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VIRTUAL BALKAN POWER CENTRE FOR ADVANCE OF RENEWABLE ENERGY SOURCES IN WESTERN BALKANS

WORKSHOP 1.4: RES PROJECT IMPLEMENTATION

Task leader: UNI-ZG
Co-Editor: ISTRABENZ

According to TA, the contributions for WS 1.4 should cover the topics on technical and non-technical aspects of RES project implementation, including project preparation, management, decision making processes at project level, organisation of RES systems. Interesting topics are also EU best practice at project implementation, barriers and country specifics as well as project potentials in WB region.

AGENDA

Faculty of Electrical Engineering and Computing, University of Zagreb,
Unska 3, Zagreb, Croatia
6th – 7th April, 2006

Thursday, 6th April 2006

9^{30} – 10^{00}	**Registration**	
10^{00} - 10^{15}	**Welcome and Introduction**	
10^{15} – 10^{45}	**Overview: EU best practice at project implementation**	**FE**
10^{45} - 11^{15}	**RES Potentials in WB Region: Barriers and country specifics**	**TUS**
11^{15} – 11^{30}	**Coffee break**	
11^{30} – 12^{00}	**Development and implementation of wind power project „Pometeno Brdo“**	**KONCAR**
12^{00} – 12^{30}	**Wind power development in Spain**	**COMILLAS**
12^{30} – 12^{45}	**Discussion**	
12^{45} – 14^{30}	**Lunch Break**	
14^{30} – 15^{00}	**Organization of RES Systems: Case of Virtual Power Plants in Biogas**	**JR**
15^{00} - 15^{30}	**Project Management: Case of Biomass**	**ISTRABENZ**

15^{30} - 15^{45}	Coffee break	
15^{45}-16^{15}	Economics of distributed energy resources	NTUA
16^{15}-16^{30}	Discussion	
16^{30}-17^{30}	Planning our future activities	
20^{00}	Official dinner	

Friday, 7th April 2006

09^{00} - 09^{30}	Technical aspects of RES project implementation: connection of RES system to power grid.	ETF
09^{30} - 10^{00}	Technical aspects of RES project implementation: Case of sHPP	INTRADE
10^{00} - 10^{30}	Regulatory and Legislative Issues in sHPP Project in Macedonia	CMU
10^{30} – 10^{45}	Coffee break	
10^{45} – 11^{15}	Project preparation: Case of CHP	DMSG
11^{15} – 11^{45}	Decision making process at project level: Case of Geothermal Energy	CRES
11^{45} – 12^{15}	Economic evaluation of wind power projects	UNI-ZG
12^{15} – 12^{45}	Barriers and incentives for RES installation projects in Romania. Green certificates market	UPB
12^{45} – 13^{15}	Discussion	
13^{15} – 14^{45}	Lunch	
15^{00}	End of workshop	

Sixth Framework Programme, DG Research, International Cooperation

Contract: INCO-CT-2004-509205

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Contract: INCO – CT – 2004 – 509205

Virtual Balkan Power Centre for Advance of
Renewable Energy Sources in Western Balkans

Balkan Power Center Report

RES Project Implementation

Workshop 1.4

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1 Summary

The two days workshop “RES Project Implementation” was held at the University of Zagreb, Faculty of Electrical Engineering and Computing, Croatia, on April 6th and 7th 2006. The Workshop belongs to the project “Virtual Balkan Power Centre for Advance of Renewable Energy Sources in Western Balkans”, project acronym: VBPC-RES, Contract: INCO-CT-2004-509205, under the Sixth Framework Programme, International Cooperation (INCO). The Workshop WS 1.4 is a part of the Work Package 1 (WP1) of the VBPC-RES project, entitled “Transfer of best practice and best available technology in RES for isolated regions”.

At the beginning of the workshop Ms. Vesna Bukarica of the University of Zagreb, Faculty of Electrical Engineering and Computing, as the organizer of this workshop, greeted the participants – Project Partners as well as representatives of the Ministry of Economy, Labour and Entrepreneurship, Croatian Energy Market Operator, Croatian electric utility (HEP) and Končar – Power Plant and Electric Traction Engineering Inc. The welcome was also expressed by the representative of the Ministry of Economy, Labour and Entrepreneurship Mr. Igor Raguzin, who pointed out the main issues about development of renewable energy sources in Croatia.

The programme of the WS comprised 14 contributions in total. 13 of them were presented by Project Partners and one from guest speakers from the company Končar-Power Plant and Electric Traction Engineering Inc., who presented very interesting project of their own 1 MW wind turbine development. Two additional papers, presented at the WS 1.2 held also in Zagreb in 2005, are included in this deliverable, since their topics fit better in the scope of the WS 1.4.

From the technical point of view the contributions reflect the deep knowledge and experience of the authors in the field of RES project implementation. Many interesting issues were presented: best practices in RES project implementation in the EU, potentials for RES implementation in Western Balkans, RES project development through different phases (planning, preparation, design, construction and operation), economics of distributed generation, connection of distributed generation to the grid, incentives and barriers to RES project implementation, etc. The contributions were understandable and a benefit for the audience. The main points of all contributions are briefly presented below.

T.Oštir, A. Gubina, University of Ljubljana, Slovenia: "Project Implementation: a Review of Best Practice in EU"

The rising energy consumption in the EU and the imported fossil fuel dependence is pushing the EU to seek alternative energy sources. Renewable energy sources (RES) are one of the main drivers for achieving the commitments of Kyoto Protocol and of EC's Green Paper. In spite of their importance, RES are still facing economic, financial, institutional, technical and social barriers. Therefore an investor should be prepared to surmount all upcoming barriers during the RES project implementation.

Achieving best practice in RES project implementation entails not only profit maximization and cost effectiveness. In addition, it covers a portfolio of traits, such as good project management, good project outreach, quality control… However, although the project excels in the technical attributes (cost effectiveness, revenue, efficiency…) it is suboptimal if it lags in non-technical attributes (e.g. has public opinion against it). In this paper, we investigate what constitutes best practice in RES project implementation, and illustrate the findings with real-world examples.

D.Popov, Technical University of Sofia, Bulgaria: "RES Potentials in Western Balkans Region: Barriers and Country Specifics"

Efficient, cost effective and reliable electricity supply form the basis for sustainable development of every country. Due to events that marked Western Balkans region in the last decade and because of big difference in grade of development within the region, some parts are still facing problems with electricity supply. War devastation significantly affected transmission and distribution networks, thus local security of supply became a challenge. However, that also provided a possibility for wider application of alternative technologies. Countries in the Western Balkan region have great unexploited potential of renewable energy sources (RES), which could by efficient use significantly contribute to security of supply within the region and wider. Special care has to be devoted to sound solutions for electricity supply of undeveloped and isolated regions due to war damage.

RES potentials in Albania, Bosnia and Herzegovina, Croatia, Serbia and Montenegro and FYROM, along with RES penetration barriers and country specifics are discussed in this paper.

P. Frías Marín, T. Gómez San Román, J. Rivier Abbad, Universidad Pontificia Comillas, Spain: "Wind Power Development in Spain"

Wind power in Spain is the most developed of all renewable technologies, and is actively contributing to reach the objective of covering 12% of primary energy consumption from renewable sources by 2011.

Currently, Spain has the second place worldwide in wind power-installed capacity with 10,028 MW at the end of 2005. The installed capacity has been steadily growing at 15% rates every year, which makes feasible to reach the recently readjusted national target for 2011 of 20,000 MW of wind power installed capacity. The wind power generated in 2005 covered 7.78% of the electric energy demand, with a peak generation of 7,300 MW in last March, which covered 24% of the demand.

This situation has been achieved with a stable regulation, where investors can predict the future earnings from wind production for the entire plant life cycle. Regulation establishes two options for wind power to sell their energy, a guaranteed feed-in-tariff, or trading the energy into the electricity markets. Currently, most wind farms sell their energy into the electricity markets, because the average price of the electricity spot market in the last year plus the incentives, are higher than the regulated fixed tariff.

Some challenges still exist for wind power integration into the network, such as highly variable production, intermittency to cover peak loads, difficulty in forecasting, disconnection in case of voltage dips, and limited operation reserves. Therefore, research studies are mainly focused on prediction tools, turbine design to increase efficiency, and network procedures to improve grid integration.

The common effort of national institutions, together with manufactures and investors, is resulting in the continuous growth of wind power sector in Spain, increasing its international competitiveness. These efforts are described in the paper.

R.Padinger, Joanneum Research, Austria: “Austrian Research Project: Virtual Biogas Power Plants”

A virtual power plant, combining 20 biogas plants is planned in the south-eastern part of the State of Styria (A). The project is funded by the Austrian Federal Ministry for Transport, Innovation and Technology and will be carried out in 2 stages: stage 1, “Project Preparation”, has started in March 2006 and is running for 18 months. Stage 2 “Project Realization” will be specified after successful end of Stage 1. The aim of the project is to realize a central reactive power control system of 20 agricultural biogas plants. The active power of the biogas plants ranges between 1 and 3 MW. Specific goals of the project are:

- increasing grid stability,
- decreasing long distance reactive power transmission,
- decreasing energy losses, and
- decreasing utility costs.

One of the members of the project consortium is the Styrian top ranking grid operator: STEWEAG - STEG. This partner will deliver information about the local requirement of reactive power (grid data) and about the grid integration equipment. He will also deal with questions of contractual issues as grid operators (liability, tariffs). But also biogas operators are members of the project consortium. They will deliver information about operational data (use of heat and power), feed-in equipment, and contractual issues as plant operators.

This paper describes in details the Virtual Gas Power Plant project and its expectations.

P. Georgilakis, N. Hatziargyriou, National Technical University of Athens, Greece: "Economics of Distributed Energy Resources"

The traditional focus in electric power planning has been on generation resources-forecasting demand, and then trying to select the most cost-effective combination of new power plants to meet the forecast. However, in the final decades of the twentieth century there was an important shift in which it was recognized that the real need was for energy services and a least-cost approach to providing those energy services should include programs to help customers use energy more efficiently. Out of that recognition a process called integrated resource planning (IRP) emerged in which both supply-side and demand-side resources were evaluated, including environmental and social costs, to come-up with a least-cost plan to meet the needs of customers for energy services.

More recently, with increased attention to the electricity grid and the emergence of efficient, cost-effective cogeneration, IRP now recognizes three kinds of electricity resources: generation resources, especially the distributed generation technologies; grid resources, which move electricity from generators to customers; and demand-side resources, which link electricity to energy services. These three distributed energy resources are all equally valid, comparable resources that need to be evaluated as part of a least-cost planning process. In this paper, the focus is on distributed energy resources that are relatively small in scale and located somewhat near to the end-user.

An essential step in any economic calculation for a distributed resource (DR) project is a careful analysis of the cost of electricity and/or fuel that will be displaced by the proposed system. The electric utility rate structures are critical factors for customers evaluating a DR project. Electric rates vary considerably, depending not only on the utility itself, but also on the electrical characteristics of the specific customer purchasing the power.

There are many ways to evaluate the economic viability of distributed energy resources. The capital cost of equipment, the operation and maintenance costs, and the fuel costs must be combined in some manner so that a comparison may be made with the costs of not doing the project.

In addition to direct energy savings, increased fuel efficiency with cogeneration, and reduced demand charges for larger customers, there are a number of other distributed generation attributes that can significantly add value, including:

- *Option Value*: small increments in generation can track load growth more closely, reducing the costs of unused capacity.
- *Deferral Value*: easing bottlenecks in distribution networks can save utilities costs.
- *Engineering Cost Savings*: voltage and power factor improvements and other ancillary benefits provide grid value.
- *Customer Reliability Value*: reduced risk of power outages and better power quality can provide major benefits to some customers.
- *Environmental Value*: reduced carbon emissions for combined heat and power systems will have value if/when carbon taxes are imposed; for fuel cells, since they are emission-free, ease of permitting has value.

In this paper, the techniques needed to evaluate the economics of both sides of the electric meter (the demand side and the supply side) are explored.

N.Rajaković, N. Milojčić, Faculty of Electrical Engineering, Serbia and Montenegro: "Connection of RES to Power Grid"

The main goal of this paper is to point out the most important technical prerequisites which have to be satisfied and problems which have to be solved for the successful connection of some renewable energy source to the existing power grid.

Most of the renewable energy sources are of small sizes, designed to produce power (some of them also produce heat) distributed within low voltage and medium voltage (LV/MV) distribution networks. The connection of RES into already built distribution networks affects the main operational concept of the traditional lateral (radial) distribution networks (with unidirectional power flows). More over, there are also some other economic and legislative requirements that have to be considered.

A.Ajanović, Intrade energija d.o.o., Bosnia and Herzegovina: "Technical Aspects of RES Project Implementation: Case Of sHPP"

Location is essential for successful realization of one (or more) small hydro power plant construction project. First, the general location – water flow with its watershed area – is selected based on estimations from experience and analyses of basic, rough parameters such as available water amount and head. Thereafter, in further phases of design, basic parameters of one small hydro power plant are precisely defined through the studies, basic designs and finally detailed design.

Processing of the basic parameters is completed during preparation of technical documentation, starting from the initial study to the main design. The installed capacity of the plants and resulting output and scope of works are estimated on the basis of these key parameters. They present the basis for calculation of technical-economic cost effectiveness of the project.

Preparatory work for realization of construction of small hydro power plant including tender announcement, selection of a contractor and supplier of the equipment are undertaken after preparation and revision of the main power plant design.

During realization of project itself, maximum attention should be paid to complying with technical criteria and conditions, complying with regulations of work safety, complying with regulations related to the environment protection as well as other legal liabilities. In order to realize the above mentioned conditions it is necessary to have permanent engagement of the specialized personnel as the supervisors for each phase of the project. In this manner one has direct control of the project development, which, in the end, results in successful realization of project.

The project is considered finished after a technical review of each phase of the project. After issuing a certificate of technical acceptance, the testing of the plant can begin. Final issuance of permit for operation is issued by the competent authority after completion of this phase of the project.

During the first months of commercial operation of the plant, special attention should be paid to the observation and check of technical parameters of the plant which were provided in the offer by the equipment supplier.

In this paper, all above mentioned phases of sHPP project implementation are discussed in details.

M.Kacarska, Ss. Cyril and Methodius University, Macedonia: “Regulatory and Legislative Issues of sHPP Projects in Macedonia”

Macedonia is mostly mountain country with 80% of the entire territory in mountainous regions. 2% of the land area is covered by water comprising 35 large and small rivers, 3 natural and 50 artificial lakes which make Macedonia’s hydro potential. According to the water energy and the exploitation potentiality, the total theoretically exploitable energy potential of all rivers is 6.434 GWh. But only 1.370 GWh of that potential is used, which gives less than 22 % usage. In this moment almost 30% of installed energy capacity in Macedonia is from HPP of which 7% is from 21 sHPP.

The basin of the river Vardar is the biggest in the country and has a potential of 5.193 GWh. Thirteen sHPP are planed to be constructed in Vardar Valley in a purpose to use hole water potential of river Vardar and it’ basin rivers. For these plants technical documentation is on the level of study. Another 29 investment projects for sHPP are planed on several locations with different level of technical documentation (from primary design to study).

Macedonia is poor country in transition and needs foreign and private investments to realize sHPP projects. Until now we have prepared all necessary legislation documents. Economic Chamber of R. Macedonia in October 2005 issued a paper prepared by Macedonian Energy Association, named “Guide for realization of sHPP in Macedonia”. The paper deals with the key components for development of sHPP projects with installed capacity up to 10 MW. In the paper a list of about 400 new selected locations with about 200 MW predicted installed capacity is annexed. The project documentation of different level exists for almost 100 of 400 potential new small hydro power plants. The Guide comprehends the procedure of issuing all permits needed for sHPP realization from 5 national bodies in Macedonia: Ministry of transport and communication; Ministry of agriculture, forestry and water supply; Energy regulatory commission of Macedonia; MEPSO (Macedonian electric power transmission system operator) and ESM (Electric Distribution Company). The procedure includes several steps and is described in details in this paper.

In January 2006 the Draft Energy Law enters the procedure in Assembly of R. Macedonia. In the law the Directive 2001/77/EC for promotion of RES is implemented. The fifth goal of the law is promoting the use of RES. Chapter X is dealing with establishing the Energy agency of R. Macedonia and its responsibilities. The Agency along with the Ministry of economy will prepare a Strategy for use of RES for a period of 10 years and a Programme for realization of the strategy.

As a conclusion it could be emphasized that in this moment Macedonia has sufficient legislative support to start realization of sHPP projects. The expected new Energy law will complete regulations, supporting documents and bodies for RES, such as Energy Agency, Strategy for use of RES, Programme for realization of the strategy for use of RES, Green certificates etc.

E.Boškov, DMS Group ltd, Novi Sad, Serbia and Montenegro: "Project Preparation: Case of CHP"

The whole region of South Eastern Europe is depending on imported fossil fuels. This is a heavy burden for national budget and economy and any increase of use of domestic energy sources will have a positive economic impact. Combined heat and power generation is well-established technology in EU and candidate countries. The share of CHP in total domestic power production ranges between 50 % for Denmark and 6 % for UK. (For Austria this share is approximately 27 %, for Czech Republic 19 %, Slovak Republic 13 %, Bulgaria 11.3%, and Poland 8.3 %). CHP applications can be roughly categorised as large-scale (>50 MWe) in large public district heating systems and industry, medium-scale plants (5-50 MWe) in municipal district heating systems, industry and large building complexes, and small-scale applications (5 kWe-5 MWe) primarily in small district heating systems, small industries, and commercial sector.

The importance of CHP is increasing, because the electricity consumption is escalating everywhere in Europe but the available production methods are restricted. New nuclear capacity may be expected but a number of existing ones are going to be retired during the years to come. Most economic hydro power resources are already developed and many among the remaining will stay undeveloped for environmental reasons. Use of renewable energy sources, windmills, bio fuel and solar power, are expanding in many countries, but are not sufficient to cover the increasing necessity.

Using renewable fuels, however, CHP/DH offers the most efficient way to proceed. In addition, solar heating and waste heat can preferentially be integrated in such systems and DH initiates efficient integration of combined generation of heating and cooling services in a CHP system.

D.Mendrinos, K. Karras, C. Karytsas, Centre for Renewable Energy Sources, Greece: "Decision Making Process at Geothermal Power Projects"

During all stages of development of a geothermal power plant a series of decisions are necessary. They include early decisions during the exploration phase, such as where to go, how to refine further the plant location, where to drill the exploratory/ production wells, as well as deciding whether proceeding to the field development and plant construction deserves the effort in terms of technical and economical aspects. Establishing a kind of partnership with local community from the early stages of field development is also important. During field development a series of technical decisions should be made including defining power plant type and capacity, sitting production and reinjection wells, and locating surface installations. Managerial decisions such as whether to construct the plant by own resources and subcontracts or through BOT projects are also necessary. During plant operation, the overall organisation structure should be decided such as whether to have one company for both the geothermal field and plant operation or have separate companies. A series of technical decisions are also necessary, such as deciding on a monitoring and maintenance program.

V.Bukarica, M.Božičević Vrhovčak, Ž.Tomšić, R.Pašičko, University of Zagreb, Croatia: "Economic Evaluation of Wind Power Projects"

Investments in any kind of power plant in open market conditions are, in the bottom line, governed by the idea of making profit. The same goes, of course, for RES-e projects. They are aimed at gaining profit through sales of electricity delivered to the power grid. Thus, it is clear that RES-e project, as any other project that requires capital investments, needs to be evaluated according to its economic characteristics. In order to perform economic analysis of a possible project, all expenditures and revenues coming from the proposed project should be evaluated. Based on the assessed annual expenditures and revenues, the project cash flow analysis is performed and relevant profitability indicators are calculated, which are then are used as a basis for decision making process.

Special attention in this paper is given to the wind power projects. The wind power plant expenditures include investment costs, operation and maintenance costs, costs of capital, depreciation and income tax. Also, additional expenditures for grid connection should be included in the analysis. The wind power plant revenues include financial gains from electricity sales to the power grid. Thus, it is necessary to determine possible electricity production from the wind power plant according to the data on the utilizable wind potential at the chosen micro-location. The paper will point out that especially important parameter for cost effectiveness of wind power project (i.e. RES-e projects in general) is guaranteed purchase price for produced electricity. Namely, renewable facilities are very capital intensive and for that reason the price of electricity produced is in most cases still higher than the price of kWh from conventional facilities.

This paper covers all previously mentioned issues. The economic evaluation of the possible wind power project WPP Stupišće on the island of Vis, proposed within the Croatian national wind energy programme ENWIND, is shown in order to support theoretical findings and point out the main issues in economic evaluation of wind power project.

L.Toma, M.Eremia, I.Triştiu, M.Costea, University “Politehnica” of Bucharest, Romania: “Incentives and Barriers for RES Installation Projects in Romania. Green Certificates Market”

The RES installations in Romania are still in a planning phase. The reason could be found in the large number of hydro power plants, which provided in 2005 electrical energy in proportion of 33,97% of the total consumption. The other reason is the inexistence of appropriate incentives.

It should be also mentioned the giant projects, i.e.: commissioning in 2007 of the Group 2 of the Cernavoda Nuclear Power Plant, and 2012 the third group. Due to operating conditions of the nuclear power plant the necessity of new significant investments in hydro power plants arose: building of a pumping-storage plant in the area Tarniţa – Lăpuşteşti with an installed power of 1,000 MW, which will be used for power balancing within national power system, as well as a hydro power plant at Măcin, Dobrogea, with an installed power of 875 MW. There is also a preoccupation for development of micro-hydro but the results are still “on stand by”.

The lack of implementation projects of renewable energy systems (especially wind turbines) prove the fact that besides S.C. Hidroelectrica S.A., in Romania there are only two entities holding a license to produce energy from renewable sources. At the same time, we have to mention that actually, in Romania there are two wind turbines in operation: one at Ploiesti – with an installed power of 660 kW and another one at Pasul Tihuta (Bistrita Nasaud), of 250 kW, to which we may add a project which is being implemented of the third wind turbine of 550 kW installed power, Tulcea county.

Although there is a generous legislative frame and an optimist strategy for development renewable energy sources, the actual problems that an investor confronts with are divided in two categories, being determined by the project duration: construction (technical, administrative) and exploitation (connection to the grid and the legislative frame).

Since 2005 in Romania a Green Certificates Market is established. It is administrated by OPCOM – the legal person that assures Green Certificates trading and determines the prices on the Centralized Green Certificates Market, performing the functions established by the Regulation for organizing and functioning of the Green Certificates Market (Order no. 15 / 2005 issued by ANRE). In this paper, the Romanian Green Certificates Market is described.

P. Georgilakis, N. Hatziargyriou , National Technical University of Athens, Greece:
"Renewable Energy Sources Technologies Installed on Greek Islands"

In this paper the current status of renewable energy sources technologies that are installed on Greek islands are presented, namely the demand and installed capacity, the RES capacity by type, the RES share in energy demand and the energy cost in Greek islands. As a case study, the effects of wind power penetration on the economy of operation of island systems are investigated. The autonomous power system of Crete, the largest Greek island is used as a study case. Based on actual operating data during 2000, it was shown that a purely thermal production system, even following optimal operation, would increase operation costs by 2.6 Million € with the associated GHG emissions. These results indicate that wind power penetration in the Greek islands contributes positively not only in preserving their environment, but also provides significant financial gains for the system.

P. Georgilakis, N. Hatziargyriou , National Technical University of Athens, Greece:
"Impact of Energy Storage in the Operation of Hybrid Power Systems in Isolated Regions"

Electrical Energy is not conveniently stored in large amounts. In small autonomous systems however, energy storage can critically contribute to the increased penetration of Renewable Energy Sources, such as wind and sun, by increasing the reliability of the power system without significant increase in the operation cost. In this paper, the impact of storage in the economic and secure operation of the system of Kythnos has been investigated. The methodology described can be used for any storage device such as flywheel or pump hydro units if the characteristics for the time and the power that they can supply are known. It is concluded that the battery bank helps significantly secure operation of the island by decreasing the number of intervals of inadequacy in case of machine trip. The level of security is greater even when the case that spinning reserve is provided by the diesel units at lower cost. It is further concluded that the unit commitment of an island system when a storage device is available can be performed in such a way that eliminates the danger of interrupting load in case of machine trip without increasing significantly the operating cost. The determination of the capacity of the storage device that eliminates the danger of insecure operation without increasing the operation cost is an area of further study. Such a study can be extended so that the cost of the storage device is taken into account so that the payback period is calculated.

Andrej Hrabar, Borut Del Fabbro, Istrabenz energetski sistemi, d.o.o., Slovenia: "Project Management: Case of Biomass"

Project management in case of biomass has many parallel points to any energy related project, but it has also many specifics. As the timeline and construction phase are basically identical to all other projects, special care has to be taken in the process of planning. The differences in system models derive specifically from the fuel type, influencing the investment costs and some construction details. Older systems are also usually oversized, therefore special care in dimensioning the system is suggested, especially when replacing an old system or just adding a new one.

In the paper, we investigate the most important issues that should be taken into consideration. While construction and operation in biomass project management don't require any additional specific know-how, the key issue is proper planning. Looking at the logistics phase, the future project must be undertaken where the resources are available as the transport cost holds a major share in fuel cost of a biomass project.

Despite all the renewable energy subsidies, incentives, programmes and low interest loans available in Western and Central Europe, capital is still an issue in Western Balkans, but the support is slowly growing also in this region.

