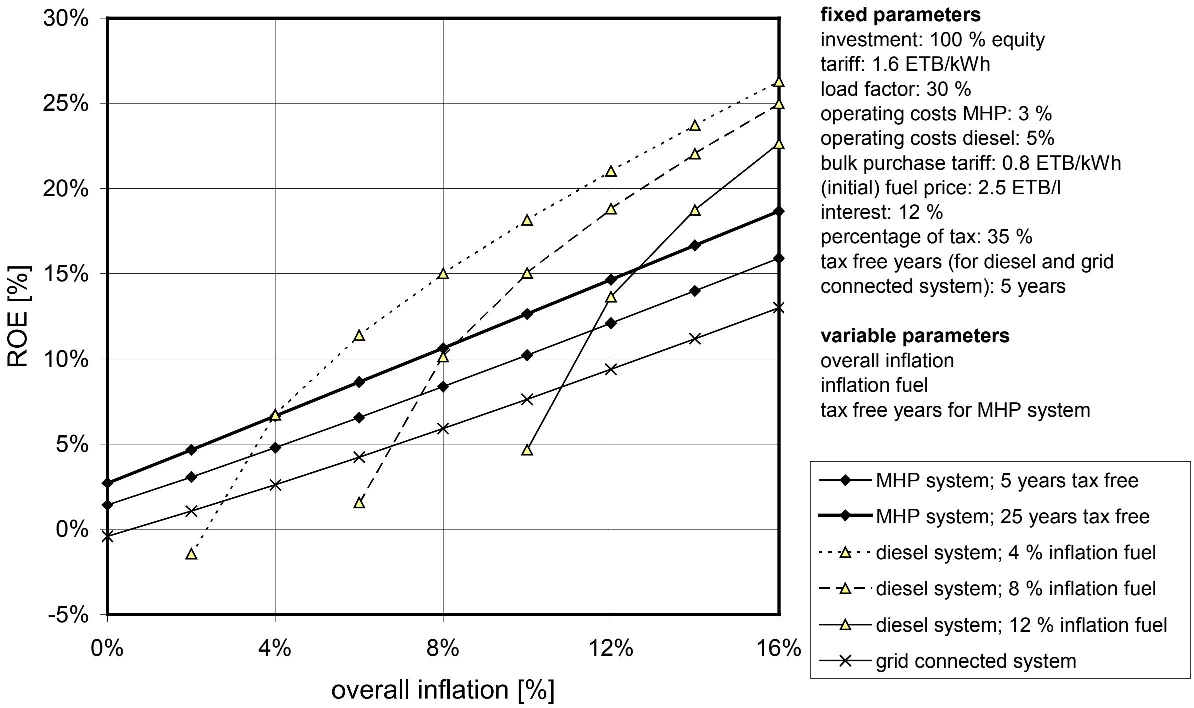



*Figure 6.6: Return on equity for a 50 kW system with 100 % equity finance, depending on overall inflation rate, fuel price inflation and the number of tax free years*

In general, increasing fuel prices tend to nudge the overall inflation rate in the country. Therefore, the effects of increasing overall inflation and increasing fuel inflation are analysed in Figure 6.6. An MHP system, which is granted 25 tax free years, is competitive to the diesel system as long as the overall inflation does not exceed fuel inflation, because the array of curves of the different diesel systems intersects the MHP-curve at those points, where the fuel inflation more or less corresponds to the overall inflation. In case that the fuel inflation is higher than the general inflation, the MHP system is even more profitable than the diesel system.

Since the overall inflation is not only related to the inflation of fuel but also to the interest rate, an additional calculation is effected (see Figure 6.7): Under the theoretical assumption of an equity to loan ratio of 50:50 the overall inflation and the tariff are varied. The inflation of the fuel price is supposed to be equal to the overall inflation. Based on a real interest rate of about 7 %, the market interest rate is calculated by adding the inflation (see Formula 4-35).

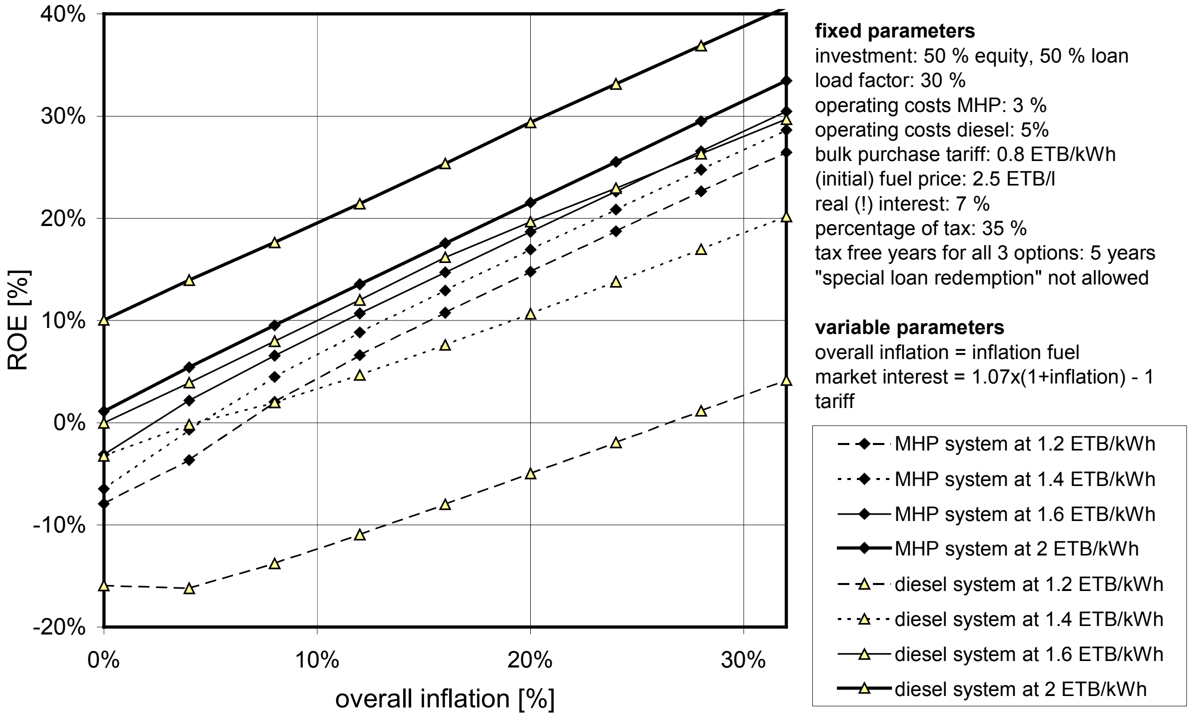



*Figure 6.7: Return on equity for a 50 kW system with 50 % equity, 50% loan finance, depending on overall inflation rate and tariff*

When the profitability of diesel and MHP system at the same tariff are compared in Figure 6.7, the distance between a pair of curves decreases up to a tariff of 1.6 ETB/kWh and then increases again. At a lower tariff MHP systems are more profitable and at a higher vice versa. The reason for that phenomenon is explained in section 6.3.2. If the shape of the curves within a "pair", meaning MHP and diesel system at the same tariff, is compared, a tariff of 1.4 ETB/kWh generates curves with most different gradients. When other boundary conditions, like tariff, step back in their importance, the increasing inflation rate itself comes to the fore and shows that high inflation rates favour MHP systems. Fast increasing prices foster high immediate investment instead of continuous investment over the time. Thus, MHP systems can be considered as built-in check against inflation because operating costs can almost be completely neglected. Only labour and maintenance costs increase at a rate depending on economic conditions. If the fuel inflation lags behind the general inflation rate, the diesel system quickly becomes more profitable (see Figure 6.6). But, here it is presumed that overall inflation and fuel inflation are directly coupled with each other.

The third type of financing to be considered for a 50 kW system is based on 30 % equity, 30 % loan and 40 % juissance capital, whereby interest rates for loan capital and periods of interest free years are varied, as presented in Figure 6.8.
Increasing the tariff from 1.4 to 1.6 ETB/kWh moves the ROE from negative to positive values for all MHP- and diesel-scenarios, whereby all diesel options reach higher values. The profitability of the MHP system can be improved by introducing an interest free period of 5 years and even more by reducing the interest rate from 10 to 5 % without interest free period, but it still remains below 10 %.

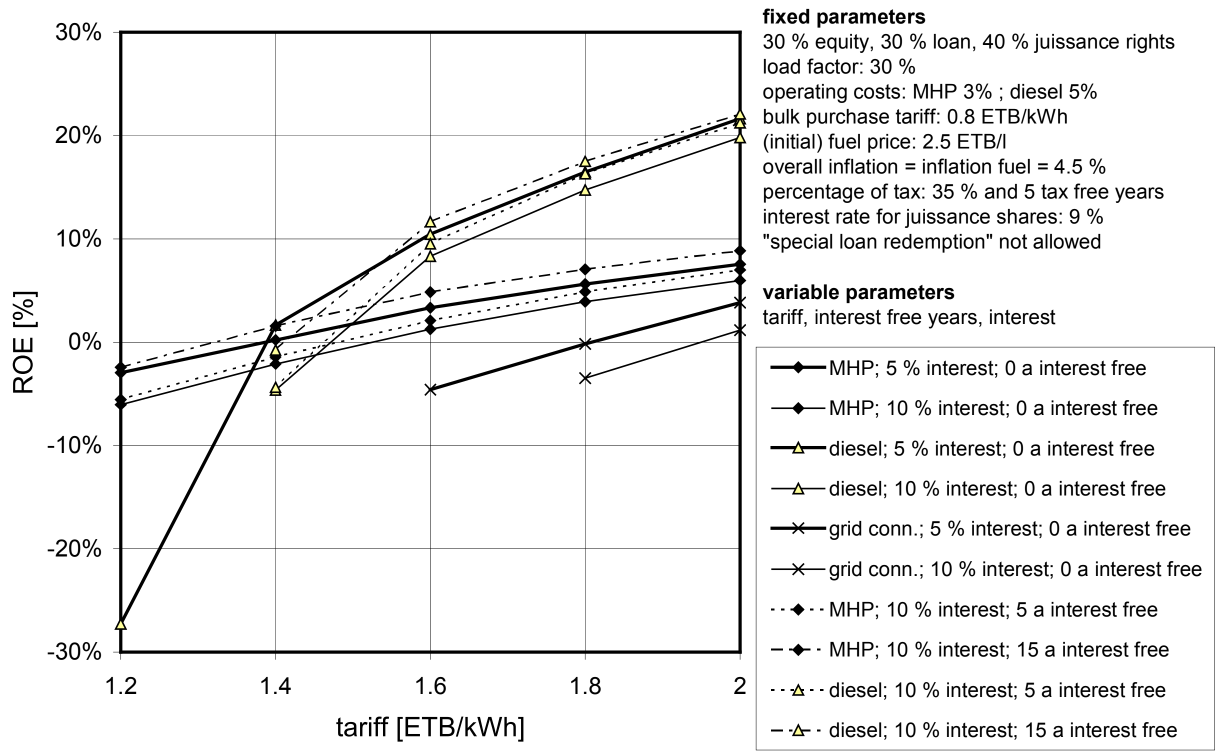



*Figure 6.8: Return on equity for a 50 kW system with 30 % equity, 30% loan, 40 % juissance finance, depending on interest rate for loans and interest free periods*

Finally, Figure 6.9 illustrates the effect of reduced dividend payment on juissance rights, admittedly under relatively "MHP-friendly" conditions: 25 tax free years for the MHP system, 6 % inflation of the fuel price and a moderate tariff of 1.5 ETB/kWh. For MHP, diesel and grid connection project it is assumed that during the first 10 years no interest has to be paid.

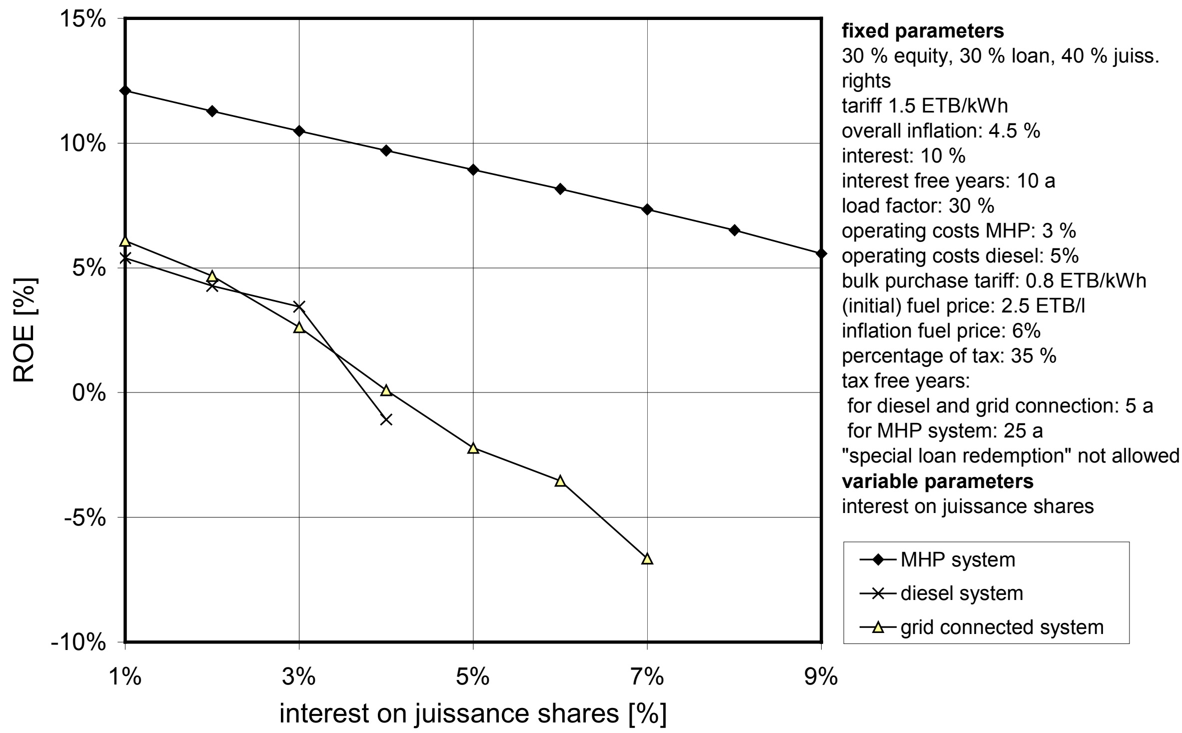



*Figure 6.9: Return on equity for a 50 kW system with 30 % equity, 30% loan, 40 % juissance finance, depending on the dividend payment on juissance rights*

Under these circumstances, the ROE for the diesel system decreases relatively quickly with increasing dividend payment, whereas the profitability of the MHP system remains much more stable. The diesel option continuously requires relatively high reinvestments. The higher the dividends, meaning more kWh's are paid on the juissance rights, the less kWh's remain to be sold regularly. Thus, less revenues are available to pay the mentioned investments and the more loan capital at high interest rates is required. The reduced cash finally entails lower profitability. For the MHP system, reduced revenues in the course of the project period, due to high dividend payments on juissance rights, are not as crucial because the critically high investment lies at the beginning of the operation period, whereas the reinvestments at later times are relatively low. A quick repayment of the initial high investment is facilitated due to 10 interest free years.

#### *6.3.4.2 Payback periods of a 50 kW system*

The length of the payback period is determined dynamically, assuming 100 % equity capital, meaning no capital costs. Yearly in- and outflows are cumulated up to the year of amortisation. Investors are interested in this figure because it indicates the duration of capital commitment. Table 6.9 illustrates, how the modification of tariff, load factor, number of tax free years and inflation rate influence the payback time. Unless otherwise specified, the calculations are based on a tariff of 1.5 ETB/kWh, a general inflation rate and inflation rate for fuel price of 4.5 %, a load factor of 30 %, 35 % income tax and 5 tax free years.

| | | **calculated payback period for...** | | |
|---|---|---|---|---|
| **modified parameter:** | | **MHP system** | **diesel system** | **grid connected system** |
| **tariff** | 1 ETB/kWh | 25 | > 25 | 25 |
| | 2 ETB/kWh | 17 | 14 | 19 |
| **load factor** | 20 % | 25 | > 25 | 25 |
| | 40 % | 17 | 15 | 20 |
| | 60 % | 14 | 8 | 18 |
| **number of tax free years** | 0 years | 21 | 23 | 24 |
| | 25 years | 18 | 16 | 22 |
| **inflation** | 2 % | 23 | 24 | 25 |
| | 10 % | 17 | 16 | 19 |
| | 20 % | 14 | 15 | 15 |

*Table 6.9: Payback periods in years calculated at varying boundary conditions*

The figures illustrate that the unfavourably long payback period of MHP projects can be reduced to some extent by means of a higher tariff or load factor. However, they are far from reaching the level of three years, as expected by some Ethiopian investors.

#### *6.3.4.3 Profitability of a 150 kW system*

For the 150 kW system the same three financing options as for the 50 kW system are studied. Due to economies of scale the investment costs per unit of installed capacity are much lower. Additionally, in a settlement of significant size, increased diversification of applications leads to a higher load factor so that the same plant capacity can supply more consumers. At a given tariff, the reduced investment costs and increased electricity sales entail higher profitability or a reduced unit price per kWh. Independent of the specific boundary conditions, the calculations prove ROE's of more than 10 % to be not exceptional for an MHP system of 150 kW. Whereas, a comparable ROE for the 50 kW system requires suitable conditions like a load factor of at least 50 %, high tariffs, redemption from income tax or relatively high inflation rates. The grid connected system can, despite equal investment costs[658], under non of the analysed conditions, compete with the MHP system.

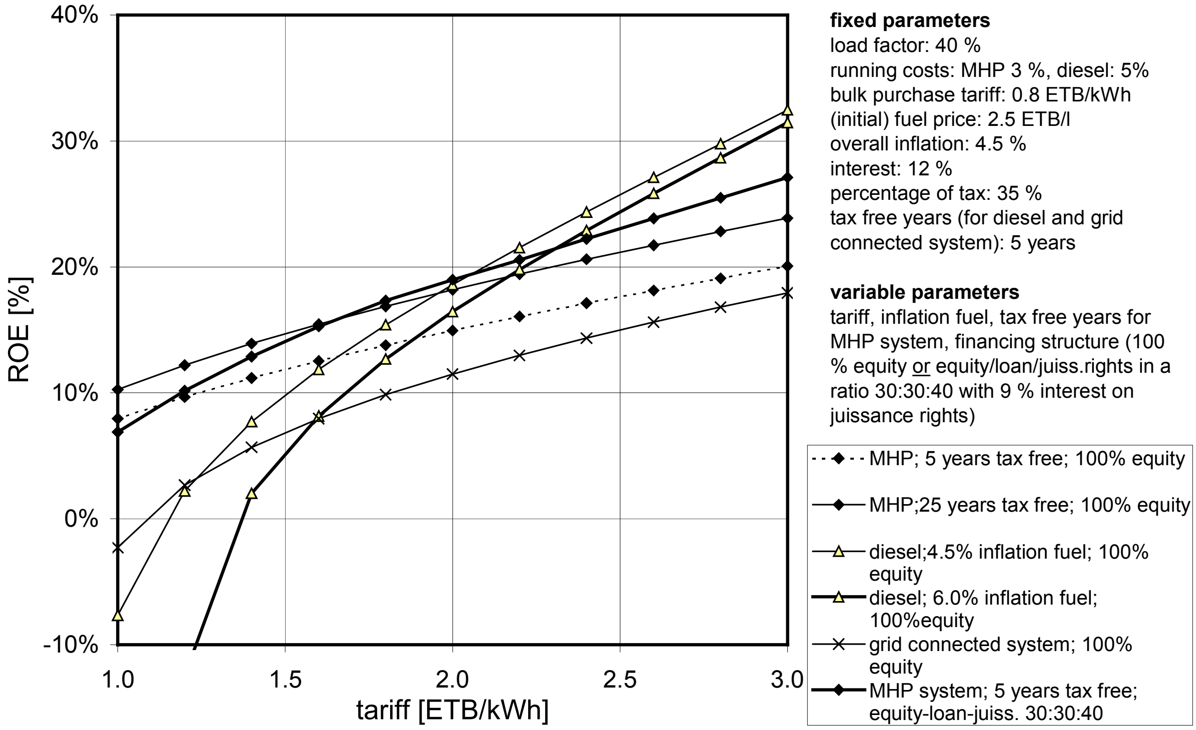



*Figure 6.10: Return on equity for a 150 kW system, depending on tariff, tax free years, inflation of fuel price and financing structure*

In Figure 6.10 the influence of the tariff is depicted. Under "normal" conditions the ROE for the diesel system outperforms the one of the MHP system at a tariff of about 1.7 ETB/kWh. At that point a profitability of about 13 % is reached by both options. Starting from the assumption of 6 % inflation rate for fuel, instead of 4.5 % and 25 tax free years for MHP, instead of 5 years the critical threshold tariff where the diesel system surpasses the MHP system moves towards 2.2 ETB/kWh, where a return of about 20 % is achieved. In case that the MHP system is not exclusively financed by equity capital but with a mixture of equity, loan and juissance capital of 30:30:40, the profitability rapidly increases from 13 % at a tariff of 1.4 ETB/kWh to 27 % at a tariff of 3 ETB/kWh. Beyond a tariff of 1.6 ETB/kWh it outbalances the positive effect of 25 years of tax exemption.

In Figure 6.10 and Figure 6.11 the two financing options "100 % equity" and "equity-loan-juissance capital ratio of 30:30:40" are considered. Especially for moderate tariffs of less than 1.2 ETB/kWh and moderate load factors of less than 32 % it takes some years until the loan is paid back. Only after that, the cash flow generates a higher ROE. Consequently, at moderate load factors and tariffs the influence exerted by varying equity-loan-ratio is relatively limited. The financing with credit capital becomes advantageous as soon as the return on total investment of the project exceeds the interest rate for loan capital, which is the so-called leverage effect (see also sections 4.10.4.1 and 5.3). In both figures the profitability of the project based on mixed financing (equity/loan/juissance) outperforms the profitability of the 100 % equity project at an ROE of about 8 - 9 %, which is very close to the assumed real interest rate of 7 %[659] for the loan.

For the profitability of the 50 kW plant the analysis mainly strove to detect under which conditions and privileges such as overall inflation, inflation of fuel, temporary redemption from interest and tax payment etc. the MHP system can keep up with the diesel system at all.

[658] The length of the transmission line is specified to be 33 km in order to achieve investment costs comparable to those of the MHP system of 150 kW (about 2.1 million ETB, see also Table 6.2).

[659] 1+real interest = (1+market interest)/(1+inflation) = 1.12/1.045

Whereas, for the MHP system of 150 kW a general competitiveness compared to the diesel system obviously reveals, even without extended tax redemption, interest free periods etc.. Observing this generally high competitiveness of bigger MHP systems, improved by mixed financing, the further analysis tries to optimise profitability and particularly address the impact of the financing structure.

Although higher load factors improve the profitability of MHP systems, the load factor looses its positive effect beyond a certain limit (see section 6.3.2). Figure 6.11 illustrates the variation of the ROE depending on the load factor. Again two financing scenarios, i.e. 100 % equity capital or 30:30:40 ratio of equity, loan and juissance capital, are considered.

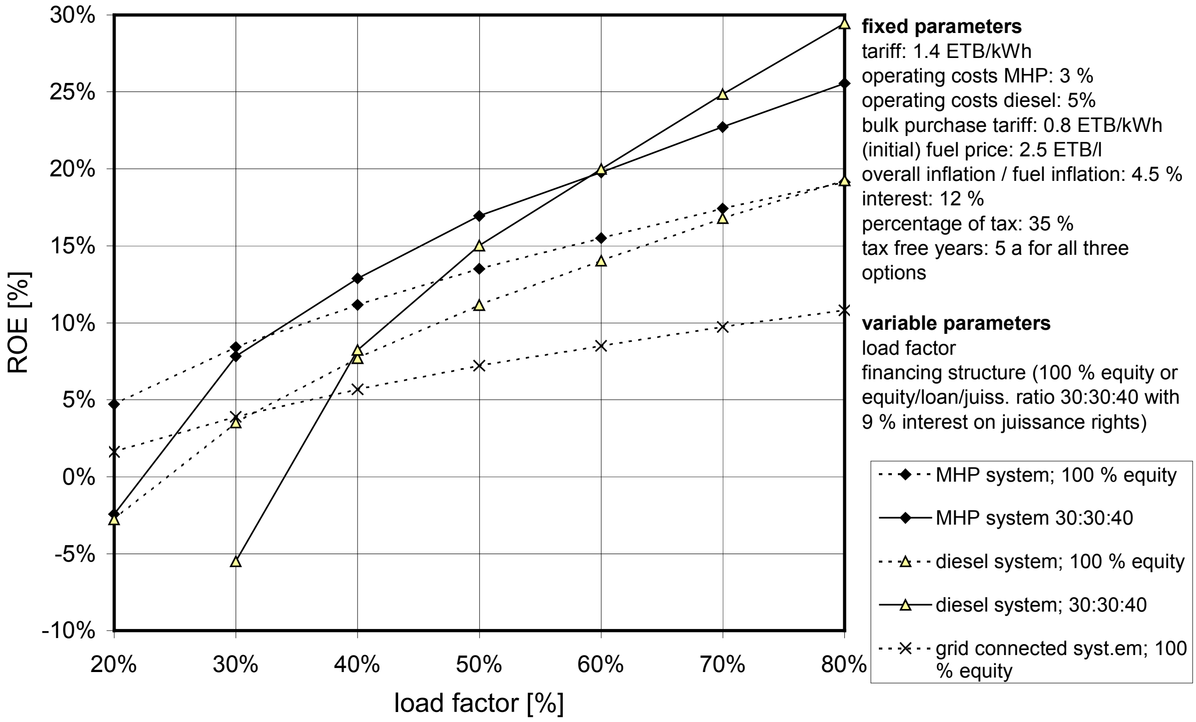



*Figure 6.11: Return on equity for a 150 kW system, depending on load factor and financing structure*

With pure equity financing the diesel system recovers the MHP system only at a load factor of 80 % (ROE of 19 %). If the financing resources are mixed up the diesel system catches up at a load factor of about 60 % (ROE of 20 %). Even with a tariff of only 1.4 ETB/kWh MHP plants are very profitable as long as importance is attached to a sufficiently high load factor.

Under Ethiopian conditions a financing mechanism using 50 % equity and 50 % loan capital is not very probable because of the problem of collateral. Nevertheless, this scenario is applied in Figure 6.12 to ascertain the effects of changing market interest. In respect of the mutual dependencies the market interest is calculated by adding the inflation to a real interest rate of about 7 % (see section 6.3.4.1). Overall inflation and fuel inflation are equated to each other. Figure 6.12 shows that the crucial tariff where the ROE values for MHP and diesel system reach an equal level, at a given inflation rate lies between 1.6 and 1.7 ETB/kWh. The lower the tariff the more pronounced the difference between the MHP- and the diesel-curve at growing inflation rate. For example, at a tariff of 1.2 ETB/kWh an inflation rate of 0 % the difference between the ROE's of MHP and diesel system is 8.6 %. At an inflation rate of 24 % the MHP system produces an ROE which is already 17.6 % better than the one of the diesel system. Thus, especially at lower tariffs the MHP system offers the better "built-in check against inflation", as already explained for the 50 kW system.

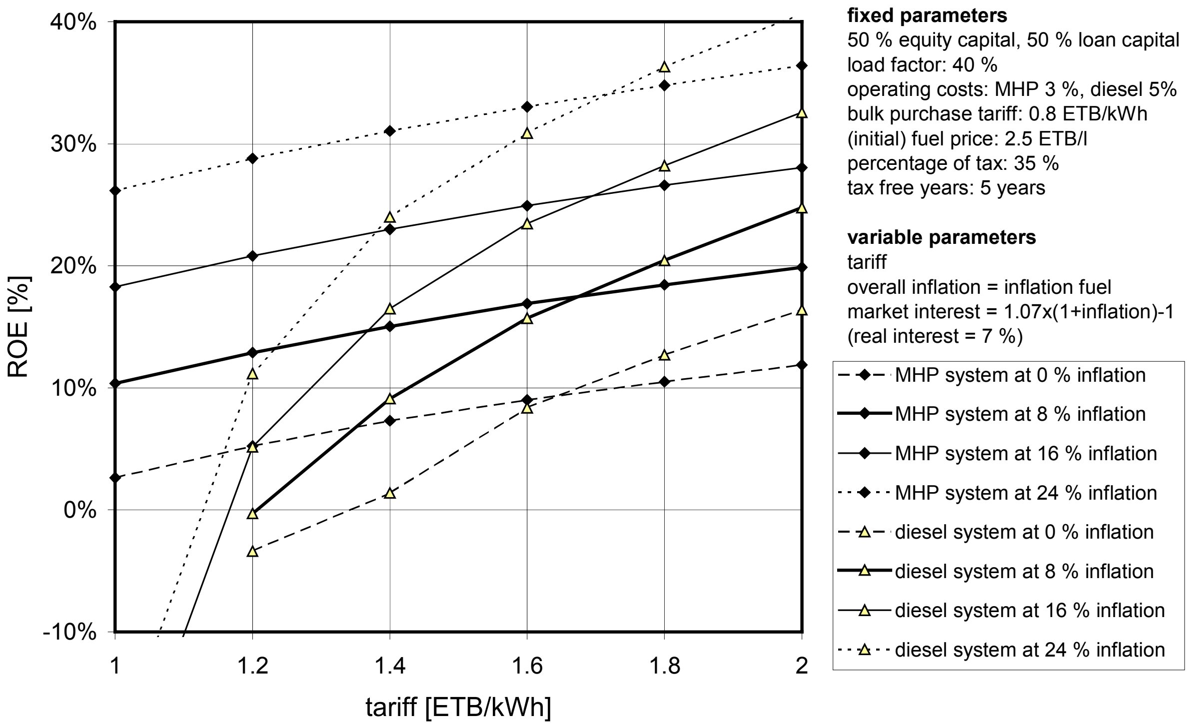



*Figure 6.12: Return on equity for a 150 kW system, depending on tariff and inflation*

Figure 6.13 shows that a real decrease of the interest rate, independent from the inflation, has a positive impact on the profitability. Different interest rates result from the variety of credit suppliers, like commercial and development banks[660], NGO's, international banks, local money lenders etc..