Conclusion

During the Workshop 1.4 valuable theoretical and practical knowledge and experience regarding to the RES project implementation was exchanged and gathered. All the findings will be useful to all participants as well as to future readers of this material. Thus, the workshop can be evaluated as very interesting, useful and successful.

The workshop has been finished with a Consortium meeting, where the results of the workshop were discussed and future activities identified in details.

2 PROJECT IMPLEMENTATION: a Review of Best Practice in EU

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2.1 Abstract

The rising energy consumption in the EU and the imported fossil fuel dependence is pushing the EU to seek alternative energy sources. Renewable energy sources (RES) are one of the main drivers for achieving the commitments of Kyoto Protocol and of EC's Green Paper. In spite of their importance, RES are still facing economic, financial, institutional, technical and social barriers. Therefore an investor should be prepared to surmount all upcoming barriers during the RES project implementation.

Achieving best practice in RES project implementation entails not only profit maximization and cost effectiveness. In addition, it covers a portfolio of traits, such as good project management, good project outreach, quality control… However, although the project excels in the technical attributes (cost effectiveness, revenue, efficiency…) it is suboptimal if it lags in non-technical attributes (e.g. has public opinion against it). In the paper, we investigate what constitutes best practice in RES project implementation, and illustrate the findings with real-world examples.

2.2 Introduction

The rising energy consumption in EU and as consequence a worrisome level of the EU's dependence on imported fossil fuel (oil and gas) is pushing the EU to seek for alternatives. European Union has also signed the Kyoto Protocol, committing the member states to reduce Greenhouse Gas (GHG) emissions in 2012 by 8 % in comparison to 1990 levels. The Green paper, adopted by the EC, is setting out the strategy to reduce the dependence on imported energy. In the paper, two main focuses are exposed: improvement of energy efficiency and increased usage of energy from renewable energy sources available within the member states.

In spite of good potential of Renewable Energy Sources, many experts argue that technologies such as solar, wind, small-scale hydropower are not economically viable. There are barriers that are holding back the progress of penetration of Renewable Energy Sources. Therefore the dissemination of best practices in the field of alternative energy is crucial to stimulate potential investors and inform the society (on the local and regional levels) of the energy supply possibilities alternative to fossil sources.

However rarely a RES project is “best-in class” in every area. Its pros and cons may vary considerably in its scale, capacity, energy resources characteristics, energy output, status of technology and a host of other factors. In the paper we therefore focus on identification of the best practice that exists within the particular country or technology rather than focusing on individual projects.

2.3 Barriers of RES Penetration

Because of the barriers that prevent penetration of RES, the renewable energy technology (RET) projects are specific. In the literature several barriers have been listed that prevent the penetration. Main barriers represent

- Economical (insufficient cost effectiveness),
- Technical and market barriers such as inconsistent pricing structures,
- Institutional, political and regulatory barriers, and
- Social and environmental barriers.

Financing issues are considered crucial for the development of RET. Barriers may vary across technology and between countries; each RET project implementation is specific with its own specific barriers, solutions and results.

2.4 RET project specific barriers

The main barriers can be divided into seven basic fields: market failure, market distortion, economic and financial barriers, institutional barriers, technical barriers, social, cultural and behavioral barriers and others [1].

As a highly controlled with governmental monopoly, the energy sector often hinders or in some cases even prevents raising of private sector funds. As a consequence the market lacks competition, knowledge and access to RET resources, assessment and implementation data, and existing suppliers are able to create barriers for newcomers. In this situation of **market failure** the access to technology is weakened; technology is not freely available on the market and technology developers are not willing to transfer technology. Investment requirements are therefore high, and so are the costs related to gathering and processing the information, procedures and delays, technology acquisition and its implementation.

Favorable treatment of conventional energy **distorts** the energy market. Conventional energy is subsidized; consumers pay average prices below marginal cost.

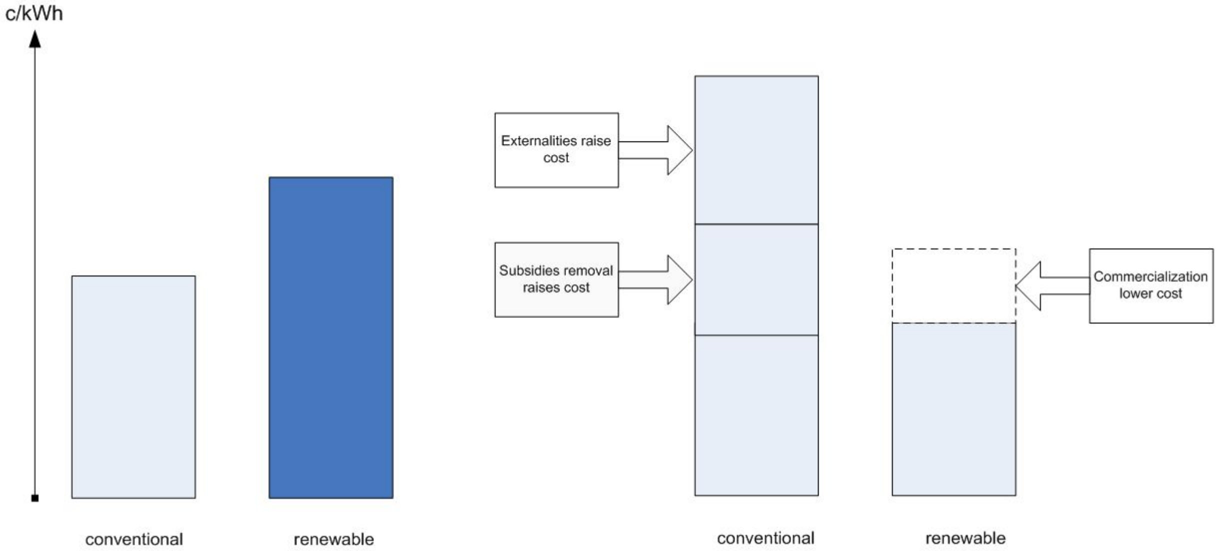

Figure 1: Conventional vs. renewable electricity: financial and social comparison

In this case, externalities are not considered in the price and the positive impact of RET is not valued. To ensure fair treatment of RES, the negative externalities such as pollution, greenhouse gas emissions etc. should also be considered in price. Figure 1 shows the impact of subsidies removal and introduction of externalities on cost of conventional and renewable energy [2].

High cost of renewable energy makes it uncompetitive, since resource costs (material, labor, capital) are higher than expected and the risk/uncertainty is perceived as high. **Economic and financial barriers** arise since the credit market is under-developed with poor credit worthiness, lack of financing instruments/institutions and unfavorable regulations. RET also faces **institutional barriers** in realizing financial incentives because of complicated procedures, red tape or corruption. Regulation is inadequate to promote renewable technologies, often unfavorable to RET with non-existent institutions to generate or disseminate information, promote and enhance energy market. RET is competing with conventional energy, threatening to undermine the utility dominance and profit.

Technical barriers manifest as capacity limitation with current grid system, low quality, missing or inadequate standards. Profitability is relatively low, further influencing the lack of investors. On the other hand, a lack of **social acceptance** and preference to traditional energy instead of unknown “new energy” (lack of information) is also an important barrier to wider RET implementation. The following barriers are also perceived:

- Governmental policies are uncertain, unsupportive to RET, leading to greater regulatory uncertainty and raising the cost of capital available to RET projects.
- Environmental aspects disturbing to the public (pollution, visual traits – e.g. wind)
- High risk perception for RET: uncertain new technology, uncertain benefits, high investment risk, and irreversibility of investment…

2.5 Project implementation

Because of the specifics of RES projects initial steps are crucial for the subsequent development of the project. Detailed analysis of legislation, regulation, possible subsidies, sites and resource data can be a major contribution to success of the project.

2.5.1 Typical steps in energy project implementation process

Project development basically consists of four steps: p*re-feasibility analysis*, *feasibility analysis*, *engineering and development* and *construction and commissioning* [3]. They follow in the sequence depicted in Figure 2. After every phase, additional information is available to aid us in decision whether to pursue the project or not.

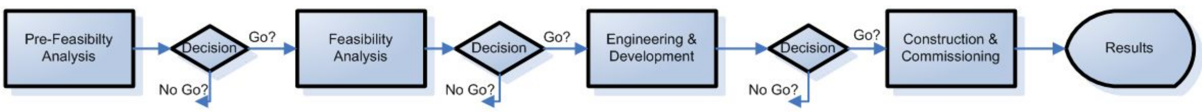

Figure 2: Typical steps in energy project implementation process

Pre-feasibility analysis is a form of quick and inexpensive initial examination in which the investor determines whether the proposed project has a good chance of satisfying our requirements for profitability or cost effectiveness. In this stage the investor uses the readily available site- and resource data, rely on coarse cost estimates, and simple calculations and judgments often involving rules of thumb.

Feasibility analysis is a more in-depth analysis of the project prospects that the investor conducts after the pre-feasibility analysis of the project confirms our expectations. It usually investigates the physical characteristics, financial viability, and environmental, social, or other impacts of the project, to the sufficient depth for him to decide about whether or not to proceed with the project. It usually involves site investigation, resource monitoring, energy auditing, computer simulation, and the solicitation of price information from equipment suppliers.

Engineering and development builds on feasibility analysis results. While engineering includes the design and planning of the physical aspects of the project, development involves the planning, arrangement, and negotiation of financial, regulatory, contractual and other nonphysical aspects of the project. Some development activities, such as training, customer relations, and community consultations extend through the subsequent project stages of construction and operation. At any project phase, the project may be halted prior to construction for various reasons: financing cannot be arranged, environmental approvals cannot be obtained, the pre-feasibility and feasibility studies “missed” important cost items, or for other reasons, even though significant investments in engineering and development have been made.

In the **Construction and commissioning** phase the project is built and put into service. Certain construction activities can be started before completion of engineering and development, and the two are conducted in parallel.

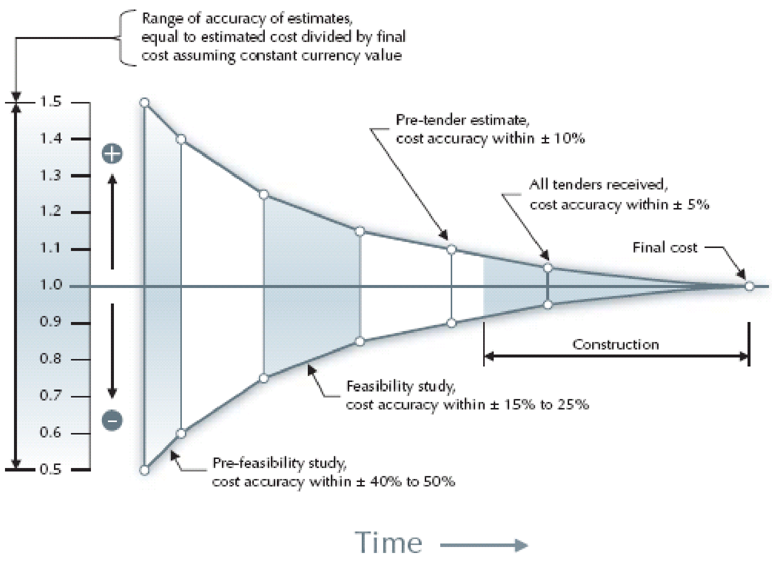

Figure 3: Accuracy of project cost estimates vs. actual costs

As shown in Figure 3, accuracy of cost estimates increases in every phase of project development. While at the preliminary stage the investor can use the rule of thumb, the closer the project is to the finish line, the more accurate the costs estimates become. The expenses of changing some detail in the project increase in every subsequent phase, so it is important to make the right decisions as soon as possible, with just enough information.

2.5.2 Checklist for project financing

Securing the project financing is the key step in RET project development. Because RE technologies are relatively new, not mass produced and sometimes “high-tech” technology bearing significant technology risks, financing a RET project might be difficult. To get financial support for the RES project from potential investors, comprehensive information is usually required. Below is a list of the main areas the implementer should prepare information in before looking for the financial support [4].

- **Project profile** – the investor should prepare the overview of the main legislation, regulation and governmental relations that can impact the RES project. It should comprise the overview of the applicable energy market, and a comparison of the existing similar-sized projects with a comparison of potential problems and their solutions.
- **Economics** – all cost (development, financing-related, construction, operating and maintenance) and revenues (electricity, steam, by-products, tipping fee) have to be foreseen. Analysis of cash flow, applicable regulated tariffs and taxation should be prepared in advance. Adequate planning is required for development budget and source of funds, project documentation, financial structure, equity contribution, participants' benefits, market research confirming financing strategy and financing timetable.
- **Legal status** – all required permits should be obtained in time, as well as the required local and governmental licenses.
- **Engineering/Feasibility Study** has to be performed, taking into account fuel and electrical interconnection, selected technology operational characteristics (efficiency, reliability, availability…), site-specifics, required fuel supply, emission control, operation and maintenance schedule.
- **Comprehensive risk analysis** is required, covering credit risk, construction risk, market and operating risk, financial and political risk, inadequate legal framework and to mitigate them, adequate insurance policy is needed.

Setting goals, foreseeing the barriers, preparing the required documentation are the first milestones for a successful project. Diligent following of these goals, overcoming the barriers and successful conclusion of the project is what makes the *best practice* project different from other projects.

2.6 The main drivers to achieve best practice

In addition to conventional measures such as profit, cost effectiveness and other measurable results, other less tangible success factors are relevant in the best practice. Among them, in the early stage of RET project, the most important is marketing outreach and communication with costumers to gain their trust. In addition to subjective evaluation of the project, an overall outcome can be measured in €/kWh. For basic evaluation **five main project areas** are important [5]:

- Project Theory and Design component,
- Project Management component, including
  - Project management,
  - Project Reporting & Tracking and
  - Quality Control & Verification Component,
- Project Implementation component, including

  - Program Outreach/Marketing/Advertising,
  - Participation Process & Customer Service and
  - Installation & Delivery Mechanisms,
- **Evaluation and Adaptability** Component, including Cross-Cutting Outcome Metrics.

In this chapter we look into each of the project areas in more detail.

2.6.1 Project theory and design component

Project design focuses on provision of a solid foundation for successful project implementation. A good project design begins with a good review of theoretical background of technology involved in the project, and complete understanding of the market and the barriers within. Processes and procedures should be well thought-out with clear steps of implementation and clear management responsibilities. Management procedures, including testing procedures, should be fully specified in order to optimize the project performance.

2.6.2 Project Management Component

The main goal of the project management is a cost-effective execution of the project. The project management importance rises with size of the project. It is crucial for implementation of large and complex projects, including projects with multiple subcontractors.

Tracking systems measure the characteristic indicators of project participation, budgets, markets and other project parameters. **Reporting** is associated with accessing and using the information in the tracking systems for communication among the participants and improvement of the project, both internally and externally. Reports should be clear and concise with all relevant data to monitor the progress towards the milestones. **Quality control** of the project process, equipment or measures taken is essential. For ensuring the appropriate measures were actually taken and that audits were actually performed **verification** plays an important role in ensuring success of the project.

2.6.3 Project Implementation Component

For project effectiveness **marketing and outreach** approaches are critical. Renewable technologies are at the early stage of development; hence each good word on behalf of RES is valuable. Marketing effectiveness and indicators of marketing cost per end user can be benchmarked; however, such quantitative data is not generally available consistently enough across various projects to be broadly used.

Participation process & customer service element is composed of the procedures, forms, communication and other interaction that occurs between the customers and the project implementer. If the project administration does not respond to the customers with sufficient diligence, the project can be sub-optimal regardless of other attributes.

At the end of the day, the project must be **finished** and results **delivered**. Some project may do well on the outreach and marketing, but their actual effectiveness is bad. The effectiveness of any financial incentives is captured under this sub-component.

2.6.4 Evaluation and Adaptability Component

Each project should be screened for the effort that has been put into evaluation of the effectiveness of the project goals, measures and activities. The findings must be used to adapt the project parameters to reflect the changing market conditions and recent technology development. For this purpose, Cross-Cutting Outcome Metrics can be used, consisting of:

- Cost Effectiveness Indicators ($/kWh or $/kW Saved, Benefit-Cost Ratios)
- Net Penetration Rates, Participant Adoption Rates, and Measure Saturation Levels
- Sustainability/Market Effects on the project outcome.

2.7 Examples of best practice

In this section, we look into the examples of best practice in RES project implementation, spanning various technologies in different EU countries. Based on an example, the potential investor can start to “build up” his RES project, anticipating the potential barriers at the project development and take measures to overcome them.

At the opening of the 6th Framework Programme for RTD, in parallel with Intelligent Energy in Europe Programme, the European Commission published a yearbook (1997 – 2000) of up-and-running best practice examples among Renewable Energy Projects [6]. Focusing on their respective technologies, we present some of them.

2.7.1 Small Hydro

2.7.1.1 Herrenhausen Mini-Hydro Plant, Hanover, Germany

Figure 4: Herrenhausen Mini-Hydro Plant

The city of Hanover accepted the “Hanover Energy Concept” in 1992, which involved a commitment to reduce emission of CO_2. RES technology was assigned an important role in achieving these aims, so Herrenhausen Mini-Hydro Plant was built. The installation was designed to fit into existing area in an optimal way. A fish ladder was also planned, allowing the various species of fish in the river Leine to swim upstream past the weir. The small hydro power station consists out of two Kaplan turbines and an average head of 2.10 m to generate electricity with capacity of 470 kW. The maximum overall turbine efficiency of the hydropower station is 92.3 % and the total power utilization factor of the plant varies between 86 % and 92.5 %. It is able to produce an average of 4,800 kWh of electricity a year.

The total investment came approximately €5.1m, of which about € 3m corresponded to the cost of the building and €1m to the cost of turbines. Additionally, the cost of operation and maintenance is about € 51,000 a year. Expo 2000 GmbH (Municipal Service of Hanover as an owner) and ProKlima offered financial aid and Lower Saxony has granted a low-interest loan covering 50 % of the investment. An environmental compatibility study was conducted to find the best way to minimize the impact of the project on its natural surroundings. All the main conservation groups and representatives of public interest participated in the authorization process, which took a little over a year. With a feed-in tariff of 0.02 €/kWh, the annual revenue from electricity sales is about € 96,000.

The Herrenhausen mini hydropower plant offers a good example of the construction of an electricity generating plant with a minimal environmental impact, thanks to both its overall design and features such as the fish ladder.

2.7.1.2 Small Hydro Plant at Anatoliki, Greece

Figure 5: Small Hydro Plant at Anatoliki

A part of the Operational Programme for Energy (OPE), a large joint fund established by EU and Greece, is intended for investments in RES applications. In the first call for proposals, 6 small hydro projects were selected for financing, of which one of them was small hydro power plant in Anatoliki. A small hydroelectric plant with installed capacity of 700 kW and a gross head of approx. 210 m was foreseen. Annual target production was 4 GWh. The generating set consists of a “Pelton-2” turbine and a synchronous generator. The total cost of the plant was estimated at approx. €1.03m of which 45 % was capital subsidy. A contract contains a ceiling that eligible auxiliary cost must not exceed 15 % of the total budget.

2.7.2 Biomass

2.7.2.1 Biomass-Fired CHP Plant Based on an ORC Process, Admont, Austria

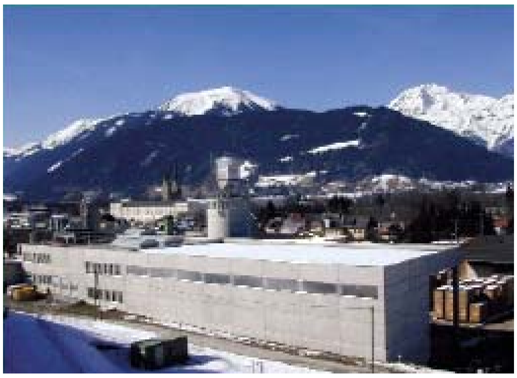

Figure 6: Biomass-Fired CHP Plant Based on an ORC Process

To supply the energy to both timber processing factory (STIA) and a local Benedictine monastery, a biomass-fired combined heat and power (CHP) plant was implemented in 1999 in Admont. It is based on Organic Rankine Cycle (ORC) process with objective to substitute oil-fired furnaces. The project was the first demonstration within the European Community of a biomass-fired plant based on the ORC process.

The plant uses sawdust and chemically untreated wood residues as fuel for its thermal boiler.

A considerable number of visits to the plant by engineering companies, potential future clients and energy authorities, in particular from EU countries, were organized. Furthermore the ORC technology was presented at the 1st World Conference on Biomass (2000) in Seville and at the Austrian Biomass Conference (2000).

Table 1: Project characteristics

Biomass input [tonnes]	5,000
Nominal capacity of the thermal oil boiler [MW_{th}]	3.2
Nominal capacity of the hot-water boiler [MW_{th}]	4.0
Nominal electric capacity of the ORC process [kW_e]	400
Nominal thermal capacity of the ORC process [MW_{th}]	2.25
Auxiliary electricity consumption [W/kW]	10-13
Thermal efficiency of the thermal oil boiler [%]	70-75
Thermal efficiency of the hot-water boiler [%]	89
Thermal efficiency of the ORC process [%]	80
Electrical efficiency of the ORC process [%]	18
Overall thermal efficiency of the plant [%]	98
Thermal and electrical losses [%]	2

Overall investment cost of implemented ORC power plant amounted to around €3,200,00 of which 46 % was covered by Austrian Kommunalkredit AG and the European Commission within the framework of the Joule Thermie Programme. Other part of costs were financed by own capital and bank loans. With a low maintenance and manpower costs and income from heat sales to monastery and STIA wood processing factory the payback period is estimated to 7 years.

The result of the project have become a new technical standard for biomass-fired CHP system in the range of 0.3 – 1.2 MW_{el}. As a follow-up and EU demonstration project, a new larger biomass district heating power plant came into operation in Lienz. The project serves as a model for decentralized biomass combustion system in the timber processing industry as well as regional biomass district heating systems.

2.7.2.2 Fischer/Facc Biomass Tri-Generation Plant, Ried im Innkreis, Austria

Fisher, the world's leading skis and tennis rackets manufacturer decided to change old steam boiler fired by heavy heating oil with the one using biomass. The Fisher tri-generation plant, operating since 2001, provides electricity, heat and cooling for the manufacturing process. Furthermore, it provides space heating and air-conditioning for the production hall and the offices. This solution was provided under an "energy contracting" arrangement by a local consultancy firm Scharoplan. In this way, the project combines an innovative biomass installation with a modern financing scheme for the plant. Scharoplan received the Energy Globe Award 2001 for this project. The total investment was about €5 m, of which 65 % financed Scharoplan out its own capital and external finance. The rest of the investment was financed by the EC, the national government and the federal state of Upper Austria. The payback period for the project is estimated at 15 years.

Figure 7: Fischer/Facc Biomass Tri-Generation Plant

The most important problem during construction was the Fisher's production, which should not be hindered or interrupted. Therefore the planning and the co-operation between Scharoplan and Fischer were crucial.

Table 2: Project characteristics

Biomass input, bulk volume [m_3/year]	50,000-60,000
Steam production [tonnes/hour]	10
Steam temperature [$_o$C]	380
Maximum operating pressure [bar]	32 (safety valve)
Boiler rating [kW]	7700
Fuel heating rating [kW]	9625
Combustion chamber temperature [$_o$C]	850-900
Electrical rating at the generator contacts [kW]	603
Turbine steam release pressure [bar]	4-6
Heat rating of the heating condenser and condensing refrigeration [kW]	6200
Condenser pressure [bar]	4-6

The annual output of the biomass tri-generation plant totals 26,000 MWh of heat, 1,000 MWh of cooling, 2,000 MWh of power, and 1,500 MWh of thermal oil with total output of €1,100,000 a year. By using biomass Fisher substitutes 3,000 tonnes annual of heavy heating oil and reduces CO2 emissions by 9,456 tonnes per year. Also the project has good impact on local economy especially to agricultural and forestry sector with €370,000 each from the purchase of their waste byproducts by a new costumer. To replicate the project with similar size and power at another site, an adequate supply of biomass should be guaranteed.

2.7.3 Wind Energy

2.7.3.1 Development of Wind-Turbine and Blade Technology, Greece

For the support of R&D activities in the environmentally friendly technology, this project aimed to enhance national technology in wind energy and in particular Wind Turbine (WT) manufacturing. Special emphasis was given to WT controllers and WT rotor blades, which were domestically designed and manufactured for the first time.

The total investment of the project was around € 1,920,000 of which over 70 % was funded from public funding. As a byproduct of the project, two partners are capable of producing WT parts, therefore lowering the cost of purchasing and installing wind turbines. With the lower start-up costs, more investors will be interested in operating WT at Greek sites. With boosting of the wind energy, substitution of fossil fuel usage with RES will increase and environmental benefits will rise, too.

Figure 8: Wind-Turbine and Blade Technology in Greece

2.7.4 Solar Thermal

2.7.4.1 Solar Thermal Collector Integrated with a Biomass Plant, Eibiswald, Austria

Since the portion of wood produced in the area of Eibiswald is unsuitable for sale in the market, the company Nahwärme Eibiswald was founded in 1991 to turn waste wood into a source of income for farmers as raw material for heat generation. The biomass boiler, installed in 1994, delivers heat to two schools, a rest home, 75 households and several companies. Because of a lack of demand during the summer, the system was supplemented with a supporting solar thermal collector system.

Table 3: Project characteristics

Net total solar collector surface [m_2]	1,246
Storage volume [m_3]	106
Storage height [m]	12
Maximum biomass boiler capacity [kW]	2,000
Total heat delivery to the network [MW_h]	4,500
Total heat consumption [MW_h]	3,650
Heat production from biomass [MW_h]	4,040
Heat production from oil [MW_h]	105
Heat production from solar collector [MWh_h	125
Specific collector yield (gross collector surface) [kWh/m_2 per year]	415
Transportation losses in summer [%]	65
Annual transportation losses [%]	16
Cover by solar collector in summer [%]	90
Average annual cover by solar collector [%]	8

The investment amounts to € 276 per m^2 of collector surface what results in the total investment of about € 343,000. The project was partly financed by the members of Nahwärme Eibiswald, Austrian government and the government of the state of Styria. The solar collector produces about 516 MWh of heat annually with heat production cost of € 0.05 per kWh (without subsidy) and 0.03 kWh (with subsidy).

2.7.5 Solar Photovoltaic

2.7.5.1 60 kWp Modular PV System, Island of Sifnos, Greece

Sifnos is a Greek island in the Aegean Sea on which electricity demand is supplied by a standalone diesel power station. Power station generates power at a higher cost than that of electricity from the main Greek power grid. Hence, the island was chosen for the installation of a photovoltaic plant.

The PV plant was installed as centralized system, but a modular approach was taken so as to allow for future replication in plants of different sizes and enable the system to be implemented in a distributed configuration.

Figure 9: A 60 kWp Modular PV System on the Greek Island of Sifnos

In the project, the following partners were involved: CRES (Centre for Renewable Energy Sources – Greece), PPC (Greece), ANIT (Italy) and SMA (Germany). The work was performed within the framework of European Commission’s Thermie A programme.

2.7.6 Geothermal

2.7.6.1 Geo-Heating Plant, Erding, Germany

The discovery of a thermal water well led the City and County of Erding to investigate how this source might be exploited commercially. The foundation stone for the Erding Geo-Heating plant was laid in October 1996 and it came into operation in 1998. The water is supplied to the district heating system, to thermal baths and to Erding’s drinking water system.

The total investment for the heat acquisition and distribution facilities amounted to approximately € 15m, which was financed by Zweckverband Geowärme. The State of Bavaria covered 50 % of the costs for the renovation of the well equipment and of bringing it up to operational readiness, as a subsidy program “Efficiency Energy Production and Use”. Some 40 % of the eligible cost for absorption heat pump and thermal water treatment plant were covered by EU’s Thermie programme.

Figure 10: Geo-Heating Plant

The geothermal well is able to produce a 28,000 MWh annually. This way, over 50 % of the town's heat demand is generated without pollution by geothermal energy. The remaining heat demand is covered by a heat pump, driven by natural gas and light heating oil.

2.8 Recommendations

Following the presented examples, we can summarize the following recommendations for achieving best practice in RES project application. First of all, the starting point of the implementation of the RES is to be aware of all barriers, financing possibilities and to assure a good marketing strategy. RES project should start with examination of all past project similar to the new one. Knowing the possible issues we can plan how to avoid or how to deal with them. This way we can shorten the implementation time and reduce the expenses. Gathering all the information about the regulation, the financing issues and subsidy possibilities in the country's legislation is the next step. Because the RES technologies are competing with conventional energy, potentially threatening the conventional generation dominance and profit, the project may face problems in realizing financial incentives (complicated procedures, delays, even corruption). Hence all the legislative issues should be known to the investor, to avoid problems during the installation of the power plant.

If the public is in favor of the new RES project, the pre-feasibility study can take place. If not, "marketing" and an open discussion with the public are in place. The project can have all the technological attributes, but if the public does not accept it, it will not perform optimally. To achieve public acceptance in the first place is very important.

For achieving the best practice, the most important is the adequate preparation of the project. During the preparation the foundation is formed, on which the project is built. Project implementation should upgrade the foundation and follow the planned milestones, but still be aware of any changes in the environment, such as new technologies and market changes.

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3 RES POTENTIALS IN WB REGION: Barriers and Country Specifics

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3.1 Introduction

Efficient, cost effective and reliable electricity supply form the basis for sustainable development of every country. Due to events that marked Western Balkans (WB) region in the last decade and because of big difference in grade of development within the region, some parts are still facing problems with electricity supply. War devastation significantly affected transmission and distribution networks, thus local security of supply became a challenge. However, that also provided a possibility for wider application of alternative technologies. Countries in the Western Balkan region have great unexploited potential of renewable energy sources (RES), which could by efficient use significantly contribute to security of supply within the region and wider. Special care has to be devoted to sound solutions for electricity supply of undeveloped and isolated regions due to war damage. RES potentials in Albania, Bosnia and Herzegovina, Croatia, Serbia and Montenegro and FYROM, along with RES penetration barriers and country specifics will be discussed in this paper.

3.2 RES potentials in Albania: barriers and country specifics

3.2.1 RES potentials in Albania

3.2.1.1 Wind

There are no operational wind energy power plants in Albania and no known projects in the planning. However, there are some old wind mills still used for grinding wheat or other grains, as well as water pumping. The total number of such turbines and the current operating conditions are unknown. There are a number of opportunities for the installation of large wind facilities. Additionally, there is the potential for small wind power facilities in the remote zones, where the cost to deliver the fuel for electricity and heat supply is expensive. Developing wind energy is one of the supported and sustainable options for long-term energy sector development program in Albania. Its development, though, requires strong governmental and international financing support. According to the newly adopted energy strategy, feasibility study should be done for selection of the best sites of installation of wind power farms with total capacity of 100-150 MW in the future.

The most promising sites are located along the Adrian coast, as well as the hills and ridges running in the north to south direction along the coast. It is also highly probable that there are isolated locations in the mountain passes and near the two big lakes at the Macedonian border.

3.2.1.2 Biomass

Biomass energy could be important in Albania’s future, consisting of the following four main resources: urban wastes, agricultural residues, forest residues, and animal wastes. The potential of urban wastes from the main Albanian cities was calculated as approximately 40,5615 Toe-ton oil equivalent, predicted for the year 2010.

The energy potential from agricultural residues was calculated at approximately 43,004 GJ in 1995. Forestry biomass resources were calculated to be approximately 460 millions of GJ in 1995. The energy potential from animal residue's was calculated at approximately 12,740 GJ in 1995 with a trend to be increased in the future. These numbers should be considered estimates; a more comprehensive study should be carried out for real validation.

3.2.1.3 Solar

There are no installed photovoltaic systems identified at this time, although The Ministry of Energy aims to install enough solar panels to provide 62.9 ktoe of energy by 2015. The total investment cost is estimated at USD 79 million. Investment costs are to be shared between the state budget and private investors.

The largest solar thermal heating system currently operating in Albania consists of three sets of solar panels totalling 48 m^2 that are installed from Centre of Energy Efficiency (founded by EU and National Energy Agency).

The climate of Albania is a typical Mediterranean one, with a hot and dry summer. This climate is good for the use of solar energy (about 1,503.8 kWh/m^2 per year). The global annual radiation varies between 3.2 kWh/m^2/day in the North East part of Albania and 6 kWh/m^2/day in Fier, with a country average of 4.0 kWh/m^2/day which is seen as a good solar energy regime

3.2.1.4 Geothermal

There are many thermal springs and wells in Albania, which represent a potential for geothermal energy. To date, the geothermal sources have never been used as a source of energy.

The geothermal situation in Albania offers two directions for exploitation of geothermal energy:

- The use of thermal water springs and wells of low enthalpy, which covers a wide territory from South, near the Albanian-Greek border to the Northeast districts in Diber region. The water temperatures reach values of up to 60^0C.
- The use of hot thermal waters, brought out from deep abandoned oil and gas wells and single wells, for geothermal energy in a form of a "Vertical Earth Heat Probe". At 2000 m depth the waters temperature reaches a value of about 48^0C.

In many deep oil and gas wells there are thermal water fountain outputs with a temperature that varies from 32 to 65.5^0 C. These waters are from different depth levels (800-3000 m) of limestone reservoirs and sandstone reservoirs. The thermal springs and wells in Albania are located in three areas:

- Kruja geothermal area - a zone that has the largest geothermal resources in Albania, with a length of 180 km and a width of 4-5 km. It starts on the Adriatic coast, north of Rodoni Cape in Ishmi region, and continues from Tirana, Elbasani up to southeastern Albanian-Greek border and extends to the Konica district in Greece.
- Ardenica geothermal area- Located 40 km North of Vlora. The area extends on the part of peri-Adriatic Depression where the Vlora-Elbasan-Diber transverse passes.

- Peshkopia geothermal area- Situated in northeastern Albania, in the Korabi hydrogeologic zone.

The most important resources explored until now are located in the northern part of the Kruja geothermal area, from Lixha Elbasan in the south to Ishmi north of Tirana. The values of the specific reserves vary between 38.5 and 39.6 GJ/m^2. The southern part of the Kruja area has resources of 20.63 GJ/m^2.

In the Ardenica geothermal area the specific reserves amount to 0.39 GJ/m^2.

Geothermal resources of Peshkopia area have been estimated similar to those of the northern half of the Kruja geothermal area.

In the peri Adriatic Depression, there are areas with a geothermal gradient of 18-20 ^{0}C/km where there are several abandoned oil and gas wells which could be used for single or double ground-source heat pump installations. They are located in the plain area of the country, e.g. in Divjaka and Kolonja where greenhouses could be built to use the hot water for heating them

3.2.1.5 Hydroelectric

Albania is known for its enormous hydropower potential. So far, the country has exploited only 35 percent of the total potential. The average output from hydropower is 4,169 GWh. Total hydropower reserves are estimated at around 3,000 MW. Potential annual generation may reach up to 10 TWh. New plants in the southern part of Albania (Vjosa and Devoll) have been successful in exploiting nearby rivers.

The Albanian Power System (APS) was created in 1957, but its origins come long before then. The total installed energy capacity in Albania is about 1650 MW, of which 1446 MW (87.2 percent) are HPP-s providing more than 95 percent of total energy supply. Three HPP-s constructed on Drini River (north of Albania) compose 80 percent of the country's installed capacity. The annual generation capacity of the country has been approx. 3300 – 3500 GWh, reaching 5800 GWh in 1996. With an average rainfall of 1,500 mm and an average available head of about 600 m, there is still an enormous potential to be developed.

The energy production is highly dependent on the hydrological situation. KESH, the operator of the APS, is also encountering problems with the technical and "non-technical" losses. The electricity demand has increased considerably over the last 10 years. The residential sector consumes over 60 percent of electricity production.

Apart from the large and medium sized HPP-s, there are 83 small hydropower plants (SHPP-s) in Albania (owned by KESH) ranging from 0.05 to 1.2 MW. Their installed capacity is 14 MW (this represents 1 percent of the APS hydropower capacity) and the average annual production has been about 50 million kWh. Their utilization scheme is often incorporated for electricity generation and irrigation. Most of them are connected to the national grid. Actually these SHPPs are in poor working conditions or out of work because of the outdated technology, lack of spare parts and poor maintenance. The production level in recent years is about 12 GWh.

3.2.2 RES penetration in Albania: barriers and country specifics

Albania has experienced an abnormally high growth rate of electrical consumption, averaging an 8.6 percent annual increase since 1992. A large part of that growth has been artificially stimulated by extraordinarily high rates of electricity theft, non-payment of electric bills and tariff rates well below cost. Consumers have failed to conserve electricity or to make adequate use of alternative fuels for the past decade.

The abnormally high demand, together with reduced hydroelectricity production in 2000, 2001 and 2002 caused by reduced river flows, has caused a substantial supply deficit, which has caused a social and economic crisis. Albania's capacity to import electricity is constrained by a transmission system in dire need of rehabilitation and upgrades to expand its capacity.

The artificially high electricity consumption, particularly for electric space heating, has diverted a valuable resource away from commercial and industrial uses that would otherwise create jobs and contribute to economic growth. The Government has subsidized imported power purchases, thereby diverting state resources from other critical government programs. In 2001, the subsidy reached 4,530 million ALL (US $ 31.5 million).

It can be concluded that the RES penetration in Albania meets the following barriers:

- All renewable – Difficult economical conditions
- All renewable – Low electricity prices
- Hydroelectric – Renovating Existing Capacity
- Wind - Lack of any previous studies on wind energy resource potential.

3.3 RES potentials in Bosnia and Herzegovina: barriers and country specifics

3.3.1 RES potentials in Bosnia and Herzegovina

3.3.1.1 Wind

There is not sufficient information to make a statement on the technical potential for wind energy development. No wind turbines operate in Bosnia and Herzegovina. A countrywide wind-atlas is not available. No other projects were identified.

The only neighbouring country with some wind energy information available is Croatia. Since the Southwest corner of the country is only some 10 - 20 kilometres away from the Dalmatian Coast, the wind energy resources are likely similar to the resources right across the border. This does not exclude the possibility of finding favourable wind conditions inland, particularly in the northeast. Some preliminary studies conducted in the University of Tuzla have indicated good wind power potential in the middle and south area of Bosnia and Herzegovina. A country wide wind resource assessment is one of the first priorities to be in place for wind development.

3.3.1.2 Biomass

Forests and forestland include around 53 percent of Bosnia and Herzegovina's territory or around 2.7 million hectares. Average annual volume growth of all forests is around 10.5 million m^2.

Regarding residues from field crops, fruit tree plantations, and livestock activities, there should be a significant potential for their collection and utilization, along with wastes including manures from intensive farms. Utilization of those resources could be done through incineration or anaerobic digestion technologies.

Detailed studies and surveys would have to be carried out to determine location, logistics, size of units, economics and viability, likewise with MSW (Municipal Solid Waste) and the waste of sewage (sewage sludge).

It is assumed that charcoal and wood fuel consumption is similar to that of the remaining inland area of former Yugoslavia.

3.3.1.3 Solar

The situation regarding solar energy is similar to that in other areas of FR Yugoslavia (Slovenia, Croatia, FYR Macedonia), and is among the highest in Europe.

The most favourable areas record a large number of sunshine hours, with the yearly ratio of actual irradiation to the total possible irradiation reaching approximately 50 percent.

The primary form of solar energy and technology used are flat plate collectors for heating houses and some commercial and public premises. But their contribution to the total energy consumption is insignificant, less that 1 percent. It is not expected that this figure will increase substantially in the near future, as new consumption could mainly come from new entrants to the market i.e. of new buildings or installations.

Due to the high cost of electricity production from solar photovoltaic sources it is likely that the use will initially be limited to research or remote locations, primarily for telecommunications.

3.3.1.4 Geothermal

Subterranean geothermal pools and lakes throughout present potential sources of thermal energy. Before the recent civil war, the first 1 MW pilot plant working on geothermal water was about to be built in Sarajevo. However, due to lack of money the project has not been pursued. Its estimated flow rate is 240 l/s at a temperature of 58°C.

The country's geothermal potential for space heating and therapeutic bath purposes, based on the existing wells, is about 33 MW_t.

3.3.1.5 Hydroelectric

Bosnia and Herzegovina's geography includes fast-flowing mountain streams and powerful rivers that are very well suited for hydro-electricity production. Thirteen hydroelectric power stations already exist with a generating capacity of 2,034 megawatts. These are supplemented by four thermal power stations that are being upgraded through an EU grant, which in itself is part of a wider scheme aimed at restoring the national electricity distribution system and in reconnecting the country to the international electric supply grid.

The hydro plants have an average annual generation of 8,900 GWh/yr, although actual generation was only 5,100 GWh in 1998. There is 430 MW of capacity in operation at pumped storage plants. No more plants are currently planned. Five existing hydro plants (totalling 1,060MW) are part of multi-purpose developments. There are 13 hydro plants with a capacity greater than 10 MW.

Bosnia has an estimated small hydro power potential of 2,500 GWh/yr. There are ten small, mini or micro hydro plants in operation, with a total capacity of 31 MW.

The total hydro power potential of is estimated at 6,100 MW mostly located within the Neretva and Trebisnjica river basins. Only about 38.75 percent of this is utilized and that amount meets approximately 40 percent of the total electricity production.

According to another estimate, the country's gross theoretical hydropower potential is 68,800 GWh/yr (equivalent to 8,000 MW), and the technically feasible potential is 24,000 GWh/yr (6800 MW), and the economically feasible potential is 19,000 GWh/yr (5,600 MW). About 37 percent of the technically feasible potential has been developed so far.

The most urgent task in Bosnia and Herzegovina is to rehabilitate and reconstruct power plants and hydro power structures damaged during the war. The construction of new hydro plants and reservoirs for water supply is also envisioned.

3.3.2 RES penetration in Bosnia & Herzegovina: barriers and country specifics

Similar to all other former member states of the Yugoslav Federation, Bosnia and Herzegovina has initiated programs of economic and energy reform and has also announced policies encouraging energy conservation and alternative sources of energy, particularly renewables. However, due to the conflict within the country in the early to mid-1990s much of the energy infrastructure has been destroyed and remains heavily damaged. Therefore, there is more focus on the rehabilitation and repair of existing energy infrastructure rather than the development of new renewable energy projects.

Nevertheless it can be concluded that the RES penetration in Bosnia & Herzegovina meets the following barriers:

- Lack of appropriate legislative framework based on the best EU practice;
- Lack of appropriate feed-in tariffs stimulating RES penetration;
- Lack of public awareness of importance of RES for community.

3.4 RES potentials in Croatia: barriers and country specifics

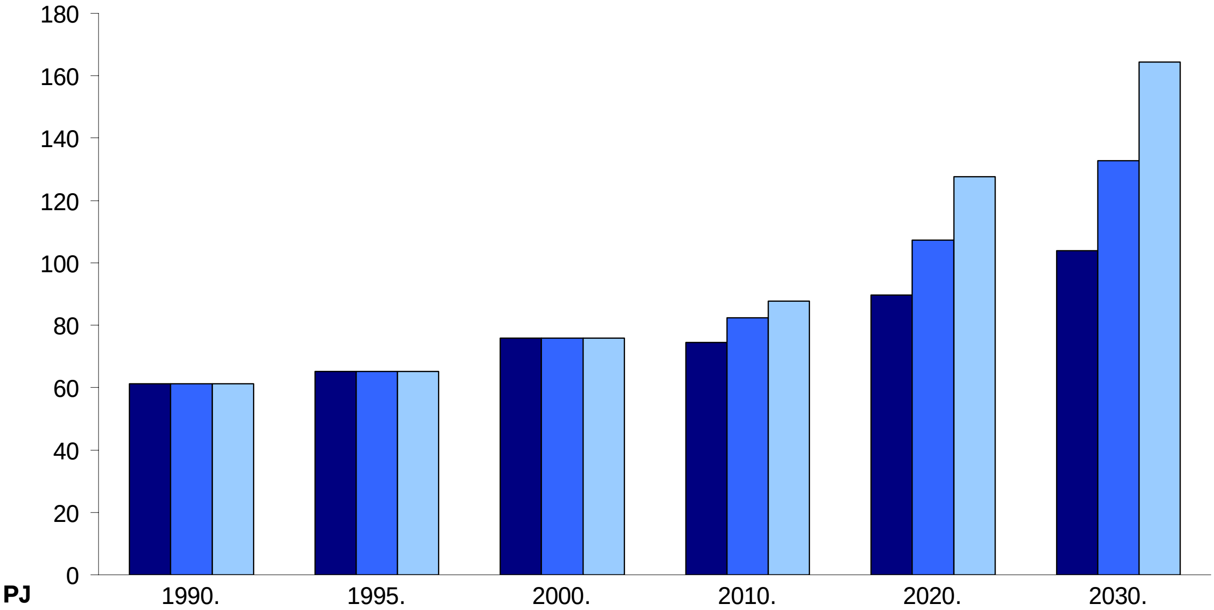
3.4.1 RES potentials in Croatia

Renewable energy sources have already quite large share in total energy production and total energy supply in Croatia, which is a consequence of the large share of hydro- power. In 2004 total primary energy production was equal to 204.40 PJ. The share of hydro-power was 33.8%. The only other RES that participates in total primary energy production is fuel wood with the share of 7.8%. Total primary energy supply in Croatia in 2004 was equal to 412.04 PJ, out of which 16.7% from hydropower and 3.9% from fuel wood. When it comes to electricity production, 51% of installed capacities are in hydro power plants, which equals to 2,078.6 MW. 26.7 MW are installed in small HPP. Apart from hydropower, there is very small share of other renewables in electricity production. Installed capacities for heat and electricity production from RES in Croatia in 2004 are given in Table 4.

Table 4: Installed RES capacities in Croatia in 2004 [9]

Type of RES	Installed heat capacity	Installed power capacity
Sun	N/A	12.74 kW
Wind	0	5.95 MW
Biomass	510 MW	0
Small hydro	0	26.7 MW
Geothermal	113.9 MW	0
TOTAL	**623.9 MW**	**32,663 MW**

However, according to the Strategy of energy sector development [10], renewables will gain more significant role in Croatian energy supply and their increased use is one of the most important strategic goals of Croatian energy policy. It will help to reach the environmental goals with regard to the commitments under the Kyoto Protocol, to increase the security of supply and increase social welfare by creating new employment opportunities. The last is especially important, since Croatian industry is experienced and technically skilled to develop and produce equipment for RES use. The good example is found in Končar Group, which is developing its own wind turbine. The Strategy considers three different scenarios all characterised by the increase of RES use from approximately 75 PJ in year 2000 to 100 PJ (business-as-usual scenario), 130 PJ (moderate scenario) and 160 PJ (distinctively ecological scenario) in year 2030. This is shown in Figure 11.



	1990.	1995.	2000.	2010.	2020.	2030.
S1	61,23	65,27	75,79	74,47	89,80	103,90
S2	61,23	65,27	75,80	82,36	107,34	132,70
S3	61,23	65,27	75,79	87,69	127,69	164,39

Figure 11: Energy production from RES – comparison of three development scenarios

As for electricity production from RES, there are three possible scenarios considered within the latest secondary legislation proposals, as shown in Figure 12. First scenario (RES1) assumes that in 2010 there will be 900 GWh produced form RES, which corresponds to 4.7% of total electricity production. Medium scenario (RES2) assumes 1,100 GWh or 5.8%, while the highest scenario (RES3) assumes 1,850 GWh or 9.7% of total electricity production in 2010.

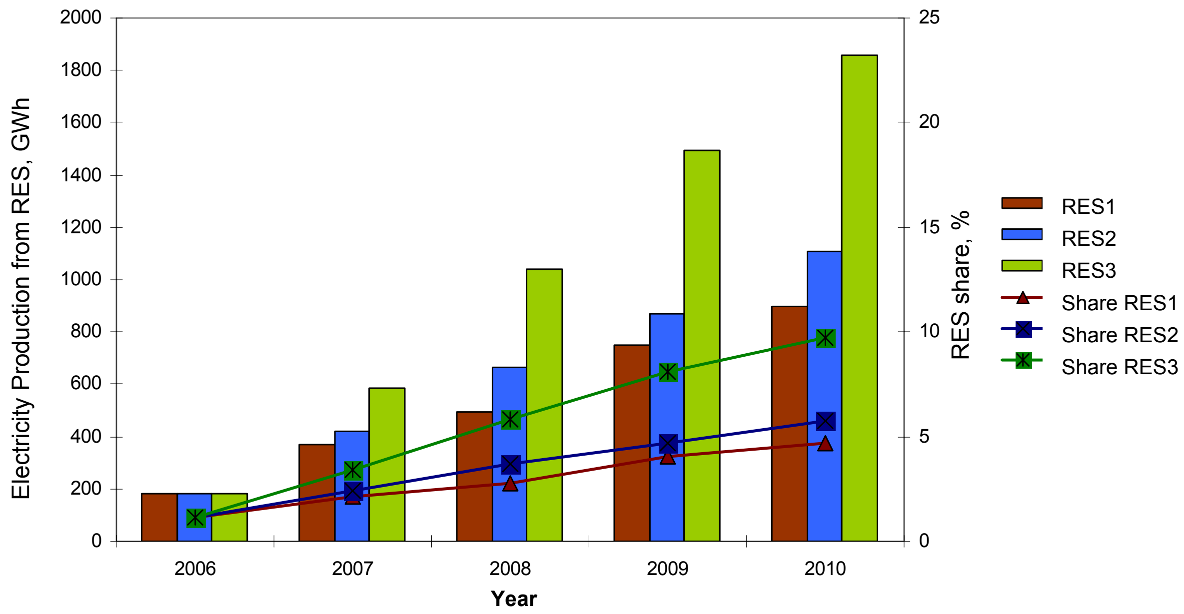


Figure 12: Electricity production from RES – comparison of three different scenarios

According to the current economy indicators, the most cost effective and thus the most probable target would be the one stated in scenario RES2. According to this target, the compensation for encouragement of RES payable by all electricity consumers will be determined. The latest proposal suggests that this compensation could be equal to 0.005 HRK/kWh (0.07 €c/kWh) in 2006 and could rise to 0.0229 HRK/kWh (0.31 €c/kWh).

Croatia has very good potentials for RES. New renewable sources of energy that are expected to contribute to the energy supply are solar, wind, biomass, geothermal energy and small hydro power plants. Solar and biomass energy are expected to participate both in thermal applications and in electricity production, geothermal energy is expected to contribute in heat production and wind energy as well as small hydro power plants will be used for electricity production.

3.4.1.1 Wind

Various studies indicate the Croatian islands and the Adriatic coast are good locations for wind energy development. The highest measured wind speeds were 7.3 m/s at 25 m above ground level (~ 8 m/s at 50 m).