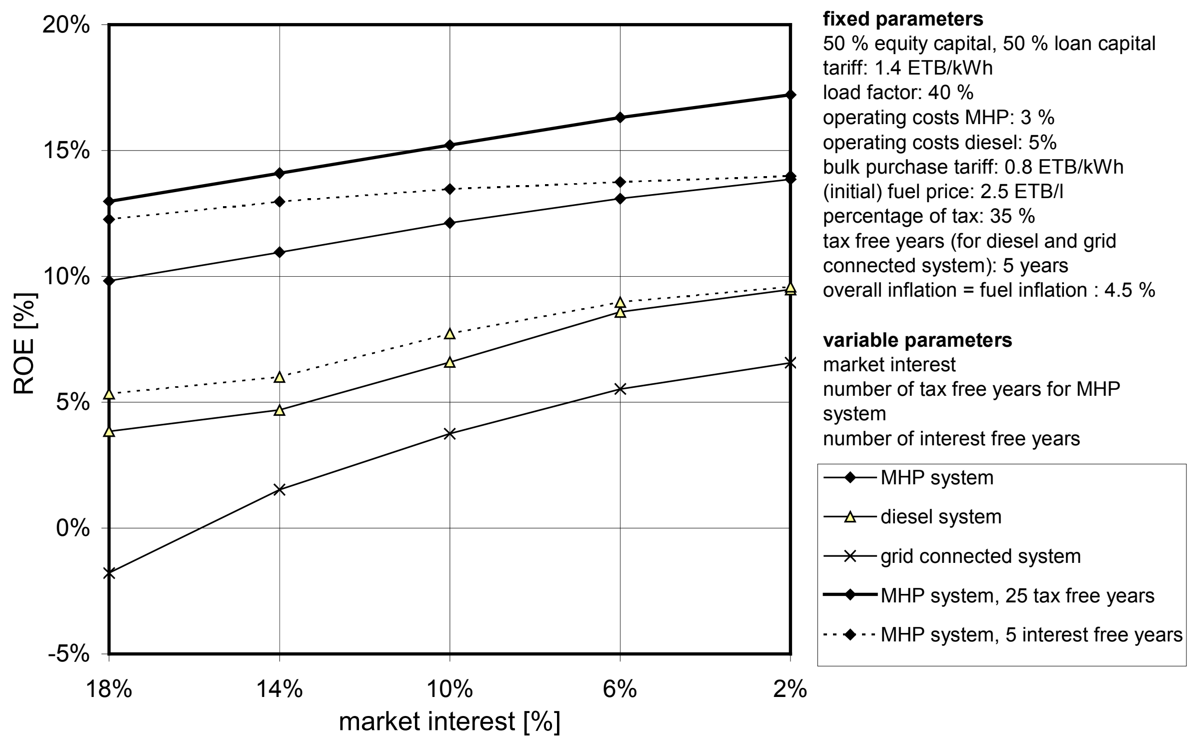



*Figure 6.13: Return on equity for a 150 kW system, depending on interest rate and number of interest or tax free years*

[660] interest rate for loans from Development Bank of Ethiopia DBE around 10.5 %

Figure 6.13 also illustrates that, as a matter of course, the higher the interest rate the more significant the positive influence of 5 interest free years on the ROE. For the MHP system the ROE is improved to a greater extent, but does not exceed the effect of 25 years of tax redemption.

The most optimistic, but still realistic, boundary conditions for an MHP plant are presented in Figure 6.14.

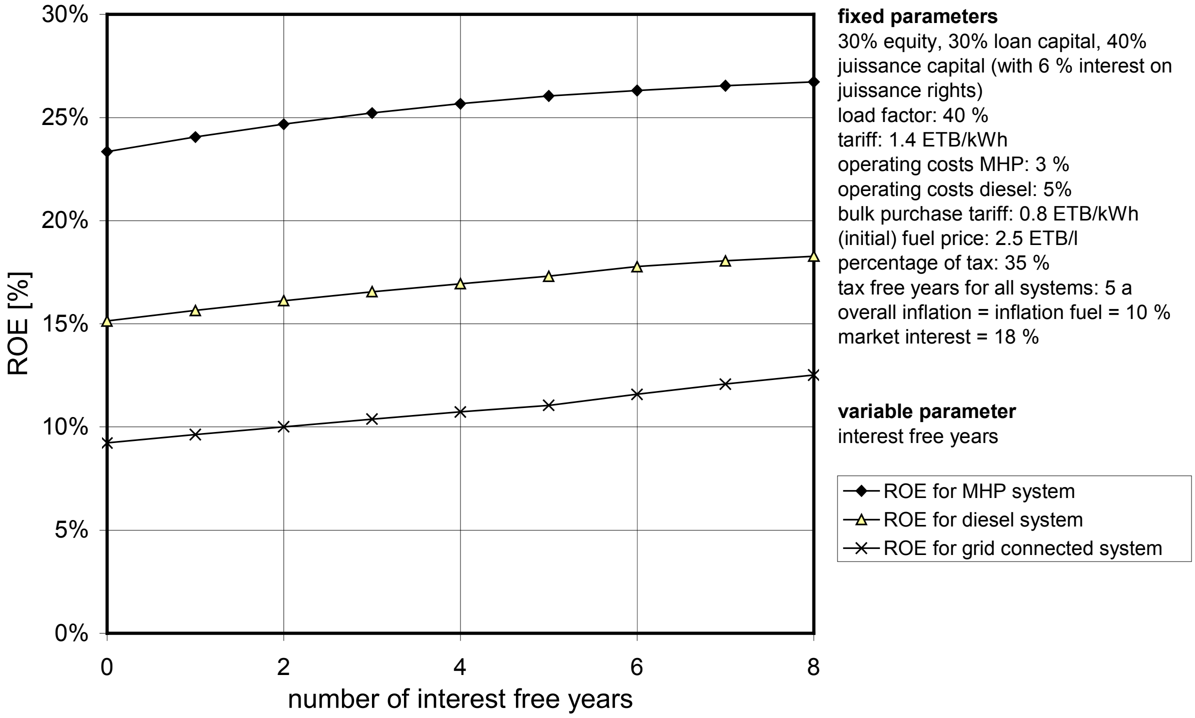



*Figure 6.14: Return on equity for a 150 kW system, depending on the number of interest free year*

Based on a mixed financing with 30 % equity capital from a private investor, 30 % quasi-equity capital in the form of juissance rights from the future customers and 40 % loan from a local bank, it is assumed that the inflation of the fuel price due to scarcity of the resource on the world market has reached 10 %. Then, the overall inflation in Ethiopia can be expected to reach 10 % accordingly. The banks would adopt the market interest rate to about 18 %, which still corresponds to a real interest of 7 %. The interest rate paid in kWh on the juissance rights is fixed at 6 % which is still very attractive because it is already inflation-adjusted. If the promotion of infrastructure projects, especially the commitment to renewable energy sources, leads to complete exemption from income tax, the ROE of the project reaches 23.4 %. In case that the credit disbursement is policy driven and granted at special conditions by a development organisation, development bank, NGO or similar, the ROE can be further improved by means of interest free years. The first 4 years are the most crucial ones. Project support by interest suspension during this period improves the profitability of the MHP system at about 2.5 %. After that the curve is flattening and 4 more interest free years only yield 1 % for the ROE.

#### *6.3.4.4 Payback periods of a 150 kW system*

Just as performed for the 50 kW system, Table 6.10 depicts the payback period variation for the 150 kW system at varying tariff, load factor, number of tax free years and inflation rate. Unless otherwise specified, the calculations are based on a tariff of 1.5 ETB/kWh, a general inflation rate and inflation rate for the fuel price of 4.5 %, a load factor of 40 %, 35 % of income tax and 5 tax free years.

| | | calculated payback period for... | | |
|---|---|---|---|---|
| **modified parameter:** | | **MHP system** | **diesel system** | **grid connected system** |
| **tariff** | 1 ETB/kWh | 18 | > 25 | > 25 |
| | 2 ETB/kWh | 12 | 8 | 14 |
| **load factor** | 20 % | 20 | > 25 | 24 |
| | 40 % | 14 | 15 | 18 |
| | 80 % | 9 | 7 | 13 |
| **number of tax free years** | 0 years | 14 | 15 | 18 |
| | 25 years | 12 | 14 | 17 |
| **inflation** | 2 % | 15 | 16 | 20 |
| | 10 % | 12 | 14 | 15 |
| | 20 % | 10 | 8 | 13 |

*Table 6.10: Payback periods in years calculated at varying boundary conditions*

High load factors as well as higher tariffs reduce the length of the payback period. As opposed to the 50 kW MHP systems the payback times can at least be approached to 12 years. Contrary to the general tacit assumption that diesel systems have much shorter payback times, the case study proves that MHP plants are quite competitive to diesel plants as far as this parameter is concerned.

### 6.3.5 Recommended financing and organisation

As amplified in section 6.3.3, raising of loans is limited by the provision of collateral and quite expensive; equity capital from private investor/s is limited by their high profit expectations. Equity capital from customers is limited due to their financial resources and the alternative interest rate on saving deposits, provided that all customers have access to a bank, which is by far not ensured in rural Ethiopia. Since interest rates for savings at commercial banks lie between 6 and 7 %[661] and after subtraction of inflation even as low as 1.4 to 2.4 %, dividend payment on juissance rights of about 4 - 8 % is already remunerative for customers.

#### *6.3.5.1 Expedience of juissance rights*

The participation of future customers by means of juissance rights requires a critical mass of customers. As indicated in section 6.1.1, an MHP system designed for a planning horizon of 25 years is quite oversized for the small initial number of consumers. This does not only question cost-efficient operation but also the issue of juissance rights. A small number of participants are not worthwhile the administrative effort if their capital contribution accounts only for a few percent of the total investment costs. Since the contribution of a single household is presumably limited, a substantial number of juissance right holders is required to achieve the positive effects described in section 4.6.3.2. For an initial investment volume of 1.524 million ETB[662] of the MHP system of 150 kW and the optimistic assumption that all connected households, which are about 80 at the start of operation, are willing to buy juissances rights, the specific juissance contributions per household, at a constant load factor of 40 %, are listed in the third column of Table 6.12. If only part of the customers are able or willing to participate, the financial burden would even increase. Yet, two aspects must be considered:

1. the development of the load factor and
2. the meaning of "specific consumption per official connection" (about 700 kWh/oc/y)

One of the special effects of the issue of juissance rights is the in-advance sale of electricity which reduces the market risk for the system operator. Therefore, the assumption of a relatively high initial load factor of 40 % for the 150 kW system is well-founded. Additionally, in-

[661] IMF, 1999, p.29, see also section 4.10.4.1
[662] taking into account only the first part of the electricity grid

creasing consumption entails a diversification of electrical appliances, due to different technical devices and time-variation. Thus, it is justified to **increase the load factor** over the project period of 25 years. So far, a constant load factor over the whole project period was applied (also for Figure 6.11). Yet, now, a continuously increasing load factor is assumed (see Table 6.11), which is not as difficult to achieve as a higher load factor from the beginning.

| | **50 kW system** | | **150 kW system** | |
|---|---|---|---|---|
| | *year 1* | *year 25* | *year 1* | *year 25* |
| **constant load factor** | retained at 30 % | | retained at 40 % | |
| total population | 500 | 1,142 | 1,850 | 4,224 |
| population supplied | 100 | 913 | 370 | 3,379 |
| households supplied | 21 | 194 | **80** | **720** |
| **increasing load factor** | 30 % | 60 % | 40 % | 77 % |
| total population | 1,100 | 2,240 | 4,000 | 8,130 |
| population supplied | 220 | 1,790 | 800 | 6,500 |
| households supplied | 47 | 381 | **170** | **1,380** |

*Table 6.11: Modified supply characteristics of the case studies at continuously growing load factor*

A higher load factor stands for a better plant utilisation meaning that a plant capacity of 150 kW serves an increased number of consumers, mainly because they consume at different times of the day.[663] Table 6.12 depicts the price of juissance rights resulting from the two scenarios of constant and increasing load factor.

| **percentage of total investment financed by issue of juissance rights** | **expressed as amount of invest-ment [ETB]** | **rounded charge per household [ETB/hh]** 2 hh's sharing 1 official connection; initially 80 hh's | **...in USD** | **rounded charge per household [ETB/hh]** 2 hh's sharing 1 official connection; initially 170 hh's | **...in USD** |
|---|---|---|---|---|---|
| | | **load factor 40 %** | | **load factor 40 % → 77 %** | |
| **10 %** | 152,400 | 1,900 | 230 | 900 | 110 |
| **20 %** | 304,800 | 3,800 | 460 | 1,790 | 220 |
| **30 %** | 457,200 | 5,700 | 700 | 2,690 | 330 |
| **40 %** | 609,600 | 7,600 | 930 | 3,590 | 440 |

*Table 6.12: Price of juissance rights per household (hh) depending on the percentage of juissance-financing at total investment costs and the development of the load factor*

A higher load factor allows to supply more customers, at constant investment costs, and thus to significantly reduce the price for juissance rights.

The **consumption figure of 700 kWh/oc/y** which underlies the calculations includes about 300 kWh/oc/y for domestic consumption and 400 kWh/oc/y for commercial and small industrial consumption. Both are, as a matter of simplification, apportioned to the so-called official connections, all with exactly equal consumption. As amplified in section 4.2.4, a forecast of total electricity consumption for a supply centre calculated on the basis of these specific consumption figures, which simultaneously takes into account the number of households per official connection, delivers a realistic estimate. 300 kWh/hh/y as domestic consumption corresponds to an initial load of 165 W, applied during 5 hours per day. The total of 700 kWh/oc/y can in some cases represent the consumption of two households and in others the

[663] Strictly speaking, the system components of the MHP plant do not have to be modified as long as the total plant capacity remains the same. Except the electricity grid, which actually has to be extended as soon as more customers are supplied. This effect is partly compensated due to the fact that an increased number of supplied households normally is accompanied by higher population density and thus reduced specific conductor length per connected household. For the diesel system the total investment costs increase more significantly than for the MHP system because the diesel system in step 2 and 3 must be designed for an increased number of consumers.

consumption of a commercial or industrial consumer. The assignment to the two customer groups results in 43 % of domestic and 57 % of commercial and industrial consumption. Starting from the theoretical assumption of "average customers" which in reality have to be subdivided into households, commercials and industrials the prices for juissance rights in Table 6.12 are applicable. Such an "average customer" would consume 350 kWh/y (700 kWh/y divided by two). Since a commercial or industrial customer in fact consumes more kWh per year, he is expected to accordingly spend a larger lump sum to buy juissance rights than a household. In general, a distribution of juissance rights more or less proportional to the specific consumption is preferable. Based on a tariff of 1.4 ETB/kWh, the yearly expenses for electricity of an average customer, as defined above, are 490 ETB. A juissance right at a price of 900 ETB costs less than twice the yearly expenses for electricity, which is still a substantial amount but payable at least by part of the population. As amplified in section 4.9.4.5, at present, the expenditures for fuel and power of the rural population is around 140 ETB/person/year resulting in 660 ETB/hh/year. According to another study (see Table 4.45), a connection fee of up to 750 ETB revealed to be affordable for the majority of potential customers, provided the possibility of instalment payment. Consequently, 900 ETB as price for a juissance right is still reasonable. Based on a realistic domestic consumption of 300 kWh/year, instead of the theoretical figure of 350 kWh/year, and a tariff of 1.4 ETB/kWh, Table 6.13 illustrates the return earned on a juissance right of different values at different rates of dividend.

| | **yearly interest payment at a dividend of:** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **3%** | | **5%** | | **7%** | | **9%** | |
| value of vested juissance right | [kWh] | in % of yearly consumption | [kWh] | in % of yearly consumption | [kWh] | in % of yearly consumption | [kWh] | in % of yearly consumption |
| 900 ETB | 19 | 6% | 32 | 11% | 45 | 15% | 58 | 19% |
| 1,790 ETB | 38 | 13% | 64 | 21% | 90 | 30% | 115 | 38% |
| 2,690 ETB | 58 | 19% | 96 | 32% | 135 | 45% | 173 | 58% |
| 3,590 ETB | 77 | 26% | 128 | 43% | 180 | 60% | 231 | 77% |

*Table 6.13: Dividend payment on juissance rights depending on value of juissance right and stipulated interest rate, assumed tariff: 1.4 ETB/kWh*

For example, at a stipulated interest rate of 7 %, a customer who bought a juissance right amounting to 900 ETB can in the first year of operation cover 15 % (= 45 kWh) of his total consumption with the dividend payment. Although the electricity tariff will increase due to inflation during the next years, the customer receives this constant amount of kWh's as dividend. In the specific case his investment of 900 ETB is recovered after 11 years.

Recapitulating, for the expedience of juissance rights two scenarios are imaginable. Under the pessimistic assumption of a **constant load factor**, even at a low percentage of juissance capital in total investment, the juissance rights are such expensive that a special mode of financing, like e.g. a micro-credit program has to be offered to the customers to enable them to participate financially. Spreading out the costs over longer periods of time is important especially for poorer households, who have short cash flow cycles. If a customer relies on refinancing by means of a micro-credit in default of equity capital, the interest rate must not exceed the interest earned on the juissance right. Preferably, a profit margin should remain for the consumer. Otherwise, the juissance right does not provide any incentive to him. Emanating from an **increasing load factor** and thus a larger clientele from the beginning, allows to reduce the price for juissance rights. More consumers also increase the project revenues and significantly improve the return on investment. Figure 6.10 indicates an ROE of about 11 % for an MHP system financed by means 30 % equity, 30 % loan and 40 % juissance capital, at a load factor of 40 %, a tariff of 1.4 ETB/kWh and 5 tax free years. Under the same conditions, the ROE, calculated on the basis of a load factor increasing from 40 % to 77 %, is found to reach remarkable 25 %. An improved return makes the project more attractive for well-funded private investors, enhancing the contribution of equity capital from their side. A reduced percentage of juissance-financing then again allows to lower the price of the individual rights to be issued. But, even a relatively minor participation of customers with quasi-equity capital is still worthwhile with regard to guarantee electricity sales. Experiences from other projects prove that a load factor increase to 70 % or even more is quite optimistic. Therefore, all possible means have to be adopted to optimise this parameter. Another possibility to lower the price of juissance rights, via an increased number of customers is to improve the **market penetration** from the beginning of operation. If the official penetration rate starts from 40 % instead of 10 % the specific contribution, in the form of juissance rights, can be reduced to a fourth !

### *6.3.5.2 Concluding recommendations for project financing and organisation*

Project profitability is one of the most crucial aspect, which decides on the attraction of different potential project partners. The project partners on their part decide on the financing structure, operation mode and organisational form (see also
Figure 5.1).

#### 6.3.5.2.1 MHP project with about 50 kW capacity

Even an **ROE of poor 10 %** can only be achieved under the following conditions:

1. with 100 % equity financing
   - at a tariff of 2.2 ETB/kWh and 25 tax free years
   - at a load factor of 50 % (5 tax free years, 1.6 ETB/kWh)
   - 8 % inflation and 25 tax free years (1.6 ETB/kWh)
2. with 50 % equity and 50 % loan
   - at 16 % inflation (1.4 ETB/kWh, 5 tax free years)
   - at 12 % inflation and 2 ETB/kWh (5 tax free years)
3. with 30 % equity, 30 % loan, 40 % juissance capital
   - at 9 % dividends on juissance rights, 10 % interest on loan, 15 years interest free and 2 ETB/kWh; ROE only at 8 % (!)
   - at 3 % dividends on juissance rights, 10 years interest free, 25 years tax free, 1.5 ETB/kWh; ROE of 10.3 %

This summary shows that MHP systems of around 50 kW hardly reach a return on investment of 10 %, which is below the opportunity costs for loan capital of about 12 %. In particular, such projects are far from the required ROE's of 20 - 30 % to attract private capital. Consequently, also the access to a commercial bank loan is restricted or even impossible. Different approaches can improve this unfavourable situation, as for example:

- **reduction of investment costs**, mainly for electrical components, by means of second hand equipment, employment of technical low-cost solutions, local labour etc.
- **increase of market penetration and load factor** by means of selective promotion measures such as sale of electrical appliances at reduced price, tax reduction for commercial and industrial enterprises, etc.

If the return on equity does not exceed about 20 %, despite tapping the full potential of possible measures, the project can be implemented as donor supported infrastructure development project. It either achieves a relatively small return, just covers the costs or even has to be subsidised. Even then, the **equity capital basis from users' participation** should be as broad as possible. Lacking capital has to be contributed as soft loan (or partly as grant) from an NGO, a development bank like the Development Bank of Ethiopia or a similar policy driven organisation. To facilitate customers financial and organisational participation the formation of a **modern co-operative or share company** is recommended.

In case that an investor's objective is not primarily the maximisation of ROE but self supply for his own business, e.g. an energy-intensive workshop, he can additionally sell surpluses to a neighbouring community. The problems of market introduction and general market risk are limited if the bulk of electricity is required for the investor's business. A precondition, however, is sufficient equity capital so that not more than about 30 - 40 % have to be covered by loan capital. For the project sponsor a crucial aspect is to keep control over the project. He is not expected to accept a co-operative organisation, where every member has one vote. In a share company he would be interested to hold the majority of common voting shares. Preference shares can be issued to customers without restricting the investor's control, because they are not associated with a voting right. For a *single* investor a **one man business**, without financial contribution of customers or other investors, and for *several* investors a **limited partnership** or **share company**, both with optional issue of juissance rights to customers, are recommended. Additionally required loan capital from a commercial bank can easier be acquired with the limited partnership due to its fully liable equity capital from the general partners. Whereas, in a share company, liability is limited to the assets of the company and every member is only liable to the extent of his share.

#### 6.3.5.2.2 MHP projects with about 150 kW capacity

An **ROE of even more than 20 %** is achieved under the following conditions:

1. with 100 % equity financing
   - at a tariff of 2.2 ETB/kWh and 25 tax free years
2. with 50 % equity and 50 % loan
   - at 24 % inflation and 1 ETB/kWh
   - at 16 % inflation and 1.4 ETB/kWh
   - at 8 % inflation and 2 ETB/kWh (ROE = 19 %)
3. with 30 % equity, 30 % loan, 40 % juissance capital (9 % dividends on juissance rights)
   - at 2.2 ETB/kWh (5 tax free years)
   - at 1.9 ETB/kWh and 25 tax free years
   - at 1.7 ETB/kWh, 25 tax free years and 4 interest free years
   - at 1.4 ETB/kWh, 5 tax free years, 70 % load factor (over the whole project period)
   - at 7 % real interest rate (10 % overall and fuel inflation, 18 % market interest), 1.4 ETB/kWh, 25 tax free years:
     - with 0 interest free years: ROE = 21.7 %
     - with 4 interest free years ROE = 23.74 %

The "non-profit" oriented participation of customers, as beneficiaries of social and economic advantages of electrification, significantly improves the profitability. From the point of view of the holders of juissance rights an interest of 9 % is still profitable, compared to even not inflation-adjusted 6 - 7 % interest on savings at commercial banks. Simultaneously their contribution of quasi-equity capital makes the project interesting enough to attract equity capital from investors. In case of outstanding bills or other financial problems with a customer, the power producer might withhold the juissance right, which gives him a certain security and lowers his financial risk. The issue of juissance rights reduces the required loan volume and due to a shorter loan payback time improves the general access to credits. Limiting factor for the banks are not the profitability but rather the provision of collateral, different risks and payback period.

With regard to the appropriate organisational form two main options are recommended:

- **limited partnership:** one or several individuals with different liabilities contribute equity capital and keep the major responsibility; customers' participation by juissance rights improve the profitability, due to lower dividends in kind; if additional loan capital is required limited partnerships have advantages over share companies (see section 6.3.5.2.1)
- **share company:** one or several project sponsors control the project by subscribing for the majority of investment capital in common shares; further interested investors can acquire preference shares; customers can participate with juissance rights.

# 7 PROSPECTS FOR INTERNATIONAL FINANCING SUPPORT

## 7.1 Flexible mechanisms and Global Environmental Fund

### 7.1.1 Description and status quo

Ethiopia having signed the United Nations Framework Convention on Climate Change (UNFCCC) in June 1992 and having ratified it in April 1994 is part of this international process and is consequently enabled to participate in the financing mechanisms. Amongst the so-called flexible mechanisms "joint implementation (JI)", "clean development mechanism (CDM)" and "emission trading (ET)", set up by the 1997 Kyoto Protocol to the UNFCCC, mainly CDM is of relevance for developing countries. The three mechanisms are defined as follows:[664]

- **joint implementation (JI)**: mechanism whereby a developed country can receive "emissions reduction units (ERUs)" when it helps to finance projects that reduce net emissions in another developed country, including countries with economies in transition. Some aspects of this approach are being tested as Activities Implemented Jointly AIJ.
- **clean development mechanism (CDM)**: enables "Annex I countries", i.e. industrialised countries and countries with economies in transition, to finance emissions-avoiding projects in developing countries and receive credit for greenhouse gas (GHG) emission reductions achieved. The certified emissions reductions (CERs) generated through CDM projects are transferred to the investing Annex I country thus helping the latter to comply with its Kyoto commitments by reduction of greenhouse gas emissions and simultaneously supporting non-Annex I countries to achieve sustainable development. Projects starting in the year 2000 are eligible to earn CERs if they lead to "real, measurable and long-term" GHG reductions, which are additional to any that would occur in the absence of the CDM project.[665] It is expected that a global trade with CERs predominantly favours the implementation of those projects which are the economically most efficient ones, meaning with the best cost-value ratio. An "Executive Board" is responsible for supervision, correct implementation of CDM, detailed modalities, issue of certificates, control of independent certifiers (accreditation of operational entities that will independently verify the emission reductions), registration of all CDM projects etc.. The mandate for the Executive Board has been established at COP 7. External verification and certification procedures by operational entities respectively an independent auditor are necessary to ensure the ecological integrity of the Kyoto Protocol. CDM is based on the same principle as JI with the important difference that in case of CDM the project is located in a developing country, meaning a Non-Annex-I-country. Since the latter do not have an obligation to limit or reduce their greenhouse gas emissions, there is a potential danger of inflating the overall emission targets. Additionally, CDM applying in countries which do not have targets or emission permits, these countries cannot trade in credits for reduced emissions, thus arising the question of flexibility for these countries ?[666] At least, one outcome of COP 7 was the permit of **unilateral CDM projects** without participation of industrialised countries.[667] In general CDM credits can be awarded for a period of 7 years with the option of two renewals and thus a total of 21 years or for 10 years without renewal option. A percentage of the proceeds from CDM projects is envisaged to be used to cover administrative costs of the Executive Board and to assist developing countries in

[664] http://unfccc.int/siteinfo/glossary.html and http://www.hwwa.de/Projects/Res_Programmes/RP/Klimapolitik/HWWA_3391_Hintergrund_Kyoto.htm downloaded 20/03/02
[665] Kelkar, Gupta, 2001 (http://www.teriin.org/climate/vpencorecdm.htm)
[666] http://www.enda.sn/energie/cc/cdmequity.htm
[667] http://www.gtz.de/climate/publications/klima-info/klima-info-cop7.pdf

meeting the costs of "adaptation" (= adaptation fund, see section 7.1.2) to the adverse consequences of climate change.[668] In the development process of CDM , there has been general agreement that "small scale" projects, particularly renewable energy projects of less than 15 MW, should receive a preferential treatment, like a fast-track approval, and take priority compared to bigger ones. But, what "preferential" means is still not yet defined. Simpler eligibility rules and approval modalities providing for competitiveness of small-scale projects will be finalised at the Eighth Conference of the Parties (COP 8) in New Delhi in October 2002.[669]

- **emission trading ET**: is only allowed between "Annex-B-countries" (= industrialised nations having agreed on emission targets), meaning that countries with emissions commitments may trade their emission allowances with others. Given the necessity to stay within their emission budgets, calculated in Assigned Amount Units (AAUs), the objective of ET is to reach global greenhouse gas emission reductions at minimal costs. Trading helps to reach this objective since specific reductions costs usually are significantly higher in countries with high environmental standards than in nations with low standards. The market price of AAUs will define if it is cheaper for a party to reduce emissions "at home" or to buy emission credits from other nations.

### 7.1.2 Institutions and their conditions of fund allocation

The Marrakesh Accords call upon Annex I and Annex II Parties (= industrialised countries, particularly the donor countries of the OECD) to provide funding to developing countries through the funds, mentioned below, increased GEF replenishment, and bi- and multilateral channels. The funds established to help developing countries address climate change and cope with its adverse effects are:[670]

1) The **"adaptation fund"** is to be financed from 2 % of the share of proceeds, meaning 2 % of the CERs generated by a project, on the CDM project activities. Its purpose is to help particularly vulnerable developing countries adapt to the adverse effects of climate change. This fund is to be operated by an entity operating the financial mechanism of the UNFCCC, i.e. the Global Environmental Facility GEF.[671]
2) The **"special climate change fund"**, also called "Convention Fund", is mainly filled by Annex II Party contributions to finance activities that are complementary to those funded by the GEF until now. This fund should support technology transfer, programs and measures in GHG emitting sectors, and diversification of economies that would be adversely affected by GHG mitigation.
3) The **"least developed country fund"** should support a work program for LDCs, including National Adaptation Programmes of Action (NAPA); the fund is to meet the agreed full cost of preparing NAPAs.