In 1997 Croatia launched the National Energy Programs (NEP), which included ENWIND or Wind Energy Utilization Program. Wind potential assessed within this programme in 29 locations equals to about 400 MW and electricity production capacity equals to 800 GWh per year [11]. Although here are still no secondary legislation prescribing the feed-in tariffs for electricity purchase, the state owned utility company HEP decided to offer a feed-in tariff equal to 90 percent of the average electricity price for renewables, which was roughly 5.7 €c/kWh. However, this tariff was applied only to projects with an installed capacity of less than 5 MW. The feed-in tariff of larger projects had to be negotiated on a case to case basis. However, this is about to change, while the secondary legislation, among which also the tariff system for electricity produced from RES and cogeneration, is in preparation and it will be adopted in 2006. Whit this tariff system feed-in tariffs for every RES-e facility type will be prescribed.

One of the most interesting opportunities for wind energy development in Croatia is the 55 inhabited islands. Autonomous wind energy systems could provide these islands with power and more importantly with clean water by using RO (Reverse Osmosis) desalination systems. The cost of clean water by RO would be about 1.3 - 2.0 €/m^3, compared to the current 5.0 €/m^3 at some islands. However, in 2005 the Ministry of Environmental Protection, Physical Planning and Construction has brought out the Decree according to which the construction of wind power plants, among other specified objects, on Croatian islands as well as 1000 meters from the cost line is forbidden, which strongly slows down and disables the higher wind power deployment in costal area, since these areas are the once with the most favourable wind conditions and potentials. Despite this fact, currently the strongest investors' interest for RES facilities in Croatia is exactly for wind power projects, since there is number of good locations, especially in Dalmatian Background. With the adoption of tariff system for electricity produced from RES it is expected that this interest will be even higher.

3.4.1.2 Biomass

Historically, biomass has been used in the rural population in large amounts for heating and cooking in all Croatian regions. Heating wood and commercial and non-commercial cutting of woodlands amounted to 15 per cent of primary energy consumption in 1970 whereas, due to urbanization and growth of living standards, the corresponding value in 1990 was 5.3 percent.

Almost 44 percent of Croatia is covered by woods and forests. Developed agriculture and woody biomass have a great potential as a source of renewable energy. Potentials are assessed to approximately 39 PJ. National bio-energy programme BIOEN has set the goal of at least 15% of the total energy consumed from the biomass by the year 2030 **Napaka! Vira sklicevanja ni bilo mogoče najti.**.

The major source for such energy is the wooden mass from forests (fuel wood, residues and wood waste from the wood processing industry). However, agricultural residues also have a significant potential in both Eastern Croatia and the coastal zone.

Agricultural crops include:

- Practically and economically collectible quantities in fresh and dried form for possible energy utilization (burning or pyrolysis gasification), or anaerobic digestion for production of biogas/electricity/heat and organic fertilizers.
- Public and private garden waste.
- Tree pruning and related woody waste.

- Livestock solid and liquid wastes. Choice of processes as above.
- Agro-industry (abattoirs, food and drink industry etc.): Solid and liquid wastes.
- Municipal solid waste (MSW), preferably separated at source. Organic fraction typically 40 percent. Options for incineration combined with desulphurization or biogas-producing anaerobic digestion.
- Sewage sludge: Incinerated in dried form or digested anaerobically. The anaerobic digestion process also mitigates pollution and protects the environment.

Appropriate infrastructure for collection/transportation combined with fiscal or monetary incentives and green taxes would be needed to achieve affective utilization of the fore-mentioned solid and liquid wastes.

Biomass use will be very important RES in Croatia for both electricity and heat production. It is estimated that increased use of biomass will also significantly contribute to the creation of new working places – according to recently conducted researches it could result in creation of almost 5000 direct jobs by 2015. Also, Croatian industry is skilled and experienced in producing the equipment for energy generation from biomass.

Due to these clear benefits, the Environmental Protection and Energy Efficiency Fund (established in 2003) will strongly encourage and support use of biomass by individual users, for small biomass heat networks and boiler rooms, use of waste deposition gases for electricity production and for the establishment of the system for collecting eatable waste oil. The Fund will also support production of bio fuels: wood pellets, bio diesel and other liquid bio fuels, wood coal and wood chips from forest biomass.

3.4.1.3 Solar

Solar energy for heating purposes has been used in Croatia since 1975 in all kinds of facilities and for various purposes, and the first photovoltaic applications occurred in the late 1980's. However, the use of solar energy in energy balance remains negligible.

The country is reported as having an aggregate installed capacity of 6 MW_{th} in the year 2000. By far the major part of this is comprised by flat plate collectors used for heat production, for houses, commercial buildings and other installations. However, as it can be seen from Table 4, there are no reliable data which enable to determine the installed heat capacities of solar collectors. During the last war in Croatia (1991-95) most of the solar production activities ceased or were severely curtailed.

Potentials for use of solar energy are great – technical potential equals to about 777 TWh [**Napaka! Vira sklicevanja ni bilo mogoče najti.**. The SUNEN national energy program was established with the aim of stimulating increased solar energy usage. The solar energy application for electric energy generation will depend on the global technology development. Solar energy is expected to be used mostly in thermal applications. The greatest potentials exist in the use of low temperature heat (30-80°C) for hot water preparation and space heating. National solar energy programme has set the goal: 80% of energy for hot water preparation in households and objects for tourism in coastal area should come from solar energy until 2020. Apart from households and especially objects for tourism, there are also significant potentials for use of solar energy in agricultural sector. It could be use for technological hot water preparation in livestock farming, for drying facilities and for greenhouses (heating and warm watering water preparation).

3.4.1.4 Geothermal

Croatia has a centuries-long tradition of using geothermal water from natural springs for medical purposes. In the early 70s, along with research for oil and gas, the existence of geothermal water began being observed. The calculations of temperature gradient based on the data obtained from exploration of the wells showed that the average gradient in the northern part of the country, part of the Pannonian sedimentary basin, is considerably higher than the world average, while in the southern Dinarides area its value is below that figure (0.049°C/m and 0.018°C/m respectively, compared to 0.03°C/m in the world, Jelić et al., 1995).

The geothermal potential of the reservoirs in the northern part of Croatia could be a significant renewable energy resource, substantially contributing to the overall energy efficiency and the environmentally acceptable energy policy. The geothermal energy content of the medium temperature reservoirs (between 100 and 200°C) can be converted into electric energy, while that of the low temperature reservoirs (below 100°C) is perfectly suitable for heating and cooling of buildings, heating greenhouses, in various industrial processes, for medical purposes, etc.

The UNDP FINAL REP ON GEOTHERMAL RESOURCES (part II) has highly useful information on Geothermal Energy for a number of countries including Croatia. The Croatian section is reproduced herewith in its main part.

The most prospective fields are located in the following areas:

- In *Zagreb* (the capital of Croatia) a reservoir containing low-mineralized (2 g/l) thermal water with temperature 55-82^{0}C was discovered at a depth of 500-1000 m during exploration drilling.
- In *Lunjkovec-Kutnjak* a geothermal reservoir formed by high-porous (7.5 percent) carbonate breccia was found. The thermal water contains 5 g/l of dissolved salts and 3 m^3/m^3 of dissolved gases (mainly CO_2). The projected average discharge of wells is 80 kg/s per each well, the wellhead pressure is 3-5 bars, and the wellhead temperature is 125-140 ^{0}C.
- In *Velika Ciglena* a dolomite jointing reservoir located at a depth of 3 km contains geothermal brine (24 g/l) with a gaseous factor of 30 m^3/m^3 (CO_2 and 59 ppm H_2S). The expected discharge of operating wells is 100 kg/s with wellhead pressure 20-25 bars and wellhead temperature of 165-170^{0}C.

The total thermal capacity potential of high and medium temperature geothermal fields is estimated as 839 MW_t with a waste discharge temperature of 50 ^{0}C, or 1170 MW_t at 25 ^{0}C. The potential capacity of binary GeoPP constitutes about 48 MW_e.

It is expected that the most geothermal projects will come from the exploitation of existing boreholes used for oil and natural gas extraction.

3.4.1.5 Hydroelectric

Croatia's mountainous territory and numerous rivers give it ample hydroelectric-generating potential. The country has numerous hydropower plants (HPPs), located predominantly along the Adriatic coastline and near the Slovenian-Croatian border. The country's four major hydroelectric plants are in those two main areas of the country. The three Varazdin hydro plants are located near the Slovenian-Hungarian border, and the three hydro plants along the Adriatic coastline are Senj, Orlovac and Zakucac. All of these and more (in total 25) are owned and operated by the national electricity company Hrvatska Elektroprivreda (HEP).

Hydroelectric power plants make 51 percent of the totally installed capacity of power plants on the territory of Croatia. The total installed capacity of hydroelectric power plants in Croatia is 2,078.6 MW, out of which 1,692.5 MW is installed capacity of storage systems, and 386.1 MW of run-of-rivers and small hydro plants.

The majority of hydro plants were constructed during the '60s and the '70s of the last century, while the last hydro plants were constructed in the late '80s. For the last 15 years mostly partial actions of refurbishment of the older hydro plants have been done, which in some cases mean the increase of the installed capacity and turbine efficiency.

The technical potential for *small hydro power plants* is assessed to about 177 MW. If some locations are disregarded due to environmental aspects, local space plans requests and/or economical unattractiveness, this potential will be equal to 100 MW [14].

3.4.2 RES penetration in Croatia: barriers and country specifics

The barriers regarding the RES development are mostly universal: high up-front investment and uncertainties connected to the energy system liberalization. Another important barrier is the needed cross-sectoral approach, which is difficult to accomplish: Renewable Energy Sources are a part of different strategies, laws and ministries.

Apart from these obstacles, major financing mechanisms for use of Renewable Energy Sources are missing in Croatia, which foremost include the tariff system for electricity produced from RES and cogenereation. Until recently only commercial loans were at disposal for RES projects. However, as already mentioned, in 2003 the Environmental Protection and Energy Efficiency Fund was established. It strongly collaborates with the Croatian Bank for Reconstruction and Development (HBOR), and can offer interest free loans, with repayment period of five years, with possibility for two years delay. Also, the Fund can provide subventions on loan interests for environmental protection, energy efficiency and RES projects. For this purpose the agreement between the Fund and HBOR was concluded, according to which the investor can benefit from the subvention up to 2% of agreed interest rate. Interest for the final user can not exceed 4%. It still remains to be seen whether this will trigger more investments in RES projects.

Further, an important barrier to the development of RES in Croatia is the lack of secondary legislation. The Energy Law which has entered into force in 2001 specifically stipulated that the Rules on Renewable Energy Sources will be adopted by the Ministry of Economy six month after the adoption of the Law. Unfortunately, this has never happened. The Energy Law has in the mean time been amended (December 2004) and the same time frame has been set for supplementing by-laws necessary for a wider RES penetration. These secondary legislation especially include the Rules on the use of RES and cogeneration, Ordinance on Minimum Share of RES in energy mix and Tariff system for electricity produced from RES and cogeneration. These acts will complete the regulatory framework for RES use and provide the institutional organisation, which should enable stronger RES penetration based on entrepreneurial initiatives. Draft versions of all relevant secondary legislation already exist and now it is up to the Government to accept them. The most probable is that these documents will be adopted in 2006.

It will be only after these preconditions – favorable financing opportunities and complete legislative framework – have been met that other barriers for a successful RES penetration will come into focus, such as legal framework complexity, necessary grid expansions or public resistance.

Some specific barriers identified for geothermal energy applications in Croatia include:

- Technological barriers – the absence of modern equipment produced in Croatia (reliable downhaul pumps, heat pumps, equipment of binary GeoPP) and of experience of applying the modern technologies;
- Legal barriers – currently there are no legislative measures encouraging the mastering and using of geothermal resources;
- Price barriers – the created geothermal projects should compete with traditional fuel projects. The existence of gas pipelines near the most prospective of the geothermal fields is a deterrent.
- Financial barriers: the shortage of budget funds and the absence of investors.

These barriers could be stated also for other RES types. However, as the previous discussion shows, significant efforts have already been done to remove those barriers.

3.5 RES potentials in Serbia and Montenegro: barriers and country specifics

3.5.1 RES potentials in Serbia and Montenegro

3.5.1.1 Wind

There are not enough data for operational wind turbines in FR Yugoslavia. The only wind plant of 500 kW is in operation since 2004. Due to insufficient data no statement can be made for the technical potential for wind energy development in FR Yugoslavia. Nevertheless, it is thought that there is some potential at least along the Adria coast

3.5.1.2 Biomass

Biomass resources represent a significant potential energy source for Serbia. Forests occupy nearly 30,000 km^2, containing over 300 million m^3 of wood biomass. The estimated renewable biomass potential is about 1.8 Mtoe. It is also estimated that the non-commercial biomass share in total primary energy production is about 10 percent. Biomass is used mainly in form of burning wood waste.

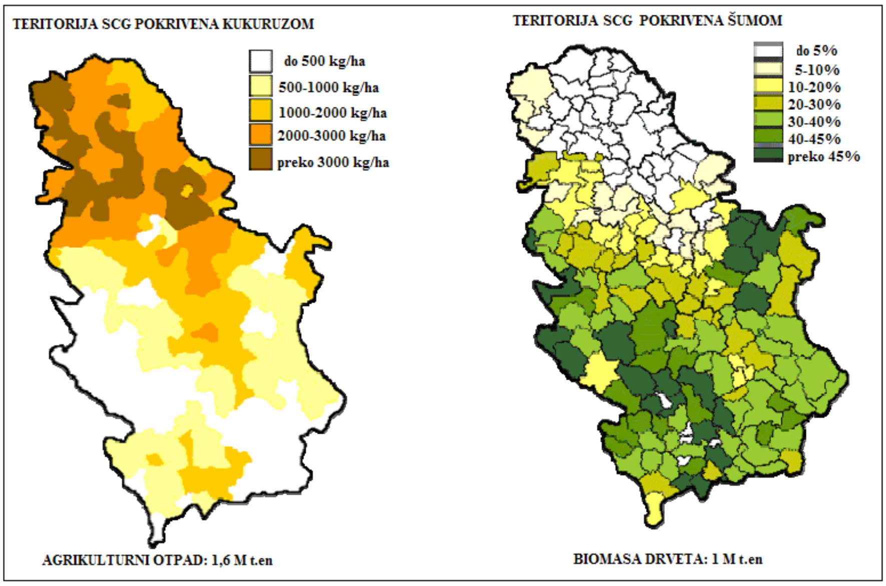


Figure 13: Biomass potential in Serbia and Montenegro

Usable energy potential of plant waste derived from agriculture is estimated to be 3.8 Mtoe per year. Animal waste is used for biogas production in biodigestors. Taking into account cattle breeding in FR Yugoslavia, the estimation is that usable energy potential of animal waste is about 0.45 Mtoe per year. Energy potential of industrial and municipal waste in Yugoslavia is estimated to be 1.4 Mtoe per year. Besides heat energy production realized by burning various industrial waste, municipal waste, and especially by burning plant waste, as well as fossil fuel savings, waste use for energy production is very important for the environment.

From the total amount of biomass designated for heating energy, approximately 3.9 million metric tons could be used to save an equivalent amount 1.3 million metric tons of extra light heating oil. The same amount of diesel fuel is consumed in the entire agricultural production process.

3.5.1.3 Solar

As in the case of other countries in the area, solar levels in the former Yugoslavia including Serbia and Montenegro are among the highest in Europe. The most favourable areas record a large number of hours of sunlight, with the yearly ratio of actual irradiation to the total possible irradiation reaching approximately 50 percent. Of course, the monthly distribution is particularly important in determining utilization for heating; and whether back-up systems will be needed during periods of extended cloudiness. Yearly average of daily solar intensity is 13.5 MJ/m^2 (3.8 kWh/m^2).

In 1998 annual sales of solar flat plate collectors was around 250,000 m^2. Some 28,000 solar thermal units were in operation, replacing the equivalent of 140 GWh of fossil fuel derived energy being used mainly for water and space heating in the domestic and tourist sectors.

The total potential for solar active technologies has been estimated to be approximately 50-60 percent of heating demand in the cloudier central regions. The in-country manufacturing base for the whole of FR Yugoslavia was reported as being strong, with about nine firms in production. But the majority were operating at less than one fifth capacity. And it is not known how many survived the recent crisis. The available expertise, however, indicates that as the economy recovers, it would be easy to accommodate growing demand.

3.5.1.4 Geothermal

Geothermal investigations in Serbia began in 1974, after the first world oil crisis. An assessment of geothermal resources has been made for all of Serbia. Detailed investigations in twenty localities are in progress. The territory of Serbia has favourable geothermal characteristics.

There are four geothermal provinces. The most promising are the Pannonian and Neogen magmatic activation provinces. More than eighty low enthalphy hydrogeothermal systems are present in Serbia. The most important are located at the southern edge of the Pannonian Basin. The reservoirs of this systems are in karstified Mesozoic limestones with a thickness of more than 500 m. Geothermal energy in

Serbia is being utilized for balneological purposes, in agriculture and for space heating with heat exchangers and heat pumps.

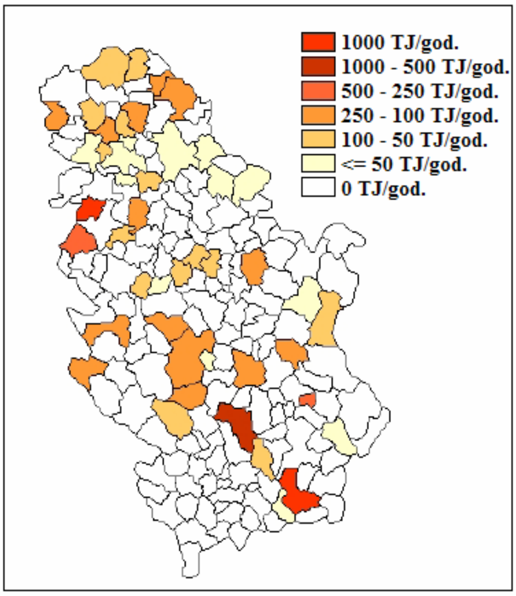


Figure 14: Geothermal potential in Serbia and Montenegro

Exploration to date has shown that geothermal energy use in Serbia for power generation can provide a significant component of the national energy balance. The prospective geothermal reserves in the reservoirs of the geothermal systems amount to 180,000 toe/year. The prospects for use of heat pumps on pumped ground water from alluvial deposits along major rivers are very good.

For intensive use of thermal waters in agro- and aqua-cultures and in district heating systems, the most promising areas are west of Belgrade westward to the Drina, i.e. Posavina, Srem, and Macva. Reservoirs are Triassic limestones and dolomites >500 m thick, which lie under Neogene sediments. The priority region is Macva, where reservoir depths are 400 - 600 m, and water temperatures are 80 °C.

The economic blockade of Serbia stopped a large project in Macva: space-heating for flower and vegetable green-houses over 25 ha (1st stage). The completed studies indicate that thermal water exploitation in Macva can provide district heating systems for Bogatic, Sabac, Sremska Mitrovica, and Loznica, with a population of 150,000.

In addition to the favorable conditions for geothermal direct use from hydro-geothermal reservoirs in Serbia, geothermal use can also be made of hot dry rocks, as there are ten identified Neogene granitoid intrusions. Geothermal exploitation program have been prepared, but they have not been brought into operation.

3.5.1.5 Hydroelectric

The total hydro-power potential of Serbia amounts to about 25 billion kWh a year. The amount of about 17.5 billion kWh a year is classified as a technically and economically usable potential, of which about 10.3 billion kWh is utilized.

Hydropower contributed 36 percent to electricity generation. The remainder originates from thermal power plants (on the basis of lignite) and some smaller amounts of CHP (1.4 percent of gross electricity generation in 2001, which is well below the European Union average of 9 percent).

There are nine hydro-power plants (HPPs) within the power system of Serbia, with fifty hydro-units of the total capacity of 2,831 MW, producing on average 12 billion kWh a year. The total power content of the seasonal reservoirs is about 1,2 billion kWh.

3.5.2 RES penetration in Serbia and Montenegro: barriers and country specifics

The main barriers to the development of RES in Serbia and Montenegro are the following:

- Vertically organized power sector:
- RES potentials are not enough investigated;
- There is no enough programs for financial and credit incentives and tax reductions in RES implementations;
- Public awareness of RES technologies and their advantages should be improved;
- There is no enough RES professionals and RES educated people;

  There is no enough local, regional and state coordination in promoting and implementing RES.
- Public awareness about RES should be improved especially for profitable RES projects with accurate technical and economic analysis. This analysis should include energy models and future energy needs, cost analysis, greenhouse gas emission analysis, financial analysis and sensitivity and risk analysis. Generally RES implemented projects have higher initial costs but lower operating costs and such an analysis is very important in low cost preliminary feasibility studies.

3.6 RES potentials in FYR of Macedonia: barriers and country specifics

3.6.1 RES potentials in FYR of Macedonia

3.6.1.1 Wind

Currently, there was not direct information on wind energy available in this country. A country-wide wind atlas is not available. However, in the neighbouring Greece 336.7 MW of the licenses granted were for Macedonia-Thrace. Furthermore there is an interconnection between both countries, and Greece would be interested to buy wind power from FYR of Macedonia. Due to lack of information it is not possible to make a statement on Macedonia's potential for wind energy.

3.6.1.2 Biomass

Macedonia currently acquires a reasonable amount of energy from biomass fuels. The country's official energy balance shows that in 2000 the total primary production of wood amounted to 8.7 TJ having a gross energy value of 8.6 TJ. Gross inland consumption was slightly higher, about 8.9 million TJ due to small quantities of imports.

Allowing for relatively small quantities of wood as energy input in heating plants the net final energy consumption amounted to 8.55 million TJ. By far the biggest users were households with about 7.6 million TJ.

The final wood-derived energy consumption of 8.5 million TJ in the year 2002 was equal to nearly 13 percent of the country's total final energy consumption.

While the use of wood as a fire fuel in the traditional form is not likely to increase, there are prospects for a better utilization of forest output for energy purposes. Better forest practices, reforestation, planting of deserted or marginal land could make a contribution, be it relatively small, to the further development of this sector. Moreover, as burning wood in the traditional way is quite polluting, there will be pressures for switching to other cleaner sources of energy, which would release fuel wood resources. This however, will be a slow process.

As far as exploitation of the residues of field crops, fruit tree plantations and livestock activities are concerned, there should be a significant potential for their collection and utilization, along with waste (incl. manures from intensive farms). This could be done through incineration or anaerobic digestion technologies. Special studies and surveys will have to be carried out to determine location, logistics, size of units, economics and viability.

3.6.1.3 Solar

Solar radiation in FYR Macedonia as well as in Serbia, Slovenia, Croatia and Bosnia/Herzegovina are amongst the highest in Europe.

The most favourable areas record a large number of sunshine hours. The yearly ratio of actual irradiation to the total possible irradiation reaches approximately 50 percent for former Yugoslavia as a whole. This ratio is approximately 45 percent for the mountainous central regions due to the prevailing weather pattern.

The primary form of solar energy and technology used are flat plate collectors for heating houses and some commercial and public premises. But their contribution to the total energy consumption is insignificant (less than 1 percent). Additionally, it is not expected that this figure will increase substantially in the near future, as new consumption could mainly come from new entrants to the market i.e. of new buildings or installations.

Likewise, electricity production from solar photovoltaic sources will be restricted to research or remote locations, primarily for telecommunications. This is due to the difficult economics for photovoltaics.

3.6.1.4 Geothermal

FYR Macedonia is located in the central part of the Balkan Peninsula, in the geothermal zone which runs from Hungary in the north and Italy in the west, and crosses Greece, Turkey, and beyond to the east. Specifically, the country is situated in the southernmost part of the Bosnian-Serbian-Macedonian geothermal area, which includes the mountains of the internal Dinarides and parts of the Serbian-Macedonian massif.

The country contains six geotectonic zones: the Cukali-Krasta zone, the West Macedonian zone, the Pelagonian horst anticlinorium, the Vardarian zone, the Serbo-Macedonian massif, and the Kraisthide zone. Geothermal manifestations are mainly connected to the Vardarian zone where the earth's crust is about 32 km.

FYR Macedonia derives useful energy in the form of heat from its geothermal wells. At present its geothermal water is used for heating greenhouses, residential houses, some commercial buildings, swimming pools and in balneology. No electricity is produced from geothermal energy. As of 2000, Macedonia had an installed capacity of 81.2 MW_t producing 510 TJ/yr or 142 GWh/yr.

The main hydrothermal systems are located in the East and North East of the country (see map below) in the crystalline rocks of Macedonian-Serbian massive. The systems are characterized by low TDS and low corrosion activity. There are 18 different geothermal fields in the country. A number of geothermal areas composed of separate fields have been identified with more than 50 prospecting and operating wells with a depth from 40 to 2100 m at temperatures of 20-79 ºC.

FYR Macedonia's geothermal development objectives to 2010 are:

- The reconstruction, modernization, and optimisation of existing projects;
- The addition of new industrial and residential projects in the Kochani geothermal system;
- Connecting additional hotels to the Bansko heating system; and
- Completion of the water centre at Negorci and the medical centre in the Katlanovo. Spa (Popovski and Popovska-Vasilevska, 1999).

3.6.1.5 Hydroelectric

There are seven large hydro plants in Macedonia with a combined capacity of 480 MW, and a number of small hydro plants with total capacity around 50 MW.

FYR Macedonia is divided into 3 separate drainage units/areas which are identified by their major rivers:

- The Vardar River water basin/drainage area of 20,535 km^2
- The Crni Drim River drainage area of 3,350 km^2; and
- The Strumica River drainage area of 1,535 km^2

The possibility for the theoretical production of hydro-potential into electric energy is estimated to be much higher than its yearly exploitation. The total hydroelectric potential in Macedonia, which is technically suitable for exploration, is 6,436 GWh/year. This energy can be best utilized by building hydropower plants with a total capacity of 1,620 MW installed power. However, only 24 percent of waterpower resources are utilized in the exiting hydropower plants.

To meet growing demand and partly substitute imports, over the long term, 2020, the country is planning new capacity including over 200 MW of new hydro power plants.

3.6.2 RES penetration in FYR of Macedonia: barriers and country specifics

The main barriers to the development of RES in Serbia and Montenegro are the following:

- Presence of institutional constraints like unsolved of water rights and issues and public ownership of the existing geothermal boreholes;
- Renewable energy projects have limited access to finance;
- There is no policy for inclusion of renewable energy in the energy mix of the country, and no rules to guide private sector development.
- There is insufficient legislative support in the forms of: funding mechanisms, electricity buyback policy, preferential taxation, etc.

- Lack of administrative capacity in the Ministry of Economy where only a small number of people are involved in the energy sector.

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4 WIND POWER DEVELOPMENT IN SPAIN

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4.1 Abstract

Wind power in Spain is the most developed of all renewable technologies, and is actively contributing to reach the objective of covering 12% of primary energy consumption from renewable sources by 2011.

Currently, Spain has the second place worldwide in wind power-installed capacity with 10,028 MW at the end of 2005. The installed capacity has been steadily growing at 15% rates every year, which makes feasible to reach the recently readjusted national target for 2011 of 20,000 MW of wind power installed capacity. The wind power generated in 2005 covered 7.78% of the electric energy demand, with a peak generation of 7,300 MW in last March, which covered 24% of the demand.

This situation has been achieved with a stable regulation, where investors can predict the future earnings from wind production for the entire plant life cycle. Regulation establishes two options for wind power to sell their energy, a guaranteed feed-in-tariff, or trading the energy into the electricity markets. Currently, most wind farms sell their energy into the electricity markets, because the average price of the electricity spot market in the last year plus the incentives, are higher than the regulated fixed tariff.

Some challenges still exist for wind power integration into the network, such as highly variable production, intermittency to cover peak loads, difficulty in forecasting, disconnection in case of voltage dips, and limited operation reserves. Therefore, research studies are mainly focused on prediction tools, turbine design to increase efficiency, and network procedures to improve grid integration.

The common effort of national institutions, together with manufactures and investors, is resulting in the continuous growth of wind power sector in Spain, increasing its international competitiveness.

4.2 Introduction

The European Directive on Renewables settled a target of 30.6% of electricity supply to come from renewable sources –including large hydro, wind power, biomass, among others- by the year 2011. On the other hand, the Kyoto protocol was focused on reducing emissions of fossil fuel power plants, and therefore promoting the use of renewable energy sources. Wind power is part of the answer to fulfill these objectives, especially in those countries with a high wind potential, such as Spain.

4.2.1 Main figures

Spain has the second place worldwide in wind power installed capacity **10,264 MW** in March 2006. Although Germany has more installed capacity, the wind energy generation in Spain has been 20,236 GWh, which means a production at full capacity for 2,015 hours, compared with 1,500 hours in Germany.

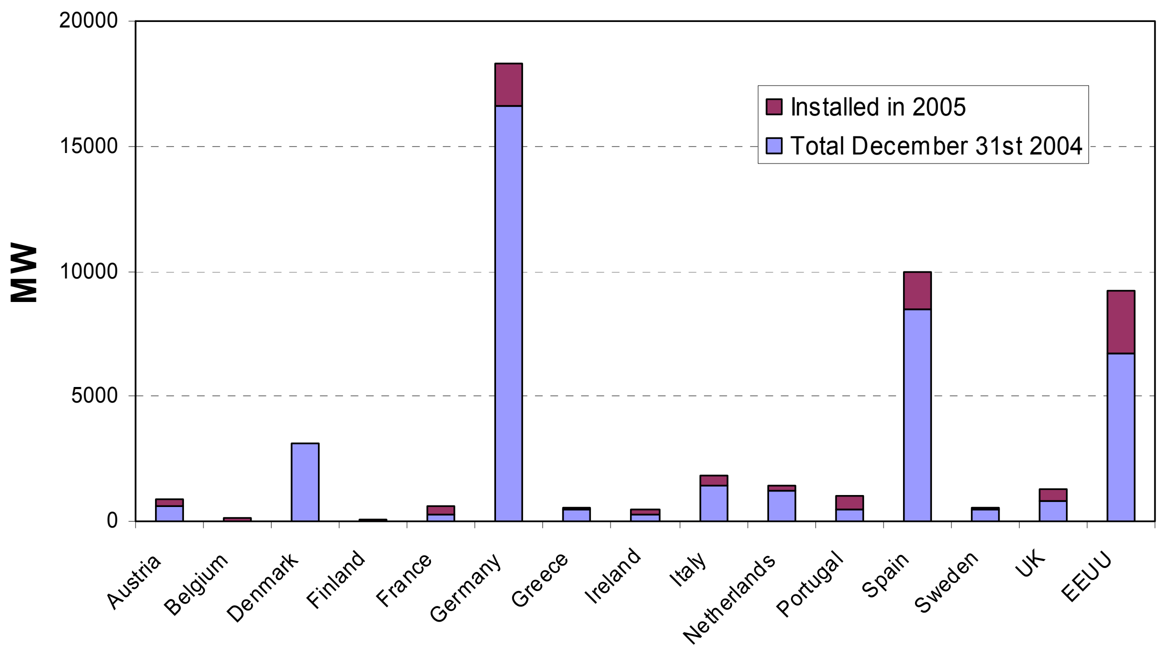

Figure 15: Wind power installed capacity at December 31st 2005

The wind power generated in 2005 **covered 7.78%** of the electric energy demand. On March 24th 2006 at 15.30h, wind power generation reached 7,300MW (of 10,200 MW currently installed capacity), covering 24% of the demand at this moment **Napaka! Vira sklicevanja ni bilo mogoče najti.**.

The installed capacity has been steadily growing since 1997, with annual rates above 30%. According to the Spanish government objectives, along with the European guidelines, the target for wind power capacity installed by 2011 is **20,000 MW**, although optimistic previsions in the sector set this figure in 23,000 MW.

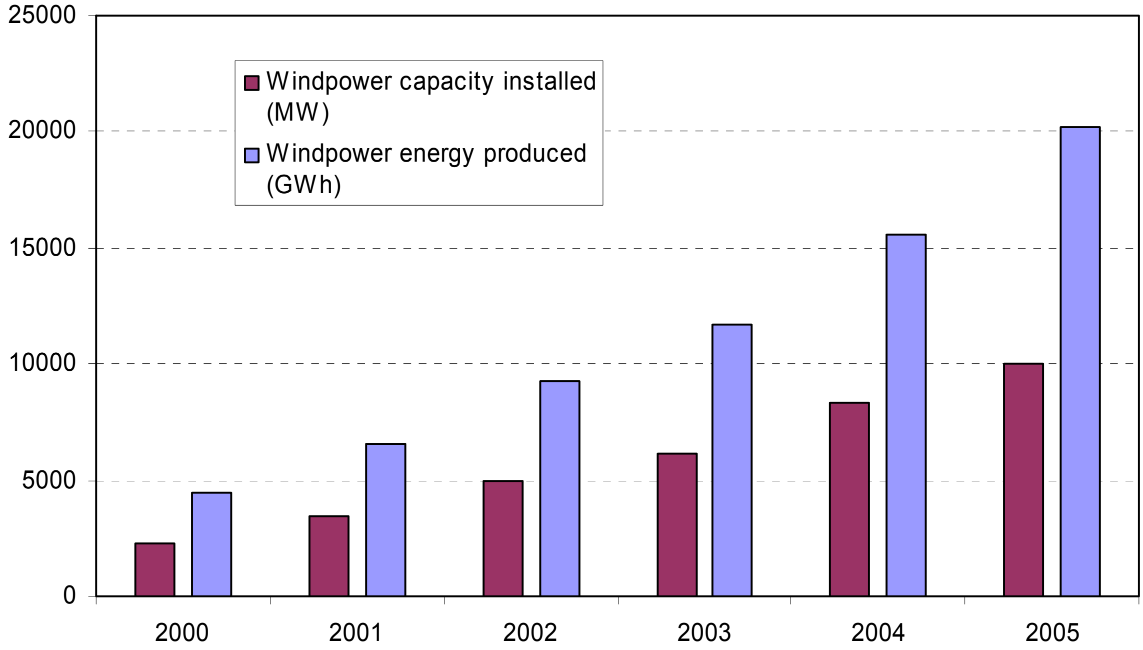

Figure 16: Wind power installed in Spain

Wind power farms were firstly introduced into the southern coast of Spain, in the province of Andalucia, near the strait of Gibraltar. The following regions to invest in wind power were Aragon and Galicia (nowadays the province leading in installed capacity). In the last few years, the new locations for wind power were in the centre of the country in the provinces Castilla La Mancha and Castilla-León (see Figure 17).

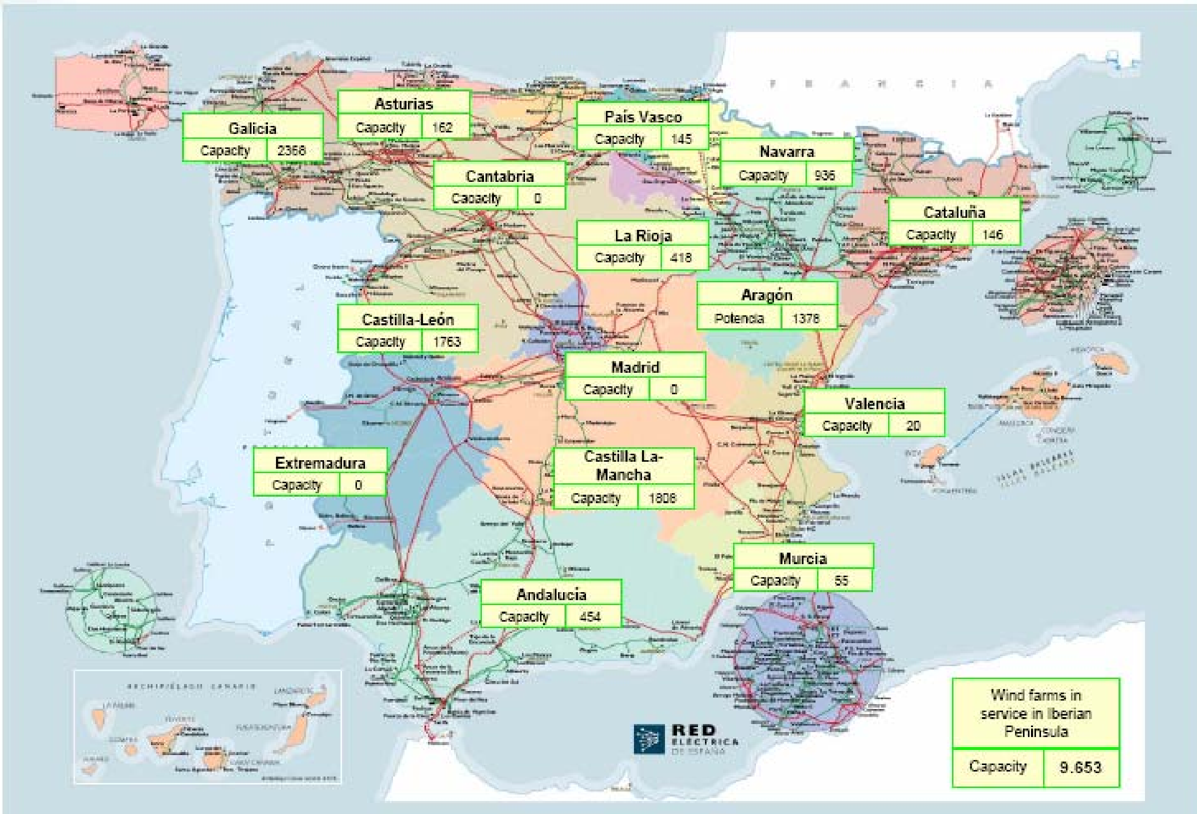

Figure 17: Wind power installed in Spain

The average unit size of a wind turbine installed in Spain is **805 kW**, Figure 18 [27]. Nowadays the unitary power for new wind power turbines is increasing, because it improves efficiency, and minimizes the number of turbines distributing their placement [19].

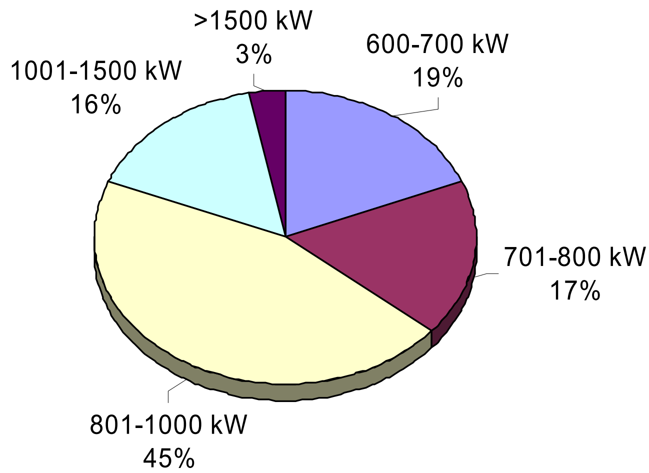

Figure 18: Size of wind power generators

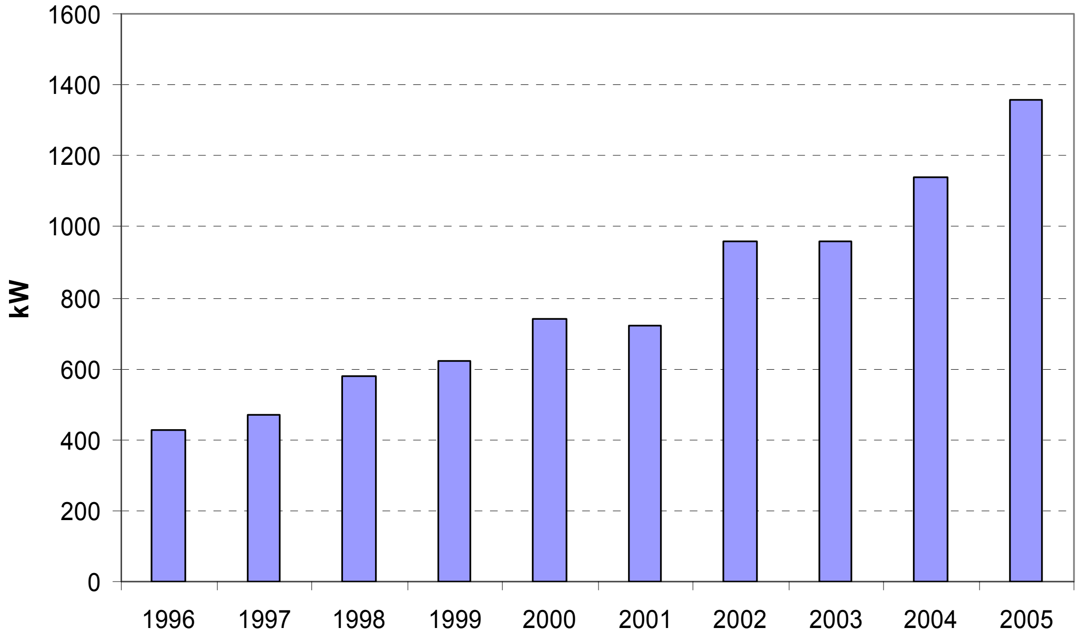

Figure 19: Evolution of wind power generators size

4.2.2 Wind power benefits

Wind power development in Spain is bringing many social and economic advantages for the country, between them, increasing the security of supply, reducing CO_2 emissions, and creating employment.

Spain energy resources are very limited, there are no oil nor gas reserves, and the electric interconnection with France is just 1,200MW (below 5% of the peak load). Consequently Spain imports about 76% of its primary energy consumption. Wind power is an indigenous energy resource, which **reduces the energy dependence**. The savings in gas and coal imports were estimated in more than 728 million euros in 2005.

When using wind energy resources, the energy coming from fuel power plants is reduced and so are the CO2 emissions. This is clearly an **environmental benefit**, but also a saving in emission rights purchases, which is valuated in 294 million euros in 2005.

A most important issue is the development of small and medium-sized enterprises, creating **new employment**. Currently, more than 500 companies are involved in the Wind power industry in Spain, and also 150 factories manufacturing wind turbine generators. The total number of direct and indirect employments in the sector reached more than 30,000 people, which is expected to be doubled by 2010 [30].

The manufacturer market share in installed wind power is shown in the Figure 20 [19].

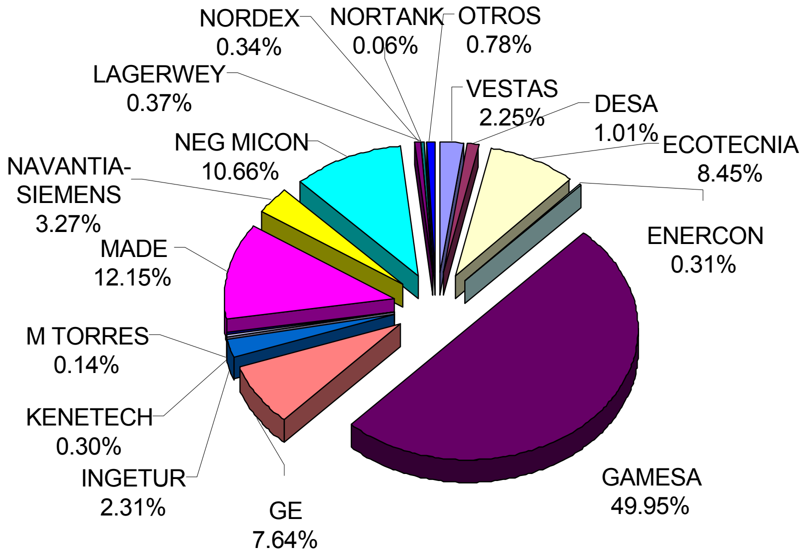

Figure 20: Manufacturer market share

Most of the wind power technology installed in Spain is domestic, as well as the wind farms investors (see Figure 21). This situation facilitates **international competitiveness and export opportunities**.

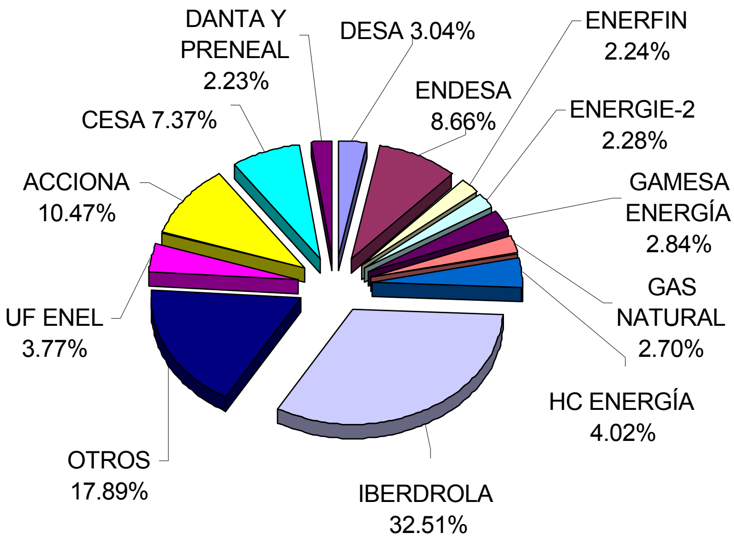

Figure 21: Wind power producers' capacity share in Spain

4.3 Wind power regulatory framework

Legislation has been the main driver for wind power development in Spain. Renewable energies have been supported by the Spanish government a long time ago, with the definition of a positive legislative landmark. The Electricity Act, published in

1997, included wind power in the **Special Regime Energy** (similar to other renewable sources, such as mini-hydro, solar, biomass, among others), to differentiate from ordinary production (nuclear, thermal, large hydro). This first Act, also guaranteed access to the grid and a premium payment for the output of Special Regime Energies.

The Royal Decree published in 1998 developed the framework for Special Regime Energy, and settled the choice of getting a fixed price or a variable price based on the electric spot market price plus a premium.

The following year, the government fixed a target for wind power installed capacity of 8,974 MW by 2010, according to the goal of 12% of renewable energy. This target was updated and increased in 2002, to 13,000 MW by 2011.

The Royal Decree 436/2004 redefined the regulation for Renewable Energy Sources, keeping the fixed price, and encouraging producers to make offers to the electricity spot market.

The target for wind power capacity installed by 2011 was again increased to **20,000 MW**. This decision was the result of the success of wind energy development in the country compared to other renewable energy sources, such as biomass and photovoltaic.

Some **important barriers** have been identified by the different Wind power associations in Spain. First of all, **administrative licenses** for building new wind farms are slow (sometimes about five years for large wind farms), and also very complex due to the numerous local and regional regulations and proceedings (currently 60 regulations and 40 proceedings have been identified). **Network access** for wind power plants sometimes takes difficult negotiations with the TSO, where many technical requirements should be met.

4.4 Market access

The current regulation for Special Regime plants, which includes wind power, is set by the Royal Decree 436/2004. The different rules defined in this document settle a long-term **predictability** for the earnings from wind power production. This is achieved by indexing the earnings of the producers to the **average electricity tariff** (ART). The ART is published every year by the government, and it is computed as the necessary final consumers' payment to remunerate energy producers and network activities. In 2006 the ART was 76.59 €/MWh, compared to 73.3 €/MWh in 2005. On the other hand, the future earnings are also defined for the entire plant life cycle.

The Royal Decree 436/2004 established two options for RES to sell energy, a guaranteed feed-in-tariff, or trading the energy into the electricity market. It opens the possibility to change from one option to another once a year.

- **Fixed tariff**. 90% of ART for the first three years, 85% of ART for the following ten years, 80% of ART for the rest of the plant life cycle.

- **Market sales**. When participating in the electricity market wind power plants obtain the clearing price, supplemented with a subsidy of 40% of ART, and an incentive of 10% of ART. There is also an additional capacity payment for providing security of supply in peak hours.

Under both mechanisms a compensation for **reactive power management** is settled, with the definition of different power factors for different load periods. This compensation oscillates between a 4% of ART penalty to an 8% of ART bonus payment, see Table 5.