The second and third fund will be replenished through voluntary contributions from donors, whereas the first one is fed by the share of proceeds, as described. To encourage a greater flow of CDM projects to the LDCs, CDM projects in LDCs will be exempt from the share of proceeds for adaptation. The "adaptation fund" will be established under the GEF as a trust fund, projects will be implemented by the UN implementing agencies and the CDM Executive Board will manage the fund.[672] As far as the "special climate change fund" and the "LDC fund" are concerned, GEF has been invited to make arrangements for their establishment and to report to COP8.

The **Global Environment Facility (GEF)** is the interim operating entity of the financial mechanism of the UNFCCC; in addition it assists developing countries in meeting the objec-

[668] http://www.cckn.net/compendium/int_cdm.asp
[669] UNEP, 2002, p.10 (http://www.uneptie.org/energy/publ/cdm.htm)
[670] http://www.teriin.org/climate/cop7.htm
[671] http://www.cckn.net/compendium/int_financial_mechanism.asp
[672] http://www.netplus.ne.jp/~casa/paper/PRESIDENT'S%20PAPER.PDF

tives of the Convention on Biological Diversity (CBD). The conferences of parties (COP) to these two international treaties (UNFCCC and CBD) help guide GEF programs and projects eligible for funding in the areas of climate change, biological diversity, international waters, and protection of the ozone layer.[673] **Climate change projects** include amongst others the areas:

1) promoting the adoption of renewable energy by **removing barriers** and **reducing implementation costs** (program No. 6)
2) **reducing the long-term costs** of low greenhouse gas emitting energy technologies (program No. 7).

Thereby, the GEF provides financial resources, including for the following activities:
- establishing pilot or demonstration projects to show how adaptation planning and assessment can be translated into projects
- developing and implementing projects identified in national communications
- etc..

The World Bank (WB), the United Nations Development Programme (UNDP), and the United Nations Environment Programme (UNEP) are the **implementing agencies** submitting funding proposals to the GEF, each of the three institutions having its own special role to play in promoting projects and supporting the GEF process. Table 7.1 depicts their focal areas.

| | |
|---|---|
| **UNDP** | - capacity building programs and technical assistance projects; human resources development, institutional strengthening, and non-governmental and community participation<br>- contribution to the development of regional and global projects, drawing on its inter-country program experience |
| **UNEP** | - scientific and technical analysis and environmental management<br>- relating to global, regional and national environmental assessments, policy frameworks and plans, and to international environmental agreements<br>- establishing and supporting the Scientific and Technical Advisory Panel (STAP) |
| **WB** | - promotion of investment opportunities and mobilisation of private sector resources |

*Table 7.1: Implementing agencies submitting funding proposals to the GEF*[674]

The GEF as operating entity can[675]

a) either pay the agreed **full incremental costs** of projects to protect the global environment or
b) **complement regular development assistance**, offering developing countries the opportunity to incorporate environmentally-friendly features that address global environmental concerns or
c) pay the **agreed full cost** for items such as studies and communications, for which there is clearly no activity in the baseline.

"**Incremental** costs" means that the GEF eligible activity has to be compared to that of the activity it replaces or makes redundant. The difference between the two costs is the relevant costs which are accepted by the GEF. For example, if a country invests in a new power plant to promote economic development, the GEF may provide the additional, or incremental, funds needed to buy equipment for reducing the emissions of greenhouse gases. In this way, GEF funds normally cover only a portion of a project's entire costs. GEF pays the **full** costs for so-called "enabling activities" including the preparation of the national communications, required by the Convention, and the development of institutional capacity for developing and

[673] http://www.gefweb.org/participants/conventions/conventions.html
[674] http://gefweb.org/Documents/Instrument/instrument.html#N
[675] http://www.gefweb.org/council/council7/c7inf5.htm

carrying out strategies and projects. GEF projects in general average 5.5 million USD per project and take several years to implement. Due to the experience that smaller projects could benefit from abbreviated approval procedures and quicker and more efficient design and implementation, GEF created a program for **medium-sized projects (MSP) of less than 1 million USD**.[676] MSP are approved

- by the GEF Council as main governing body, meeting twice a year, and the Scientific and Advisory Panel (STAP), a group of 12 experts, in case of a project volume of **more than 750,000 USD** and
- by the implementing agency (WB, UNEP or UNDP) and the Chief Executive Officer of GEF in case of a project volume of **less than 750,000 USD.**

Additional funding, for example in "category A" of up to 25,000 USD, may be available through the GEF Project Preparation and Development Facility (PDF) to assist in preparing a project. Medium-sized projects should fulfil the following **criteria** for consenting appraisal:[677]

- being undertaken in an eligible country
- consistency with national priorities and programs and thus
- endorsement by the government(s) of the country(ies) in which they will be implemented
- addressing one or more of the **GEF focal areas**
- consistency with the GEF Operational Strategy, which provides for operational programs and short-term response measures
- seeking GEF financing only for the **agreed incremental costs** of measures to achieve global environmental benefits
- involvement of the public in project design and implementation
- attraction of **co-financing** from other sources

Especially the last aspect is of special importance, because projects which provide for a minimum of **co-financing** commitment equal to or greater than the amount of GEF financing are more likely and quicker to be approved than projects with minimal or no co-financing. Projects with no co-financing have to provide more detailed justification for GEF financing, since, in such cases, all costs would be incremental. In addition it is desirable that the design of the mechanisms chosen to remove the barriers should be **replicable to other markets**.

### 7.1.3 Ethiopia's activities so far

As a priority, GEF funding will be given to countries who comply with their obligations to prepare **national communications** containing:

1) national inventories of greenhouse gas sources and sinks
2) national programs containing measures to address: mitigation of net greenhouse emissions and adaptation to the predicted adverse effect of climate change.

Ethiopia at least fulfils the first condition, because the country participated in the "U.S Countries Studies Programme to carry out GHG Emissions Inventory, Vulnerability, Adaptation and Mitigation Assessments". The overall objective of the program is to develop inventories of the country's anthropogenic emissions of greenhouse gases, assessing its vulnerabilities to climate change, evaluating response strategies for mitigating and adapting to climate change, formulating national climate change action plans, and performing technology assessments. Ethiopia presented an **initial formal communication**[678] under the Enabling Activities Project and conducted an inventory of GHGs to identify the principal sources and to establish estimates of GHG emission from different sectors. The main GHG and precursors emitted in year 1990 are $CO_2$ (16,297 Gg), CO (7,611 Gg) ,$CH_4$ (1,586 Gg), and $NO_X$ (171 Gg) and $N_2O$ (4.7 Gg).[679] The results of the inventory of GHGs suggested that land use changes and forestry are the principal emission sources in Ethiopia while agriculture and

[676] http://www.gefweb.org/operport/msp/mspbroch.htm
[677] loc. cit.
[678] UNFCCC, 2001 (http://unfccc.int/resource/docs/natc/ethnc1.pdf )
[679] Tg $CO_2$ Eq = (Gg of gas) · GWP · (Tg/1,000 Gg); whereby Tg $CO_2$ Eq = tera grams of $CO_2$ equivalents, Gg of gas = giga grams of a gas and GWP = global warming potential (1 for $CO_2$, 21 for $CH_4$, 310 for $N_2O$ etc.)

energy are second and third respectively. Changes in land use and forestry are principally related to the expansion of agricultural activities, whereby other sources also mention exploitation for fuel wood and timber as further basic causes. Emissions in the energy sector are related to the combustion of products originating in petroleum and traditional biomass burning to meet the energy demand, particularly in the household and transportation subsector.[680]

The national inventory was submitted to the COP through the UNFCCC in October 2001 and was effected in support of preparation of a National Climate Change Action Plan. The initial formal communication proposes mitigation options like promotion of renewable energy, improving energy efficiency and conservation, e.g. through dissemination of mirt injera stoves and lackech charcoal stoves[681], improving forest management practices, etc.. It provides for a preliminary vulnerability assessment and adaptation options and summarises already existing environmentally oriented policies, strategies and action plans. One of the major overall objectives of these sectoral environmental policies is to foster hydropower and other renewable energies so as to minimise GHG emissions. In addition, amongst the options for financial support, technology transfer and project development in GHG mitigation not only the **promotion of renewable energy** but particularly the replacement of diesel generators by hydropower, mainly in urban centres, are explicitly mentioned.[682]

However, until now Ethiopia did not yet participate in the Support for National Action Plans SNAP and therefore did not yet explicitly formulate specific climate change policies, programs and measures in the form of a comprehensive National Action Plan.[683] A National CDM Authority evaluating potential CDM projects and implementing a standardised system to screen, evaluate and approve CDM projects is not yet defined. Although the international process gives general guidelines, for example on baselines and additionality, the host country itself must formulate the national criteria for project approval.

## 7.2 Other possible financing

Ethiopia being a member of the **International Finance Corporation (IFC)**, an MHP project with private sector participation running on a commercial basis can be eligible for IFC funding. As amplified in section 4.6.3.5 IFC support is limited by the following criteria:

- only equity finance possible, no loan !
- any kind of foreign involvement like foreign investor, foreign management etc. required
- financial volume > 200,000 USD[684] (officially > 1,000,000 USD in the REEF program and < 250,000 USD in the SME program, see below)

Besides being a multilateral source of loan and equity financing for private sector projects IFC also offers financial risk management products and intermediary finance. To ensure private sector participation, the maximum amount covered by the IFC is 25 % of the total estimated project costs, or, on an exceptional basis, **up to 35 %** in small projects. A number of special financing facilities have been created to support investments in renewable energy projects. These special funds focus in particular on projects that, because of their relatively small size, could not be financed directly by IFC. The two relevant funds are:

a) the Renewable Energy and Energy Efficiency Fund (REEF) and
b) Small and Medium-Scale Enterprise (SME) Programme

**REEF** is a private equity fund, together with a parallel debt facility and a GEF co-financing arrangement. It targets investments below 50 MW.[685] REEF actively seeks to make minority

[680] Ministry of Mines and Energy, 1994 (http://www.gcrio.org/CSP/pdf/ethiopia_inven_vuladap_mitop.pdf) and http://unfccc.int/resource/docs/natc/presentations/ethincpresent.pdf
[681] http://www.worldbank.org/html/fpd/esmap/workshop_addis/improvedstoves.pdf
[682] UNFCCC, 2001, p.102 (http://unfccc.int/resource/docs/natc/ethnc1.pdf )
[683] loc. cit. p.90
[684] personal communication: Danino (IFC) 03/2000

equity and quasi-equity investments in profitable, commercially viable private companies and projects in sectors that include on or off-grid electricity generation primarily fuelled by renewable energy sources, energy efficiency and conservation, and renewable energy/efficiency product manufacturing and financing. The REEF considers investment in projects with total capitalisation requirements of between 1 million and 100 million USD.[686] Based on the assumption that the costs per installed kW of bigger MHP plants in Ethiopia are around 1,700 USD/kW (see Table 6.2) only systems of capacities of at least 600 kW meet the IFC criteria. Alternatively, two or more smaller projects must be bundled to exceed the minimum volume. In general, REEF's investments may take a variety of forms including common and preferred stock, partnership and limited liability company interests. Equity transactions are typically structured so that the entrepreneur retains the majority of shares and/or management of the company.

The second option, the **SME** program, is a GEF-financed fund, meaning that besides directly providing grants, the GEF facilitates other bilateral, co-financing, and parallel financing arrangements. Thus, GEF promotes the leveraging of private-sector participation and resources. The SME program supports smaller scale ventures in renewable energy through financial intermediaries (FIs). SME's are defined as viable businesses with less than 5 million USD in assets. An independent power producer, acting as an SME addressing the climate change objectives of the GEF can receive a loan from a so-called Intermediary. The latter receives a long-term low interest rate loan of from 0.5 to 1 million USD (for up to 10 years at an interest rate as low as 2.5 % p.a.). Intermediaries use the loan proceeds to finance, with debt or equity. The maximum amount of SME Program funding an Intermediary may advance to any one SME or SME project is **250,000 USD**. Calculating again with investment costs of about 1,700 USD per installed kW of MHP capacity, this amount corresponds to a system with a capacity of around 150 kW, which makes it a very suitable way of financing.

Summarising, among the IFC portfolio either the SME program or the REEF program can be applied for. Whereby, for the SME application a financial intermediary is required and the REEF is likely to be a potential option only in case of project bundling. Although in general IFC prices its finance in line with the market, the obvious advantages are:

- the reduction of the problem of collateral
- the facilitation or support to access to international capital markets
- the reduction of risk for foreign investor due to project approval by IFC

Besides these IFC options, the **Prototype Carbon Fund (PCF)** can also be relevant for MHP financing. This fund was set up by the World Bank to demonstrate how the CDM can effectively support developing countries to meet their sustainable development objectives by promoting the transfer of finance and climate-friendly technology. As one of the entities serving the purposes of the Kyoto Protocol the PCF started its operations in April 2000. As opposed to GEF which is essentially supported by public funds, even though it is also interested in mobilising private sector financing, the PCF heavily relies on private sector funding. Although the PCF contribution to a project in general is between 3.6 - 18 million USD,[687] it can also support smaller projects that require less than about 3 million USD in carbon finance, if they are contracted as sub-projects through established intermediaries. An established intermediary is a broker, a private sector project developer, a private equity fund, a commercial bank, or any other financial intermediary that has a demonstrated track record in identifying and closing deals, which support the energy technologies eligible for PCF financing. That means, PCF's strategic objectives for its financing of small-scale projects of less than 1 - 3 million USD in carbon finance, and in the **100 - 1,000 kW range** include the demonstration of environmentally credible, streamlined procedures for CDM compliance and require a **financial intermediary**.[688]

[685] http://www.ifc.org/enviro/EPU/Renewable/renewable.htm
[686] http://www.ifc.org/enviro/EPU/Renewable/REEF/reef.htm
[687] corresponding to "no less than approximately 2%, nor more than approximately 10% of the fund's assets", see http://prototypecarbonfund.org/router.cfm?Page=ProjSubmit
[688] loc. cit.

## 7.3 Relevance for the Ethiopian energy sector and contribution of the present study

Ethiopia having ratified the relevant treaty is eligible to propose climate change projects. Energy efficiency, renewable energy, and forest sink projects can qualify in the CDM. A project to be implemented in Ethiopia should integrate the following overall **objectives**:

1. avoidance of future increase of $CO_2$ emissions by means of renewable energy resources
2. reduction of deforestation, leading to extended carbon "sinks"
3. development of a model for replication of renewable energy technologies.

MHP technology is predestined to play a crucial role in this context. It contributes to climate change mitigation by $CO_2$ substitution since it replaces fossil fuel combustion in diesel gensets. Given the fact that cooking with open fire is one of the very energy-intensive appliances in rural households, in the long run electrical cooking, for example based on hydropower, should be envisaged. However, in the short term, energy saving stoves are the most appropriate, competitive and thus realistic solution. Significant slowdown or even prevention of deforestation and thus land degradation caused by overexploitation of biomass can only be achieved by means of **combined measures** like MHP as renewable resource for electrical appliances and energy saving stoves for reduced biomass consumption.

Generally spoken, with regard to an application for financial support, for example at GEF, two different paths can be stricken, namely either:

1. a conceptual project proposal, meaning an operational program to remove barriers, targeting at a structural change in limiting boundary conditions of the present Ethiopian energy market or
2. one or several concrete MHP projects at specific site(s), directly contributing to measurable GHG emissions reduction to obtain CERs and / or to promote MHP technology via pilot projects.

It is to be expected that a **barrier removal project** can be classified as enabling activity for which the agreed full costs can be funded as grant by the GEF. It can be approved as a "Medium Sized Project" (< 1 million USD)[689] or in case of a very small project it is funded by means of the "Small Grants Programme" (< 50,000 USD).[690] The second option however, the implementation of a **concrete MHP system**, can be understood as a typical CDM project for which merely the full incremental costs are paid. Further support for a concrete MHP project can be achieved through equity of up to 35 % by the IFC, either in the REEF or in the SME program. Whereby SME as well as the small scale projects of the PCF require a Financial Intermediary.

In fact, the two approaches can not replace each other. On the one hand, assistance in capacity building is required to ensure creation of viable CDM projects, including calculation of baselines, monitoring and verification. On the other hand, immediate project implementation will, due to gathered experience, lower the risks and provide economies of scale. After a technology-penetration phase commercial viability can be achieved thus facilitating broader CDM participation. In the following two sections the two project options are illuminated in-depth.

### 7.3.1 Barrier removal project

As amplified in the Operational Program Number 6 of the GEF[691] one of the expected outcomes of a proposed project is the increase of the market share for the renewable energy technology in a specified application. Therefore in any given market, **all major barriers must be effectively removed** for this technology to be available on a sustainable basis. To avoid

[689] < 750,000 USD directly to be approved by the implementing agency (World Bank, UNDP, UNEP) and the Chief Executive Officer of GEF
[690] http://www.undp.org/gef/sgp/main.htm
[691] http://www.gefweb.org/Operational_Policies/Operational_Programs/OP_6_English.pdf

a merely temporarily or partially surmounting of barriers a potential project proposal should demonstrate:

- how key barriers are interrelated
- how they can be removed; technology demonstration and provision of hardware alone are not sustainable
- how distortion of competition, for example effectuated by subsidised "demonstration projects", can be avoided; importance of open bidding process
- how appropriate cost recovery, development of institutional capacities etc. can be achieved after GEF support has ended.

The present study with its comprehensive analysis of key barriers, which encumber the dissemination of MHP technology in Ethiopia, provides the **basis for the preparation of such a GEF project proposal**, meticulously tailored to the specific legal, political, economic and institutional Ethiopian context. A project proposal aiming on a superior level at the promotion of MHP technology mainly covers the objectives of GEF operational program 6 for removing barriers and reducing implementation costs.[692] Program 7 for reducing long-term costs of the renewable energy technology is not as much applying because the long-term costs of MHP are, as opposed to investment costs, not an inhibiting factor. Insofar as program 7 is designed to reach commercial competitiveness of the MHP technology, for example by achieving economies of scale in manufacture of components, it is also of relevance to support the dissemination process.

A project proposal targeting at "barrier removal" should include the following measures:

- **financing sector**: capacity building for banks and other financial institutions with view to rating MHP projects, procurement of refinancing and collateral; support for the introduction of "innovative financing", concessional[693] and contingent lending, trust and revolving funds, temporary equity finance etc.
- implementation of **demonstration plants** (see also section 7.3.2) with local enterprises at real market conditions, whereby external collateral or loan support is required
- legal and policy sector: analysis and counselling with regard to options for **investment incentives**, like tax and duty reductions, in co-operation with the Investment Authority, Chamber of Commerce and policy makers, as amplified in section 8.3.1
- capacity building for **local consultants** for appropriate MHP planning to reduce planning and implementation costs
- **"institutional guidance"** to clarify the competence for water rights and to elaborate a simplified and workable licensing procedure, which includes all requirements for MHP systems, e.g. facilitated by the Ethiopian Investment Authority
- establishment of a National **CDM Authority** evaluating potential CDM projects and implementing a standardised system for project approval
- development of **information structures** accessible to private investors and institutions promoting MHP technology and explaining potential investment opportunities
- analysis of substantial **cost reduction potential** for MHP plants in Ethiopia, for example as part of demonstration plant projects

### 7.3.2 Direct implementation of MHP project(s)

Another option for potential projects is the implementation of concrete MHP systems. The CDM, as mentioned above, is destined for countries which by definition -"developing"- are expected to increase their emissions in the immediate future. For this reason, unlike JI, the CDM can only operate with net emission limitations or future avoided emissions. Especially for projects aiming at the receipt of certified emission reductions (CERs), a decision support model developed on the basis of the present study is very useful to facilitate the calculation of total unit costs per kWh and the profitability of different technological options. To demon-

[692] http://www.gefweb.org/Operational_Policies/operational_programs/operational_programs.html
[693] favourable terms on interest rates maturity grace periods

strate the GHG mitigation effect of an MHP project, a **baseline scenario** has to be developed, i.e. the implementation of an electricity system based on a diesel genset. Apart from investment cost estimations for both options, achievable emission reduction, which is the difference in GHG emission between "baseline" and "project" scenario, have to be calculated. The analysis of associated $CO_2$ emissions leads to a ratio of the difference in costs and difference in $CO_2$ per kWh thus yielding the incremental cost of $CO_2$ emissions reduction per unit of electricity sent out. The sensitivity of these costs-per-ton of avoided GHGs with regard to a variation of discount rate, price of fuel etc. can easily be analysed by means of a DSS tool, similar to the analysis illustrated in chapter 5. This approach also reveals if carbon offset funding brings projects, which are only near-commercial, to viability by generating additional revenues from the sale of carbon credits. The value of CERs depends on the price which can in future be achieved for GHG reductions. Values in literature vary between 0.5 - 20 USD per ton $CO_2$. The price is determined by the total tradable CERs, meaning supply and demand for CERs on the global market. In general, prices increase as the sales volume is reduced and the number of buyers is increased. Due to the withdrawal of the USA from the Kyoto protocol[694] and the so-called "hot air" of Russia and Ukraine[695] presently a price of about **2 to 4 USD per ton $CO_2$** has to be anticipated.[696] Other sources assume a market price of about 1 - 2 USD per ton of $CO_2$, whereby also buyers willing to pay more than this, but no more than 5 - 6 per ton of $CO_2$[697] are mentioned. An IFC study states that the indications from trades that have taken place so far are mixed but suggest a price in the range of 0.5 to 2.25 USD per ton of $CO_2$ equivalent.**[698]** Since the calculations of reduction potentials always refer to baseline scenarios, countries like China and India with higher present energy consumption per capita and inefficient usage of local fossil fuels are privileged. In such countries the reduction of $CO_2$ emissions is more obvious than in Ethiopia, where the reduction must be based on an expected *increase* of energy demand. To improve this situation, CDM must give equal attention to avoided future emissions as emission reductions. A "baseline handbook", which is in the pipeline, is expected to facilitate the definition of baseline scenarios in such a way as to take into account these expected future emissions but also in a way to achieve approval by independent certifiers.[699] Concluding, several dependencies can be recapitulated:[700]

- the project appraisal depends on the amount of achieved GHG reductions
- the price in USD for an obviated ton $CO_2$ depends on the "market situation"
- the credibility of credits gained through CDM depends on the chosen baseline and verification methodology
- due to the fungibility of credits any change in the value of ERUs on the emission trading market will have an impact on the value and demand for CERs and consequently the demand for CDM projects which generate them.

In general, MHP projects in Ethiopia can in many respects **fulfil essential conditions for approval**. A potential MHP project design can easily fulfil the GEF term of being consistent and mainstreamed with ongoing implementing agency programs, because it ties in with previous and ongoing World Bank activities in the country, targeted on cost covering electricity tariffs, rural electrification, restructuring and liberalisation of the energy sector, e.g. allowing for independent power producers. National policy and development priorities are in conformity with and supportive of this World Bank strategy, so that MHP projects for cost recovering rural electrification can be regarded as "country driven" as it is equally required by the GEF terms. In addition, the introduction of MHP technology can guarantee a catalytic effect.

[694] United States are estimated to account for 50 % to 70 % of the total Annex B emission reduction requirements. In the absence of the United States as a buyer aggregate demand for emission credits is significantly lower, so implementing the Kyoto Protocol without the United States has strong implications for the CDM.
[695] "Hot Air" are emission reductions, resulting from the economic decline in Russia, Ukraine and other Eastern European countries. In these countries today's emissions are 20-30 % lower than 1990.
[696] http://www.gtz.de/climate/deutsch/klimainfo5.htm
[697] http://www.ifc.org/enviro/EPU/Climate/develop/develop.htm
[698] Armstrong et al., 2000, p.12
[699] http://www.gtz.de/climate/deutsch/cdm.htm
[700] http://www.enda.sn/energie/cc/cdmequity.htm

The present study proves that MHP projects, under certain boundary conditions and after a start-up phase, are profitable investments and thus can leverage additional financing from other sources. "Public involvement" which is also one of the crucial requirements for funding can be provided by participatory organisational forms for example the juissance rights concept (see sections 4.6.3.2 and 4.7.3). MHP technology as such represents a replicable and sustainable technology. Once it proved to be cost-effective it is predestined to wider application. As amplified in section 4.9.4.5, the willingness to pay for electricity is high, although the gross domestic product GDP in Ethiopia is extremely low. Even in remote areas and non-electrified towns and villages, profit-oriented markets for the supply with electric energy can be identified. This and the positive social, economic and environmental impacts of the technology are aspects which justify a financial support by CDM. Summarising, the following conclusions are drawn with regard to CDM financing of MHP projects in Ethiopia:

**crucial requirements:**

- "National Agency" for CDM project approval has to be defined
- "fast track approval procedures", to be finalised in November 2002, required for MHP projects
- definition of baseline scenario should be standardised
- investors and "CER dealing" required
- emphasis of renewable energies, especially MHP, in future guidelines for "National Adaptation Programme for Action" for Ethiopia

**opportunities:**

- MHP projects are well compatible with CDM criteria for approval
- they correspond to the host country's sustainable development priorities
- bundling of several projects reduce the transaction costs[701]
- according to the COP 7 resolutions cooperation with an industrialised country but also unilateral CDM projects are possible
- GEF support through meeting the additional / incremental cost is a competitive advantage of MHP systems, compared to diesel systems
- GEF leverages private investments by underwriting the risk of investments in MHP technology, through investment guarantees or venture capital; certification process of CDM can assure investors' confidence in project viability[702]
- after initial support, economic viability of MHP projects is expected and thus provide the opportunity for IFC participation or other private sector participation

[701] approximately 50,000 USD is considered the current minimum for non-reducible procedures; a minimum of 100,000 t $CO_2$ reductions over the lifetime of a project is recommended. http://cdmsusac.energyprojects.net/Links/investor_workshop/inv_workshop_proceedings.pdf

[702] Humphreys et al., 1998 (http://www.enda.sn/energie/cdm2.htm)

# 8 CONCLUSIONS AND PROSPECT FOR FUTURE DEVELOPMENT

The analysis of aspects which influence the successful implementation of MHP in Ethiopia led to the development of a comprehensive information basis. Combined with the insights on interrelationships between the different aspects, suitable fundamentals for the implementation of a decision support tool are available now. An interdisciplinary planning approach starting from this knowledge base is expected to facilitate successful implementation of MHP projects. The main findings and conclusions, but also unsolved problems (italicised), are summarised in section 8.1. In section 8.2, the potential and the limits of a decision support tool are adumbrated. And finally, in section 8.3, essential recommendations, mainly with regard to customers' (financial) participation, investment incentives and improvement of loan conditions are derived from the preceding results. On the background of international financing prospects, proposals for barrier removal projects or direct implementation of MHP projects are formulated.

## 8.1 Summarising conclusions and open questions

The lack of runoff measurements often impede the estimation of the **hydropower potential** at a specific site. Therefore, a multiple non-linear regression analysis between catchment characteristics and runoff indices Q(x,daily) is effected, resulting in a set of expedient equations. The multiple coefficients of determination of the non-linear regressions for Q(90,daily), which is the general design runoff for a hydropower plant, are unfortunately not very high, meaning between 0.4 and 0.6. Nevertheless, the equations are adequate to make a very rough estimation for Q(90,daily) on the basis of catchment characteristics as input parameters. It is recommended to check the estimated value Q(90,daily) with other information like random runoff measurements in the dry season.
*The method developed here, should be further improved, especially with regard to a deepened analysis of hydrogeological parameters, since these are expected to strongly affect the base flow.*

The database available to **forecast electricity consumption** in small isolated grids is very limited. Therefore, different methods are compared and studies, available so far, are reviewed and evaluated. Additionally, the outcome is compared to the results of a micro approach, realised in a field study, in order to verify or circumstantiate assumptions and findings. Finally, it is concluded that the figures given by the cited EEPCO-Acres study are realistic as long as the crucial parameter "households per official connection" is taken into account. The present research work yields a set of figures and assumptions appropriate for a realistic consumption forecast and allows to roughly sketch a daily load pattern. The importance of consumption steering is stressed with regard to market penetration and load factor which have to be as high as possible from the beginning to ensure optimal plant utilisation and thus project profitability. To leverage electricity consumption, the purchase of electrical appliances must be promoted. Since Injera baking is the most important end-use with the highest share of energy consumption in rural areas in Ethiopia, it stands to reason to introduce electrical injera baking. Yet, compared to the opportunity costs of about 0.1 - 0.2 ETB/kWh, electricity from MHP plants at a tenfold price is by far not competitive. Solely, at daytimes of very low plant utilisation, surplus electricity can be sold at such a low tariff instead of leaving it completely unused.
*Future investigations should concentrate on the impact and the quantified effect of steering instruments. They are more vitally than a detailed consumption forecast as such, since the forecast is very sensitive to the modification of the above-named steering options and to general boundary conditions, like tariff, payment mode and incentives.*

To alleviate the **technical design** of an electricity generation and distribution system the most cost-bearing components are sorted out, whereby emphasis is put on MHP systems. Excavation works, type of building material and powerhouse are well-grouped to facilitate the determination of unit prices. For the most important components, technical design procedures for power channel, penstock pipe etc. and decision procedures for the selection of turbine, generator, one- or three-phase distribution system etc. are elaborated in the form flow charts and tables. Local availability and technical suitability of the components under Ethiopian conditions are analysed and evaluated, showing for example that in most cases locally produced crossflow turbines, synchronous generators with integrated automatic voltage regulator and electronic load controller, and a combination of single-and three-phase system for the distribution grid are in many respects advantageous.
*The few existing MHP plants in Ethiopia which drive grain mills, prove that civil works and mechanical equipment do not pose a real problem. However, experience with the electrical part of a supply system, like the distribution grid, is still very limited, as it becomes apparent at lacking protection equipment like fuses etc.. Further research and capacity building is required here, especially with regard to cost savings but also technical reliability and simplification.*

The high variability of kW- and kWh-prices of MHP systems world wide prevent a realistic cost estimation for MHP plants under Ethiopian conditions where almost no experience in this field is available. The present study delivers a profound basis for a rough cost estimation and thus overcomes this problem. To facilitate estimation of **investment costs**, unit prices are collected from suppliers, construction enterprises but also from former feasibility studies. They are applied to estimate the costs for two fictitious case studies. The collected unit prices, based on year 2000, provide a database for the estimation of the purchasing costs. A breakdown of investment costs, a comparison of different projects world wide and a transfer of the findings to Ethiopian conditions allow to evaluate the importance of different types of costs as percentage of the purchasing costs. For MHP systems in Ethiopia, study and planning costs are ~ 15 - 8 % depending on the system size, transport costs depend on the distance and road quality, taxes for imported electrical equipment are ~8 % and staff training ~3 %. **Operating costs** of MHP systems mainly consist of fixed costs, meaning salaries and material, whereas for diesel systems energy costs as variable costs preponderate the operating costs. Indicatory values for fixed operating costs are estimated at 3 % for MHP systems and 5 % for diesel systems.
*Since electrical equipment accounts for the bulk of investment costs, the focus of cost saving potential must be put on this part. Investment costs are identified as one of the crucial aspects, influencing several other aspects in the decision-making process, like profitability, access to financing options, participating project partners etc., so that special attention has to be paid to its accurate computation. Diesel systems exerting the highest pressure of competition to MHP systems, the development of the oil price on the world market also merits special attention.*

The study revealed a very close interdependency between **profitability**, interested **project partners** and **financing** opportunities. As soon as a return on equity of at least 20 % can be achieved, private investors' equity capital can be attracted, which facilitates the access to bank loans. Both, private investors and banks, attach great importance to minimisation of project risks, short payback times and high profitability, mainly for investors, whereby banks are even more risk averse than investors. To be sure of creditworthiness of the debtor, banks demand **high collateral**. Besides collateral, a short payback time is the second condition hampering loan financing of MHP projects. Among commercial banks mainly CBE and CBB come into question. CBE is relatively innovative, less risk averse in its loan disbursement policy and has numerous branches Ethiopia-wide. CBB is mainly an interesting partner in the long run, because they expressed to be interested as soon as pilot projects have proved technical and economic feasibility. The best prospects are offered by DBE, which, due to its access to non-commercial funds, is less profit oriented. For infrastructure projects like MHP,

which are well fitting to the bank's policy, low interest loans are offered, even with an ROI of only about $\geq$ 10 %.
Due to a generally difficult access to loans, the issuance of **juissance rights** revealed to be a very interesting financing instrument. They facilitate the participation of customers as co-financiers and due to their flexible design allow dividend payment in kWh or kW. This approach reduces market risk and delayed payments. Juissance rights are permitted within the framework of several organisational forms. They offer fiscal advantages. As opposed to normal shares no stock exchange is required. They accommodate access to "cheap" quasi-equity capital from customers whilst, in return, also offer advantages to them. Project managers can keep control because juissance rights do not confer any ownership rights. In case of capital shortage of the customers, the latter can acquire refinancing mainly in the informal sector at money lenders, Iqqubs[703] etc. or new financing services must be introduced.
Another interesting financing partner are NGO's. They can assign loan capital at an interest rate below the one offered at the official capital market or, as an intermediary, provide collateral for a bank loan. Thus, despite decreasing funds, NGO's can act as **guarantor** to facilitate access to loans from the (free) capital market.
A case-by-case analyses must reveal if the participation of public entities is useful. **Public Private Partnership (PPP)** especially on lower administrational level, mainly regional and local, like municipalities, is a promising approach. It simultaneously can help to harmonise important legal aspects such as water right, land use permit etc..
*Further investigations should concentrate on the problem of collateral, precisely an alternative approach, how to use the plant itself or at least part of it as collateral. Closely related to this is the unsolved problem of risk management. The evaluation of organisational forms already revealed how risks can be shared between involved parties, but further research with regard to risk minimisation is required. Although the option of juissance rights is very promising, its acceptance by customers still remains an open question.*

The favoured **organisational form** depends on numerous aspects, namely the participating partners, their number and liability, which influence the access to loans, but also control aspects such as voting rights and management responsibility, the type of financing including customer participation, acquisition of equity capital and loan raising and finally the total investment volume. It is recommended to firstly evaluate locally existing organisations with regard to their appropriateness to implement and manage an MHP system. Amongst the organisational forms analysed in the present study, the most appropriate are **limited partnership, share company and modern cooperative**. All three are suitable for equity involvement from investors, customers and NGO's and thus basically provide for the access to loan capital. A joint venture is appropriate for the co-operation between local and foreign investors. A general partnership is only advantageous for a group of few well funded and creditworthy business men. This also applies to a private limited company. However, due to the limited liability of the partners, the PLC is less creditworthy than the general partnership. A limited partnership should be chosen in case of investors with different liabilities, supplemented by consumers with juissance rights. A share company is suitable for a big number of investors, consumers, NGO's etc., whereby the different share values and types of shares allow for different influence on the project. A modern co-operative is the form to be applied by a well funded community which is independent from big investors and banks.
*The chosen organisational form definitely decides on participation options of the users, which is a very project- and site-specific question. Although pros and cons of different organisational forms are weighed up here, customers interest to participate and to which extent can not be predicted and has to be included in the decision-making process in every specific case.*

The analysis of licensing procedures and administrative responsibilities clarify the **legal situation** and the required formalities. The acquisition of an investment licence opens up the service of the one-stop-shop, which includes trade and operating licences, working permits,

[703] Ethiopian expression for Rotating Saving and Credit Associations (ROSCA)

the registration of the business organisation, the allocation of land and water rights. Once the specific conditions for the acquisition of an investment licence are fulfilled, this licence provides attractive incentives, like tax holidays and exemption from custom duties. Inauspiciously, a minimum level of investment, which is 31,000 USD for domestic investors, 300,000 USD for joint investment and 500,000 USD for foreign investors, restricts the access to the licence. It prevents smaller MHP projects from reaping the benefits of redemption from the 35 % of income tax during the first 5 years of operation, respectively carrying forward losses. In case that no investment licence is acquired, electricity licence, land and water use permits must be achieved one by one, whereby the electricity licence rules the access to land and water.
*Although the present wording of the law gives the impression that the investment licence is of prime importance and the electricity licence is at second rate, both facilitating access to further rights, the administrative responsibilities, especially with regard to water rights, are not that clear. The allocation of competence between national and regional level is not well-defined. Only putting the rule to the test by means of implementing a pilot project can display the legal responsibilities. Precedent-setting alleviates the procedure for future projects.*

The analysis of pros and cons of different **tariff systems** shows that in small villages with predominantly residential consumption, simple flat rates can be absolutely effectual. Inhomogeneous consumption patterns within a supply area require a more sophisticated system. Then, flat rates or a coin system (investment: 400 ETB/oc, operating costs: 5 ETB/oc/y) adopted to ability-to-pay-variations should be offered for low income households. For medium income households load limiters (investment: 27 - 390 ETB/oc; operating costs: 6 - 8 ETB/oc/y) and / or time limiters (investment: 60 ETB/oc, operating costs: 4 ETB/oc/y) are a recommendable option. Time limiters are useful in case of "time of day subscription tariffs". Normal kWh meters (investment: 430 ETB/oc, operating costs: 11 ETB/oc/y) are appropriate for medium income households, as well as for commercial and industrial consumers. To save costs, the metering interval of e.g. 3 - 4 months can be longer than the billing interval of e.g. 1 month. Convenient **paying modalities** are a pivotal prerequisite to achieve a large number of connections and a high load factor, both together increasing the plant utilisation. Significant initial payments, like connection fee and juissance right payment should take place in high income months, which are mainly November to January, or be facilitated by means of instalment payments, for example via micro credit schemes. From the point of view of the project, incentives for early and in-advance payments and penalties for late payments help to improve the financial situation of the project. These possibly opposed viewpoints of customers and suppliers necessitate a reasonable compromise. The proposed **juissance rights** model entails several advantages for both sides. Beneficiaries are provided with kWh's or kW which are not subject to inflation. The project benefits financially and due to secured electricity sales. Sharing of project responsibility through customers' participation in addition reduces the problems of illegal connections, fraud, theft etc..
*Although expenses of around 10 - 12 ETB/month/hh, which correspond to about 100 kWh/y/hh at a tariff of 1.5 ETB/kWh mirror a clue for an average willingness to pay, further investigation on the capacity and willingness to pay are required. Especially the estimated lump-sum payments of 1,000 - 7,000 ETB for juissance rights, depending on market penetration, load factor and the part of juissance capital in total investment, require deepened investigations on paying limits in order to assess the prospects of this model.*

The analysis of **interrelationships** revealed vital dependencies. First of all, to achieve project success an appropriate tariff system must optimise temporal balancing of loads by truncating peaks and filling of load gaps and additionally adopt the continuously growing demand function to the stepwise increase of supply capacity. Selling of capacities in kilowatt instead of energy units in kilowatt hours contributes to achieve this objective and can be realised with the juissance rights model. Since profitability of MHP systems is marginal, mixed financing is recommended: firstly, some non- or less-profit oriented equity capital donors such as customers, development banks and NGO's, secondly, venture capitalists with significant equity capital for the provision of collateral, enforcing successful management, and, thirdly, banks

with loan capital to increase the ROE for the investors due to a positive leverage effect should be involved. About 30 % of the total investment can be covered by loan capital, requiring about 38 % of the total project value as collateral. A comprehensive flowchart sums up the decisive aspects and facilitates the decision-making process (see Figure 5.1).
*Although theoretically the co-operation of different project partners and institutions, meaning also different forms of financing, is recommended, the realisation can encounter serious difficulties. Recent experience has proven that donor funds e.g. from development banks, NGO's etc. are not available as soon as a mixture with private sector capital is proposed. Incompatible perceptions of policy and / or risk aspects can be hindering. The reservations that different actors bear towards each other should not be underestimated and require further investigations.*

To make the theoretical analyses more tangible, fictitious **case studies**, systems of 50 kW and 150 kW, are dealt with. A consumption forecast clearly detects the dilemma of slowly growing plant utilisation. For the 50 kW plant, the plant utilisation increases from 2 % in year 1 to 12 % in year 10 and 30 % in year 25. For the 150 kW plant, it grows from 2 % in year 1 to 15 % in year 10 and 40 % in year 25. The weak customer base at operation start can not contribute a significant part of capital in the form of juissance rights. Therefore, the improvement of plant utilisation, through increased market penetration and load factor, must be a main focus. The unit costs of about 1,700 USD/kW for the 150 kW system compared to 2,500 USD/kW for the 50 kW system can be attributed to economies of scale. Referring to investment costs, 37 % for the 50 kW system and 51 % for the 150 kW system are assigned to electrical equipment, advising to investigate further saving potential in this field. The sensitivity analysis of profitability quantifies the impact of different parameters, like financing mechanisms, tariff, load factor, inflation and exemption from income tax on the profitability. Supposing a ratio equity : loan : juissance capital of 30:30:40 and a complete exemption from tax payments, the 50 kW system achieves an ROE of 10.3 % at a tariff of 1.5 ETB/kWh, 3 % interest on juissance rights and 10 interest free years, whereas the 150 kW system achieves an ROE of 21.1 % at a tariff of 1.7 ETB/kWh, 9 % interest on juissance rights and 4 interest free years. The examples show, that for smaller plant the investment costs have to be significantly reduced to reach higher profitability.

## 8.2 Potential and limits of a DSS tool

Since the dissemination process of MHP is an interdisciplinary problem, which can not be solved simply by providing technical solutions or financing (see chapter 1), the present study investigates all relevant crucial aspects and their interdependencies. To enable key persons and decision makers to support the dissemination process of the MHP technology, sufficiently detailed but also ample information on must be made available in a perspicuous way. Therefore, the presented results are intended as a basis for the development of a DSS tool. With regard to the usefulness of such a tool several requirements have to be fulfilled:

- **applicability and access** to the tool
  At best, a software tool should be applicable by means of a personal computer without requiring further software. A Java program can fulfil these requirements and offers high flexibility. It is understood that the tool should be as user-friendly as possible, comprising interactive spreadsheets, maps, charts, tables, databases, useful references etc..
- **target groups**
  The type of tool, for example computer based, restricts the availability to a certain group of people and excludes those which are used to other kinds of knowledge systems. Given the fact that not the end-users or customers but rather planers and decision makers should be addressed the choice of a computer based tool in English language seems to be appropriate. Thereby, a terminology understandable to engineers, economists, legal advisers and the like, is recommended, so that bankers, donors, investors, representatives of user groups etc. can apply the tool.

- **up-to-dateness of information**
  Especially for the estimation of investment and operating costs and the analysis of profitability the availability of current data such as costs, inflation rate, etc. is indispensable. Therefore, either up-to-date unit prices have to be delivered from contractors and suppliers or older cost estimations must be adopted by means of an appropriate inflation rate. A decision support tool should ideally deliver information as up-to-date as possible but also offer the possibility to enter more recent data in case that they are available to the software user.

Concluding, a DSS can only be as up-to-date as the information applied for its design. It has to be administered and updated to take into account modifications of boundary conditions, like default values of unit prices, inflation but also legal amendments and new scientific findings. In general, the broadness of aspects considered here, goes at the expense of the depth of the analysis of every specific detail. Therefore, this first "screening" does not replace a detailed planning of a specific system. The enormous **advantages** of a DSM include:

- the overcoming of the limiting narrowness of access to information at the beginning of the planning process, when many decisions implicitly have to be taken
- the improvement of the discernment and thus the quality of a final decision
- the possibility to compare scenarios with regard to submission of project applications, for example as CDM project
- the reduction of study and planning costs
- the prevention to concentrate on technical aspects due to embedding of legal, economic, financial, organisational aspects etc. thus broadening the view of the specialist.

## 8.3 Recommended measures

Besides the objective to develop a DSS, the outcome of the present study provides a basis for immediate actions. On the one hand, it facilitates the formulation of key aspects for **project proposals** and, due to the provision of ample information, significantly reduces project preparation and transaction costs. With regard to the so-called flexible mechanisms, the information can either be applied by the host country itself when it intends to attract investors by drafting a portfolio of potential CDM projects or immediately by national or international investors. On the other hand, the interdisciplinary approach, which illuminates institutional, legal and financial barriers, reveals **strategies** how to tackle and overcome such hindrances, also with regard to upcoming policy formulation and design and implementation of development programs in different sectors. Especially Oromia Region with its promising hydropower potential is fortunately quite innovative and outright towards investment projects and seems to be very interested to promote the introduction of the MHP technology. The results of the present study allow to give an outlook on different options and instruments to stimulate future investment in MHP projects. Based on ample negative experience with projects completely subsidised by external support agencies, the main focus is put on private sector finance, supposing that "private" involvement is one of the guarantors for sustainable operation. However, since MHP projects are still at the limit of profitability, incentives have to be created for investors or entrepreneurs to invest in rural markets for appropriate energy systems and thus to put renewable energy sources on more equal terms with fossil fuels. Major hindrances for the dissemination of the MHP technology are: high project risk, difficulties to raise loan capital for long-term investment and a low awareness of the technology. The following measures can help to surmount these shortcomings:

- **integration of future customers** into project financing, which
  - leads to reduced market risk
  - facilitates access to loans, due to higher percentage of equity or quasi-equity capital
  - increases the ROE, because beneficiaries of electrification accept moderate dividends
- **investment incentives** like tax exemption, assistance for legal affairs etc.
- abolition or **reduction of privileges for diesel import** to improve competitiveness of MHP
- general **reduction of duties** on locally non-available electrical equipment, not only for holders of an investment licence
- **improvement of loan conditions**

Further recommendations on tariff structure, demand steering, organisational forms etc. are illustrated in the specific sections. Those aspects which are not yet amplified in detail are highlighted in the sections 8.3.1 to 8.3.3.

Although grant financing or highly subsidised donor financing is not considered to be an economically sustainable approach some **"kick-off" activities**, not profitable as such, require subsidisation and donor support. Among these are counted:
- general promotion and awareness creation campaigns
- training programs to improve local technical, economic, organisational etc. know-how
- support of some (private sector) pilot plants for demonstration objectives.

### 8.3.1 Investment incentives

Investment incentives can either be achieved by changes of legal guidelines or by direct economic incentives. Measures that revealed to be appropriate are:

1. facilitation of the acquisition of an **investment licence** by:
   - reducing the minimum amount of investment to be entitled to incentives, which is at present at 31,000 USD for domestic investors, at 300,000 USD for joint investment, at 500,000 USD for foreign investors[704]
   - allowance of transmission, distribution and sales of electricity, not only generation, also for joint investment and foreign investors
   - alleviation and acceleration of the approval procedure especially for smaller projects
2. complete redemption from **income tax** for MHP projects, to promote renewable energy compared to fossil energy resources
3. included promotion of subsequent **energy-intensive enterprises**, which receive energy from MHP plants, in order to ensure market security

According to the investment law, national investors are favoured compared to foreign ones. However, as soon as the availability of capital is limited as it is the case in Ethiopia, at least **joint ventures** or even foreign investment should be encouraged equivalent to domestic projects in order to promote a capital flow into the country.

### 8.3.2 Customs duties and exchange rate

In general **duties** aim at the protection of a weak local market against imported products in order to promote domestic production. If special equipment, like electrical components, is not available locally, protection measures are fruitless and should therefore be reviewed. Although Ethiopia has significantly reduced customs duties on a wide range of imports over the last years and further reductions are scheduled, tariff rates still range from 0 to 50 %, with an average tariff rate of approximately 20 %. Tariff reductions, for example in January 1997, especially targeted at imported goods that enhance exports, but not at goods required for local energy supply. In addition customs clearance remains a hindrance to the business of

[704] note: acting on the assumption of about 1,700 USD/kW, 31,000 USD correspond to a plant of 18 kW, 300,000 USD to 175 kW and 500,000 USD to 295 kW

importing. Not only is the **clearance process** slow, the imported goods are sometimes charged at attributed values instead of invoice values, even when the invoices have been certified by trade officials of the exporting country. The government requires that all imports be channelled through Ethiopian national registered as official import or distribution agents.[705] Relieved import conditions especially for electrical components are an important measure to promote the implementation of local decentralised energy projects. Additionally, **excise tax** at present ranging at 10 % for electronic products could be reduced for energy saving devices or equipment well suited to replace wood consuming applications, e.g. electrical injera stoves.

The case studies reveal that the competitiveness of diesel systems heavily depends on the **price of fuel** on the world market, the inflation rate of the fuel price and closely connected the **exchange rate** between ETB and USD. The first devaluation of the Ethiopian Birr was effected in October 1992 from the fixed ETB 2.1 to 4.98 to a dollar. Since the first devaluation, the Birr has grown weaker up to a current exchange rate of 1 USD = 8.2 ETB at the end of 2000.[706] The recent decline can partly be attributed to the fall in the world prices of coffee, Ethiopia's principal export commodity.[707] A further currency devaluation will have a negative impact on fuel prices, but also on other imported goods. As opposed to MHP systems, for diesel systems a very high percentage of 66 - 77 % of investment costs, including the genset itself, depends on import conditions. For MHP systems, a substantial part of investment, namely all civil works and mechanical equipment, can be supplied by Ethiopian companies. Solely electrical equipment for the distribution grid, which account for 35 - 50 % of the investment, has to be bought in foreign currency, mainly in USD, and thus depends on the exchange rate. A devaluation of the Birr would further improve the competitiveness of MHP and have a twofold negative effect on diesel systems, due to higher investment costs <u>and</u> an increased fuel price. Since diesel systems vitally depend on fuel supply, they additionally suffer from difficult transport situations, especially during the rainy season.

### 8.3.3 Options for improvement of loan conditions

Based on the fact that equity capital from private investors and / or future customers is relatively limited, at least part of the costs often have to be covered by loan capital. Loan conditions, like the provision of collateral, redemption schedule and interest rate, reveal to be crucial aspects for project feasibility. As discussed in section 4.10.3.2, one important measure to facilitate profitability is the option of bullet-loan, which is a credit with a certain **redemption-free period**. Especially in the first years of operation of an electricity system market penetration and consequently total consumption is still low, thus keeping down the income from tariff payments. As long as high expenses caused by the initial investment, interest payment etc. surmount by far the income, the loan cannot be redeemed and further equity capital is required, thus negatively affecting the cash flow and finally deteriorating the ROE. It has to be taken into account that in case of annuity payments the interest portion is predominant at the beginning of the loan period, but continually decreases, whereas the repayment portion continually increases. Therefore, the inauspicious conditions of high financial burden during the first years of operation can only be improved by retarding the start of loan repayment <u>and</u> of interest payment. The impact of granting an interest free period was already illustrated in Figure 6.14, but is accomplished here by Figure 8.1.

[705] http://www.telecom.net.et/~usemb-et/wwwhecgu.htm#Import_Policies
[706] IGAD / RHEP (2000), http://igadrhep.energyprojects.net/GetDoc.asp?DocumentID=7
[707] http://www.ptabank.co.ke/PTA%20Annual%20ReportII/environ.htm

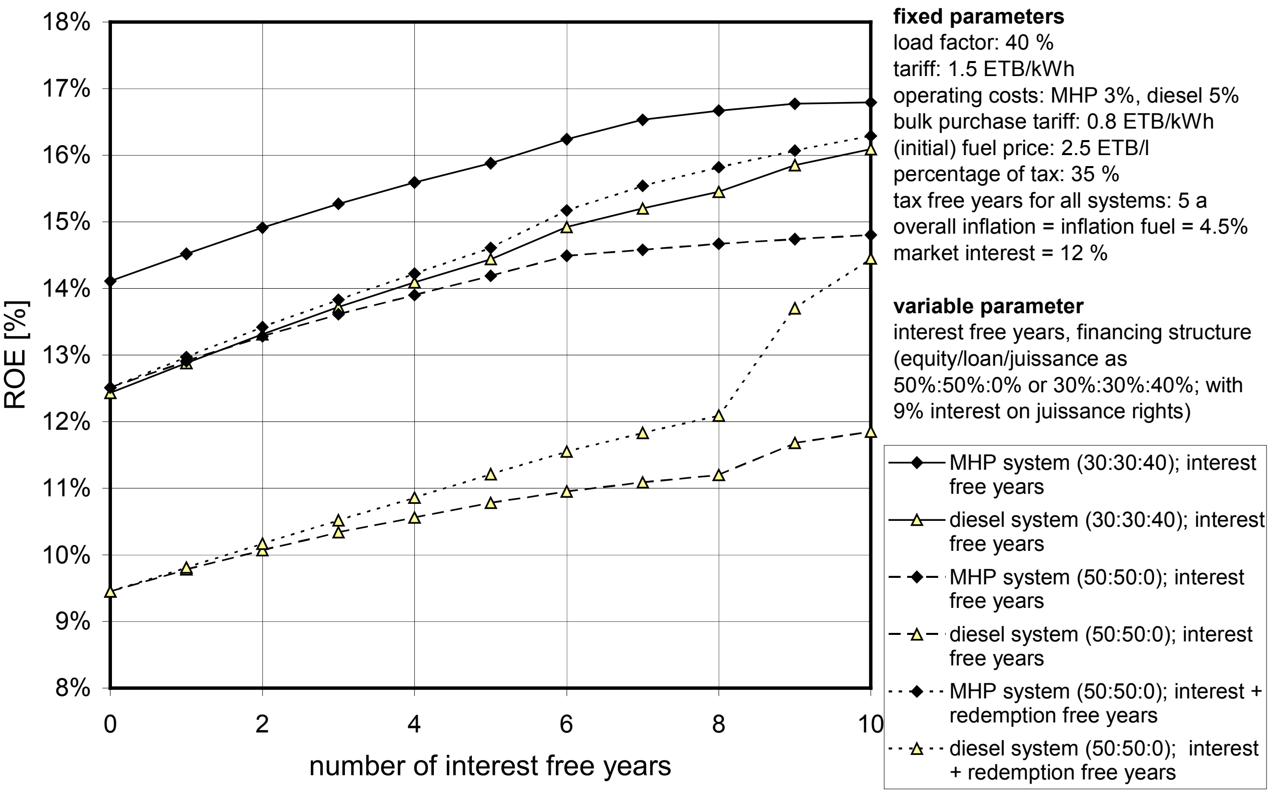



*Figure 8.1: Return on equity for 150 kW systems, depending on the number of interest and redemption free years, and the mode of financing*

The curves for the MHP system reveal a decisive importance of the first years of operation. As soon as increased electricity consumption and thus enhanced income is achieved, regular interest payment and loan repayment is facilitated and exemption from these payments looses its strikingly positive effect on the ROE. Though further borrowing in year 5 again pushes the ROE improving effect, the curve afterwards significantly flattens. The conclusion can be drawn that for MHP systems the exemption from interest payment has an improving effect mainly **during the first 4 or 5 years of operation**. The abrupt increase of the ROE for the diesel system can be explained by the fact that the second huge investment in year 8 is completely absorbed by the release from payments.

Taking into account the difficult situation of the Ethiopian banking sector (see sections 4.6.4.1 and 5.3) a bullet loan from local banks seems to be no realistic option in the near future. **Co-operation with external support agencies** can be a possible loophole, in case that they are disposed to stand in for the financing during the first high-risk years of operation. Such a loan refinancing as indirect project support accommodates the interests of different involved stakeholders:

- the external agency economises its funds by a merely partial support; instead of complete grant financing or a low interest loan for the whole project period only a "start-up support" is offered; in addition, the agency can rely on enforcing mechanisms of the local bank as far as loan redemption is concerned
- the local financing institution is involved in the project, profiting from the interest payment and thus benefiting due to a strengthened position on the market
- the project participants profit from relieved loan conditions, improving the ROE and competitiveness compared to diesel systems.

In principle this approach resembles the idea of **"mixed financing"** and **"composite financing"** schemes, introduced in 1994 by the German Kreditanstalt für Wiederaufbau KfW. The latter combines funds procured on the capital market with low interest-bearing official aid budget resources. This combination is mainly applied by KfW in economically stronger developing countries and provides a greater financing volume for specific developmentally sound operations than would be possible merely with budget funds. The funds can be combined in proportions, permitting a flexible adjustment of the financing conditions to the individual situation of the recipient country and the commercial viability of the project.[708] In the present case however, the capital market would be the local, risk averse Ethiopian banking sector, supported by funds from development aid. The external donor agency who provides an intermediate financing, e.g. soft loan, for the first four or five years of market creation facilitates higher project profitability and simultaneously increases attractiveness of the project for private investors willing to financially participate. As soon as a higher consumption level is reached and investment risk is lowered the local bank can pursue the business on its own account, independent from external support, and under its usual loan conditions. Since adverse boundary conditions would impede project initiation, the development bank plays a decisive role for the "project kick-off", but backs out after the first few years. This approach temporally limits the capital commitment of the development bank which is then placed in a position to reappoint the capital for further projects.

Given the general trend of decreasing funds for development co-operation at governmental as well as non-governmental organisations but also the "self-help" development goal, pure grant financing is more and more renounced in development co-operation. Consequently, most of the organisations start to try out similar new approaches often combined with the acquisition of funds on the capital market. MHP projects are predestined for this mixture of public and private funds (**public private partnership**), because after an initial period of market penetration, which necessitates a start-up financing at soft conditions, the profitability rapidly increases and the project pays for itself.

Besides the assignment of loan capital for re-financing at an interest rate below the one of the official capital market, another important instrument is to **provide collateral** for raising a bank loan (see section 4.6.4.2). This instrument facilitates the actual access to local commercial bank loans, whereas the re-financing as described in the preceding paragraphs improves the loan conditions towards a higher project profitability. Non-governmental organisations, especially church organisations, often deplore the payment behaviour of beneficiaries in a project. Church organisations are expected to act according to pure welfare principles without considering economic parameters like profitability or repayment of invested money. Economic sustainability of a project however can only be achieved if beneficiaries can pay for all costs occurring during the operation of a system. Complete or, at least a certain degree of financial autonomy from the beginning is absolutely desirable. Being aware of this, church organisations like EECMY, supported by "Bread for the World", apply new approaches based on increased user contributions. One approach is project financing by beneficiaries whereby required bank loans are collateralised by the NGO, which then acts in the role as guarantor, standing in for the debtor in case of insolvency.[709] Without this risk taking by a financially stronger organisation the access to credit markets especially in Ethiopia is very limited.

### 8.3.4 Recent trends...

At the World Summit in Johannesburg, the Germany Government declared to provide, during the coming 5 years, 1 billion Euro for the development of renewable energies and improved energy efficiency in developing countries and the European Union announced an energy initiative at a volume of about 700 million Euro.[710] Obviously, due to the ongoing debate on climate change phenomena, several promising funds are made available for renewable energy technologies but the challenge remains to harness them for decentralised MHP systems in rural Ethiopia.