Table 5: Reactive power management compensation

<table>
<tr><th colspan="2" rowspan="2">Power factor</th><th colspan="3">Bonus/penalty (%) of ART</th></tr>
<tr><th>Peak hours</th><th>Plain hours</th><th>Valley hours</th></tr>
<tr><td rowspan="5">The power plant imports reactive power from the grid</td><td><0.95</td><td>-4</td><td>-4</td><td>8</td></tr>
<tr><td><0.96 y ≥0.95</td><td>-3</td><td rowspan="3">0</td><td>6</td></tr>
<tr><td><0.97 y ≥0.96</td><td>-2</td><td>4</td></tr>
<tr><td><0.98 y ≥0.97</td><td>-1</td><td>2</td></tr>
<tr><td><1 y ≥0.98</td><td rowspan="3">0</td><td>2</td><td rowspan="3">0</td></tr>
<tr><td></td><td>1</td><td>4</td></tr>
<tr><td rowspan="5">The power plant exports reactive power to the grid</td><td><1 y ≥0.98</td><td>2</td></tr>
<tr><td><0.98 y ≥0.97</td><td>2</td><td rowspan="3">0</td><td>-1</td></tr>
<tr><td><0.97 y ≥0.96</td><td>4</td><td>-2</td></tr>
<tr><td><0.96 y ≥0.95</td><td>6</td><td>-3</td></tr>
<tr><td><0.95</td><td>8</td><td>-4</td><td>-4</td></tr>
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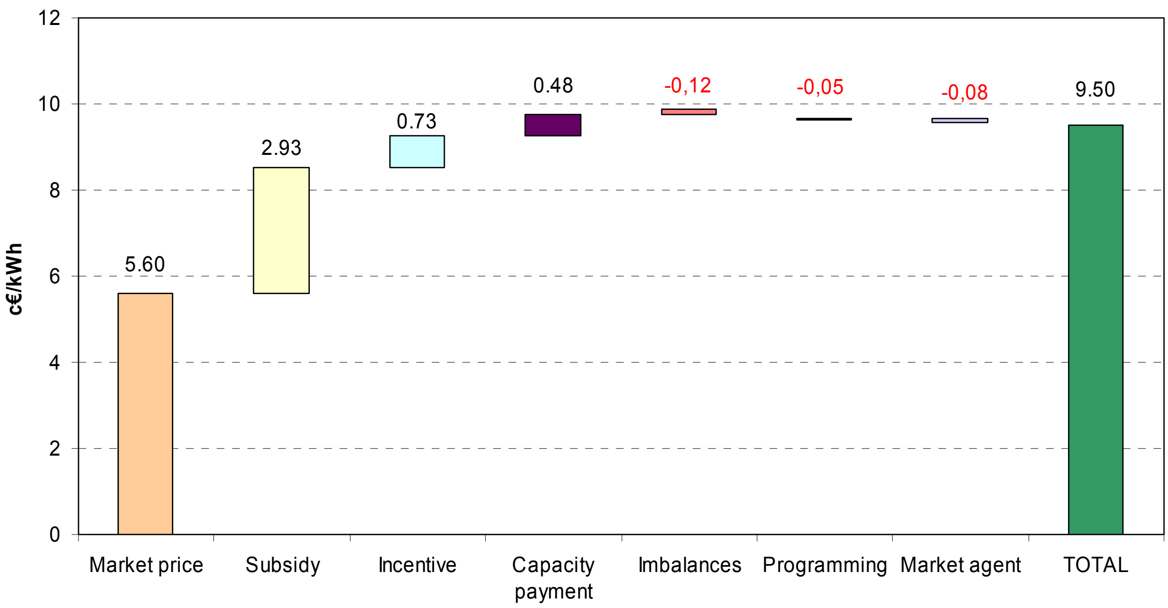

Figure 22: Final price for wind power under market price, in 2005

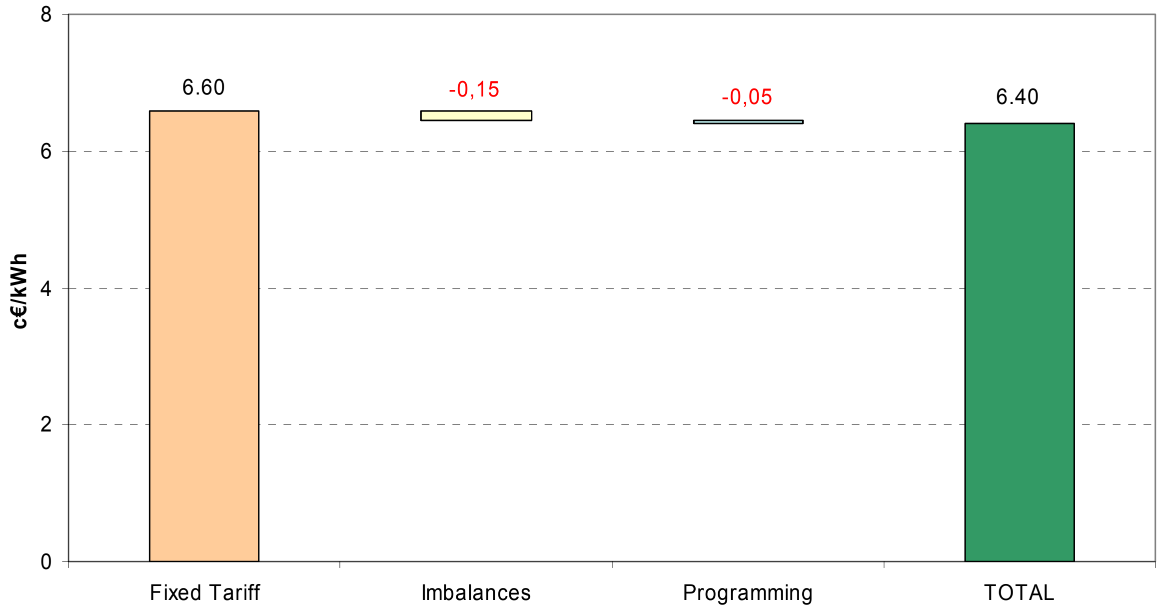

Figure 23: Final price for wind power under fixed tariff (90% ART), in 2005

An example of the total remuneration for wind power under the RD436/2004 is shown in Figure 22 and Figure 23, where different price assumptions have been used. According to the graphs, the most profitable option is selling the energy into the electricity markets, although there is some risk associated to wind prediction and deviation costs. Most wind power produces **aggregate** their offers to the market (wind portfolio) to reduce deviation costs.

Currently most wind power producers, about 90%, have moved from fixed-tariffs to the electricity **spot markets**, specially motivated by the high energy prices in the spot market last year (56 €/MWh, while the calculated fixed tariff corresponds to an average spot market price of 29 €/MWh in 2004).

4.5 Network access

The continuous increase of wind power penetration into the Spanish network, together with the limited interconnections capacity requires new network studies and operational procedures. To improve wind power network access, the Spanish TSO together with wind power producers must solve some challenges, such as highly variable production, intermittency to cover peak loads, difficulty in production forecasting, disconnection in case of voltage dips, and limited operation reserves. A conscious study is being carried out to determine the maximum wind capacity that the network is able to accommodate in the short and long-term.

4.5.1 Wind Prediction

Wind forecast is a major issue for wind power management in the electricity markets and network access. An effective forecast of wind power production is needed for the operation of the electricity system, especially when managing power reserves from conventional power plants that ensure real-time demand supply. Moreover, operation measures may be needed to reduce system stability risks in the event of disturbances on the power system, due to the effects of the voltage dips on wind generators.

The new regulation on renewable energies imposes on those wind farms of above 10 MW capacity covered by **fixed tariff** an obligation to communicate to the grid operator the power production they forecast each day, thirty hours in advance. For these wind producers, if the deviation in each of the scheduling intervals is more than 20% higher or lower than the forecast production, a deviation cost will be passed on to the wind producers. This deviation cost is obtained by multiplying the deviated energy over the 20% tolerance by the 10% of the ART. When the wind power producer trades its energy into the **electricity market**, the deviation cost is calculated as the product of all the deviated energy (there is no tolerance) by 10% of the spot price for the considered period.

Currently, all the market participants and the TSO have their own wind prediction tools, using them from different purposes, security, demand or sales forecasting.

4.5.1.1 SIPREOLICO

The Spanish TSO has developed a prediction tool known as SIPREOLICO. The wind forecast model provides three time-dependent results:

- Wind forecast for day D published at 10 h. of day D-1. The results are used to integrate wind power production into the technical constraint analysis.
- Wind forecast for day D published at 20 h. of D-1 day. These results help with decisions regarding connection of additional thermal generation.
- Real wind power of day D-1 telemetered or estimated.

To determine the reliability of present forecasting model a monthly analysis is carried out, comparing forecasting and real values. Figure 24 illustrates the average errors for day D-1 at 10h and 20h, for different wind power production forecasting.

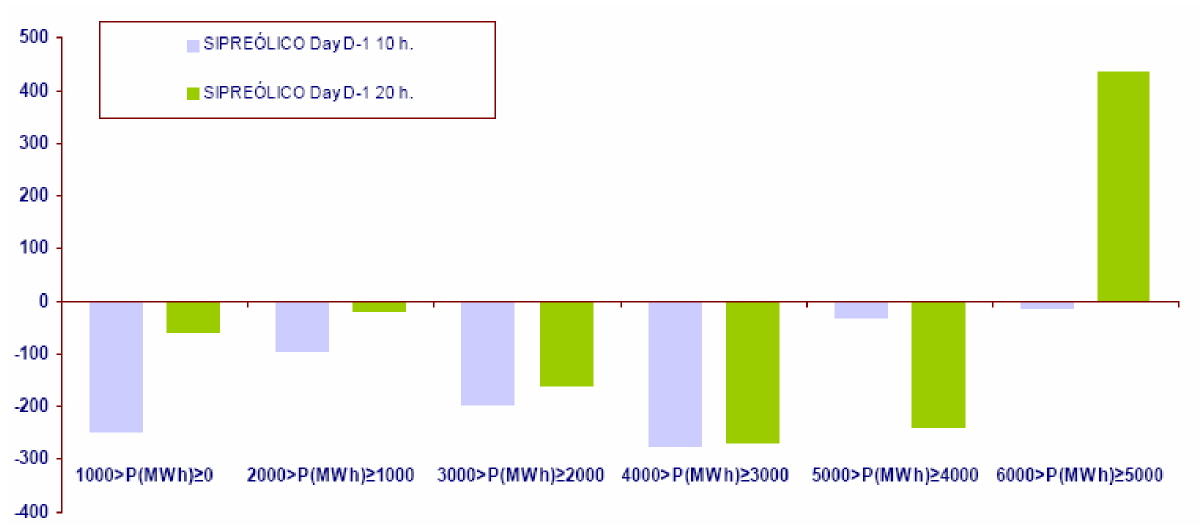

Figure 24: Average error (MWh) from January to December 2005

According to the results obtained by SIPREOLICO, for a forecast wind production between 2,000 MW to 4,000 MW it is necessary to have an additional reserve of ordinary generation between 400 MW and 650 MW.

Both real-time and forecast for wind energy production are shown in the web of the TSO [18].

4.5.1.2 The Forecasting Exercise

The Forecasting Exercise [19] is a pioneer project that aims to improve the programming of electrical production from wind power, developed and executed by the Spanish wind sector itself. This project integrates the efforts of the forecasting companies, the wind power producers, and institutional entities, especially the Market Operator (OMEL), the energy efficiency agency (IDAE) and the National Institute of Weather Forecast.

The Forecasting Exercise analyses the results of **six forecasting models** (both statistical and physical tools) applied across **seven wind plants**. These plants were selected as the representatives of the Spanish wind installations, in terms of turbine technology and site topography.

The results showed that the combination of bids from different wind farms, especially those with different wind basins, could reduce the imbalances by up to 50%.

4.5.2 Stability analysis

Voltage dips are short reductions in voltage usually caused by short-circuits or faults. In case of a voltage dip, some technologies of wind generators (asynchronous alternators) tend to disconnect from the electric network due to their protection systems.

At present, in Spain 50% of the wind capacity disconnect in the event of 0.9 p.u. voltage dips, while 54% of the wind capacity disconnect in the event of 0.85 p.u. voltage dips.

A specific database, called REINGENEO, has been developed by the TSO to register transmission grid incidents with wind energy generation loss, see Table 6.

Table 6: Power disconnections due to voltage dips

Lost power ranges (MW)	Number of disconnections
0 < P < 100	155
100 ≤ P < 200	25
200 ≤ P < 300	6
300 ≤ P < 400	5
400 ≤ P < 500	4
500 ≤ P < 600	2
600 ≤ P < 700	1
700 ≤ P < 800	-
800 ≤ P < 900	1
900 ≤ P < 1000	-
1000 ≤ P < 1100	1

One way to avoid the spread of voltage dips in the transmission grid is to **unbraid** the transmission grid. For example, the 400 kV line MUDARRA-GRIJOTA is opened when the predicted wind power loss in case of a three phase fault in one of both busses exceeds the maximum power loss admissible to the system. This manoeuvre is not always feasible. According to TSO data, this transmission line has been opened 24 times from January to December 2005. This solution is not fairly good as it clearly reduces system security.

Currently the TSO has presented a draft for the requirements regarding wind power facility response to grid voltage dips, see Figure 25. Current regulation defines an incentive for those wind farms which are able to deal with voltage dips without disconnection from the network. This incentive along with the TSO requirements will encourage wind power producers to install equipment to handle voltage dips.

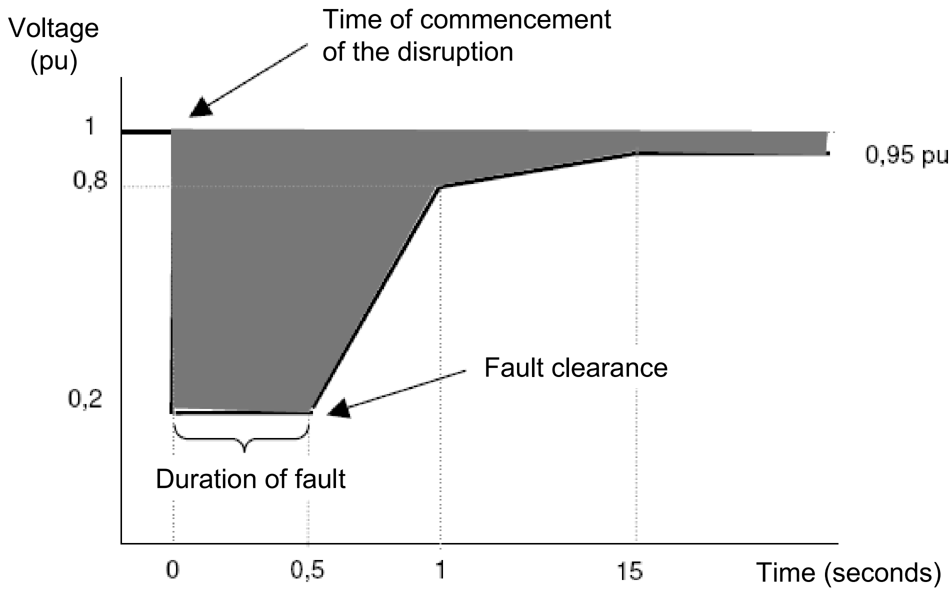

Figure 25: Voltage dip requirement

Finally, it has been suggested a **central control centre** for Special Regime Producers Plants, which would be managed by the TSO. The objectives of this centre are to unify measurement and forecasting, and develop objective operation criteria to manage this kind of energy.

4.5.3 Grid expansion

Wind power has greatly contributed to the national network expansion, as it is a kind of distributed generation. Wind power farms are sometimes connected to the transmission network, or to distribution levels.

To accommodate new wind power plants (20,000 MW by 2011), detailed studies of transient stability for the Spanish and Portuguese networks should be developed.

According to the wind power associations' data, the sector will invest in network expansions about €490 million in the period 2002-2011, which is 18% of the total grid investment carried out by the TSO (110 new substations and 4;000 km power lines).

Finally, a major issue in wind power integration into the network has been the limited interconnection with France (1,200 MW commercial, and 2,800 MW maximum capacity). This limitation affects the amount of secondary reserve needed when wind generators are producing. Although governments and wind associations have made much effort, this problem will only be solved in the medium or long-term.

4.5.4 Demand coverage

Wind power production has **very high variability** with gradients of 1,000 MW increase or decrease in just an hour, see Figure 26. Furthermore, wind production does not necessarily follow the load curve, and sometimes has an opposite behaviour. This variability should be handled with better forecasting tools.

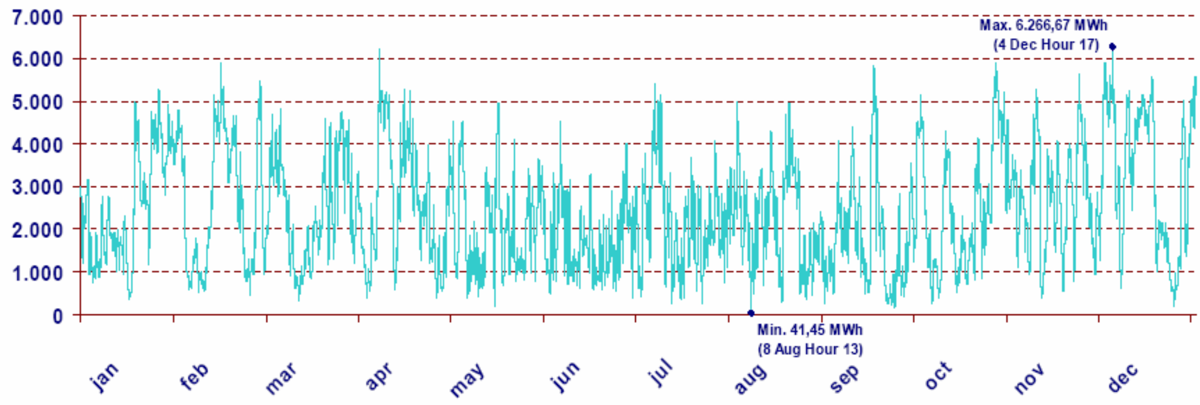

Figure 26: Hourly wind power (MWh), January-December 2005

The **demand covered** by wind power energy in Spain is also very variable, moving on average from 2% to 15%, see Figure 27. The availability of hydro-power resources is a key issue in the adequate integration of wind energy, as hydro can cover wind power variability.

The improvement on the reliability of wind power forecasting models would allow higher wind power generation at off-peak hours due to reduction in the number of connected thermal plants that would be necessary to ensure peak demand coverage. Also, an adequate management of pumping units should ensure their maximum availability at off-peak hours, to combine with wind power.

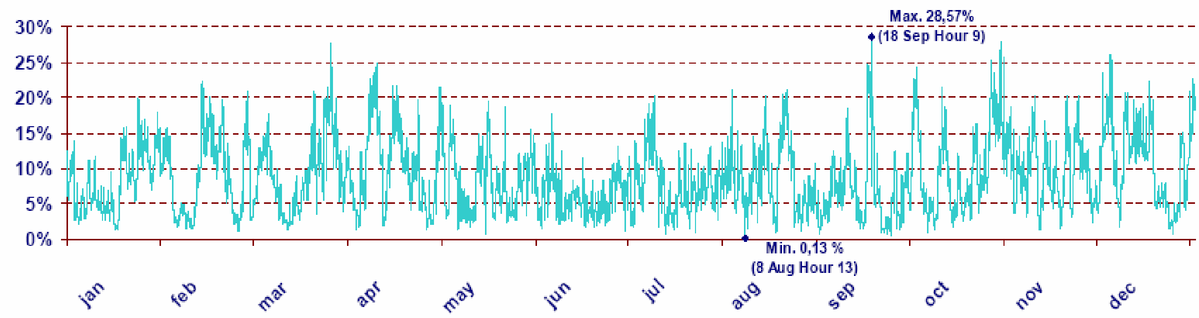

Figure 27: Hourly demand covered with wind energy (%), January-December 2005

4.6 New research and investment objectives

New research studies are placed in offshore wind plants and the combination of wind power with seawater-desalination.

Although Spain has not got yet any **offshore wind power plant**, there are some projects that are currently being developed (four of them in the strait of Gibraltar, and the other two in the east coast). Last January 2006, a near-shore wind power plant in the Port of Bilbao breakwater was inaugurated, with five units of 2 MW each.

The Spanish National Hydrological Plan from 2004, planned to build twenty **seawater-desalination plants** to produce potable water in the east coast. These plants are meant to be supplied by wind energy backed-up by conventional power plants. Currently, research on wind power working on isolated grids has become of great interest for this purpose.

The **research and development investment** in wind power in Spain, including turbine and component manufacturers, is very intensive. In 2004 this investment reached 11% of the Gross Value Added, followed by 5.6% on transport material R&D, and an average value of 1% in Spain.

The common effort of the different manufacturers, promoters, wind power associations, and the government have design a R&D plan for the sector, which aims to unify the standard certificates of Spanish companies and international entities.

4.7 Conclusions

Wind power is a very active sector in Spain, creating new employment and placing their companies in the first places worldwide. The success of wind power development in Spain is the result of a stable regulation which sends adequate investment signals. Wind power is fully integrated into energy markets, as nowadays most wind power producers in Spain are trading their energy into the spot market. Notwithstanding, there exist some barriers, such as slow administrative licences, and complex negations to get connection to the grid.

The government has assumed a very ambitious target of 20 GW for wind power installed by 2011. To achieve this goal the wind sector is actively working on wind forecasting tools, and wind power network integration.

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5 AUSTRIAN RESEARCH PROJECT: VIRTUAL BIOGAS POWER PLANTS

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5.1 Abstract

A virtual power plant, combining 20 biogas plants is planned in the south-eastern part of the State of Styria (A). The project is funded by the Austrian Federal Ministry for Transport, Innovation and Technology and will be carried out in 2 stages: stage 1, “Project Preparation”, has started in March 2006 and is running for 18 months. Stage 2 “Project Realization” will be specified after successful end of Stage 1. The aim of the project is to realize a central reactive power control system of 20 agricultural biogas plants. The active power of the biogas plants ranges between 1 and 3 MW. Specific goals of the project are:

- increasing grid stability,
- decreasing long distance reactive power transmission,
- decreasing energy losses, and
- decreasing utility costs.

One of the members of the project consortium is the Styrian top ranking grid operator: STEWEAG - STEG. This partner will deliver information about the local requirement of reactive power (grid data) and about the grid integration equipment. He will also deal with questions of contractual issues as grid operators (liability, tariffs). But also biogas operators are members of the project consortium. They will deliver information about operational data (use of heat and power), feed-in equipment, and contractual issues as plant operators.

5.2 Introduction

Electrical energy from biogas plants in Austria usually is fed into the public grid. Due to the fact, that biogas plants normally have a gas storage with a capacity corresponding to at least several hours of biogas production, they are suitable to adjust the energy production to the given energy demand of the grid. This concerns the following options:

- Active power control and
- Reactive power control

Up to now, neither the first, nor the second possibility is used. The reason concerning the first possibility is, that biogas power stations are operated under maximum load conditions as long as possible (this means nearly the whole year) due to economic reasons (green-tariffs).

Barriers against making use of the second option are missing control equipment, unclear advantage of reactive power control for the operator, and low or even detrimental effect to the grid stability, if singular biogas plants are feeding reactive power into the grid without any common control strategy. This problem can be solved by connecting a certain number (in the order of 20) biogas plants together to a big centrally controlled “Virtual Biogas Power Plant”.

Such a Virtual Biogas Power Plant should be realized in the subject project in the Region of South Styria (A).

The project is funded by the Austrian Ministry for Transport, Innovation and Technology

It will be carried out in 2 stages

- Stage 1: Project preparation

Stage 1 has been started in April 2006 and will be finished in February 2008

- Stage 2: Project realization

Details of stage 2 will be specified after successful end of Stage 1

5.3 Project content

The aims of the project are to carry out preliminary investigations on the installation of a “Virtual Biogas Power Plant” consisting of 20 biogas power plants with a real power capacity of some 1 - 3 MW_{el} each, and to propose the realization of such a “Virtual Biogas Power Plant”. The necessary data about the economical, technical, ecological and social boundary conditions have to be determined. This will be carried out in 3 main Tasks:

- Task 1: **Analysis and model development**

In Task 1, a concept of a Virtual Biogas Power Plant has to be worked out, based on requests of both, the grid operator and the biogas plant operator. Experience in the field of centralized reactive power control (e. g. /1/) will be taken into account. Technical boundary conditions of individual plants (control possibilities) will be investigated and evaluated. Key figures of the plants will be worked out:

  - Course of the power factor (without centralized reactive power control) in the related grid sections is measured for on year
  - Improvement and/or deterioration of the power factor (yearly average) and the influence on voltage stability and transmission losses in case of centralized reactive power control are investigated by model calculations.
  - Possible benefits or other consequences for grid operator and biogas plant operators are calculated.

Operators of the biogas plants will be informed about possible benefits or even undesired consequences of a central reactive power control system. The interest of plant operators to participate in the Virtual Biogas Power Plant will be checked. A first evaluation of the balance between economical benefits or losses to be expected will be made, based on estimation concerning the physical long term effect of the planned control strategy.

- Task 2: Green **House Gas Balance (Life Cycle Analysis)**

In Task 2, investigations about the effect of central reactive power control on the climate protection (reduction of fossil CO_2 emission) will be carried out, using the method of a Life Cycle Analysis. By reaching a better power factor and grid stability, energy losses from power transmission in the mainly “fossil” fed grid can be reduced, which leads to the expected reduction of fossil fuels.

- Task 3: **Workshops**

Workshops will be carried out with:

  - Grid operators,
  - Biogas plant operators,
  - Possible funding institution and
  - Representatives of policy and economy.

Goal of the workshops is to discuss all aspects of the planned Virtual Biogas Power Plant between operators and decision makers. The specific questions which will be dealt with are:

- How can a Virtual Biogas Power Plant be realized best?
- What are the technical boundary conditions?
- What are the barriers and how can we overcome them?
- Are the operators of the biogas plants willing to meet the requests of a central reactive power control?
- What are the requests and expected benefits for the grid operators?
- Which legal requirements have to be fulfilled?
- Which medium- and long term economical boundary conditions (green tariffs, subsidies) can be expected?
- Which experience of comparable projects (e.g. wind power, small hydro power) is available, how can it be used?

National and international representatives and guests are welcome of course to participate in the workshops, to contribute to the efforts, but also to disseminate information of interest for possible comparable projects in Europe.

- Task 4: **Preparation of a demonstration project**

In this task, based on the results of the previous tasks, preliminary negotiations with grid operators, biogas plant operators, and other decision makers (policy, funding) will be carried out. The goal is to prepare letters of intent of the partners to realize a demonstration "Virtual Biogas Power Plant" in stage 2 of the project.

5.4 Geographical situation

The Virtual Biogas Power Plant will be realized in the South-Eastern part of the Austrian State of Styria. The geographical location is shown in Figure 28. As one can see in that figure, the total area foreseen for the Virtual Biogas Power Plant is some 50 by 50 km.