[708] http://www.kfw.de/EN/Entwicklungszusammenarbeit/KfW-diedeu23/ZahlenundF56/TermsandCo.jsp
[709] personal communication: Hess (BfW), 01/1999
[710] FAZ Nr. 206/02, 5th September 2002, p.7

# 9 ANNEXES

*Annex 1: List of interviewed persons*

| institution / organisation | interviewed person / assessed stakeholder | date of interview/s |
|---|---|---|
| Abyssinia Bank | Baissa Gemeda | 03/2000 |
| Addis Ababa University AAU | - Dr. Abdulkarim Hussein, Faculty of Technology, Civil Engineering<br>- Dr. Dejene Aredo, Faculty of Economics<br>- Dr. Fekadu Shewarega, Faculty of Technology, Electrical Engineering<br>- Dr. Edessa Dribssa, Faculty of Technology, Mechanical Engineering<br>- Dean of Faculty of Law<br>- Dr. Alula Pankhurst, Department of Sociology and Social Administration<br>- Dr. Tegegne Gebre, Egziabher, Director Institute of Development Research<br>- Dr. Tenalem, Geology Department | 03/2000 |
| Asea Brown Boveri Midroc Industrial Services Private Limited Company, ABB, Addis Ababa | - Abdurahman Mohamed, Managing Director<br>- Amare Mergia, Manager Installations<br>- Hylton Bennett (international sales manager), ABB England | 03/2000, 12/2000 |
| Austrian Embassy Development Cooperation AEDC | Dr. Leonhard Moll, Counsellor | 03/2000 |
| Awash International Bank AIB | Solomon Awoke, Manager Credit Department | 03/2000 |
| Bread for the World BfW, Stuttgart, Germany | Helmut Hess | 01/1999 |
| Chamber of Commerce | Fasil Osman | 03/2000 |
| Commercial Bank of Ethiopia CBE | Hailu Legesse | 02/2000 |
| Commercial Nominees | Molla Gessesse | 03/2000 |
| Construction and Business Bank CBB | Ato Tariku | 03/2000 |
| DED (Deutscher Entwicklungsdienst) | Günther Schröder | 03/2000 |
| Development Bank of Ethiopia DBE | Kidane Nikodimos, Deputy General Manager - Operation | 03/2000 |
| Energy Concept | Peter Bank | 07/2000 |
| Ethio-African Export & Import | Yilma Tekleyohannes | 03/2000 |
| Ethiopian Electric Agency EEA | - Getahun Moghes, (present) General Manager<br>- Gosaye Mengistie, former General Manager | 03/2000, 11/2000 |
| Ethiopian Electric Power Corporation EEPCO | - Wadi Abdurahim, planning department<br>- Girma Biru, Central Regional Office<br>- Moges Belachew, Central Regional Office<br>- Tesfaye Aragaw, Customer Service Department<br>- Ato Michael, economist; Mekbib Lemma<br>- Araya Sendako, public relations<br>- Ato Alemu, purchasing division | 03/2000, 11/2000, 12/2000 |
| Ethiopian Evangelical Church Mekane Yesus EECMY | - Feyissa Kayemo, Central Office Development Director<br>- Assefa Ita | 02/2000, 11/2000 |

| | | |
|---|---|---|
| | - Shiferaw Ayana, MHP Program Section Head<br>- Berhanu Yismaw, technical advisor, Swedish Mission | |
| Ethiopian Insurance Company | Ato Shifferaw | 03/2000 |
| Ethiopian Investment Authority EIA (on national level) | - Tadesse Haile, General Manager<br>- Abdi Hussien, Senior Promotion Expert<br>- Alemayehu Teferi, Legal Advisor | 03/2000 |
| Ethiopian Rural Energy Development and Promotion Centre EREDPC | Hilawe Lakew, also consultant at MEGEN Power | 03/2000 |
| Ethiopian Rural Self-Help Association ERSHA, Guder | - Mrs. Alewiya, Development Agent in Guder<br>- Zeleke Tesfaye, Executive Director | 03/2000 |
| Ethiopian Science & Technology Commission | - Dr. Asrat Bulbula<br>- Mulugeta Amha, energy division | 03/2000 |
| Ethiopian Social Rehabilitation and Development Fund ESRDF | - Mrs. Saba<br>- Tesfaye Desta, Deputy General Manager / National Program Coordinator (UNDP) | 03/2000 |
| European Union (Delegation of the European Commission in Ethiopia) | Franco Conzato (economic adviser) | 03/2000 |
| Factor 4 Energy, Addis Ababa | Benjamin Jargstorf | 03/2000 |
| German Embassy Addis Ababa | Heiko Warnken, First Secretary, Head Development Cooperation | 03/2000 |
| Gesellschaft für Technische Zusammenarbeit (German Technical Co-operation) GTZ, Eschborn and Addis Ababa | - Horst Höfling, Energy Department, GTZ Eschborn<br>- Trudy Könemund, Project Manager, Household Energy Program at Ministry of Agriculture<br>- Karin Roeske, Project Coordinator, GTZ Eschborn, Household Energy Program<br>- Ruth Erlbeck, Project Manager Low-cost housing project at Ministry of Works & Urban Development<br>- Ralph Trosse, Project Adviser Low cost housing project at Ministry of Works & Urban Development<br>- Prof. Gerd Förch, Project Manager Water supply project at OWMERDB<br>- Karin Gesing, LUPO (Oromia Landuse Project) | 03/2000, 06/2000, 11/2000 |
| hydro power, Bammental / Germany | Valentin Schnitzer | 02/2000 to 10/2002 |
| International Finance Corporation IFC (member of the World Bank Group) | Andrew M. Danino, Representative | 03/2000 |
| Ireland Aid | Brendan Mc Grath | 11/2000 |
| MEGEN Power Ltd MGP | - Melessew Shanko, General Manager<br>- Hilawe Lakew, Energy Expert | 03/2000, 11/2000 |
| Menschen für Menschen Foundation MfM | - Michaela Böhm, Public Relations | 11/2000 |
| Metaferia Consulting Engineers Private Limited Company MCE | - Amha Yesus Metaferia, Managing Director<br>- Assefa Telila, Project Director Oromia Water Resources Baseline Survey | 03/2000 |
| MIDROC, Equatorial Business Group | Dr. Tesfaye Bayou, Manager Energy Division | 11/2000 |
| Ministry of Agriculture | Dr. Yohannes Debre Michael | 11/2000 |
| Ministry of Mines and Energy | - Tekola Shimeles, Head Energy Operations | 03/2000 |

| | | |
|---|---|---|
| MME | Department<br>- Lemma Eshetu, General Manager, Rural Energy Development and Expansion Centre (former: Ethiopian Energy Studies & Research Centre) and Ato Moghes | |
| Ministry of Water Resources MoWR | - Ato Deksios (hydrologist)<br>- Abdurashid Dulane<br>- Teferra Beyene, Tadesse Dinku, Ato Kaleab, Tsegaye Debebe, Ato Bekele (operation engineer), Ato Kidane (chief Hydrology Department)<br>- Dr. Mohammed Hagos, Chief Engineer | 03/2000, 11/2000 |
| National Bank of Ethiopia NBE | Gebreyesus Gunte | 03/2000 |
| NIB Bank | Ato Mahmoud | 03/2000 |
| Oromia Cooperatives Bureau OCB, Volunteers in Overseas Cooperative Assistance VOCA | Haile Gebre, Head of Bureau | 03/2000 |
| Oromia Economic Study Project Office | Shiferaw Jamo | 03/2000 |
| Oromia Investment Office OIO | Tahir Aman, General Manager | 03/2000 |
| Oromia Water, Minerals and Energy Research and Development Bureau OWMERD | - Prof. Gerd Foerch, Project Manager Water supply project<br>- Hirpa Duressa, Energy Department | 02/2000, 03/2000 |
| owner of a rubber factory | Berhane Mewa | 03/2000 |
| Paradizo Engineers Mechanical Workshop | General Manager | 03/2000 |
| Prime Minister Office PMO | Head Cooperatives Department | 03/2000 |
| Private Investor, Ambo | Ato Gadissa, entrepreneur | 03/2000 |
| Robe Municipality | Robe Municipality staff | 11/2000 |
| Schenker Logistics / Kelsterbach, Germany | | 05/2002 |
| Selam Technical and Vocational Training Centre | Olaf Erz, Chief Engineer | 03/2000, 11/2000 |
| SIEMENS, Ethiopia, Addis Ababa | Tefera Limeneh, General Manager | 12/2000 |
| Sigma Electric PLC | Makonnen G. Wolde, Marketing and Business Development Director; Taye Teklewold, general manager, Ato Yarek, engineer | 11/2000 |
| TROPICs Consulting Engineers, PLC | - Eyob Defere, Senior Economist<br>- Wakjira Umetta, Senior Civil Engineer<br>- Melaku Mulugetta, Managing Director | 03/2000<br>11/2000 |
| Water Works Construction Enterprise, Addis Ababa | Bekele Gadissa | 03/2000 |
| Wegagen Bank | Asfaw Alemu Tessema | 03/2000 |
| World Bank, Addis Ababa | Negede Lewi | 03/2000 |

## *Annex 2: Catchments used in the present study and their characteristics for calculating the regression equations*

| SL. No. | main catchm. | sub catchm. | station no. | river | site | latitude | longitude | region | precipitation regime | average elevation | area | mean annual precipitation | AET | hydraul. conductivity | specific capacity | slope | Q50 | Q70 | Q90 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | [m] | [km²] | [mm] | [mm] | [m/day] | [l/s/m] | [%] | [$m^3$/s] | [$m^3$/s] | [$m^3$/s] |
| 12 | WABI S.(06) | UPPER W.S.1 | 061012 | ROBE | Nr. ROBE | 7d51'n | 39d38'e | CEN | 1A | 3,280 | 175 | 1056 | 843 | 0.712 | 0.1 | 5.933 | 0.234 | 0.107 | 0.030 |
| 16 | WABI S.(06) | UPPER W.S.1 | 061014 | HERERO | @ HERERO | 7d00'n | 39d19'e | AWS | 1A | 3,057 | 133 | 924 | 630 | 0.400 | 0.1 | 5.065 | 0.346 | 0.133 | 0.032 |
| 76 | RIFT V.(08) | CENTRAL (2) | 082023 | WOSHA | @ WONDO GENET | 7d05'n | 38d38'e | AWS | 1A | 2,240 | 20 | 1020 | 164 | 0.500 | 0.53 | 6.400 | 0.537 | 0.403 | 0.312 |
| 77 | RIFT V.(08) | CENTRAL (2) | 082032 | RINZAF | @ BUTAGIRA | 8d07'n | 38d22'e | CEN | 1A | 2,725 | 49 | 954 | 231 | 0.714 | 0.1 | 8.308 | 0.495 | 0.200 | 0.029 |
| 78 | G. OMO (09) | M. GHIBE 2 | 092010 | AJANCHO | Nr. ARAKA | 7d08'n | 37d43'e | AWS | 1A | 1,845 | 306 | 1246 | 1,129 | 0.350 | 0.1 | 2.545 | 0.421 | 0.256 | 0.157 |
| 78 | RIFT V.(08) | CENTRAL (2) | 082039 | GUDER | Nr. HOSAINA | 7d33'n | 37d52'e | CEN | 1A | 2,405 | 74 | 1253 | 635 | 0.300 | 0.1 | 2.914 | 0.346 | 0.114 | 0.018 |
| 84 | RIFT V.(08) | NORTHERN 1 | 081011 | KETAR | Nr. FETE | 7d47'n | 39d03'e | CEN | 1A | 3,278 | 1975 | 770 | 602 | 0.350 | 0.1 | 3.365 | 2.900 | 1.790 | 1.480 |
| 108 | WABI S.(06) | UPPER W.S.1 | 061015 | MARIBO | Nr. KARA BIROLE | 6d52'n | 39d22'e | AWS | 1A | 3,208 | 200 | 1135 | 602 | 0.402 | 0.53 | 3.768 | 1.760 | 0.716 | 0.275 |
| 162 | G.-OMO (09) | U.GHIBE (1) | 091005 | MEGECHA | @ GUBRE | 8d11'n | 37d48'e | CEN | 1A | 2,665 | 286 | 1129 | 753 | 0.387 | 0.53 | 2.583 | 0.250 | 0.095 | 0.048 |
| 166 | GENALE D.07 | GENELE (2) | 072004 | SHAWE | @ MES PROJ. | 6d26'n | 39d41'e | AWS | 1A | 2,147 | 340 | 683 | 445 | 0.363 | 0.53 | 3.928 | 1.660 | 1.110 | 0.662 |
| 171 | GENALE D.07 | WEYB (3) | 073007 | TEGONA | @ GOBA | 7d00'n | 39d59'e | AWS | 1A | 3,187 | 83.1 | 1028 | 573 | 0.387 | 0.53 | 10.165 | 0.373 | 0.136 | 0.071 |
| 174 | RIFT V.(08) | NORTHERN 1 | 081008 | LOWER TIM. | Nr.SAGURE | 7d41'n | 39d09'e | CEN | 1A | 3,194 | 184.4 | 1169 | 1,018 | 0.350 | 0.1 | 4.329 | 0.344 | 0.234 | 0.166 |
| 180 | RIFT V.(08) | NORTHERN 1 | 081014 | KATAR | Nr. HOFI | 7d42'n | 39d13'e | CEN | 1A | 3,127 | 1040 | 1234 | 853 | 0.425 | 0.1 | 4.633 | 4.000 | 2.530 | 2.000 |
| 181 | RIFT V.(08) | CENTRAL (2) | 082016 | GIDABO | Nr.APOSTO | 6d45'n | 38d23'e | AWS | 1A | 2,435 | 646 | 1203 | 841 | 0.610 | 0.53 | 5.200 | 5.220 | 3.440 | 2.030 |
| 232 | G. OMO (09) | M. GHIBE 2 | 092009 | SOKIE | Nr. ARAKA | 7d09'n | 37d43'e | AWS | 1A | 2,364 | 103 | 1246 | 772 | 0.275 | 0.1 | 5.047 | 0.810 | 0.543 | 0.409 |
| 240 | G.-OMO (09) | U.GHIBE (1) | 091004 | WABI | Nr. WOLKITE | 8d15'n | 37d46'e | CEN | 1A | 2,597 | 1866 | 1146 | 779 | 0.250 | 0.53 | 2.046 | 6.260 | 3.520 | 1.850 |
| 264 | G.-OMO (09) | U.GHIBE (1) | 091007 | GOGHEB | Nr. ENDEBER | 8d06'n | 37d54'e | CEN | 1A | 2,400 | 109 | 1175 | 692 | 0.425 | 0.53 | 3.200 | 0.256 | 0.104 | 0.041 |
| 265 | G.-OMO (09) | U.GHIBE (1) | 091019 | BIDRU AWA. | Nr. SOKURU | 7d55'n | 37d24'e | JIM | 1A | 1,964 | 41 | 1546 | 1,092 | 0.250 | 0.53 | 6.187 | 0.330 | 0.190 | 0.053 |
| 266 | G.-OMO (09) | U.GHIBE (1) | 091024 | AWAITU | @ JIMMA | 7d41'n | 36d50'e | JIM | 1A | 1,925 | 72 | 1702 | 1,144 | 0.325 | 0.53 | 2.884 | 0.241 | 0.084 | 0.001 |
| 270 | G.-OMO (09) | M. GHIBE 2 | 092002 | GECHA | Nr. BONGA | 7d17'n | 36d13'e | JIM | 1A | 1,800 | 175 | 1114 | 388 | 0.250 | 0.53 | 3.200 | 1.770 | 0.680 | 0.318 |
| 290 | RIFT V.(08) | NORTHERN 1 | 081010 | ASHEBEKA | Nr. SAGURE | 7d41'n | 39d09'e | CEN | 1A | 3,194 | 236.9 | 1169 | 961 | 0.350 | 0.1 | 4.329 | 0.937 | 0.730 | 0.634 |
| 59 | RIFT V.(08) | CENTRAL (2) | 082018 | HARE | Nr. ARBA MINCH | 6d07'n | 37d34'e | AWS | 1B | 2,282 | 169 | 868 | 410 | 0.420 | 0.53 | 7.932 | 1.790 | 1.020 | 0.347 |
| 117 | G.-OMO (09) | M. GHIBE 2 | 092008 | MAZIE | Nr. MORKA | 6d26'n | 37d12'e | AWS | 1B | 2,279 | 937 | 1371 | 1,039 | 0.387 | 0.1 | 6.066 | 3.703 | 1.136 | 0.066 |
| 119 | G.-OMO (09) | L. GHIBE 3 | 093003 | NERI | Nr. JINKA | 5d48'n | 36d33'e | AWS | 1B | 2,433 | 166 | 1478 | 1,076 | 0.250 | 0.1 | 6.283 | 1.250 | 0.682 | 0.258 |
| 120 | RIFT V.(08) | CENTRAL (2) | 082015 | GATO | Nr. GIDOLE | 5d43'n | 37d26'e | AWS | 1B | 1,871 | 148 | 836 | 620 | 0.313 | 0.53 | 9.207 | 0.319 | 0.155 | 0.025 |
| 132 | RIFT V.(08) | CENTRAL (2) | 082019 | HARE | Nr.ARBA MINCH | 6d04'n | 37d36'e | AWS | 1B | 2,212 | 212 | 868 | 512 | 0.537 | 0.53 | 4.355 | 1.700 | 0.988 | 0.383 |
| 136 | RIFT V.(08) | CENTRAL (2) | 082022 | A.M.SPRING | Nr.ARBA MINCH | 6d00'n | 37d33'e | AWS | 1B | 1,685 | 37 | 868 | 722 | 0.250 | 0.53 | 10.080 | 0.153 | 0.124 | 0.100 |
| 140 | RIFT V.(08) | CENTRAL (2) | 082028 | KOLA | Nr. ALETA WONDO | 6d38'n | 38d24'e | AWS | 1B | 2,500 | 206.25 | 1231 | 821 | 0.869 | 0.53 | 4.727 | 1.840 | 0.950 | 0.490 |
| 147 | RIFT V.(08) | CENTRAL (2) | 082029 | UPPER GELA | Nr. YIRGA CHEFE | 6d09'n | 38d11'e | AWS | 1B | 1,959 | 140.62 | 1270 | 442 | 0.231 | 3.3 | 0.903 | 2.260 | 1.290 | 0.550 |
| 151 | RIFT V.(08) | CENTRAL (2) | 082034 | BEDESSA | Nr. DILLA | 6d23'n | 38d18'e | AWS | 1B | 2,255 | 81 | 1158 | 335 | 0.947 | 3.3 | 10.109 | 1.150 | 0.608 | 0.270 |
| 21 | ABBAY (11) | DABUS (5) | 115007 | GAMBELLA | Nr. ASOSSA | 10d00'n | 34d37'e | JIM | 1D | 1,540 | 5.5 | 1279 | 276 | 0.269 | 0.1 | 1.371 | 0.113 | 0.062 | 0.031 |
| 40 | ABBAY (11) | DABUS (5) | 115009 | DILLA | Nr. NEDJO | 9d27'n | 35d33'e | JIM | 1D | 1,882 | 69 | 1872 | 1,135 | 0.400 | 0.1 | 22.338 | 0.981 | 0.521 | 0.328 |
| 43 | AWASH (03) | LOWER (3) | 033001 | MILLE | Nr. PASSO MILLE | 11d23'n | 39d38'e | WEL | 1D | 2,092 | 206 | 1107 | 750 | 0.751 | 0.53 | 5.482 | 0.170 | 1.033 | 2.316 |
| 45 | AWASH (03) | LOWER (3) | 033010 | DESSO | @ DESSIE | 11d08'n | 39d38'e | WEL | 1D | 2,774 | 76.2 | 1107 | 1,001 | 0.680 | 0.53 | 5.680 | 0.050 | 0.026 | 0.015 |
| 48 | BARO A.(10) | UPPER B.(1) | 101005 | KETO | Nr. CHANKA | 8d47'n | 35d02'e | JIM | 1D | 1,876 | 1006 | 1488 | 985 | 0.250 | 0.53 | 3.360 | 5.200 | 1.570 | 0.470 |
| 59 | AWASH (03) | LOWER (3) | 033033 | BORKENA | Nr. BORU MEDA | 11d13'n | 39d37'e | WEL | 1D | 2,994 | 50 | 1110 | 289 | 0.794 | 0.53 | 3.583 | 0.179 | 0.123 | 0.078 |
| 68 | BARO A.(10) | UPPER B.(1) | 101006 | UKA | @ UKA | 8d10'n | 35d22'e | JIM | 1D | 1,668 | 52.5 | 1826 | 1,126 | 0.250 | 0.53 | 2.292 | 0.623 | 0.237 | 0.049 |
| 69 | BARO A.(10) | UPPER B.(1) | 101007 | GUMERO | Nr.GORE | 8d09'n | 35d29'e | JIM | 1D | 1,850 | 106 | 1725 | 1,153 | 0.295 | 0.53 | 1.969 | 0.692 | 0.277 | 0.088 |
| 70 | BARO A.(10) | UPPER B.(1) | 101009 | OUWA | Nr. GULISO | 9d10'n | 35d33'e | JIM | 1D | 1,740 | 287.5 | 1663 | 917 | 0.250 | 3.3 | 1.250 | 3.954 | 2.027 | 1.031 |
| 100 | BARO A.(10) | UPPER B.(1) | 101015 | KUNI | Nr. CHANKA | 8d51'n | 35d05'e | JIM | 1D | 1,695 | 87.5 | 1653 | 933 | 0.275 | 0.53 | 2.711 | 0.440 | 0.181 | 0.059 |
| 123 | ABBAY (11) | MIDDEL N. 3 | 113026 | NESHI | Nr. SHAMBO | 9d45'n | 37d15'e | CEN | 1D | 2,205 | 322 | 1734 | 1,164 | 0.104 | 0.53 | 5.400 | 0.920 | 0.450 | 0.230 |
| 125 | ABBAY (11) | DIDESSA-A.4 | 114006 | UKE | Nr. NEKEMTE | 9d19'n | 36d31'e | CEN | 1D | 1,945 | 201.9 | 1938 | 95 | 0.250 | 0.1 | 3.171 | 5.110 | 1.970 | 0.710 |
| 153 | ABBAY (11) | UPPERNILE 2 | 112038 | YEDA | Nr. AMBER | 10d15'n | 37d49'e | DEM | 1D | 2,900 | 125 | 1452 | 1,055 | 0.480 | 0.53 | 4.067 | 0.240 | 0.130 | 0.000 |
| 195 | ABBAY (11) | MIDDEL N. 3 | 113009 | DIJIL | Nr. DEBREMARKOS | 10d21'n | 37d40'e | DEM | 1D | 2,445 | 70 | 1268 | 856 | 0.300 | 0.53 | 2.533 | 0.130 | 0.060 | 0.040 |
| 196 | ABBAY (11) | MIDDEL N. 3 | 113013 | BIRR | Nr. JIGA | 10d39'n | 37d23'e | DEM | 1D | 2,205 | 978 | 1280 | 678 | 0.313 | 0.53 | 2.896 | 5.452 | 1.620 | 0.440 |
| 198 | ABBAY (11) | MIDDEL N. 3 | 113018 | SELALA | Nr. BURE | 10d42'n | 37d07'e | DEM | 1D | 2,317 | 38 | 1379 | 962 | 0.300 | 0.53 | 4.220 | 0.200 | 0.130 | 0.080 |
| 203 | ABBAY (11) | MIDDEL N. 3 | 113023 | DURA | Nr. METEKEL | 10d59'n | 36d29'e | DEM | 1D | 1,898 | 539 | 1454 | 78 | 0.250 | 0.1 | 6.150 | 5.390 | 1.760 | 0.910 |

*Annex 2 (cont.): Catchments used in the present study and their characteristics for calculating the regression equations*

| SL. No. | main catchm. | sub catchm. | station no. | river | site | latitude | longuitude | region | precipitation regime | average elevation | area | mean annual precipitatio | AET | hydraul. conductivity | specific capacity | slope | Q50 | Q70 | Q90 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | [m] | [km²] | [mm] | [mm] | [m/day] | [l/s/m] | [%] | [$m^3$/s] | [$m^3$/s] | [$m^3$/s] |
| 10 | G.-OMO (09) | U.GHIBE (1) | 091022 | WERABESSA | Nr. TOLE | 8d26'n | 37d27'e | CEN | 1E | 2,020 | 234 | 1385 | 621 | 0.394 | 0.53 | 2.400 | 3.380 | 1.410 | 0.180 |
| 37 | ABBAY (11) | DIDESSA-A.4 | 114003 | SIFA | Nr. NEKEMTE | 8d52'n | 36d47'e | CEN | 1E | 1,545 | 951 | 1794 | 1,346 | 0.250 | 0.53 | 1.378 | 4.375 | 2.039 | 0.972 |
| 56 | ABBAY (11) | UPPERNILE 2 | 112002 | MUGHER | Nr. CHANCHO | 9d18'n | 38d44'e | CEN | 1E | 2,674 | 489 | 1322 | 870 | 1.024 | 0.53 | 0.832 | 0.381 | 0.226 | 0.127 |
| 56 | AWASH (03) | UPPER (1) | 031001 | BERGAA | Nr. ADDIS ALEM | 9d01'n | 38d21'e | CEN | 1E | 2,434 | 248 | 1302 | 954 | 0.256 | 0.53 | 1.270 | 0.383 | 0.191 | 0.076 |
| 115 | ABBAY (11) | UPPERNILE 2 | 112012 | ALELTU | Nr. CHANCHO | 9d21'n | 38d41'e | CEN | 1E | 2,609 | 29 | 1322 | 738 | 1.024 | 0.53 | 2.380 | 0.665 | 0.468 | 0.334 |
| 137 | G.-OMO (09) | U.GHIBE (1) | 091020 | GHIBE | Nr. BACO | 9d07'n | 37d03'e | CEN | 1E | 2,414 | 288.1 | 1428 | 1,006 | 0.429 | 0.53 | 5.093 | 1.469 | 0.714 | 0.452 |
| 143 | ABBAY (11) | MIDDEL N. 3 | 113005 | GUDER | @ GUDER | 8d57'n | 37d45'e | CEN | 1E | 2,342 | 524 | 1075 | 298 | 0.425 | 0.53 | 2.840 | 3.092 | 1.567 | 1.011 |
| 146 | ABBAY (11) | MIDDEL N. 3 | 113001 | BELLO | Nr. GUDER | 8d52'n | 37d40'e | CEN | 1E | 2,495 | 290 | 1075 | 382 | 0.450 | 0.53 | 1.418 | 3.183 | 1.469 | 0.895 |
| 183 | ABBAY (11) | UPPERNILE 2 | 112013 | DENEBA | Nr. CHANCHO | 9d16'n | 38d43'e | CEN | 1E | 2,695 | 86 | 1322 | 699 | 1.024 | 0.53 | 0.833 | 1.042 | 0.538 | 0.079 |
| 184 | ABBAY (11) | MIDDEL N. 3 | 113002 | FATTO | Nr. GUDER | 8d52'n | 37d43'e | CEN | 1E | 2,709 | 96 | 1075 | 294 | 0.450 | 0.53 | 2.468 | 2.914 | 1.541 | 1.011 |
| 194 | AWASH (03) | UPPER (1) | 031002 | HOLETA | Nr. HOLETA | 9d05'n | 38d31'e | CEN | 1E | 2,615 | 119 | 1556 | 1,093 | 0.173 | 0.53 | 3.760 | 0.368 | 0.248 | 0.150 |
| 261 | AWASH (03) | UPPER (1) | 031003 | TEJI | Nr. ASGORI | 8d47'n | 38d20'e | CEN | 1E | 2,812 | 662.5 | 1062 | 883 | 0.306 | 0.1 | 2.341 | 0.229 | 0.091 | 0.039 |
| 276 | AWASH (03) | UPPER (1) | 031004 | AKAKI | @ AKAKI | 8d53'n | 38d47'e | CEN | 1E | 2,200 | 884.4 | 1116 | 331 | 0.850 | 0.1 | 1.760 | 2.036 | 1.371 | 0.775 |
| 293 | G.-OMO (09) | U.GHIBE (1) | 091003 | REBU | Nr. WOLKITE | 8d21'n | 37d47'e | CEN | 1E | 2,292 | 480 | 1146 | 888 | 0.250 | 0.53 | 2.253 | 0.650 | 0.280 | 0.080 |
| 307 | G.-OMO (09) | U.GHIBE (1) | 091015 | UPPER REBU | Nr. WOLISO | 8d32'n | 38d00'e | CEN | 1E | 2,467 | 136 | 1233 | 320 | 0.294 | 0.53 | 3.332 | 0.560 | 0.260 | 0.080 |
| 309 | G.-OMO (09) | U.GHIBE (1) | 091021 | AMARA | Nr.BACO | 9d05'n | 37d08'e | CEN | 1E | 2,145 | 68.8 | 1645 | 922 | 0.288 | 0.53 | 4.950 | 0.659 | 0.419 | 0.219 |
| 11 | AWASH (03) | UPPER (1) | 031014 | MOJO | @ MOJO VILLAGE | 8d36'n | 39d05'e | CEN | 2D | 1,880 | 1264.4 | 970 | 843 | 1.210 | 3.3 | 2.667 | 1.283 | 0.377 | 0.228 |
| 157 | AWASH (03) | UPPER (1) | 031019 | KESSEM | @ BEKE | 9d10'n | 39d04'e | CEN | 2D | 2,782 | 50 | 1379 | 655 | 0.626 | 0.53 | 4.830 | 0.053 | 0.020 | 0.010 |
| 168 | AWASH (03) | LOWER (3) | 033005 | BORKENA | Nr. COMBOLCHA | 11d03'n | 39d44'e | WEL | 2D | 2,203 | 281 | 1487 | 1,284 | 0.405 | 0.53 | 4.714 | 0.599 | 0.399 | 0.183 |
| 169 | AWASH (03) | LOWER (3) | 033015 | JEWEHA | @ JEWEHA | 10d06'n | 39d58'e | WEL | 2D | 1,845 | 514.4 | 807 | 525 | 0.552 | 3.3 | 6.756 | 1.839 | 0.813 | 0.354 |
| 170 | AWASH (03) | LOWER (3) | 033016 | ATAYE | Nr. AFESON | 10d20'n | 39d58'e | WEL | 2D | 2,522 | 166.4 | 807 | 512 | 1.020 | 3.3 | 9.262 | 0.762 | 0.377 | 0.133 |
| 172 | AWASH (03) | LOWER (3) | 033017 | JARA | @ JARA | 10d31'n | 39d57'e | WEL | 2D | 1,828 | 235.4 | 1065 | 757 | 0.641 | 3.3 | 3.796 | 0.658 | 0.313 | 0.154 |
| 173 | AWASH (03) | LOWER (3) | 033018 | BORKENA | D.S.OF SWAMP | 10d38'n | 39d56'e | WEL | 2D | 1,903 | 1735 | 1159 | 1,048 | 0.572 | 3.3 | 5.201 | 1.412 | 0.544 | 0.113 |
| 179 | AWASH (03) | LOWER (3) | 033038 | SENBETE | @ SENBETE | 10d18'n | 39d58'e | WEL | 2D | 1,890 | 119 | 807 | 650 | 1.019 | 3.3 | 4.480 | 0.233 | 0.117 | 0.017 |

# Annex 3: Values for potential and actual evapotranspiration (PET and AET)

**PET values from the "Oromia Study"**

| Station | altitude | average yearly PET |
|---|---|---|
| | [m] | [mm] |
| Adaba | 2,485 | 1,304 |
| Adami Tulu | 1,630 | 1,748 |
| Addis | 2,400 | 1,216 |
| Adele | 2,480 | 1,289 |
| Agaro | 2,030 | 1,345 |
| Agere Mariam | 2,000 | 1,422 |
| Alaba Kulito | 1,850 | 1,380 |
| Aleta Wendo | 1,860 | 1,367 |
| Ambo | 2,130 | 1,226 |
| Arba Minch | 1,290 | 1,541 |
| Arjo | 2,565 | 1,187 |
| Asebe Teferi | 1,730 | 1,448 |
| Asela | 2,450 | 1,237 |
| Atnago | 2,000 | 1,340 |
| Awash | 960 | 2,124 |
| Awassa | 1,750 | 1,422 |
| Bako | 1,650 | 1,349 |
| Bambesi | 1,460 | 1,442 |
| Bedele | 2,030 | 1,251 |
| Begi | 1,722 | 1,333 |
| Bekoji | 2,800 | 1,215 |
| Bonga | 1,725 | 1,319 |
| Butajira | 2,000 | 1,350 |
| Debre Berhan | 2,750 | 1,276 |
| Debre Zeyt | 1,900 | 1,423 |
| Dembi Dolo | 1,850 | 1,265 |
| Dire Dawa | 1,160 | 2,145 |
| Fiche | 2,750 | 1,246 |
| Filtu | 1,150 | 1,711 |
| Gebre Guracha | 2,560 | 1,211 |
| Gidami | 2,040 | 1,246 |
| Gimbi | 1,970 | 1,281 |
| Goba | 2,700 | 1,109 |
| Gore | 2,024 | 1,254 |
| Guder | 2,002 | 1,355 |
| Harer | 1,856 | 1,351 |
| Hosaina | 2,290 | 1,325 |
| Hurso | 1,085 | 1,674 |
| Jijiga | 1,644 | 1,618 |
| Jimma | 1,725 | 1,398 |
| Kibre Mengist | 1,680 | 1,294 |
| Kofele | 2,680 | 1,279 |
| Koka | 1,650 | 1,533 |
| Kuyera | 2,010 | 1,340 |
| Mega | 2,215 | 1,464 |
| Mendi | 1,650 | 1,345 |
| Metehara | 975 | 1,901 |
| Metu | 1,940 | 1,327 |
| Mojo | 1,880 | 1,560 |
| Nejo | 1,800 | 1,249 |
| Nekemte | 2,080 | 1,252 |
| Robe | 2,480 | 1,182 |
| Shambu | 2,430 | 1,313 |
| Sheno | 2,655 | 1,305 |
| Tepi | 1,200 | 1,432 |
| Ticho | 2,800 | 1,158 |
| Tikur Inchini | 2,480 | 1,119 |
| Wama | 1,450 | 1,463 |
| Wendo Genet | 1,880 | 1,426 |
| Yirgachefe | 1,925 | 1,352 |
| Yubdo | 1,520 | 1,348 |
| Ziway | 1,640 | 1,584 |

**PET values calculated with regressions and AET values calculated with "water balance"**

| Station No. | river | site | latitude | longuitude | main catchment | sub catchment | average yearly PET estimated by means of regression equations | average yearly AET = precipitation - runoff |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | [mm] | [mm] |
| 031001 | BERGAA | Nr. ADDIS ALEM | 9d01'n | 38d21'e | AWASH (03) | UPPER (1) | 1,260 | 954 |
| 031002 | HOLETA | Nr. HOLETA | 9d05'n | 38d31'e | AWASH (03) | UPPER (1) | 1,215 | 1,093 |
| 031003 | TEJI | Nr. ASGORI | 8d47'n | 38d20'e | AWASH (03) | UPPER (1) | 1,171 | 883 |
| 031004 | AKAKI | @ AKAKI | 8d53'n | 38d47'e | AWASH (03) | UPPER (1) | 1,328 | 331 |
| 031014 | MOJO | @ MOJO VILLAGE | 8d36'n | 39d05'e | AWASH (03) | UPPER (1) | 1,439 | 843 |
| 031019 | KESSEM | @ BEKE | 9d10'n | 39d04'e | AWASH (03) | UPPER (1) | 1,177 | 655 |
| 033001 | MILLE | Nr. PASSO MILLE | 11d23'n | 39d38'e | AWASH (03) | LOWER (3) | 1,362 | 750 |
| 033005 | BORKENA | Nr. COMBOLCHA | 11d03'n | 39d44'e | AWASH (03) | LOWER (3) | 1,327 | 1,284 |
| 033010 | DESSO | @ DESSIE | 11d08'n | 39d38'e | AWASH (03) | LOWER (3) | 1,179 | 1,001 |
| 033015 | JEWEHA | @ JEWEHA | 10d06'n | 39d58'e | AWASH (03) | LOWER (3) | 1,453 | 525 |
| 033016 | ATAYE | Nr. AFESON | 10d20'n | 39d58'e | AWASH (03) | LOWER (3) | 1,238 | 512 |
| 033017 | JARA | @ JARA | 10d31'n | 39d57'e | AWASH (03) | LOWER (3) | 1,460 | 757 |
| 033018 | BORKENA | D.S.OF SWAMP | 10d38'n | 39d56'e | AWASH (03) | LOWER (3) | 1,430 | 1,048 |
| 033033 | BORKENA | Nr. BORU MEDA | 11d13'n | 39d37'e | AWASH (03) | LOWER (3) | 1,133 | 289 |
| 033038 | SENBETE | @ SENBETE | 10d18'n | 39d58'e | AWASH (03) | LOWER (3) | 1,435 | 650 |
| 061012 | ROBE | Nr. ROBE | 7d51'n | 39d38'e | WABI S.(06) | UPPER W.S.1 | 1,099 | 843 |
| 061014 | HERERO | @ HERERO | 7d00'n | 39d19'e | WABI S.(06) | UPPER W.S.1 | 1,138 | 630 |
| 061015 | MARIBO | Nr. KARA BIROLE | 6d52'n | 39d22'e | WABI S.(06) | UPPER W.S.1 | 1,111 | 602 |
| 072004 | SHAWE | @ MES PROJ. | 6d26'n | 39d41'e | GENALE D.07 | GENELE (2) | 1,299 | 445 |
| 073007 | TEGONA | @ GOBA | 7d00'n | 39d59'e | GENALE D.07 | WEYB (3) | 1,099 | 573 |
| 081008 | LOWER TIM. | Nr.SAGURE | 7d41'n | 39d09'e | RIFT V.(08) | NORTHERN 1 | 1,153 | 1,018 |
| 081010 | ASHEBEKA | Nr. SAGURE | 7d41'n | 39d09'e | RIFT V.(08) | NORTHERN 1 | 1,153 | 961 |
| 081011 | KETAR | Nr. FETE | 7d47'n | 39d03'e | RIFT V.(08) | NORTHERN 1 | 1,142 | 602 |
| 081014 | KATAR | Nr. HOFI | 7d42'n | 39d13'e | RIFT V.(08) | NORTHERN 1 | 1,163 | 853 |
| 082015 | GATO | Nr. GIDOLE | 5d43'n | 37d26'e | RIFT V.(08) | CENTRAL (2) | 1,422 | 620 |
| 082016 | GIDABO | Nr.APOSTO | 6d45'n | 38d23'e | RIFT V.(08) | CENTRAL (2) | 1,283 | 841 |
| 082018 | HARE | Nr. ARBA MINCH | 6d07'n | 37d34'e | RIFT V.(08) | CENTRAL (2) | 1,316 | 410 |
| 082019 | HARE | Nr.ARBA MINCH | 6d04'n | 37d36'e | RIFT V.(08) | CENTRAL (2) | 1,332 | 512 |
| 082022 | A.M.SPRING | Nr.ARBA MINCH | 6d00'n | 37d33'e | RIFT V.(08) | CENTRAL (2) | 1,482 | 722 |
| 082023 | WOSHA | @ WONDO GENET | 7d05'n | 38d38'e | RIFT V.(08) | CENTRAL (2) | 1,325 | 164 |
| 082028 | KOLA | Nr. ALETA WONDO | 6d38'n | 38d24'e | RIFT V.(08) | CENTRAL (2) | 1,270 | 821 |
| 082029 | UPPER GELA | Nr. YIRGA CHEFE | 6d09'n | 38d11'e | RIFT V.(08) | CENTRAL (2) | 1,397 | 442 |
| 082032 | RINZAF | @ BUTAGIRA | 8d07'n | 38d22'e | RIFT V.(08) | CENTRAL (2) | 1,227 | 231 |
| 082034 | BEDESSA | Nr. DILLA | 6d23'n | 38d18'e | RIFT V.(08) | CENTRAL (2) | 1,322 | 335 |
| 082039 | GUDER | Nr. HOSAINA | 7d33'n | 37d52'e | RIFT V.(08) | CENTRAL (2) | 1,289 | 635 |
| 091003 | REBU | Nr. WOLKITE | 8d21'n | 37d47'e | G.-OMO (09) | U.GHIBE (1) | 1,270 | 888 |
| 091004 | WABI | Nr. WOLKITE | 8d15'n | 37d46'e | G.-OMO (09) | U.GHIBE (1) | 1,206 | 779 |
| 091005 | MEGECHA | @ GUBRE | 8d11'n | 37d48'e | G.-OMO (09) | U.GHIBE (1) | 1,193 | 753 |
| 091007 | GOGHEB | Nr. ENDEBER | 8d06'n | 37d54'e | G.-OMO (09) | U.GHIBE (1) | 1,246 | 692 |
| 091015 | UPPER REBU | Nr. WOLISO | 8d32'n | 38d00'e | G.-OMO (09) | U.GHIBE (1) | 1,232 | 320 |
| 091019 | BIDRU AWA. | Nr. SOKURU | 7d55'n | 37d24'e | G.-OMO (09) | U.GHIBE (1) | 1,355 | 1,092 |
| 091020 | GHIBE | Nr. BACO | 9d07'n | 37d03'e | G.-OMO (09) | U.GHIBE (1) | 1,243 | 1,006 |
| 091021 | AMARA | Nr.BACO | 9d05'n | 37d08'e | G.-OMO (09) | U.GHIBE (1) | 1,306 | 922 |
| 091022 | WERABESSA | Nr. TOLE | 8d26'n | 37d27'e | G.-OMO (09) | U.GHIBE (1) | 1,339 | 621 |
| 091024 | AWAITU | @ JIMMA | 7d41'n | 36d50'e | G.-OMO (09) | U.GHIBE (1) | 1,366 | 1,144 |
| 092002 | GECHA | Nr. BONGA | 7d17'n | 36d13'e | G.-OMO (09) | M. GHIBE 2 | 1,405 | 388 |
| 092008 | MAZIE | Nr. MORKA | 6d26'n | 37d12'e | G.-OMO (09) | M. GHIBE 2 | 1,273 | 1,039 |
| 092009 | SOKIE | Nr. ARAKA | 7d09'n | 37d43'e | G. OMO (09) | M. GHIBE 2 | 1,254 | 772 |
| 092010 | AJANCHO | Nr. ARAKA | 7d08'n | 37d43'e | G. OMO (09) | M. GHIBE 2 | 1,390 | 1,129 |
| 093003 | NERI | Nr. JINKA | 5d48'n | 36d33'e | G.-OMO (09) | L. GHIBE 3 | 1,239 | 1,076 |
| 101005 | KETO | Nr. CHANKA | 8d47'n | 35d02'e | BARO A.(10) | UPPER B.(1) | 1,290 | 985 |
| 101006 | UKA | @ UKA | 8d10'n | 35d22'e | BARO A.(10) | UPPER B.(1) | 1,325 | 1,126 |
| 101007 | GUMERO | Nr.GORE | 8d09'n | 35d29'e | BARO A.(10) | UPPER B.(1) | 1,295 | 1,153 |
| 101009 | OUWA | Nr. GULISO | 9d10'n | 35d33'e | BARO A.(10) | UPPER B.(1) | 1,313 | 917 |
| 101015 | KUNI | Nr. CHANKA | 8d51'n | 35d05'e | BARO A.(10) | UPPER B.(1) | 1,320 | 933 |
| 112002 | MUGHER | Nr. CHANCHO | 9d18'n | 38d44'e | ABBAY (11) | UPPERNILE 2 | 1,191 | 870 |
| 112012 | ALELTU | Nr. CHANCHO | 9d21'n | 38d41'e | ABBAY (11) | UPPERNILE 2 | 1,203 | 738 |
| 112013 | DENEBA | Nr. CHANCHO | 9d16'n | 38d43'e | ABBAY (11) | UPPERNILE 2 | 1,187 | 699 |
| 112038 | YEDA | Nr. AMBER | 10d15'n | 37d49'e | ABBAY (11) | UPPERNILE 2 | 1,151 | 1,055 |
| 113001 | BELLO | Nr. GUDER | 8d52'n | 37d40'e | ABBAY (11) | MIDDEL N. 3 | 1,226 | 382 |
| 113002 | FATTO | Nr. GUDER | 8d52'n | 37d43'e | ABBAY (11) | MIDDEL N. 3 | 1,185 | 294 |
| 113005 | GUDER | @ GUDER | 8d57'n | 37d45'e | ABBAY (11) | MIDDEL N. 3 | 1,259 | 298 |
| 113009 | DIJIL | Nr. DEBREMARKOS | 10d21'n | 37d40'e | ABBAY (11) | MIDDEL N. 3 | 1,236 | 856 |
| 113013 | BIRR | Nr. JIGA | 10d39'n | 37d23'e | ABBAY (11) | MIDDEL N. 3 | 1,291 | 678 |
| 113018 | SELALA | Nr. BURE | 10d42'n | 37d07'e | ABBAY (11) | MIDDEL N. 3 | 1,264 | 962 |
| 113023 | DURA | Nr. METEKEL | 10d59'n | 36d29'e | ABBAY (11) | MIDDEL N. 3 | 1,374 | 78 |
| 113026 | NESHI | Nr. SHAMBO | 9d45'n | 37d15'e | ABBAY (11) | MIDDEL N. 3 | 1,291 | 1,164 |
| 114003 | SIFA | Nr. NEKEMTE | 8d52'n | 36d47'e | ABBAY (11) | DIDESSA-A.4 | 1,497 | 1,346 |
| 114006 | UKE | Nr. NEKEMTE | 9d19'n | 36d31'e | ABBAY (11) | DIDESSA-A.4 | 1,360 | 95 |
| 115007 | GAMBELLA | Nr. ASOSSA | 10d00'n | 34d37'e | ABBAY (11) | DABUS (5) | 1,499 | 276 |
| 115009 | DILLA | Nr. NEDJO | 9d27'n | 35d33'e | ABBAY (11) | DABUS (5) | 1,379 | 1,135 |

*Annex 4: Soil types, associated grain class and hydraulic conductivity*

| soil type | grain size | | hydraulic conductivity HC [m/day] = $k_f$ |
|---|---|---|---|
| | description | abbreviation | |
| Cambisol | clay loam to sand clay loam | Lt2 – Lts | 1.024 |
| Xerosols | Silty clay loam to sandy clay loam | Ltu – Lts | 0.45 |
| Luvisols | Sandy clay loam to sandy loam | Lts – Ls2 | 0.5 |
| Gleysols | Loam to silty clay loam | L – Ltu | 0.4 |
| Solonchak | Clay loam to sandy loam | Lt2 – Ls2 | 0.058 |
| Regosol | Clay loam to sandy loam | Lt2 – Ls2 | 0.4 |
| Vertisols | Clay to clay loam | T – TL | 0.25 |
| Nitosols | Clay to clay loam | T – TL | 0.25 |
| Fluvisols | Clay to sandy clay loam | T – Lts | 0.816 |
| Arenosols | Sandy clay loam to sand | Lts – mS | 1 |
| Andosols | Sandy loam to loamy sand | Ls2 – SL2 | 0.65 |
| Acrisols | Clay to clay loam | T – TL | 0.25 |
| Leptosols | Sandy clay loam to sandy loam | Lts – Ls2 | 0.5 |
| Phaeozem | Porous, well aerated | gS | 3.5 |
| Histosols | Organic soils, thick soil horizon | - | 3 |

*Annex 5: Resulting values of r² and their stepwise improvement*

| rainfall regime | runoff index Q(x,daily) | improvement of r² by stepwise inclusion of parameters in the multiple regression | | | | | | final r² |
|---|---|---|---|---|---|---|---|---|
| 1A | Q(90,daily) | **A** | **AET** | | | | | |
| | r² | 0.424 | 0.549 | | | | | **0.549** |
| | Q(70,daily) | **A** | **S** | **HC** | **SC** | **AET** | | |
| | r² | 0.5 | 0.550 | 0.586 | 0.607 | 0.698 | | **0.698** |
| | Q(50,daily) | **A** | **S** | **SC** | **HC** | **AET** | | |
| | r² | 0.533 | 0.567 | 0.627 | 0.643 | 0.752 | | **0.752** |
| 1B | Q(90,daily) | **S** | **AET** | **HC** | **P** | | | |
| | r² | 0.275 | 0.350 | 0.511 | 0.531 | | | **0.531** |
| | Q(70,daily) | **S** | **P** | **HC** | **AET** | **SC** | | |
| | r² | 0.316 | 0.440 | 0.629 | 0.631 | 0.977 | | **0.977** |
| | Q(50,daily) | **A** | **P** | **S** | **HC** | **SC** | **AET** | |
| | r² | 0.584 | 0.664 | 0.739 | 0.854 | 0.855 | 0.987 | **0.987** |
| 1D | Q(90,daily) | **A** | **AET** | **P** | **HC** | **SC** | | |
| | r² | 0.4824 | 0.546 | 0.559 | 0.591 | 0.592 | | **0.592** |
| | Q(70,daily) | **A** | **P** | **HC** | **AET** | **S** | **SC** | |
| | r² | 0.578 | 0.669 | 0.672 | 0.755 | 0.761 | 0.761 | **0.761** |
| | Q(50,daily) | **A** | **P** | **HC** | **AET** | **SC** | **S** | |
| | r² | 0.555 | 0.764 | 0.770 | 0.864 | 0.867 | 0.882 | **0.882** |
| 1E | Q(90,daily) | **AET** | **HC** | **A** | **SC** | **P** | | |
| | r² | 0.163 | 0.166 | 0.187 | 0.268 | 0.416 | | **0.416** |
| | Q(70,daily) | **AET** | **HC** | **SC** | **A** | **S** | **P** | |
| | r² | 0.184 | 0.191 | 0.255 | 0.358 | 0.391 | 0.567 | **0.567** |
| | Q(50,daily) | **AET** | **A** | **SC** | **HC** | **S** | **P** | |
| | r² | 0.180 | 0.228 | 0.378 | 0.393 | 0.415 | 0.538 | **0.538** |
| 2D | Q(90,daily) | **A** | **AET** | | | | | |
| | r² | 0.508 | 0.530 | | | | | **0.530** |
| | Q(70,daily) | **A** | **SC** | **S** | **HC** | | | |
| | r² | 0.592 | 0.635 | 0.743 | 0.781 | | | **0.781** |
| | Q(50,daily) | **A** | **SC** | **S** | | | | |
| | r² | 0.733 | 0.789 | 0.866 | | | | **0.866** |

*Annex 6: Significance levels of the F-distribution[711] (quoted according to R.A. Fisher[712]): if $F_0$ exceeds the respective value in the table the coefficient of determination is significantly different from zero at a significance level of (1 - $\alpha$)*

| | $v_1 = 1$ | | |
|---|---|---|---|
| $v_2$ | α = 10 % | α = 5 % | α = 1 % |
| 1 | 39.86 | 161.40 | 4052 |
| 2 | 8.53 | 18.51 | 98.50 |
| 3 | 5.54 | 10.13 | 34.12 |
| 4 | 4.54 | 7.71 | 21.20 |
| 5 | 4.06 | 6.61 | 16.26 |
| 6 | 3.78 | 5.99 | 13.75 |
| 7 | 3.59 | 5.59 | 12.25 |
| 8 | 3.46 | 5.32 | 11.26 |
| 9 | 3.36 | 5.12 | 10.56 |
| 10 | 3.29 | 4.96 | 10.04 |
| 11 | 3.23 | 4.84 | 9.65 |
| 12 | 3.18 | 4.75 | 9.33 |

| | $v_1 = 1$ | | |
|---|---|---|---|
| $v_2$ | α = 10 % | α = 5 % | α = 1 % |
| 13 | 3.14 | 4.67 | 9.07 |
| 14 | 3.10 | 4.60 | 8.86 |
| 15 | 3.07 | 4.54 | 8.68 |
| 16 | 3.05 | 4.49 | 8.53 |
| 17 | 3.03 | 4.45 | 8.40 |
| 18 | 3.01 | 4.41 | 8.29 |
| 19 | 2.99 | 4.38 | 8.18 |
| 20 | 2.97 | 4.35 | 8.10 |
| 21 | 2.96 | 4.32 | 8.02 |
| 22 | 2.95 | 4.30 | 7.95 |
| 23 | 2.94 | 4.28 | 7.88 |
| 24 | 2.93 | 4.26 | 7.82 |

*Annex 7: Diesel price in ETB/litre from 29/03/00 (source: SHELL and MOBIL, Ethiopia)*

| location | tariff [ETB/litre] | location | tariff [ETB/litre] | location | tariff [ETB/litre] |
|---|---|---|---|---|---|
| Addis Ababa | 1.96 | Debre Zeyt | 1.96 | Mojo | 1.96 |
| Agere Mariyam | 2.09 | Dembidolo | 2.48 | Nazret | 1.95 |
| Ambo | 2.02 | Dessie | 1.87 | Negele | 2.16 |
| Arba Minch | 2.11 | Dilla | 2.05 | Nekemte | 2.08 |
| Asela | 1.97 | Gambela | 2.57 | Pawe | 2.15 |
| Asosa | 2.51 | Goba Robe | 2.08 | Shashemene | 2.01 |
| Awassa | 2.02 | Jimma | 2.1 | Weldiya | 1.91 |
| Bahir Dar | 2.05 | Jinka | 2.55 | Weliso | 2.02 |
| Bati | 1.84 | Metu | 2.19 | Welkite | 2.03 |
| Debre Birhan | 1.94 | Mizan Teferi | 2.41 | Ziway | 1.99 |
| Debre Markos | 2.08 | | | | |

[711] Maniak, 1993, p.222
[712] Sachs, 2002, p.115ff

## Annex 8: Development of consumption and required capacity for a 50 kW system

| | | | | | | |
|---|---|---|---|---|---|---|
| **initial population** | 500 | | **consumption per official connection [kWh/oc/year]** | | **yearly growth rate** | **amount of kWh that can be produced per year based on the design capacity of the plant [kwh/year]:** |
| **yearly growth rate** | 3.50% | | **residential** | 304 | 2.57% | 403,546 |
| **occupants per household** | 4.7 | (constant) | **commercial** | 176 | 2.98% | |
| **number of households per official connection [hh/oc]** | 2 | | **small industrial** | 216 | 1.65% | |
| **initial penetration rate** | 10% | | **street lighting** | 6 | 2.57% | |
| **yearly growth of penetration rate** | 3.00% | | **load factor** | 30% | | |
| **maximum penetration rate** | 40% | after 10 years | **peak factor** | 3.3 | | |

| | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **total population [pers]** | 500 | 518 | 536 | 554 | 574 | 594 | 615 | 636 | 658 | 681 | 705 | 730 | 756 | 782 | 809 | 838 | 867 | 897 | 929 | 961 | 995 | 1,030 | 1,066 | 1,103 | 1,142 |
| **number of households [hh]** | 106 | 110 | 114 | 118 | 122 | 126 | 131 | 135 | 140 | 145 | 150 | 155 | 161 | 166 | 172 | 178 | 184 | 191 | 198 | 205 | 212 | 219 | 227 | 235 | 243 |
| **"official" penetration rate** | 10% | 13% | 16% | 19% | 22% | 25% | 28% | 31% | 34% | 37% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% |
| **population supplied [pers]** | 100 | 135 | 171 | 211 | 252 | 297 | 344 | 394 | 448 | 504 | 564 | 584 | 604 | 626 | 647 | 670 | 694 | 718 | 743 | 769 | 796 | 824 | 853 | 882 | 913 |
| **number of official connections [oc]** | 11 | 14 | 18 | 22 | 27 | 32 | 37 | 42 | 48 | 54 | 60 | 62 | 64 | 67 | 69 | 71 | 74 | 76 | 79 | 82 | 85 | 88 | 91 | 94 | 97 |
| **number of households connected [hh]** | 21 | 29 | 36 | 45 | 54 | 63 | 73 | 84 | 95 | 107 | 120 | 124 | 129 | 133 | 138 | 143 | 148 | 153 | 158 | 164 | 169 | 175 | 181 | 188 | 194 |
| **residential consumption per oc [kWh/oc/year]** | 304 | 312 | 320 | 328 | 336 | 345 | 354 | 363 | 372 | 382 | 392 | 402 | 412 | 423 | 434 | 445 | 456 | 468 | 480 | 492 | 505 | 518 | 531 | 545 | 559 |
| **commercial consumption per oc [kWh/oc/year]** | 176 | 181 | 187 | 192 | 198 | 204 | 210 | 216 | 223 | 229 | 236 | 243 | 250 | 258 | 265 | 273 | 282 | 290 | 299 | 307 | 317 | 326 | 336 | 346 | 356 |
| **small industrial consumption per oc [kWh/oc/year]** | 216 | 220 | 223 | 227 | 231 | 234 | 238 | 242 | 246 | 250 | 254 | 259 | 263 | 267 | 272 | 276 | 281 | 285 | 290 | 295 | 300 | 305 | 310 | 315 | 320 |
| **street lighting consumption per oc [kWh/oc/year]** | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 9 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 11 | 11 |
| **total residential consumption [kWh/year]** | 3,234 | 4,463 | 5,832 | 7,352 | 9,037 | 10,902 | 12,962 | 15,235 | 17,738 | 20,492 | 23,519 | 24,967 | 26,505 | 28,138 | 29,871 | 31,711 | 33,665 | 35,739 | 37,940 | 40,277 | 42,758 | 45,392 | 48,188 | 51,157 | 54,308 |
| **total commercial consumption [kWh/year]** | 1,872 | 2,594 | 3,403 | 4,307 | 5,316 | 6,439 | 7,686 | 9,070 | 10,603 | 12,298 | 14,170 | 15,103 | 16,098 | 17,158 | 18,287 | 19,491 | 20,775 | 22,143 | 23,601 | 25,155 | 26,811 | 28,576 | 30,458 | 32,463 | 34,601 |
| **total small industrial consumption [kWh/year]** | 2,298 | 3,143 | 4,070 | 5,084 | 6,194 | 7,405 | 8,725 | 10,163 | 11,727 | 13,426 | 15,271 | 16,066 | 16,903 | 17,783 | 18,709 | 19,683 | 20,709 | 21,787 | 22,922 | 24,115 | 25,371 | 26,692 | 28,083 | 29,545 | 31,084 |
| **total street lighting consumption [kWh/year]** | 64 | 88 | 115 | 145 | 178 | 215 | 256 | 301 | 350 | 404 | 464 | 493 | 523 | 555 | 590 | 626 | 664 | 705 | 749 | 795 | 844 | 896 | 951 | 1,010 | 1,072 |
| **total consumption per year [kWh/year]** | 7,468 | 10,288 | 13,419 | 16,888 | 20,725 | 24,960 | 29,629 | 34,768 | 40,418 | 46,621 | 53,424 | 56,630 | 60,029 | 63,634 | 67,457 | 71,512 | 75,813 | 80,374 | 85,211 | 90,342 | 95,784 | 101,557 | 107,679 | 114,174 | 121,064 |
| **total consumption per connected person [kWh/pers/year]** | 75 | 76 | 78 | 80 | 82 | 84 | 86 | 88 | 90 | 92 | 95 | 97 | 99 | 102 | 104 | 107 | 109 | 112 | 115 | 117 | 120 | 123 | 126 | 129 | 133 |
| **actually required system output ("50 kW system") [kW]** | 3 | 4 | 5 | 6 | 8 | 9 | 11 | 13 | 15 | 18 | 20 | 22 | 23 | 24 | 26 | 27 | 29 | 31 | 32 | 34 | 36 | 39 | 41 | 43 | 46 |
| **possible yearly energy generation based on the "required system output" [kWh/year]** | 24,894 | 34,295 | 44,731 | 56,294 | 69,082 | 83,200 | 98,763 | 115,894 | 134,726 | 155,403 | 178,080 | 188,765 | 200,097 | 212,114 | 224,858 | 238,374 | 252,709 | 267,912 | 284,037 | 301,140 | 319,280 | 338,522 | 358,932 | 380,581 | 403,546 |
| **development of the plant utilisation (relation between producible kwh's and produced kWh's)** | 2% | 3% | 3% | 4% | 5% | 6% | 7% | 9% | 10% | 12% | 13% | 14% | 15% | 16% | 17% | 18% | 19% | 20% | 21% | 22% | 24% | 25% | 27% | 28% | 30% |