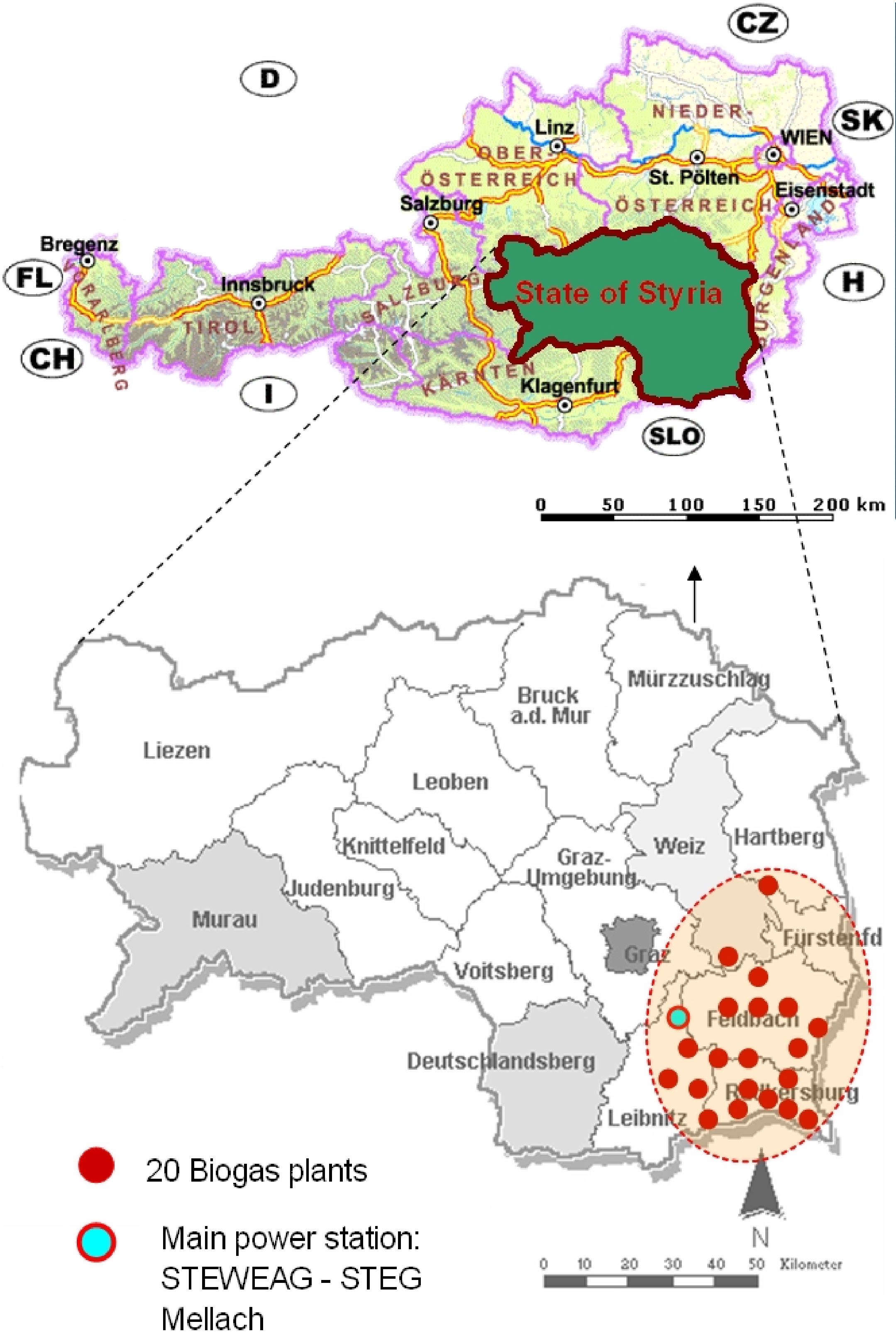

Figure 28: Location of the Virtual Biogas Power Plant

5.5 Benefits expected

Expected benefits for the biogas plant operator are possible improvement of the economic situation of their plant by operation the generator with a better power factor. Today, the power factor of most of the plants is set to a level between 0.90 and 0.92, due to contractual issues with the grid operator. If the results of the project show, that in the yearly average a better power factor will happen, the biogas plant operator could feed more active power into the grid and therefore increase the proceeds of the plant.

In case of an expected reduction of the power factor in the yearly average, the benefits for the grid operator have to be evaluated. A possible result could be that the grid operator may pay some compensation for the reactive power to the grid operator. A reactive power market could be established, as it is already realized in United Kingdom.

Expected benefits for the grid operator might be reduction of transmission losses and the optimized operation of large power plants used for reactive power control so far.

An impression about the expected quantity of reactive power which will be influenced by the Virtual Biogas Power Plant is given by the following example.

Reactive power requirement, area of Graz, summertime:

07:00 The whole reactive power requirement is covered by capacity of cables.

09:30 The reactive power requirement increases up to some 250 MVar.

This requirement leads to considerable transmission losses, which could be partially reduced by a quickly centrally controlled Virtual Biogas Power Plant.

Furthermore, as already mentioned above, benefits for climate protection can be expected due to the fact, that reduced transmission losses will correspondingly lead to reduced fossil consumption of fossil fuels.

5.6 Preliminary results

Due to an unexpected postponement of the project start, this report comes at a very early stage of the project. So no conclusions can be drawn in the subject report up to know. However some preliminary results, which will point the way ahead, can be mentioned:

- Most of the biogas plants are equipped with a synchronous generator, allowing reactive power control.
- Also other technical boundary conditions are expected to be positive in general.

- All the biogas plants are operating under full active power load conditions nearly during the whole year: Active power control would not be possible but is also not foreseen in the project.
- Power factor of most of the biogas plants is currently set to 0.9 – 0.92.
- A prediction, whether the power factor can be improved in the yearly average is not possible so far, but will be measured in the 1 year measurement program.
- Operators of biogas plants are very co-operative and interested in improvements and innovations in terms of economy and ecology.

6 ECONOMICS OF DISTRIBUTED ENERGY RESOURCES

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6.1 Introduction

The traditional focus in electric power planning has been on generation resources-forecasting demand, and then trying to select the most cost-effective combination of new power plants to meet the forecast. However, in the final decades of the twentieth century there was an important shift in which it was recognized that the real need was for energy services and a least-cost approach to providing those energy services should include programs to help customers use energy more efficiently. Out of that recognition a process called *integrated resource planning* (IRP) emerged in which both supply-side and demand-side resources were evaluated, including environmental and social costs, to come-up with a least-cost plan to meet the needs of customers for energy services.

More recently, with increased attention to the electricity grid and the emergence of efficient, cost-effective cogeneration, IRP now recognizes three kinds of electricity resources: *generation resources*, especially the distributed generation (DG) technologies; *grid resources*, which move electricity from generators to customers; and *demand-side resources*, which link electricity to energy services. These three distributed energy resources are all equally valid, comparable resources that need to be evaluated as part of a least-cost planning process. In this paper, the focus is on distributed energy resources that are relatively small in scale and located somewhat near to the end-user.

An essential step in any economic calculation for a distributed resource (DR) project is a careful analysis of the cost of electricity and/or fuel that will be displaced by the proposed system. The *electric utility rate structures* are critical factors for customers evaluating a DR project. Electric rates vary considerably, depending not only on the utility itself, but also on the electrical characteristics of the specific customer purchasing the power.

There are many ways to evaluate the economic viability of distributed energy resources. The capital cost of equipment, the operation and maintenance costs, and the fuel costs must be combined in some manner so that a comparison may be made with the costs of not doing the project.

In this paper, the techniques needed to evaluate the economics of both sides of the electric meter (the demand side and the supply side) will be explored.

6.2 Distributed energy resources

Distributed energy resources are split into three categories: generation resources, grid resources, and demand-side resources. In this paper, the focus is on distributed energy resources that are relatively small in scale and located somewhat near to the end-user. Examples of such distributed resources are shown in Table 7 [33].

Table 7: Examples of distributed energy resources

Distributed generation	Grid resources	Demand-side resources
Fuel cells	Increased grid capacity	Heat pumps
Internal combustion engines	Decreased grid losses	Solar architecture
Combustion turbines	Grid-sited storage	Motor controls
Biomass cogeneration	Improved power factor	Efficient lighting
Wind turbines	Reduced connection losses	Load shifting
Photovoltaics	Unaccounted for losses	Appliance efficiency
Mini-hydro		Absorption cooling

6.3 Electric utility rate structures

An essential step in any economic calculation for a distributed resource project is a careful analysis of the cost of electricity and/or fuel that will be displaced by the proposed system. The *electric utility rate structures* are critical factors for customers evaluating a DR project.

Electric rates vary considerably, depending not only on the utility itself, but also on the electrical characteristics of the specific customer purchasing the power.

The rate structure for a *residential customer* will typically include a *basic fee* to cover costs of billing, meters, and other equipment plus an *energy charge* based on the number of kilowatt-hours of energy used. The *standard residential rates* usually include a few tiers based on monthly kWh consumed, where the rates increase with increasing demand so as to discourage excessive consumption. In an effort to encourage customers to shift their loads away from the peak demand times, some utilities are beginning to offer *residential time-of-use (TOU) rates*, where the TOU rates are higher during peak demand times and significantly lower for example at night when there is idle capacity.

The *commercial and industrial customers* bill is based not only on the energy charge but also on the *demand charge* that is linked with the peak amount of power that they use. The demand charge may be especially severe if the customer's peak corresponds to the time during which the utility has its maximum demand since at those times the utility is running its most expensive peaking power plants. Large industrial customers may also pay *power factor fees*, if their power factor is outside of certain bounds.

Some utilities now offer one-day-ahead, hour-by-hour, *real-time pricing*. When the customers know that tomorrow afternoon the price of electricity will be high, they can implement appropriate measures to respond to that high price. With the price of electricity more accurately reflecting the real, almost instantaneous, cost of power, it is hoped that market forces will encourage the most efficient management of demand.

6.4 Energy economics

There are many ways to evaluate the economic viability of distributed energy resources. The capital cost of equipment, the operation and maintenance costs, and the fuel costs must be combined in some manner so that a comparison may be made with the costs of not doing the project.

6.4.1 Simple payback period

One of the most common ways to evaluate the economic value of a project is with a simple payback analysis, which is the ratio of the extra first cost ΔP (\$) to the annual savings S (\$/yr):

$$\text{Simple payback} = \frac{\Delta P}{S} \tag{1}$$

Simple payback has the advantage of being the easiest to understand of all economic measures. However, simple payback is also one of the most misleading measures since it does not include anything about the longevity of the system.

6.4.2 Initial rate of return

The initial rate of return is just the inverse of the simple payback period:

$$\text{Initial rate of return} = \frac{1}{\text{Simple payback}} = \frac{S}{\Delta P} \tag{2}$$

6.4.3 Net present value

To account for the time value of money, a present worth analysis in which all future costs are converted into an equivalent *present value* or *present worth* is often required. The future amount of money F (\$) in an account that starts with P (\$), which earns annual interest rate i (%) over a period of n years, will be:

$$F = P \cdot (1+i)^n \tag{3}$$

When converting a future value F into a present worth P, the interest term i is usually referred to as a discount rate d (%), so using (3) we obtain:

$$P = \frac{F}{(1+d)^n} \tag{4}$$

The present value P of a stream of annual cash flows A, for n years into the future, with a discount rate d is calculated as follows:

$$P = A \cdot PVF(d,n) \tag{5}$$

where the present value function (PVF) is:

$$PVF(d,n) = \sum_{i=1}^{n} \frac{1}{(1+d)^i} = \frac{(1+d)^n - 1}{d \cdot (1+d)^n} \tag{6}$$

The present value of all costs, present and future, for a project is called the *life-cycle cost* of the system under consideration. When a choice is to be made between two investments, the present value, or life-cycle cost, for each, is computed and compared. The difference between the two is called the *net present value* (NPV) of the lower-cost alternative.

The net present value can be computed by comparing the value of all future fuel savings ΔA with the extra first cost of the more efficient product ΔP as follows:

$$NPV = \Delta A \cdot PVF(d,n) - \Delta P \tag{7}$$

6.4.4 Internal rate of return

The *internal rate of return* (IRR) is perhaps the most persuasive measure of the value of an energy-efficiency or distributed-generation project. The IRR allows the energy investment to be directly compared with the return that might be obtained for any other competing investment. IRR is the discount rate that makes the net present value of the energy investment equal to zero. In the simple case of a first-cost premium ΔP for the more efficient product, which results in an annual fuel savings ΔA, it is the discount rate that makes the net present value in (7) be zero:

$$NPV = \Delta A \cdot PVF(IRR, n) - \Delta P = 0 \tag{8}$$

6.4.5 NPV and IRR with fuel escalation

Typically, the cost of fuel in the future will be higher than it is today, which means that the annual amount of money saved by an energy efficiency measure could increase with time. As a result, there is a need to include a fuel price escalation factor in the present worth analysis.

If d is the buyer's discount rate, e is the fuel escalation and n is the number of years, then the present value function is calculated as follows:

$$PVF(d, e, n) = \sum_{i=1}^{n} \left[\frac{1+e}{1+d} \right]^{i} \tag{9}$$

A comparison of (6) with (9) gives an equivalent discount rate d' when there is fuel savings escalation e:

$$\frac{1+e}{1+d} = \frac{1}{1+d'} \tag{10}$$

Solving (10) we can calculate the equivalent discount rate d' as follows:

$$d' = \frac{d-e}{1+e} \tag{11}$$

6.4.6 Annualizing the investment

In many circumstances the extra capital required for an energy investment will be borrowed from a lending company, obtained from investors who require a return on their investments, or taken from one's own accounts. In all of these circumstances, the economic analysis can be thought of as a loan that converts the extra capital cost into a series of equal annual payments that eventually pay off the loan with interest. Even if the money is not actually borrowed, the same approach can be used to annualize the cost of the energy investment.

If P (\$) is the principal borrowed, i (%/yr) is the annual interest rate, and n (yrs) is the loan term, then the annual loan payments A (\$/yr) are calculated as follows:

$$A = P \cdot CRF(i,n) \tag{12}$$

where the *capital recovery factor* (yr^{-1}) is given by the formula:

$$CRF(i,n) = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \tag{13}$$

6.4.7 Levelized bus-bar costs

To do an adequate comparison of cost per kilowatt-hour from a renewable energy system versus that for a fossil-fuel-fired power plant, the potential for escalating future fuel costs must be accounted for. To ignore that key factor is to ignore one of the key advantages of renewable energy systems; that is, their independence from the uncertainties associated with future fuel costs.

The cost of electricity per kilowatt-hour for a power plant has two key components: an up-front fixed cost to build the plant plus an assortment of costs that will be incurred in the future. In the usual approach to cost estimation, a present value calculation is first performed to find an equivalent initial cost, and then that amount is spread out into a uniform series of annual costs. The ratio of the equivalent annual cost ($/yr) to the annual electricity generated (kWh/yr) is called the *levelized bus-bar cost* of power (the "bus-bar" refers to the wires as they leave the plant boundaries).

In the first step, the present value of all future costs must be found, including the impact of inflation. To keep things simple, we will assume that the annual costs today are A_0, and that they escalate due to inflation (and other factors) at the rate e. The present value of these escalating annual costs over a period of n years is given by:

$$PV = A_0 \cdot PVF(d', n) \tag{14}$$

where d' is the equivalent discount rate including inflation introduced in (11).

Having found the present value of those costs, we now want to find an equivalent levelized annual cost using the capital recovery factor:

$$\text{Levelized annual cost} = A_0 \cdot \left[PVF(d', n) \cdot CRF(d, n) \right] \tag{15}$$

The product in the brackets of (15), called the *levelizing factor*, is a multiplier that converts the escalating annual fuel and O&M (operating and maintenance) costs into a series of equal annual amounts:

$$LF = \left[\frac{(1+d')^n - 1}{d' \cdot (1+d')^n} \right] \cdot \left[\frac{d \cdot (1+d)^n}{(1+d)^n - 1} \right] \tag{16}$$

Notice that when there is no escalation ($e = 0$), then $d' = d$ and the levelizing factor is just unity.

Normalizing the levelized annual costs to a per kWh basis can be done using the heat rate of the plant (Btu/kWh), the initial fuel cost ($/Btu), the O&M cost ($/kWh) and the levelizing factor:

$$\text{Levelized annual cost} = \left[(\text{Heat rate}) \cdot (\text{Fuel cost}) + (\text{O\&M cost})\right]_0 \cdot \text{LF} \tag{17}$$

Just as the future cost of fuel and O&M needs to be levelized, so does the capital cost of the plant. To do so, it is handy to combine the CRF with other costs that depend on the capital cost ($/kW) of the plant into a quantity called the *fixed charge rate* (FCR). The fixed charge rate covers costs that are incurred even if the plant does not operate, including depreciation, return on investment, insurance, and taxes. Fixed charge rates vary depending on plant ownership and current costs of capital, but tend to be in the range of 10-18% per year. The governing equation that annualizes capital costs is then:

$$\text{Levelized fixed cost} = \frac{(\text{Capital cost}) \cdot \text{FCR}}{8760 \cdot \text{CF}} \tag{18}$$

where CF is the capacity factor of the plant.

The levelized bus-bar cost is calculating by adding the levelized fixed cost, equation (18), and the levelized annual cost, equation (17):

$$\text{Levelized busbar cost} = (\text{Levelized fixed cost}) + (\text{Levelized annual cost}) \tag{19}$$

6.4.8 Cash flow analysis

One of the most flexible and powerful ways to analyze an energy investment is with cash flow analysis. This technique easily accounts for complicating factors such as fuel escalation, tax-deductible interest, depreciation, periodic maintenance costs, and disposal or salvage value of the equipment at the end of its lifetime. In a cash flow analysis, rather than using increasingly complex formulas to characterize these factors, the results are computed numerically using a spreadsheet. Each row of the resulting table corresponds to one year of operation, and each column accounts for a contributing factor. Simple formulas in each cell of the table enable detailed information to be computed for each year along with very useful summations.

6.5 Energy conservation supply curves

By converting all of the costs of an energy efficiency measure into a uniform series of annual costs, and dividing that by the annual energy saved, a convenient and persuasive measure of the value of saved energy can be found. The resulting *cost of conserved energy* (CCE) has units of \$/kWh, which makes it directly comparable to the \$/kWh cost of generation:

$$\mathrm{CCE} = \frac{\text{Annualized cost of conservation}}{\text{Annual energy saved}} \qquad (20)$$

When only the conservation measure is the extra initial capital cost, the annualized cost of conservation in the numerator of (20) is easy to obtain using an appropriate capital recovery factor (CRF). In more complicated situations, it may be necessary to do a levelized cost analysis in which the present value of all future costs is obtained, and then that is annualized using CRF and a fuel-savings levelizing factor.

While CCE provides another measure of the economic benefits of a single efficiency measure for an individual or corporation, it has greater application as a policy tool for energy forecasters. By analyzing a number of efficiency measures and then graphing their potential cumulative savings, policy makers can estimate the total energy reduction that might be achievable at a cost less than that of purchased electricity.

6.6 Benefits of distributed generation

In addition to direct energy savings, increased fuel efficiency with cogeneration, and reduced demand charges for larger customers, there are a number of other distributed generation attributes that can significantly add value, including [34]:

- *Option Value*: small increments in generation can track load growth more closely, reducing the costs of unused capacity.
- *Deferral Value*: easing bottlenecks in distribution networks can save utilities costs.
- *Engineering Cost savings*: voltage and power factor improvements and other ancillary benefits provide grid value.
- *Customer Reliability Value*: reduced risk of power outages and better power quality can provide major benefits to some customers.
- *Environmental Value*: reduced carbon emissions for combined heat and power systems will have value if/when carbon taxes are imposed; for fuel cells, since they are emission-free, ease of permitting has value.

6.6.1 Option values

In the context of distributed generation, the *option* part of *option value* refers to the choice of the incremental size of new generation capacity; that is, the buyer has the option to purchase a large power plant that will satisfy future growth for many years, or a series of small ones that will each, perhaps, only satisfy growth for a year or two. The *value* part of *option value* refers to the economic advantages that go with small increments, which are better able to track load growth.

Smaller increments, such as distributed generation, better track the changing load and result in less idle capacity on line over time. The advantage is especially apparent when forecasted load growth does not materialize and a large incremental power plant may result in long-term overbuilt capacity that remains idle but still incurs costs.

One way to quantify the cost advantage of the option value is to do a present worth analysis of the capital cost of a single large plant compared with a series of small ones. Let us compare one large power plant, which can supply N years of load growth, with N small plants, each able to supply one year's worth of growth. Let us assume that it takes only one year between the time a plant is ordered and the time it comes on line, so at time $t = 0$, either a large plant or a small plant must be ordered. Finally, assume that full payment for a plant is due when it comes on line. If P_S (\$/kW) is the capital cost of the small plant, P_L (\$/kW) is the capital cost of the large plant, and d is the discount rate, then it can be proved that the ratio of the small-plant-to-large-plant capital costs that makes them equivalent on a present worth basis is calculated as follows [35]:

$$\frac{P_S}{P_L} = \frac{N}{(1+d)\cdot PVF(d,N)} = N\left[\frac{d\cdot(1+d)^{N-1}}{(1+d)^N - 1}\right] \tag{21}$$

The equation (21) quantifies the advantage of small DG plants over one large plant, however it omits another important advantage of smaller plants. Large plants tie up capital for a longer period of time before the plant can be designed, permitted, built, and turned on. That longer lead time costs money, so we have to modify the analysis to include it. Imagine the initial cost of the large plant being spread over years 1 through L, where L is the lead time. Also, suppose payments on the N small plants begin in year L. It can be proved that the ratio of the small-plant-to-large-plant capital costs that makes them equivalent on a present worth basis is calculated as follows [35]:

$$\frac{P_S}{P_L} = \frac{N\cdot(1+d)^{L-1}}{L}\cdot\frac{PVF(d,L)}{PVF(d,N)} \tag{22}$$

6.6.2 Distribution cost deferral

Distribution systems are plagued by bottlenecks. When a new housing development or shopping centre gets built, distribution feeders and the local substation may have to be upgraded even though their current capacity may be exceeded for only a few hours each day during certain months of the year. The effect of the localized growth can ripple from feeder to substation to transmission lines to power plants.

Distributed generation by utility customers can help avoid or delay the need for distribution system upgrades, leading to more efficient use of existing facilities. Customers in portions of the distribution grid where capacity constraints are imminent could in the future be provided with incentives to generate some of their own power (or shed some of their load), especially at times of peak power demand. Area-and-time-based differential pricing of grid services could well become an important driver of distributed generation.

6.6.3 Electrical engineering cost benefits

Besides capacity deferrals, distributed generation can also decrease costs in the distribution network by helping to improve the efficiency of the grid. Power injected into the grid by local distributed generation resources helps to reduce losses in several ways.

Injecting power onto the grid not only provides voltage support to offset $i \cdot R$ drops and reduce $i^2 \cdot R$ losses, it can also raise the power factor of the lines. Improving the power factor is usually accomplished by adding banks of capacitors to the line, but it can also be helped if DG systems are designed to inject appropriately phased reactive power. Improved power factor reduces line current, which reduces voltage sag and line losses. On the top of that, a better power factor also helps distribution transformers waste less energy, supply more power, and extend their lifetime.

6.6.4 Reliability benefits

Most power outages are caused by faults in the transmission and distribution system. To the extent that a customer can provide some fraction of their own power during those outages, especially to critical loads such as computers and other digital equipment, the value of the added reliability can easily surpass the cost of generation by orders of magnitude. Such emergency standby power is now often provided with backup generators, but such systems are usually not designed to be operated continuously, nor are they permitted to do so given their propensity to pollute. Fuel cells, on the other hand, can operate in parallel with the grid. With natural gas reformers, or sufficient stored hydrogen, they can cover extended power outages. With no emissions or noise they be housed within a building and can be permitted to run continuously so they are an investment with annual returns in addition to providing protection against utility outages.

6.6.5 Emissions benefits

As concerns about climate change grow, there is increasing attention to the role of carbon emissions from power plants. The shift from large, coal-fired power plants to smaller, more efficient gas turbines and combined-cycle plants fuelled by natural gas can greatly reduce those emissions. Reductions result from both the increased efficiency that many of these plants have and the lower carbon intensity (kgC/GJ) of natural gas.

6.7 Connection costs and charges of distributed generation

Two issues related to the connection of distributed generation are of considerable importance [36]:

1. The voltage level to which generation should be connected, as this has a major impact on the overall profitability of generation projects.
2. The question of whether a connection is based on 'shallow' or 'deep' charges. Shallow charges reflect only costs exclusively associated with making the new connection, while deep charges also include the additional costs that are indirectly associated with the reinforcement of the system.

6.7.1 Voltage level related connection cost

The overall connection costs may considerably alter the cost base of a distributed generator and are primarily driven by the voltage level to which the generator is connected. Generally, but not exclusively, the higher the voltage level the larger the connection cost. To secure the viability of a generation project, developers and operators of DG would prefer to be connected at the lowest possible voltage level. On the other hand, the higher the connecting voltage the lower the impact that DG has on the performance of the local network, particularly in terms of steady-state voltage profile and power quality. Therefore, the network operators generally prefer connecting DG to higher voltage levels. These two conflicting objectives need to be balanced appropriately, and may require an in-depth technical and economic analysis of the alternative connection designs [37].

To which voltage level a distributed generator can be connected to the distribution network will largely depend on its size, but also on the layout of the local network, its parameters. The proximity of load may also be important, and it is therefore not possible to derive generalized rules.

6.7.2 Connection charges

Another issue that can significantly influence the profitability of a generation project is whether connection charges should reflect only costs exclusively associated with making the new connection or also include the additional costs that are indirectly associated with any reinforcement of the system. In other words, should connection charges be based on shallow or deep connection costs?

The costs associated with connecting a distributed generator to the nearest point in the local distribution network are referred to as *shallow connection charges*. Clearly, only the new distributed generator uses a circuit between that generator and the system. The generator is therefore required to cover the cost of this connection through connection charges, which could be imposed over a period of time if the distribution company invests and owns the connection, or alternatively, as a one-off payment, in which case the generator is effectively the owner of the line.

It has been argued that the advantage of shallow connection charges lies in the simplicity of their definitions. Also, it is relatively straightforward to identify the cost related exclusively to connecting the generator to the nearest point in the network. On the other hand, the cost associated with a new connection might not be fully reflected in the connection charge made, as such a connection may require reinforcement of the system away from the connection itself. The majority of electric utilities charge new entrants for the cost of connection itself and the cost incurred for any upstream reinforcement.