## Annex 9: Development of consumption and required capacity for a 150 kW system

| | | | | | | |
|---|---|---|---|---|---|---|
| **initial population** | 1,850 | | **consumption per official connection [kWh/oc/year]** | | **yearly growth rate** | **amount of kWh that can be produced per year based on the design capacity of the plant [kwh/year]:** |
| **yearly growth rate** | 3.50% | | **residential** | 304 | 2.57% | 1,119,841 |
| **occupants per household** | 4.7 | (constant) | **commercial** | 176 | 2.98% | |
| **number of households per official connection (hh/oc]** | 2 | | **small industrial** | 216 | 1.65% | |
| **initial penetration rate** | 10% | | **street lighting** | 6 | 2.57% | |
| **yearly growth of penetration rate** | 3.00% | | **load factor** | 40% | | |
| **maximum penetration rate** | 40% | after 10 years | **peak factor** | 2.5 | | |

| | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **total population [pers]** | 1,850 | 1,915 | 1,982 | 2,051 | 2,123 | 2,197 | 2,274 | 2,354 | 2,436 | 2,521 | 2,610 | 2,701 | 2,795 | 2,893 | 2,995 | 3,099 | 3,208 | 3,320 | 3,436 | 3,557 | 3,681 | 3,810 | 3,943 | 4,081 | 4,224 |
| **number of households [hh]** | 394 | 407 | 422 | 436 | 452 | 467 | 484 | 501 | 518 | 536 | 555 | 575 | 595 | 616 | 637 | 659 | 683 | 706 | 731 | 757 | 783 | 811 | 839 | 868 | 899 |
| **penetration rate** | 10% | 13% | 16% | 19% | 22% | 25% | 28% | 31% | 34% | 37% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% | 40% |
| **population supplied [pers]** | 370 | 498 | 634 | 779 | 934 | 1099 | 1274 | 1459 | 1657 | 1866 | 2088 | 2161 | 2236 | 2315 | 2396 | 2480 | 2566 | 2656 | 2749 | 2845 | 2945 | 3048 | 3155 | 3265 | 3379 |
| **number of official connections [oc]** | 39 | 53 | 67 | 83 | 99 | 117 | 135 | 155 | 176 | 198 | 222 | 230 | 238 | 246 | 255 | 264 | 273 | 283 | 292 | 303 | 313 | 324 | 336 | 347 | 360 |
| **number of households connected [hh]** | 79 | 106 | 135 | 166 | 199 | 234 | 271 | 310 | 352 | 397 | 444 | 460 | 476 | 492 | 510 | 528 | 546 | 565 | 585 | 605 | 627 | 649 | 671 | 695 | 719 |
| **residential consumption per oc [kWh/oc/year]** | 304 | 312 | 320 | 328 | 336 | 345 | 354 | 363 | 372 | 382 | 392 | 402 | 412 | 423 | 434 | 445 | 456 | 468 | 480 | 492 | 505 | 518 | 531 | 545 | 559 |
| **commercial consumption per oc [kWh/oc/year]** | 176 | 181 | 187 | 192 | 198 | 204 | 210 | 216 | 223 | 229 | 236 | 243 | 250 | 258 | 265 | 273 | 282 | 290 | 299 | 307 | 317 | 326 | 336 | 346 | 356 |
| **small industrial consumption per oc [kWh/oc/year]** | 216 | 220 | 223 | 227 | 231 | 234 | 238 | 242 | 246 | 250 | 254 | 259 | 263 | 267 | 272 | 276 | 281 | 285 | 290 | 295 | 300 | 305 | 310 | 315 | 320 |
| **street lighting consumption per oc [kWh/oc/year]** | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 9 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 11 | 11 |
| **total residential consumption [kWh/year]** | 11,966 | 16,514 | 21,577 | 27,201 | 33,436 | 40,336 | 47,959 | 56,368 | 65,631 | 75,822 | 87,019 | 92,379 | 98,070 | 104,111 | 110,524 | 117,332 | 124,560 | 132,233 | 140,378 | 149,026 | 158,205 | 167,951 | 178,297 | 189,280 | 200,939 |
| **total commercial consumption [kWh/year]** | 6,928 | 9,599 | 12,592 | 15,937 | 19,669 | 23,823 | 28,438 | 33,558 | 39,229 | 45,502 | 52,430 | 55,882 | 59,561 | 63,483 | 67,663 | 72,118 | 76,867 | 81,928 | 87,322 | 93,072 | 99,200 | 105,732 | 112,693 | 120,113 | 128,022 |
| **total small industrial consumption [kWh/year]** | 8,502 | 11,628 | 15,057 | 18,812 | 22,916 | 27,397 | 32,283 | 37,603 | 43,390 | 49,677 | 56,502 | 59,445 | 62,540 | 65,797 | 69,224 | 72,829 | 76,622 | 80,612 | 84,810 | 89,227 | 93,873 | 98,762 | 103,905 | 109,316 | 115,009 |
| **total street lighting consumption [kWh/year]** | 236 | 326 | 426 | 537 | 660 | 796 | 947 | 1,113 | 1,295 | 1,496 | 1,717 | 1,823 | 1,936 | 2,055 | 2,181 | 2,316 | 2,458 | 2,610 | 2,771 | 2,941 | 3,122 | 3,315 | 3,519 | 3,736 | 3,966 |
| **total consumption per year [kWh/year]** | 27,632 | 38,067 | 49,652 | 62,487 | 76,681 | 92,352 | 109,627 | 128,642 | 149,546 | 172,498 | 197,669 | 209,529 | 222,107 | 235,446 | 249,593 | 264,595 | 280,507 | 297,382 | 315,281 | 334,265 | 354,401 | 375,759 | 398,414 | 422,445 | 447,936 |
| **total consumption per connected person [kWh/pers/year]** | 75 | 76 | 78 | 80 | 82 | 84 | 86 | 88 | 90 | 92 | 95 | 97 | 99 | 102 | 104 | 107 | 109 | 112 | 115 | 117 | 120 | 123 | 126 | 129 | 133 |
| **actually required system output ("150 kW system") [kW]** | 8 | 11 | 14 | 18 | 22 | 26 | 31 | 37 | 43 | 49 | 56 | 60 | 63 | 67 | 71 | 76 | 80 | 85 | 90 | 95 | 101 | 107 | 114 | 121 | 128 |
| **possible yearly energy generation based on the "required system output" [kWh/year]** | 69,080 | 95,168 | 124,130 | 156,217 | 191,702 | 230,880 | 274,067 | 321,605 | 373,865 | 431,244 | 494,171 | 523,823 | 555,268 | 588,616 | 623,981 | 661,488 | 701,267 | 743,456 | 788,203 | 835,663 | 886,003 | 939,398 | 996,035 | 1,056,113 | 1,119,841 |
| **development of the plant utilisation (relation between producible kwh's and produced kWh's)** | 2% | 3% | 4% | 6% | 7% | 8% | 10% | 11% | 13% | 15% | 18% | 19% | 20% | 21% | 22% | 24% | 25% | 27% | 28% | 30% | 32% | 34% | 36% | 38% | 40% |

## Annex 10: Rough investment cost estimation for a 50 kW-MHP-system

**important design figures:**

| | |
|---|---|
| **available Q (90, daily)** | 0.50 m³/s |
| **required available net height** | 20.04 m |
| **overall efficiency** | 0.52 |
| **roughly estimated capacity at the end-user** | 46 kW |
| **system capacity (generator output)** | 56 kW |
| **exchange rate USD:ETB** | 8.2 ETB ~ 1USD<br>7.1 ETB ~ 1 € |

| | **components** | **description** | **unit price** | **unit** | **quantity** | **total cost [ETB]** | **subtotals [ETB]** |
|---|---|---|---|---|---|---|---|
| **civil works** | access road | | 150 | ETB/m | 1,000.00 | 150,000 | |
| | weir (l = 5m, w = 0.4m); concrete | excavation (depth 0.5 m) | 20 | ETB/m³ | 1.00 | 20 | |
| | | construction (height 1 m) | 800 | ETB/m³ | 3.00 | 2,400 | |
| | intake with settling bassin (l=5m, w=3m);masonry | excavation | 20 | ETB/m³ | 12.10 | 242 | |
| | | construction | 300 | ETB/m³ | 4.34 | 1,303 | |
| | trash rack (1 at intake, 1 at penstock) | | 6,800 | ETB/m² | 0.63 | 4,250 | |
| | inlet gate (1 at intake, 1 at penstock) | | 2,500 | ETB/m² | 0.63 | 1,563 | |
| | power channel; masonry | excavation | 20 | ETB/m³ | 768.75 | 15,375 | |
| | | construction | 300 | ETB/m³ | 396.25 | 118,875 | |
| | forebay (same as intake settling bassin) | excavation | 20 | ETB/m³ | 12.10 | 242 | |
| | | construction | 300 | ETB/m³ | 4.34 | 1,303 | |
| | tailrace;masonry | excavation | 20 | ETB/m³ | 7.69 | 154 | |
| | | construction | 300 | ETB/m³ | 3.96 | 1,189 | |
| | powerhouse (with turbine, mill, generator, transformer, sustainer, trolley etc.) | | 2,500 | ETB/m² | 16.00 | 40,000 | |
| | ***subtotal civil works*** | | | | | | ***336,915*** |
| **mechanical equipment** | penstock with diameter ...[m] | 0.50 | 1,550 | ETB/m | 41.32 | 64,052 | |
| | valves / plant equipment | | | | | 70,000 | |
| | penstock support facilities | | 10 | % | | 6,405 | |
| | turbine | T12 Selam | 33,600 | ETB/pc | 1.00 | 33,600 | |
| | capacity at design flow: | 66 | kW | | | | |
| | ***subtotal mechanical equipment*** | | | | | | ***174,057*** |
| **electrical equipment** | **3-phase synchronous generator** with rated output of about: ...[kVA] | 70 | 40,000 | ETB/pc | 1.00 | 40,000 | |
| | ELC with capacity of: ...[kW] | 62 | 39,989 | ETB/pc | 1.00 | 39,989 | |
| | switch board + electric wiring | | 20,000 | ETB/pc | 1.00 | 20,000 | |
| | step up transformer (0.4/15 kV) [kVA]: | 74 | 26,000 | ETB/pc | 1.00 | 26,000 | |
| | step down transformer (15/0.4 kV) [kVA]: | 25 | 11,000 | ETB/pc | 3.00 | 33,000 | |
| | **transmission line (15 kV), with total length [m]:** | 5,000 | | | | | |
| | | 3 ACSR conductors, 20 mm² | 1.50 | ETB/m/conduc. | 15,000 | 22,500 | |
| | spanning [m] | 50 | | | | | |
| | | impregnated wooden poles of 10 m height | 160 | ETB/pc | 100 | 16,000 | |
| | | insulators | 90 | ETB/pc | 300 | 27,000 | |
| | | suspension cross arms | 300 | ETB/pc | 100 | 30,000 | |
| | installation material + all fixation material | 15% | of transmission items | | | 14,325 | |
| | *subtotal transmission line* | | | | | | *109,825* |
| | **distribution grid with total length [m]** | 8,000 | | | | | |
| | | 3 AAC conductors (3 phases), 25 mm² | 2.70 | ETB/m/conduc. | 24,000 | 64,800 | |
| | | 1 AAC conductor (neutral), 15 mm² | 1.35 | ETB/m/conduc. | 8,000 | 10,800 | |
| | spanning [m] | 30 | | | | | |
| | | impregnated wooden poles of 8 m height | 110 | ETB/pc | 267 | 29,333 | |
| | | N 80 insulators | 33 | ETB/pc | 1,067 | 35,200 | |
| | installation material + all fixation material | 15% | of distribution items | | | 21,020 | |
| | *subtotal distribution line* | | | | | | *161,153* |
| | electricity meters (optional) | standard kWh meter | 430 | ETB/pc | 11 | 4,574 | |
| | ***subtotal electrical equipment*** | | | | | | ***434,541*** |
| **SUBTOTAL 1 (civil works + purchasing cost)** | | | | | | **945,514.20** | **ETB** |
| **ADDITIONAL COSTS:** | | | | | | | |
| **international transport costs for imported (mainly electrical) equipment** | | all prices as CIF prices Addis Ababa (incl. transport and insurance to Bole Airport) | | | | 0 | |
| **duties for imported (electrical) equipment** | normally about 8 % on the average | exemption for holders of an investment licence !!! | | | | 0 | |
| **national transport costs (for a site 500 km from Addis); as percentage of** | 500 | km from Addis: | | | | | |
| | 490 | km asphalt | 98.00% | 3.00% | 2.94% | 27,798 | |
| | 10 | km gravel | 2.00% | 4.50% | 0.09% | 851 | |
| **total installation costs (as percentage of purchasing cost; except civil works)** | 10% | for MHP | | | 1 | 60,860 | |
| **staff training costs** | 3% | | | | | 28,365 | |
| **SUBTOTAL 2 (investment without planning cost)** | | | | | | **1,063,389** | **ETB** |
| **planning costs as percentage of subtotal 1** | 11% | 10 - 100 kW | MHP system | | 1 | 104,007 | |
| **TOTAL** | | | | | | **1,167,395** | |
| **total specific costs per kW** | | | | | | **20,734** | **ETB/kW installed capacity** |
| | | | | | | **2,529** | **USD/kW installed capacity** |
| **without electrical part** | | | | | | ***10,930*** | ETB/kW installed capacity |
| | | | | | | ***1,333*** | USD/kW installed capacity |

## *Annex 11: Rough investment cost estimation for a 50 kW - diesel genset - system*

**important design figures:**

| | | | |
|---|---|---|---|
| **overall efficiency** | 0.32 | | |
| **roughly estimated capacity at the end-user** | 13.23 | kW | |
| **system capacity (generator output)** | 16.17 | kW | =capacity required for **step 1** (8 years - period) |

| | components | description | chosen unit price | unit | quantity | total cost | subtotals [ETB] |
|---|---|---|---|---|---|---|---|
| **civil works** | powerhouse (with generator set, barrels or diesel reservoir and mill) | | 1,700 | ETB/m² | 16.00 | 27,200 | |
| | ***subtotal civil works*** | | | | | | 27,200 |
| **mechanical and electrical equipment** | rated output of diesel genset [kVA] | 20 | 40,000 | ETB/pc | 1.00 | 40,000 | |
| | switch board / electric installation | | 18,000 | ETB/pc | 1.00 | 18,000 | |
| | *subtotal genset + "accessories'* | | | | | | 58,000 |
| | **distribution grid with total length [m]** | 8,000 | | | | | |
| | **1/3 of the "distribution investment" every 8 years (!)** | 3 AAC conductors (3 phases), 25 | 2.70 | ETB/m/ cond. | 24,000 | 64,800 | |
| | | 1 AAC conductors (neutral), 15 mm² | 1.35 | ETB/m/ cond. | 8,000 | 10,800 | |
| | spanning [m] | 30 | | | | | |
| | | impregnated wooden poles of 8 m height | 110 | ETB/pc | 267 | 29,333 | |
| | | N 80 insulators | 33 | ETB/pc | 1,067 | 35,200 | |
| | installation material + all fixation material | 15% | of distribution items | | | 21,020 | |
| | *1/3 of subtotal distribution line* | | | | | | 53,718 |
| | electricity meters (optional) | standard kWh mete | 430 | ETB/pc | 11 | 4,574 | 4,574 |
| | ***subtotal electr.+mech. equipment*** | | | | | | ***116,292*** |
| **SUBTOTAL 1** | | | | | | **143,492** | |
| **ADDITIONAL COSTS:** | | | | | | | |
| **internat. transport costs for imported (mainly electrical) equipment** | | all prices as CIF prices Addis Ababa (incl. transport and insurance to Bole Airport) | | | | 0 | |
| **duties for imported (electrical) equipment** | normally about 8 % on the average | exemption for holders of an investment licence !!! | | | | 0 | |
| **national transp. costs (for a site 500 km from Addis); as % of subtotal 1** | 500 | km from Addis: | | | | | |
| | 490 | km asphalt | 98.00% | 3.00% | 2.94% | 4,219 | |
| | 10 | km gravel | 2.00% | 4.50% | 0.09% | 129 | |
| **total installation costs (as percentage of purchasing cost; except civil works)** | 12% | for diesel genset | | | 1 | 13,955 | |
| **staff training costs** | 3% | | | | | 4,305 | |
| **SUBTOTAL 2 (investment without planning cost)** | | | | | | **166,100** | **ETB** |
| **planning costs as percentage of subtotal 1** | 8% | < 100 kW | diesel plant or grid connection | | 1 | 11,479 | |
| ***TOTAL*** | | | | | | **177,579** | |
| ***total specific costs per kW*** | | | | | | **10,982** | **ETB/kW installed capacity** |
| | | | | | | **1,339** | **USD/kW installed capacity** |

## *Annex 12: Rough investment cost estimation for a connection to an existing grid / substation* ***for a total load of about 50 kW***

**important design figures:**

| | | |
|---|---|---|
| **roughly estimated capacity at the end-user** | 46 | kW |
| **power to be transmitted** | 56 | kW |

| | components | description | chosen unit price | unit | quantity | total cost [ETB] | subtotals [ETB] |
|---|---|---|---|---|---|---|---|
| **electrical equipment** | **power to be transmitted** [kVA] | 70 | | | | | |
| | step down transformers (15/0.4 kV) with capacity [kVA]: | 23 | 12,000 | ETB/pc | 3.00 | 36,000 | |
| | **transmission line (15 kV) with total length [m]** | 25,000 | | | | | |
| | | 3 ACSR conductors, 129 mm² | 4.00 | ETB/m/ con-ductor | 75,000 | 300,000 | |
| | spanning [m] | 50 | | | | | |
| | | impregnated wooden poles of 12 m height | 220 | ETB/pc | 500 | 110,000 | |
| | | insulators | 90 | ETB/pc | 1500 | 135,000 | |
| | | suspension cross arms | 300 | ETB/pc | 500 | 150,000 | |
| | installation material and all fixation materials | 15% | of distribution items | | | 81,750 | |
| | *subtotal transmission line* | | | | | | *776,750* |
| | **distribution grid with total length [m]** | 8,000 | | | | | |
| | | 3 AAC conductors (3 phases), 25 mm² | 2.70 | ETB/m/ conduct or | 24,000 | 64,800 | |
| | | 1 AAC conductor (neutral), 15 mm² | 1.35 | ETB/m/ conduct or | 8,000 | 10,800 | |
| | spanning [m] | 30 | | | | | |
| | | impregnated wooden poles of 8 m height | 110 | ETB/pc | 267 | 29,333 | |
| | | N 80 insulators | 33 | ETB/pc | 1,067 | 35,200 | |
| | installation material and all fixation materials | 15% | of distribution items | | | 21,020 | |
| | *subtotal distribution line* | | | | | | *161,153* |
| | electricity meters (optional) | standard kWh mete | 430 | ETB/pc | 11 | 4,574 | |
| | ***subtotal electrical equipment*** | | | | | | ***978,478*** |
| **SUBTOTAL 1 (civil works + purchasing cost)** | | | | | | **978,478** | **ETB** |
| **ADDITIONAL COSTS:** | | | | | | | |
| **international transport costs for imported (mainly electrical) equipment** | | all prices as CIF prices Addis Ababa (incl. transport and insurance to Bole Airport) !!! | | | | 0 | |
| **duties for imported (electrical) equipment** | normally about 8 % on the average | exemption for holders of an investment licence !!! | | | | 0 | |
| **national transport costs (for a site 500 km from Addis); as percentage of subtotal 1** | 500 | km from Addis: | | | | | |
| | 490 | km asphalt | 98.00% | 3.00% | 2.94% | 28,767 | |
| | 10 | km gravel | 2.00% | 4.50% | 0.09% | 881 | |
| **total installation costs (as percentage of purchasing cost; except civil works)** | 15% | for grid connection | | | 1 | 146,772 | |
| **staff training costs** | 3% | | | | | 29,354 | |
| **SUBTOTAL 2 (investment without planning cost)** | | | | | | **1,184,252** | |
| **planning costs as percentage of subtotal 1** | 8% | < 100 kW | | | 1 | 78,278 | |
| **TOTAL** | | | | | | **1,262,530** | |
| **total specific costs per kW** | | | | | | **22,423** | **ETB/kW installed capacity** |
| | | | | | | **2,735** | **USD/kW installed capacity** |

## *Annex 13: Rough investment cost estimation for a 150 kW-MHP-system*

**important design figures:**

| | |
|---|---|
| **available Q (90, daily)** | 0.75 m³/s |
| **required available net height** | 37.07 m |
| **overall efficiency** | 0.52 |
| **roughly estimated capacity at the end-user** | 128 kW |
| **system capacity (generator output)** | 156 kW |
| **exchange rate USD:ETB** | 8.2 ETB ~ 1USD<br>7.1 ETB ~ 1 € |

| | **components** | **description** | **chosen unit price** | **unit** | **quantity** | **total cost [ETB]** | **subtotals [ETB]** |
|---|---|---|---|---|---|---|---|
| **civil works** | access road | | 150 | ETB/m | 1,000.00 | 150,000 | |
| | weir (l = 10m, w = 0.6m); concrete | excavation (depth 0.8m) | 20 | ETB/m³ | 4.80 | 96 | |
| | | construction (height 1.5 m) | 800 | ETB/m³ | 13.80 | 11,040 | |
| | intake with settling bassin (l=10m, w=6m);masonry | excavation | 20 | ETB/m³ | 55.97 | 1,119 | |
| | | construction | 300 | ETB/m³ | 15.94 | 4,781 | |
| | trash rack (1 at intake, 1 at penstock) | | 6,800 | ETB/m² | 0.94 | 6,375 | |
| | inlet gate (1 at intake, 1 at penstock) | | 2,500 | ETB/m² | 0.94 | 2,344 | |
| | power channel; masonry | excavation | 20 | ETB/m³ | 1,025.00 | 20,500 | |
| | | construction | 300 | ETB/m³ | 476.25 | 142,875 | |
| | forebay (same as intake settling bassin) | excavation | 20 | ETB/m³ | 55.97 | 1,119 | |
| | | construction | 300 | ETB/m³ | 15.94 | 4,781 | |
| | tailrace;masonry | excavation | 20 | ETB/m³ | 10.25 | 205 | |
| | | construction | 300 | ETB/m³ | 4.76 | 1,429 | |
| | powerhouse (with turbine, mill, generator, transformer, sustainer, trolley etc.) | | 2,500 | ETB/m² | 20.00 | 50,000 | |
| | ***subtotal civil works*** | | | | | | ***396,664*** |
| **mechanical equipment** | penstock with diameter ...[m] | 0.60 | 1,800 | ETB/m | 76.11 | 136,990 | |
| | valves / plant equipment | | | | | 90,000 | |
| | penstock support facilities | | 10 | % | | 13,699 | |
| | turbine | T12 Selam | 35,000 | ETB/pc | 1.00 | 35,000 | |
| | capacity at design flow: | 183 | kW | | | | |
| | ***subtotal mechanical equipment*** | | | | | | ***275,689*** |
| **electrical equipment** | **3-phase synchronous generator** with rated output of about: ...[kVA] | 195 | 95,000 | ETB/pc | 1.00 | 95,000 | |
| | ELC with capacity of: ...[kW] | 172 | 86,224 | ETB/pc | 1.00 | 86,224 | |
| | switch board + electric wiring | | 28,000 | ETB/pc | 1.00 | 28,000 | |
| | step up transformer (0.4/15 kV) [kVA] | 205 | 40,000 | ETB/pc | 1.00 | 40,000 | |
| | step down transformer (15/0.4 kV) [kVA] | 41 | 13,000 | ETB/pc | 5.00 | 65,000 | |
| | **transmission line (15 kV) with total length [m]** | 5,000 | | | | | |
| | | 3 ACSR conductors, 20 mm² | 1.50 | ETB/m/con-ductor | 15,000 | 22,500 | |
| | spanning [m] | 50 | | | | | |
| | | impregnated wooden poles of 10 m height | 160 | ETB/pc | 100 | 16,000 | |
| | | insulators | 90 | ETB/pc | 300 | 27,000 | |
| | | suspension cross arms | 300 | ETB/pc | 100 | 30,000 | |
| | installation material + all fixation material | 15% | of transmission items | | | 14,325 | |
| | *subtotal transmission line* | | | | | | *109,825* |
| | **distribution grid with total length [m]** | 25,000 | | | | | |
| | | 3 AAC conductors (3 phases), 50 mm² | 4.10 | ETB/m/conductor | 75,000 | 307,500 | |
| | | 1 AAC conductor (neutral), 25 mm² | 2.70 | ETB/m/conductor | 25,000 | 67,500 | |
| | spanning [m] | 30 | | | | | |
| | | impregnated wooden poles of 8 m height | 110 | ETB/pc | 833 | 91,667 | |
| | | N 80 insulators | 33 | ETB/pc | 3,333 | 110,000 | |
| | installation material + all fixation material | 15% | of distribution items | | | 86,500 | |
| | *subtotal distribution line* | | | | | | *663,167* |
| | electricity meters (optional) | standard kWh meter | 430 | ETB/pc | 39 | 16,926 | |
| | ***subtotal electrical equipment*** | | | | | | ***1,104,141*** |
| **SUBTOTAL 1 (civil works + purchasing cost)** | | | | | | **1,776,493.22 ETB** | |
| **ADDITIONAL COSTS:** | | | | | | | |
| **international transport costs for imported (mainly electrical) equipment** | | all prices as CIF prices Addis Ababa (incl. transport and insurance to Bole Airport) !!! | | | | 0 | |
| **duties for imported (electrical) equipment** | normally about 8 % on the average | exemption for holders of an investment licence !!! | | | | 0 | |
| **national transport costs (for a site 500 km from Addis); as percentage of subtotal 1** | 500 | km from Addis: | | | | | |
| | 490 | km asphalt | 98.00% | 3.00% | 2.94% | 52,229 | |
| | 10 | km gravel | 2.00% | 4.50% | 0.09% | 1,599 | |
| **total installation costs (as percentage of purchasing cost; except civil works)** | 10% | for MHP | | | | 137,983 | |
| **staff training costs** | 3% | | | | | 53,295 | |
| **SUBTOTAL 2 (investment without planning cost)** | | | | | | **2,021,599** | |
| **planning costs as percentage of subtotal 1** | 8% | 100 - 1000 kW | MHP system | | | 142,119 | |
| **TOTAL** | | | | | | **2,163,718** | |
| **total specific costs per kW** | | | | | | **13,848** | **ETB/kW installed capacity** |
| | | | | | | **1,689** | **USD/kW installed capacity** |
| **without electrical part** | | | | | | **5,083** | ETB/kW installed capacity |
| | | | | | | **620** | USD/kW installed capacity |

## Annex 14: Rough investment cost estimation for a 150 kW - diesel genset system

**important design figures:**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **overall efficiency** | 0.32 | | | | | | |
| **roughly estimated capacity at the end-user** | 36.71 | kW | | | | | |
| **system capacity (generator output)** | 44.87 | kW | =capacity required for **step 1** (8 years - period) | | | | |
| | **components** | **description** | **chosen unit price** | **unit** | **quantity** | **total cost** | **subtotals [ETB]** |
| **civil works** | powerhouse (with generator set, barrels or diesel reservoir and mill) | | 1,700 | ETB/m² | 20.00 | 34,000 | |
| | ***subtotal civil works*** | | | | | | 34,000 |
| **mechanical and electrical equipment** | diesel genset with rated output of about: ... [kVA] | 56 | 90,000 | ETB/pc | 1.00 | 90,000 | |
| | switch board + electric wiring | | 25,200 | ETB/pc | 1.00 | 25,200 | |
| | *subtotal genset + "accessories"* | | | | | | 115,200 |
| | **distribution grid with total length [m]** | 25,000 | | | | | |
| | | 3 AAC conductors (3 phases), 50 mm² | 4.10 | ETB/m/cond. | 75,000 | 307,500 | |
| | | 1 AAC conductors (neutral), 25 mm² | 2.05 | ETB/m/cond. | 25,000 | 51,250 | |
| | spanning [m] | 30 | | | | | |
| | | impregnated wooden poles of 8 m height | 110 | ETB/pc | 833 | 91,667 | |
| | | N 80 insulators | 33 | ETB/pc | 3,333 | 110,000 | |
| | installation material and all fixation materials | 15% | of distribution items | | | 84,063 | |
| | *1/3 of subtotal distribution line* | | | | | | 214,826 |
| | electricity meters (optional) | standard kWh meter | 430 | ETB/pc | 39 | 16,926 | 16,926 |
| | ***subtotal electr.+mech. equipment*** | | | | | | ***346,952*** |
| **SUBTOTAL 1** | | | | | | **380,952** | |
| **ADDITIONAL COSTS:** | | | | | | | |
| **international transport costs for imported (mainly electrical) equipment** | | all prices as CIF prices Addis Ababa (incl. transport and insurance to Bole Airport) !!! | | | | 0 | |
| **duties for imported (electrical) equipment** | normally about 8 % on the average | exemption for holders of an investment licence !!! | | | | 0 | |
| **national transport costs (for a site 500 km from Addis); as percentage of subtotal 1** | 500 | km from Addis: | | | | | |
| | 490 | km asphalt | 98.00% | 3.00% | 2.94% | 11,200 | |
| | 10 | km gravel | 2.00% | 4.50% | 0.09% | 343 | |
| **total installation costs (as percentage of purchasing cost; except civil works)** | 12% | for diesel genset | | | 1 | 41,634 | |
| **staff training costs** | 3% | | | | | 11,429 | |
| **SUBTOTAL 2 (investment without planning cost)** | | | | | | **445,558** | |
| **planning costs as percentage of subtotal 1** | 8% | < 100 kW | diesel plant | | 1 | 30,476 | |
| **TOTAL** | | | | | | **476,034** | |
| **total specific costs per kW** | | | | | | **10,609** | ***ETB/kW installed capacity*** |
| | | | | | | **1,294** | ***USD/kW installed capacity*** |

## Annex 15: Rough investment cost estimation for a connection to an existing grid / substation **for a total load of about 150 kW**

**important design figures:**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **roughly estimated capacity at the end-user** | 128 | kW | | | | | |
| **power to be transmitted** | 156 | kW | | | | | |
| **exchange rate USD:ETB** | 8.2 | ETB ~ 1USD | | | | | |
| | 7.1 | ETB ~ 1 € | | | | | |
| | **components** | **description** | **chosen unit price** | **unit** | **quantity** | **total cost [ETB]** | **subtotals [ETB]** |
| **electrical equipment** | **power to be transmitted** [kVA] | 195 | | | | | |
| | step down transformers (15/0.4 kV) with capacity [kVA]: | 39 | 13,000 | ETB/pc | 5.00 | 65,000 | |
| | **transmission line (15 kV) with total length [m]** | 33,000 | | | | | |
| | | 3 ACSR conductors, 129 mm² | 4.00 | ETB/m/con-ductor | 99,000 | 396,000 | |
| | spanning [m] | 50 | | | | | |
| | | impregnated wooden poles of 12 m height | 220 | ETB/pc | 660 | 145,200 | |
| | | insulators | 90 | ETB/pc | 1980 | 178,200 | |
| | | suspension cross arms | 300 | ETB/pc | 660 | 198,000 | |
| | installation material and all fixation materials | 15% | of distribution items | | | 107,910 | |
| | *subtotal transmission line* | | | | | | *1,025,310* |
| | **distribution grid with total length [m]** | 25,000 | | | | | |
| | | 3 AAC conductors (3 phases), 50 mm² | 4.10 | ETB/m/cond. | 75,000 | 307,500 | |
| | | 1 AAC conductor (neutral), 25 mm² | 2.70 | ETB/m/cond. | 25,000 | 67,500 | |
| | spanning [m] | 30 | | | | | |
| | | impregnated wooden poles of 8 m height | 110 | ETB/pc | 833 | 91,667 | |
| | | N 80 insulators | 33 | ETB/pc | 3,333 | 110,000 | |
| | installation material and all fixation materials | 15% | of distribution items | | | 86,500 | |
| | *subtotal distribution line* | | | | | | *663,167* |
| | electricity meters (optional) | standard kWh meter | 430 | ETB/pc | 39 | 16,926 | |
| | ***subtotal electrical equipment*** | | | | | | ***1,770,402*** |
| **SUBTOTAL 1 (civil works + purchasing cost)** | | | | | | **1,770,402** | **ETB** |
| **ADDITIONAL COSTS:** | | | | | | | |
| **international transport costs for imported (mainly electrical) equipment** | | all prices as CIF prices Addis Ababa (incl. transport and insurance to Bole Airport) !!! | | | | 0 | |
| **duties for imported (electrical) equipment** | normally about 8 % on the average | exemption for holders of an investment licence !!! | | | | 0 | |
| **national transport costs (for a site 500 km from Addis); as percentage of subtotal 1** | 500 | km from Addis: | | | | | |
| | 490 | km asphalt | 98.00% | 3.00% | 2.94% | 52,050 | |
| | 10 | km gravel | 2.00% | 4.50% | 0.09% | 1,593 | |
| **total installation costs (as percentage of purchasing cost; except civil works)** | 15% | for grid connection | | | 1 | 265,560 | |
| **staff training costs** | 3% | | | | | 53,112 | |
| **SUBTOTAL 2 (investment without planning cost)** | | | | | | **2,142,718** | |
| **planning costs as percentage of subtotal 1** | 5% | 100-1000 kW | | | 1 | 88,520 | |
| **TOTAL** | | | | | | **2,231,238** | |
| **total specific costs per kW** | | | | | | **14,281** | **ETB/kW installed capacity** |
| | | | | | | **1,742** | **USD/kW installed capacity** |

# Annex 16: Calculation of profitability for a 50 kW MHP and a 50 kW diesel system

| MHP system | | |
|---|---|---|
| system capacity (generator output) | 56.30 | kW |
| available final output capacity | 46.07 | kW |
| cost of output capacity | 20,734 | ETB/kW |
| operating cost | 3.0% | |
| load factor | 30.0% | |
| resulting operational hours | 2628 | hours |
| tariff | 1.5 | ETB/kWh |
| lifetime | 25 | years |

| Diesel system | step1 | step2 | step3 | |
|---|---|---|---|---|
| system capacity (generator output) | 16.17 | 33.26 | 53.10 | kW |
| available final output capacity | 13.23 | 27.21 | 43.45 | kW |
| cost of output capac. (incl. inflation) | 10,982 | 8,948 | 10,268 | ETB/kW |
| operating cost | 5.0% | 5.0% | 5.0% | |
| load factor | 30.0% | 30.0% | 30.0% | |
| resulting operational hours | 2628 | 2628 | 2628 | hours |
| tariff (incl. inflation) | 1.5 | 2.13 | 3.03 | ETB/kWh |
| fuel price | 2.5 | ETB/l | | |
| fuel price | 0.3 | USD/l | | |
| inflation fuel | 4.50% | per year | | |
| lifetime | 8 | years | | |
| calorific value | 0.1 | litre fuel/kWh | | |

**general parameters:**

| | | |
|---|---|---|
| interest (average) | 12% | |
| inflation | 4.50% | |
| exchange rate | 8.2 | ETB/USD |

| financing parameters: | % of total inv. | interest |
|---|---|---|
| equity | 30% | |
| loan | 30% | 12.0% |
| juissance | 40% | 3.0% |
| total "loan-financing" | 70% | 6.86% |
| percentage of supplied households with juissance shares | | 100% |
| initial average juissance charge | 18,955 ETB/connected hh | |
| redemption free period: | 0 *years* | |
| interest free period: | 10 *years* | |
| **"special" loan redemption** allowed: for yes fill in 1, for no fill in 0: | 0 | |

**tax parameters:**

| | |
|---|---|
| **MHP systems** | |
| percentage to be paid: | 35% |
| number of tax free years | 25 |
| **diesel systems** | |
| percentage to be paid: | 35% |
| number of tax free years: | 5 |
| **grid connection systems** | |
| percentage to be paid: | 35% |
| number of tax free years: | 5 |

| **years** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| kWh's sold | 7,468 | 10,288 | 13,419 | 16,888 | 20,725 | 24,960 | 29,629 | 34,768 | 40,418 | 46,621 | 53,424 | 56,630 | 60,029 | 63,634 | 67,457 | 71,512 | 75,813 | 80,374 | 85,211 | 90,342 | 95,784 | 101,557 | 107,679 | 114,174 | 121,064 |

**MHP system [costs in 1,000 ETB !]**

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| investment costs | 1,008 | | | | | 50 | | | | | 62 | | | | | 77 | | | | | 96 | | | | -158 |
| equity part | 302 | | | | | 15 | | | | | 19 | | | | | 23 | | | | | 29 | | | | -47 |
| loan part | 302 | | | | | 15 | | | | | 19 | | | | | 23 | | | | | 29 | | | | -47 |
| juissance part | 403 | | | | | 20 | | | | | 25 | | | | | 31 | | | | | 38 | | | | -63 |
| tariff [ETB/kWh] ! | 1.50 | 1.57 | 1.64 | 1.71 | 1.79 | 1.87 | 1.95 | 2.04 | 2.13 | 2.23 | 2.33 | 2.43 | 2.54 | 2.66 | 2.78 | 2.90 | 3.03 | 3.17 | 3.31 | 3.46 | 3.62 | 3.78 | 3.95 | 4.13 | 4.31 |
| return on juissance [kWh] | 8,066 | 8,066 | 8,066 | 8,066 | 8,066 | 8,398 | 8,398 | 8,398 | 8,398 | 8,398 | 8,731 | 8,731 | 8,731 | 8,731 | 8,731 | 9,064 | 9,064 | 9,064 | 9,064 | 9,064 | 9,396 | 9,396 | 9,396 | 9,396 | 8,938 |
| total operating costs | 30 | 32 | 33 | 35 | 36 | 39 | 41 | 43 | 45 | 47 | 51 | 53 | 55 | 58 | 60 | 65 | 68 | 71 | 75 | 78 | 84 | 88 | 92 | 96 | 101 |
| depreciation | 40 | 40 | 40 | 40 | 40 | 42 | 42 | 42 | 42 | 42 | 45 | 45 | 45 | 45 | 45 | 48 | 48 | 48 | 48 | 48 | 52 | 52 | 52 | 52 | 52 |
| income | 0 | 3 | 9 | 15 | 23 | 31 | 41 | 54 | 68 | 85 | 104 | 117 | 130 | 146 | 163 | 181 | 202 | 226 | 252 | 281 | 313 | 348 | 388 | 433 | 484 |
| loan | 302 | 302 | 302 | 302 | 302 | 317 | 308 | 298 | 289 | 279 | 289 | 261 | 229 | 194 | 155 | 134 | 67 | 0 | 0 | 0 | 29 | 0 | 0 | 0 | 0 |
| interest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 35 | 31 | 28 | 23 | 19 | 16 | 8 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 |
| liquid funds for redemption (= income - operating costs - tax) | -6 | -4 | -2 | 1 | 5 | 9 | 15 | 22 | 30 | 40 | 63 | 68 | 75 | 88 | 103 | 116 | 134 | 155 | 178 | 203 | 228 | 260 | 296 | 336 | 383 |
| additionally required equity capital | 6 | 4 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| fixed rate of annuity redemption | 0 | 0 | 0 | 0 | 0 | 9 | 9 | 9 | 9 | 9 | 63 | 63 | 63 | 63 | 63 | 83 | 76 | 0 | 0 | 0 | 32 | 0 | 0 | 0 | 0 |
| special redemption | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| repayment portion (= annuity - interest + special redemption) | 0 | 0 | 0 | 0 | 0 | 9 | 9 | 9 | 9 | 9 | 28 | 31 | 35 | 39 | 44 | 67 | 67 | 0 | 0 | 0 | 29 | 0 | 0 | 0 | 0 |
| profit before tax | -71 | -68 | -65 | -60 | -54 | -51 | -42 | -31 | -19 | -4 | -26 | -12 | 3 | 20 | 39 | 52 | 78 | 107 | 130 | 155 | 173 | 208 | 244 | 284 | 331 |
| profit after tax | -46 | -44 | -42 | -39 | -35 | -33 | -27 | -20 | -12 | -2 | -17 | -8 | 3 | 20 | 39 | 52 | 78 | 107 | 130 | 155 | 173 | 208 | 244 | 284 | 331 |
| cash flow | -308 | -4 | -2 | 1 | 5 | -15 | 6 | 13 | 21 | 30 | -19 | 5 | 13 | 26 | 40 | 10 | 59 | 155 | 178 | 203 | 167 | 260 | 296 | 336 | 430 |
| cash flow cumulated | -308 | -312 | -314 | -312 | -307 | -322 | -316 | -304 | -283 | -253 | -271 | -266 | -253 | -227 | -187 | -178 | -119 | 35 | 213 | 416 | 583 | 843 | 1,139 | 1,476 | 1,906 |
| **net present value NPV** | **-68** | | | | | | | | | | | | | | | | | | | | | | | | |
| **internal ROE** | **10.35%** | | | | | | | | | | | | | | | | | | | | | | | | |

**Diesel system [costs in 1,000 ETB !]**

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| total investment costs | 178 | | | | | | | | 298 | | | | | | | | 545 | | | | | | | | |
| part of distribution grid | 72 | | | | | | | | 98 | | | | | | | | 136 | | | | | | | | -118 |
| equity part | 53 | | | | | | | | 89 | | | | | | | | 164 | | | | | | | | -35 |
| loan part | 53 | | | | | | | | 89 | | | | | | | | 164 | | | | | | | | -35 |
| juissance part | 71 | | | | | | | | 119 | | | | | | | | 218 | | | | | | | | -47 |
| tariff [ETB/kWh] ! | 1.50 | 1.57 | 1.64 | 1.71 | 1.79 | 1.87 | 1.95 | 2.04 | 2.13 | 2.23 | 2.33 | 2.43 | 2.54 | 2.66 | 2.78 | 2.90 | 3.03 | 3.17 | 3.31 | 3.46 | 3.62 | 3.78 | 3.95 | 4.13 | 4.31 |
| return on juissance [kWh] | 1,421 | 1,421 | 1,421 | 1,421 | 1,421 | 1,421 | 1,421 | 1,421 | 3,170 | 3,170 | 3,170 | 3,170 | 3,170 | 3,170 | 3,170 | 3,170 | 5,424 | 5,424 | 5,424 | 5,424 | 5,424 | 5,424 | 5,424 | 5,424 | 5,081 |
| fuel costs (= part of operating costs | 6 | 8 | 11 | 15 | 19 | 24 | 29 | 36 | 44 | 53 | 63 | 70 | 77 | 86 | 95 | 105 | 116 | 129 | 143 | 158 | 175 | 194 | 215 | 239 | 264 |
| further operating costs | 9 | 9 | 10 | 10 | 11 | 11 | 12 | 12 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 41 | 43 | 45 | 47 | 49 | 52 | 54 | 56 | 59 |
| depreciation | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 63 | 63 | 63 | 63 | 63 | 63 | 63 | 63 | 63 |
| income | 9 | 14 | 20 | 26 | 35 | 44 | 55 | 68 | 79 | 97 | 117 | 130 | 145 | 161 | 179 | 198 | 214 | 238 | 264 | 294 | 327 | 363 | 404 | 449 | 500 |
| loan | 53 | 51 | 49 | 47 | 45 | 43 | 41 | 39 | 126 | 110 | 94 | 90 | 85 | 79 | 73 | 66 | 222 | 193 | 160 | 124 | 83 | 37 | 0 | 0 | 0 |
| interest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11 | 11 | 10 | 10 | 9 | 8 | 27 | 23 | 19 | 15 | 10 | 4 | 0 | 0 | 0 |
| liquid funds for redemption (= income - operating costs - tax) | 2 | 3 | 5 | 7 | 9 | 9 | 14 | 19 | 16 | 23 | 32 | 38 | 43 | 47 | 52 | 57 | 56 | 65 | 76 | 85 | 92 | 100 | 110 | 122 | 137 |
| additionally required equity capital | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| fixed rate of annuity redemption | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 56 | 56 | 56 | 56 | 56 | 42 | 0 | 0 | 0 |
| special redemption | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| repayment portion (= annuity - interest + special redemption) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 16 | 16 | 4 | 5 | 6 | 6 | 7 | 8 | 29 | 33 | 36 | 41 | 46 | 37 | 0 | 0 | 0 |
| profit before tax | -22 | -20 | -17 | -14 | -11 | -7 | -2 | 4 | -16 | -8 | -11 | -5 | 1 | 9 | 17 | 26 | -34 | -21 | -6 | 10 | 29 | 50 | 71 | 91 | 114 |
| profit after tax | -14 | -13 | -11 | -9 | -7 | -7 | -2 | 3 | -16 | -8 | -11 | -5 | 1 | 6 | 11 | 17 | -34 | -21 | -6 | 7 | 19 | 32 | 46 | 59 | 74 |
| cash flow | -53 | 1 | 3 | 5 | 7 | 7 | 12 | 17 | -89 | 8 | 16 | 22 | 27 | 31 | 36 | 41 | -164 | 10 | 20 | 29 | 36 | 58 | 110 | 122 | 173 |
| cash flow cumulated | -53 | -52 | -49 | -45 | -38 | -30 | -18 | -2 | -91 | -83 | -67 | -45 | -18 | 13 | 49 | 90 | -73 | -64 | -43 | -14 | 22 | 80 | 190 | 312 | 485 |
| **net present value NPV** | **2** | | | | | | | | | | | | | | | | | | | | | | | | |
| **internal ROI** | **12.26%** | | | | | | | | | | | | | | | | | | | | | | | | |

## *Annex 17: Calculation of profitability for a 150 kW MHP and a 150 kW diesel system*

| **MHP system** | | |
|---|---|---|
| system capacity (generator output) | 156.24 | kW |
| available final output capacity | 127.84 | kW |
| cost of output capacity | 13,848 | ETB/kW |
| operating cost | 3.0% | |
| load factor | 40% | |
| resulting operational hours | 3504 | hours |
| tariff | 1.4 | ETB/kWh |
| lifetime | 25 | years |

| **Diesel system** | step1 | step2 | step3 | |
|---|---|---|---|---|
| system capacity (generator output) | 44.87 | 92.29 | 147.35 | kW |
| available final output capacity | 36.71 | 75.51 | 120.56 | kW |
| cost of output capacity (incl. inflation) | 10,609 | 12,874 | 21,136 | ETB/kW |
| operating cost | 5% | 5% | 5% | |
| load factor | 40% | 40% | 40% | |
| resulting operational hours | 3504 | 3504 | 3504 | hours |
| tariff (incl. inflation) | 1.4 | 3.00 | 6.43 | ETB/kWh |
| fuel price | 2.5 | ETB/l | | |
| fuel price | 0.3 | USD/l | | |
| inflation fuel | 10.0% | per year | | |
| lifetime | 8 | years | | |
| calorific value | 0.1 | litre fuel/kWh | | |

**general parameters:**

| | | |
|---|---|---|
| interest (average) | 18% | |
| inflation | 10.0% | |
| exchange rate | 8.2 | ETB/USD |

| **financing parameters:** | | |
|---|---|---|
| | | interest |
| equity | 30% | |
| loan | 30% | 18.0% |
| juissance | 40% | 9.0% |
| total "loan-financing" | 70% | 12.86% |
| % of supplied hh's with juissance shares | 100% | |
| initial average juissance charge | 7,711 | ETB/connected hh |
| redemption free period: | 0 | *years* |
| interest free period: | 4 | *years* |
| **"special" loan redemption** allowed: for yes fill in 1, for no fill in 0: | 0 | |

**tax parameters:**

| **MHP systems** | |
|---|---|
| percentage to be paid: | 35% |
| number of tax free years: | 25 |
| **diesel systems** | |
| percentage to be paid: | 35% |
| number of tax free years: | 5 |
| **grid connection systems** | |
| percentage to be paid: | 35% |
| number of tax free years: | 5 |

| **years** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| kWh's sold | 27,632 | 38,067 | 49,652 | 62,487 | 76,681 | 92,352 | 109,627 | 128,642 | 149,546 | 172,498 | 197,669 | 209,529 | 222,107 | 235,446 | 249,593 | 264,595 | 280,507 | 297,382 | 315,281 | 334,265 | 354,401 | 375,759 | 398,414 | 422,445 | 447,936 |

**MHP system [costs in 1,000 ETB !]**

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| investment costs | 1,518 | | | | | 260 | | | | | 419 | | | | | 675 | | | | | 1,087 | | | | -1,494 |
| equity part | 455 | | | | | 78 | | | | | 126 | | | | | 202 | | | | | 326 | | | | -448 |
| loan part | 455 | | | | | 78 | | | | | 126 | | | | | 202 | | | | | 326 | | | | -448 |
| juissance part | 607 | | | | | 104 | | | | | 168 | | | | | 270 | | | | | 435 | | | | -598 |
| tariff [ETB/kWh] ! | 1.40 | 1.54 | 1.69 | 1.86 | 2.05 | 2.25 | 2.48 | 2.73 | 3.00 | 3.30 | 3.63 | 3.99 | 4.39 | 4.83 | 5.32 | 5.85 | 6.43 | 7.08 | 7.78 | 8.56 | 9.42 | 10.36 | 11.40 | 12.54 | 13.79 |
| return on juissance [kWh] | 39,023 | 39,023 | 39,023 | 39,023 | 39,023 | 43,592 | 43,592 | 43,592 | 43,592 | 43,592 | 48,161 | 48,161 | 48,161 | 48,161 | 48,161 | 52,731 | 52,731 | 52,731 | 52,731 | 52,731 | 57,300 | 57,300 | 57,300 | 57,300 | 53,010 |
| total operating costs | 46 | 50 | 55 | 61 | 67 | 81 | 89 | 98 | 108 | 119 | 143 | 158 | 173 | 191 | 210 | 251 | 276 | 304 | 334 | 367 | 437 | 480 | 528 | 581 | 639 |
| depreciation | 61 | 61 | 61 | 61 | 61 | 71 | 71 | 71 | 71 | 71 | 88 | 88 | 88 | 88 | 88 | 115 | 115 | 115 | 115 | 115 | 158 | 158 | 158 | 158 | 158 |
| income | 0 | 0 | 18 | 44 | 77 | 110 | 164 | 232 | 318 | 426 | 543 | 645 | 764 | 905 | 1,071 | 1,239 | 1,465 | 1,731 | 2,044 | 2,411 | 2,798 | 3,299 | 3,887 | 4,577 | 5,446 |
| loan | 455 | 455 | 455 | 455 | 455 | 533 | 533 | 533 | 533 | 533 | 659 | 533 | 385 | 210 | 3 | 202 | 0 | 0 | 0 | 0 | 326 | 0 | 0 | 0 | 0 |
| interest | 0 | 0 | 0 | 0 | 82 | 96 | 96 | 96 | 96 | 96 | 119 | 96 | 69 | 38 | 1 | 36 | 0 | 0 | 0 | 0 | 59 | 0 | 0 | 0 | 0 |
| liquid funds for redemption (= income - operating costs - tax) | -8 | -11 | -3 | 10 | 57 | 77 | 107 | 146 | 210 | 307 | 400 | 487 | 591 | 715 | 861 | 988 | 1,189 | 1,428 | 1,710 | 2,043 | 2,362 | 2,819 | 3,359 | 3,996 | 4,807 |
| additionally required equity capital | 8 | 11 | 3 | 0 | 25 | 19 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| fixed rate of annuity redemption | 0 | 0 | 0 | 0 | 0 | 96 | 96 | 96 | 96 | 96 | 244 | 244 | 244 | 244 | 4 | 239 | 0 | 0 | 0 | 0 | 385 | 0 | 0 | 0 | 0 |
| special redemption | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| repayment portion (= annuity - interest + special redemption) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 126 | 148 | 175 | 207 | 3 | 202 | 0 | 0 | 0 | 0 | 326 | 0 | 0 | 0 | 0 |
| profit before tax | -106 | -111 | -98 | -78 | -132 | -138 | -93 | -33 | 43 | 140 | 193 | 303 | 434 | 589 | 773 | 837 | 1,074 | 1,313 | 1,595 | 1,928 | 2,145 | 2,661 | 3,201 | 3,838 | 4,648 |
| profit after tax | -69 | -72 | -64 | -50 | -86 | -90 | -60 | -22 | 43 | 140 | 193 | 303 | 434 | 589 | 773 | 837 | 1,074 | 1,313 | 1,595 | 1,928 | 2,145 | 2,661 | 3,201 | 3,838 | 4,648 |
| cash flow | -464 | -11 | -3 | 10 | -25 | -97 | 11 | 50 | 114 | 211 | 30 | 243 | 347 | 470 | 857 | 547 | 1,189 | 1,428 | 1,710 | 2,043 | 1,651 | 2,819 | 3,359 | 3,996 | 5,255 |
| cash flow cumulated | -464 | -475 | -478 | -467 | -493 | -589 | -579 | -529 | -415 | -204 | -175 | 68 | 415 | 885 | 1,742 | 2,289 | 3,478 | 4,906 | 6,615 | 8,659 | 10,310 | 13,129 | 16,488 | 20,484 | 25,739 |
| **net present value NPV** | **524** | | | | | | | | | | | | | | | | | | | | | | | | |
| **internal ROE** | **23.74%** | | | | | | | | | | | | | | | | | | | | | | | | |

**Diesel system [costs in 1,000 ETB !]**

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| total investment costs | 476 | | | | | | | | 1,188 | | | | | | | | 3,114 | | | | | | | | |
| part of distribution grid | 290 | | | | | | | | 600 | | | | | | | | 1,265 | | | | | | | | -1,001 |
| equity part | 143 | | | | | | | | 356 | | | | | | | | 934 | | | | | | | | -300 |
| loan part | 143 | | | | | | | | 356 | | | | | | | | 934 | | | | | | | | -300 |
| juissance part | 190 | | | | | | | | 475 | | | | | | | | 1,246 | | | | | | | | -401 |
| tariff [ETB/kWh] ! | 1.40 | 1.54 | 1.69 | 1.86 | 2.05 | 2.25 | 2.48 | 2.73 | 3.00 | 3.30 | 3.63 | 3.99 | 4.39 | 4.83 | 5.32 | 5.85 | 6.43 | 7.08 | 7.78 | 8.56 | 9.42 | 10.36 | 11.40 | 12.54 | 13.79 |
| return on juissance [kWh] | 12,241 | 12,241 | 12,241 | 12,241 | 12,241 | 12,241 | 12,241 | 12,241 | 27,919 | 27,919 | 27,919 | 27,919 | 27,919 | 27,919 | 27,919 | 27,919 | 47,091 | 47,091 | 47,091 | 47,091 | 47,091 | 47,091 | 47,091 | 47,091 | 44,215 |
| fuel costs (= part of operating costs) | 21 | 32 | 46 | 63 | 85 | 113 | 147 | 190 | 243 | 309 | 389 | 454 | 529 | 617 | 720 | 839 | 979 | 1,141 | 1,331 | 1,552 | 1,810 | 2,111 | 2,462 | 2,872 | 3,350 |
| further operating costs | 24 | 26 | 29 | 32 | 35 | 38 | 42 | 46 | 90 | 99 | 109 | 120 | 132 | 146 | 160 | 176 | 287 | 315 | 347 | 381 | 420 | 462 | 508 | 558 | 614 |
| depreciation | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 317 | 317 | 317 | 317 | 317 | 317 | 317 | 317 | 317 |
| income | 22 | 40 | 63 | 94 | 132 | 181 | 242 | 318 | 365 | 477 | 616 | 725 | 853 | 1,003 | 1,179 | 1,384 | 1,502 | 1,771 | 2,088 | 2,459 | 2,894 | 3,405 | 4,004 | 4,705 | 5,567 |
| loan | 143 | 143 | 143 | 143 | 143 | 143 | 143 | 143 | 499 | 499 | 499 | 499 | 499 | 499 | 499 | 499 | 1,434 | 1,434 | 1,434 | 1,434 | 1,434 | 1,434 | 1,434 | 1,434 | 1,133 |
| interest | 0 | 0 | 0 | 0 | 26 | 26 | 26 | 26 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 204 |
| liquid funds for redemption (= income - operating costs - tax) | -3 | 0 | 5 | 11 | 29 | 29 | 52 | 74 | 31 | 69 | 118 | 151 | 192 | 226 | 264 | 309 | 236 | 315 | 410 | 525 | 633 | 742 | 873 | 1,030 | 1,224 |
| additionally required equity capital | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 21 | 0 | 0 | 0 | 0 | 0 | 0 | 22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| fixed rate of annuity redemption | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 | 258 |
| special redemption | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| repayment portion (= annuity - interest + special redemption) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 54 |
| profit before tax | -58 | -53 | -46 | -36 | -49 | -31 | -9 | 20 | -168 | -130 | -81 | -48 | -7 | 41 | 100 | 170 | -339 | -261 | -166 | -50 | 89 | 257 | 458 | 699 | 1,082 |
| profit after tax | -38 | -35 | -30 | -23 | -32 | -31 | -9 | 13 | -168 | -130 | -81 | -48 | -7 | 27 | 65 | 110 | -339 | -261 | -166 | -50 | 58 | 167 | 298 | 455 | 703 |
| cash flow | -146 | 0 | 5 | 11 | 3 | 4 | 26 | 48 | -415 | -21 | 28 | 61 | 102 | 136 | 174 | 219 | -956 | 57 | 152 | 267 | 375 | 484 | 615 | 772 | 1,267 |
| cash flow cumulated | -146 | -145 | -140 | -129 | -126 | -122 | -96 | -48 | -463 | -484 | -456 | -395 | -293 | -157 | 17 | 236 | -720 | -663 | -511 | -244 | 131 | 615 | 1,231 | 2,003 | 3,269 |
| **net present value NPV** | **-85** | | | | | | | | | | | | | | | | | | | | | | | | |
| **internal ROE** | **13.59%** | | | | | | | | | | | | | | | | | | | | | | | | |

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No. 116/1998, Investment-Proclamation (Amendment), Addis Ababa 1998

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No. 165/1960, Civil Code of the Empire of Ethiopia, Addis Ababa 1960

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No. 31/1975, Public ownership of rural land, Addis Ababa 1975

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No. 80/1993, Urban Lands Lease Holding Proclamation, Addis Ababa 1993

No. 86/1997, Electricity Proclamation, Addis Ababa 1997

No. 89/1997, Federal Rural Land administration, Addis Ababa 1997

No. 92/1994, Utilization of water resources, Addis Ababa 1994

**Proclamations (Magalata Oromiyaa)**

No. 15/1997, Establishment of the Oromia Agricultural Co-operatives Bureau, Addis Ababa 1997

No. 19/1997 Utilization of rural land for investment in the Oromia Region, Addis Ababa 1995

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**Regulations (Magalata Oromiyaa)**

No. 1/1995, Lease and Rent Holding of Urban Lands in the Oromia Region, Addis Ababa 1995

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