6.8 Conclusions

Distributed energy resources are split into three categories: generation resources, grid resources, and demand-side resources. In this paper, the focus was on distributed energy resources that are relatively small in scale and located somewhat near to the end-user. Distributed generation can significantly add value including option value, deferral value, engineering cost savings, customer reliability value, and environmental value. The techniques needed to evaluate the economics of distributed energy resources were explored. There are many ways to evaluate the economic viability of distributed energy resources, e.g. the internal rate of return, the net present value, and the levelized bus-bar cost method. For distributed generation, in particular, the connection costs and connection charges are of considerable importance.

6.9 References

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7 CONNECTION OF RES TO POWER GRID

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7.1 Introduction

The main goal of this paper is to point out the most important technical prerequisites which have to be satisfied and problems which have to be solved for the successful connection of some renewable energy source to the existing power grid. Most of the renewable energy sources are of small sizes, designed to produce power (some of them also produce heat) distributed within low voltage and medium voltage (LV/MV) distribution networks. The connection of RES into already built distribution networks affects the main operational concept of the traditional lateral (radial) distribution networks (with unidirectional power flows). More over, there are also some other economic and legislative requirements that have to be considered.

There are different institutions (regulatory bodies) which prescribe technical conditions that have to be satisfied when power producers require the connection of small power sources to the existing distribution network. As the first step it is important to identify the ownership with respect to the distribution network and the appropriate legislative documentation.

The current situation about RES implementation in Serbia is still at the beginning with reasons of different nature. But, it is very evident that there are big efforts to popularize the use of RES, to enlarge the research potential and to define relevant technical conditions for RES practical implementations. The actual Energy Law defines the possible existence of the independent power producers and the priority is given to power production from RES. Public power company "Power industry of Serbia" has issued different technical recommendations by their specialized departments. One of them is the recommendation No. 16 named: "Base technical requirements for the connection of the small-scale power stations to the distribution network of Serbia". All documents are public and available to be downloaded from the official company's web site www.eps.co.yu

7.2 Technical recommendation No. 16 – short review

7.2.1 Intention of the technical recommendation

The first part of this recommendation consists of key facts which should be applied in practical connection of RES to the existing grid. It is related to main technical requirements for the connection of small power stations (with real power of up to 16 MVA) to the already built distribution networks of following voltage levels: 0,4 kV, 10 kV, 20 kV and 35 kV.

This recommendation doesn't include the following problems:

- Building of the small power station,
- Automatic or manual control of the power station,
- Isolated operation of the small power stations.

In this recommendation the current technical regulations, international standards in the power engineering field and the remaining technical recommendations of the "Power industry of Serbia" are taken into consideration. The great significance is given to the development and use of the modern technical solutions for this type of the power installations.

The main aims of this recommendation are:

- To establish basic criteria which can serve as the reference for the estimate of the possibility to connect the small power station, considering the distribution network type and specific characteristics, real power and operation modes of the small power station,
- To establish the standard ways of the connection,
- To determine the way and the locations of electric energy and power measurements,
- To choose types and characteristics of protection devices and circuit breakers,
- To determine the way of the reactive power compensation in the small power station,
- To establish actions and activity sequence from the registration to the connection of the small power station to the distribution network, with necessary documentation and application forms,
- To establish the way and conditions for the small power station operation modes (with special attention to the parallel work with distribution network),
- To determine the operation modes of the small power stations.

7.2.2 Terms and definitions

The most important terms used in this technical recommendation will be defined. Some of them are simple statements, but there are some terms with very exact explanations. For easier understanding of the connection problems these terms are of great importance. For example, there are two similar terms with different definitions which require precise distinctions.

- **Place of the connection to the distribution network** (feeding point of the distribution network) – place within the distribution network where the connection of the small power station is connected to the network
- **Place of the connection of the small power station** (feeding point of the small power station) – place in the small power station from which the connection starts
- **Connection** (connection of the small power station) – set of the lines, equipment and devices which link the place of the connection to the distribution network with the place of the connection of the small power station, via the measurement system.

7.2.3 Technical data about the distribution network

The small power station can be connected to distribution network at different rated voltage levels: 0.4 kV (or up to 1kV in the LV networks), 10 kV, 20 kV or 35 kV. It is considered that MV distribution networks have the radial configuration.

The other technical recommendation (No. 6) gives detailed information about ground type at the different voltage levels. Typically, there is the next situation:

- Neutral point in the 0.4 kV (1 kV) network is directly grounded,
- Neutral point in the 10 kV and 20 kV network is isolated or grounded via the low impedance,
- Neutral point in the 35 kV network is grounded via the low impedance.

There are standardized values of the maximal allowed three-phase short circuit currents (powers) and ground connection currents in the distribution networks of Serbia:

- network 0,4 kV: 26 kA (18 MVA) in the cable network and 16 kA (11 MVA) in the overhead line network
- network 10 kV: 14.5 kA (250 MVA)
- network 20 kV: 14.5 kA (500 MVA)
- network 35 kV: 12 kA (750 MVA)

These currents can vary around the values specified above and the competent distribution network company would specify the real values at the place of the connection to the distribution network.

In the grounded distribution networks of Serbia at the voltage levels 10 kV, 20 kV or 35 kV standardized value of the single phase-to-earth fault current is 300 A. Sometimes that current may be even greater (standardized value of 1,000 A) in accordance to the conditions prescribed in technical recommendation No. 6. The auto-re-closing break time in such distribution networks would be more than 1s.

7.2.4 Technical data about small power stations

The small power station could be any type of source with the installed apparent power between 25 kVA and 16000 kVA. The number of units and installed power of power stations can be different, but there is a standardized series of the generator's rated apparent power. For example: 25 kVA, 40 kVA, 63 kVA, 100 kVA, 125 kVA, 160 kVA, 250 kVA, 315 kVA and so on up to 8,000 kVA. There are different generator types which are suitable for applications in small power stations:

- AC synchronous generators,
- AC asynchronous generators,
- DC generators with the static transforming devices (invertors DC/AC 50 Hz),
- asynchronous generators with the frequency transforming device (invertors AC/AC 50 Hz).

Regarding to the installed power of the small power station, the operation mode and the distance from the consumers, rated voltage of the generators can be:

U_{ng} = 0.42 kV; 3.15 kV; 6.3 kV; 10.5 kV

When the rated generator's voltage is different from the rated voltage at the place of the connection to the distribution network, the owner of the small power station is obliged to use the appropriate transformation.

The rated value of generator's frequency is 50 Hz. Form of the voltage wave is sinusoidal with the form factor grater than 7 %.

The maximum allowed voltage deviation at the place of the connection to the distribution network in regard to the rated voltages can be:

- in the steady state:
    - $\Delta u_m = \pm 5$ % if place of the connection is in the MV network
    - $\Delta u_m = +5$ % / -10 % if place of the connection is in the LV network
- in the transient state:
    - $\Delta um = 2$ %
    - $\Delta um \leq 5$ % especially with the given permission of the competent distribution company

7.2.5 Technical requirements for the connection of the small power station to the distribution network

The small power station has to fulfil some conditions in order to be connected to distribution network. The fifth article defines these conditions. It is needed to equip the power station with the appropriate protection and other devices in order to protect generators and other equipment from damages. Faults in the distribution network, prohibited deviations in voltage profiles, frequency or phase position in the small power station and network could be critical factors. The additional condition, which sometimes can be very decisive, is to satisfy all regulations in regard to environment protection.

In regard to the type of the connection to the network, the small power station can be equipped with:

- equipment for parallel work with the distribution network
- equipment for combined work, parallel or isolated type of work

It is not allowed for small power station to work independently in some network island without the black start-up possibilities. Isolated type of work can be used only when the self consumption of the small power station is independently provided.

The small power station should satisfy four primary criteria:

a) **criterion of the small power station allowed installed power**,

b) **criterion of the allowed flickers**,

c) **criterion of the allowed higher harmonics currents**,

d) **criterion of the short circuit power**.

<u>Criterion of the small power station allowed installed power</u>

This criterion refers to the transient states (start-up and shut-down procedures) and requires that voltage deviation (voltage shock) at the place of the connection to the distribution network is not allowed to be greater than Δu_m = 2 %. The next inequality is needed to be satisfied:

$$S_{ng}^{max} \le \frac{S_{ks}}{50 \cdot k}$$

- S_{ng}^{max} is the maximal value of the generator's power or total power of the all generators within small power station if they are connected to the distribution network simultaneously [MVA],
- S_{ks} is the 3 phase short circuit power (value at the place of the connection) [MVA],
- $k = I_p/I_n$ is the coefficient defined as the quotient of the starting current I_p (start-up current) and rated generator's current I_n (for example: k = 1 for the synchronous generators and inverters, k = 2 for the asynchronous generators, k = 8 when the data about the starting current isn't known)

Criterion of the allowed flickers

This criterion estimates with the help of the disturbance factor A_{fs} of some small power station which is caused by the long lasting flicker (more than 2 hours long) and it is dominant especially in the solar or wind power plants. The next inequality is needed to be satisfied:

$$A_{fs} = \left(c_{fMEL} \cdot \frac{S_{MEL}}{S_{ks}} \right)^3 = \left(\frac{c_{f1}}{\sqrt{n}} \cdot \frac{S_{MEL}}{S_{ks}} \right)^3 \leq 0,1$$

- $S_{MEL}=\Sigma S_{ng}$ is the total installed power in the small power station [MVA],
- S_{ng} is the single power of generators within the power station [MVA],
- S_{ks} is the 3 phase short circuit power (value at the place of the connection) [MVA],
- n is the number of the generators,
- c_{fMEL} is the flicker coefficient of the small power station with n generators,
- c_{f1} is the flicker coefficient of the small power station separately for each generator.

Flicker coefficient c_f designates the property of the small power station to produce flickers. The flicker criterion is satisfied if c_f is smaller than 20. This condition is generally satisfied in the case of small power station with water, steam or gas turbines. The biggest problem is in the case of solar or wind power plant when the coefficient c_f is often much more greater than 20 and criterion defined above still has to be satisfied.

Criterion of the allowed higher harmonics currents

This criterion is linked with the next expression:

$$I_{vhdoz} = I_{vhs} \cdot S_{ks}$$

- I_{vhdoz} is the allowed value of the higher harmonic current at the generator's voltage level [A],
- I_{vhs} is the value of the higher harmonic current regarding the short circuit power at the place of the connection to the distribution network [A/MVA]
- S_{ks} is the 3 phase short circuit power (real value at the place of the connection) [MVA]

The table bellow contains the values of the higher harmonic current regarding the short circuit power at the place of the connection to the distribution network [A/MVA] which are not allowed to be exceeded.

Higher harmonic current I_{vhs} [A/MVA]	The higher harmonic order [ν]							
	5	7	11	13	17	19	23	25
	0.7	0.6	0.5	0.3	0.3	0.2	0.2	0.2

Criterion of the short circuit power

If the three phase short circuit current increased by the contribution of the small power station is greater than the current which has dictated the choice of the equipment the next solution can be used:

- the limitation of the three phase short circuit current in the small power station
- replacement of the switching devices and/or other equipment that do not fulfil requirements in regard to calculated values of the short circuit powers (currents)
- the change of the connection location to the distribution network, or the change of the parameters of the connection line etc.

Generally, small power stations with the installed capacity below 1 MVA should not increase the value of the short circuit power significantly.

7.2.6 Technical requirements for the connection of the small power station

Every connection of the small power station consists of:

- connection line (MV/LV cable or overhead line of different types),
- switching, measuring, protection and other devices at the place of the connection of the small power station (these devices are placed in the connection line cell within the small power station facility)

  The main elements of this equipment are:

  - circuit breaker
  - measuring transformers for supply of the protection devices and for other measurements
- switching, measuring, protection and other devices at the place of the connection to the distribution network (these devices are placed in the connection line cell within the distribution transformer station or directly connected to the distribution network for the small power stations up to 160 kVA in MV network or up to 63 kVA in LV network)
- equipment and devices for the measurement location

7.2.7 Technical requirements for the measurement location

The measurement location is the place for monitoring the delivered or the received power (or energy) to or from the network. The competent distribution company prescribes the location of the measuring place, needed measuring devices (electric energy meters), control devices, measuring transformers etc.

If the small power station is connected to MV distribution network, measuring place can be within some distribution network facility or within the small power station facility. When the power station is directly connected to LV distribution network over the connection line measuring place is always within the power station facility.

Each measurement location should be equipped with the following devices:

- digital active electric energy meter
- digital reactive electric energy meter
- control device of the measuring group

The complete set of functions specified by the above devices can perform only one special device - multifunctional microprocessor energy meter. All technical requirements for every element in the measuring place are given in this recommendation.

7.2.8 The generator and connection line protection

In this part the recommendation defines the base requirements for the selection of the protection devices. These devices are intended to protect generators and all the other elements of the equipment in the small power station against damages due to failures and different disturbances in the distribution network (short circuit, phase-to-earth faults, voltage and frequency changes etc.).

Two types of protection should be taken into consideration:

- system protection
- protection of the connection line

There are some other types of protection, not discussed in this recommendation, for example: protection from the generator's internal failures, turbine protection, protection of the power transformers, protection against atmospheric discharges, protection against failures of the switching devices etc.

All protection devices affect connection switch to interrupt automatically generator's parallel work with the distribution network.

System protection consists of:

- voltage protection
  - over-voltage protection (U>) – 3 phase voltage relay with the minimal setting range $(0.9 \div 1.2)\cdot U_{ng}$ and with time delay (0.2 ÷ 3) seconds
  - under-voltage protection (U<) – 3 phase voltage relay with the minimal setting range $(1 \div 0.7)\cdot U_{ng}$ and with time delay (0.2 ÷ 3) seconds
- frequency protection
  - over-frequency protection (f>) – single phase frequency relay with the minimal setting range (49 ÷ 52) Hz and with time delay (0.2 ÷ 3) seconds

- o under-frequency protection (f<) – single phase frequency relay with the minimal setting range (51 ÷ 48) Hz and with time delay (0.2 ÷ 3) seconds

Protection of the connection line can be over-current protection or earth-to-ground failure protection. There are two types of over current protection: general over-current protection (I>) and short circuit protection (I>>).

7.2.9 Reactive energy compensation in the small power station

Power factor of the small power station in all operating regimes should be greater than 0,95. In order to maintain this specified target it is necessary to use additional reactive power sources (capacitors). It is possible to use individual, group or central reactive energy compensation installations.

In order to properly design the reactive energy compensation facility the following circumstances should be taken into account:

- reactive energy necessary for the generator operation
- reactive energy necessary for the consumers of the small power station (when generators are turned on and also, when they are disconnected)
- harmful effects (possibility of the appearance of the higher harmonics)

Automatic control of the power factor is needed when the small power station has very variable power output (wind power plant).

7.2.10 Connection agreement between small power stations and the distribution network

This part of recommendations specifies the necessary documentation for the connection realization. The important parts are regulations prescribed by the distribution network owner and contract documentation which has to be signed by both sides. The final document is the order for the connection of the small power station to the distribution network.

7.2.11 The first connection of the small power station to the distribution network

After the contract is signed between the power plant owner and the distribution network company there are some necessary activities to be performed before the initial start of work. It is needed to check all the equipment, especially to examine all protection and synchronization devices. The next practical simulations are of the crucial importance:

- disconnection of the voltage in the distribution network,
- the protection performance and other devices performance in the case of the applied auto-re-closing procedure,
- sequence during start-up procedures for generators,
- the reactive energy compensation facility performance in regard to the generator type and other reactive energy needs within the power station self-consumption.

The final result of the all tests is the separate document (protocol) agreed upon the power plant owner, authorized representative of the distribution company and main building contractor.

7.2.12 Operation

The further way of work of the small power station is prescribed by the different rules. In this recommendation the relationships between the power station's owner and the distribution company are defined and they are precisely in the contract obligations. The first owner obligation is to maintain the secure and reliable work of the power station. The work of the small power station should not cause the prohibited or harmful regimes from the point of view of distribution network in any case.

7.2.13 Connection schemes of the small power station to the distribution network

There are four different connection schemes given in this recommendation. They differ among themselves in regard to the installed power of the small power station and to the voltage level at the location of the connection.

Explanation of the figure details: (1) generator, (2) generator's circuit breaker, (3) place of the connection of the small power station, (4) connection switch, (5) connection line, (6) switching device at the location of the connection to the distribution network, (7) place of the connection to the distribution network, (8) measuring group, (9) protection of the connection line in the power station, (10) protection of the connection line at the place of the connection to the distribution network, (11) power transformer in the small power station (home transformer), (12) self - consumption of the small power station, (13) generator's block transformer, (14) system protection in the small power station (voltage and frequency protection).

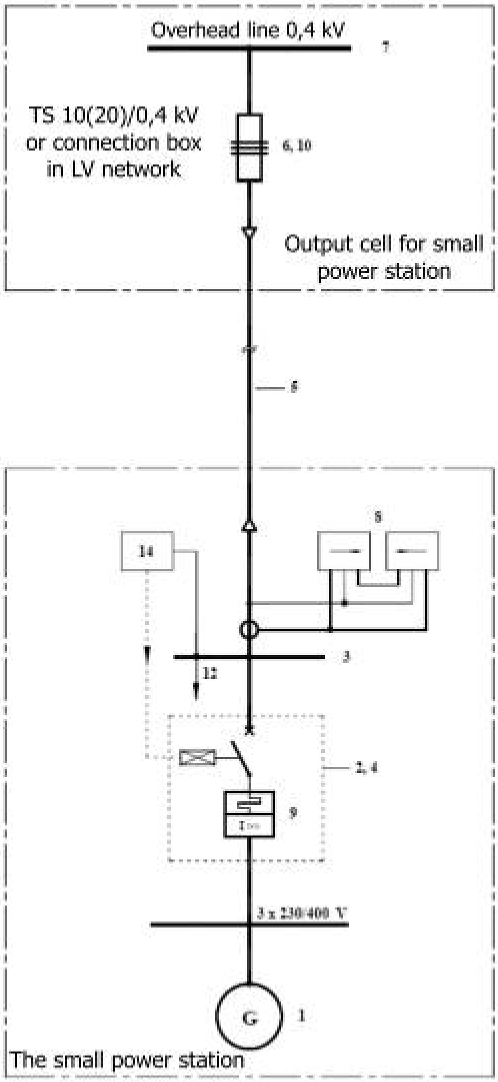

Figure 29a: Connection of the small power station of the power up to 63 kVA directly to the LV network

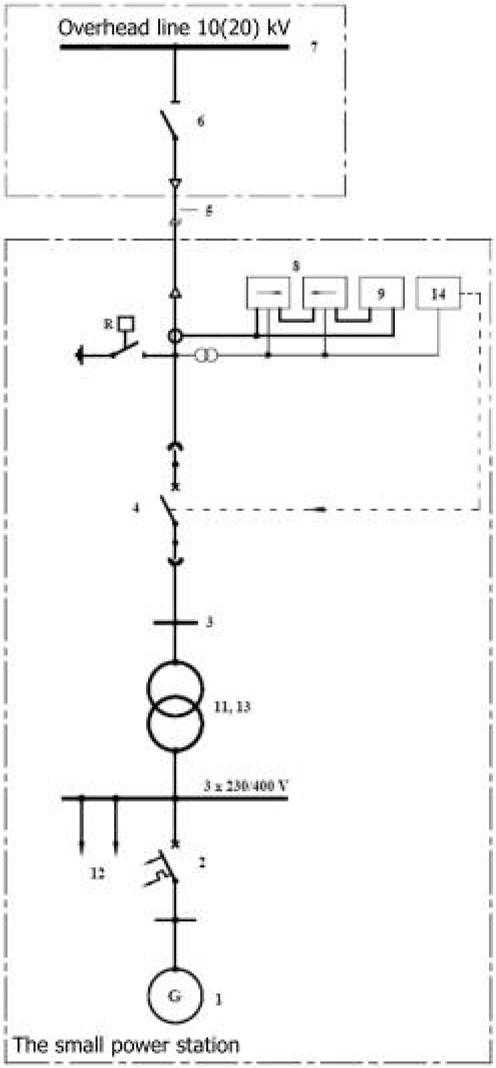

Figure 29b: Connection of the small power station of the power up to 160 kVA to the MV overhead line

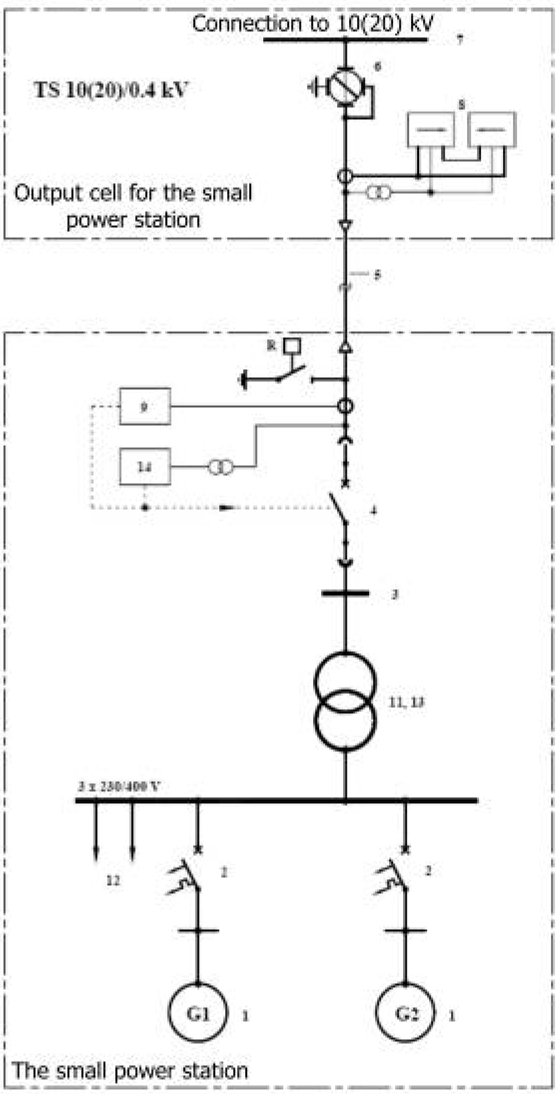

Figure 30a: Connection of the small power station to the MV bus in the TS 10(20)/0,4 kV

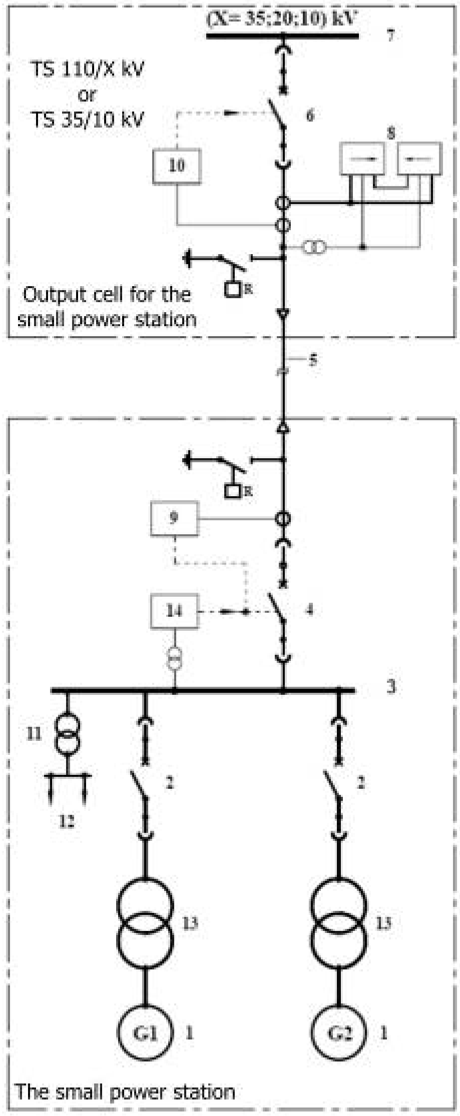

Figure 30b: Connection of the small power station to the TS 110/X kV or 35/10 kV

7.3 References

[38] "Power industry of Serbia" - department for distribution of electrical energy: **The recommendation No. 16** "Base technical requirements for the connection of the small-scale power stations at the distribution network of Serbia", Belgrade, www.eps.co.yu, May 2003.

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8 TECHNICAL ASPECTS OF RES PROJECT IMPLEMENTATION: Case of sHPP

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8.1 Introduction

Location is essential for successful realization of one (or more) small hydro power plant construction project. First, the general location – water flow with its watershed area – is selected based on estimations from experience and analyses of basic, rough parameters such as available water amount and head. Thereafter, in further phases of design, basic parameters of one small hydro power plant are precisely defined through the studies, basic designs and finally detailed design.

Processing of the basic parameters is completed during preparation of technical documentation, starting from the initial study to the main design. The installed capacity of the plants and resulting output and scope of works are estimated on the basis of these key parameters. They present the basis for calculation of technical-economic cost effectiveness of the project.

Preparatory work for realization of construction of small hydro power plant including tender announcement, selection of a contractor and supplier of the equipment are undertaken after preparation and revision of the main power plant design.

Preparatory work in principle doesn't last long nor require much material and organizational costs. But in case of construction of a few small hydro power plants, as was the case with construction of four small hydro power plants (Company Intrade energija) or the case with two small hydro power plants on one river (where), then this work is very important.

During realization of project itself, maximum attention should be paid to:

- complying with technical criteria and conditions,
- complying with regulations of work safety,

- complying with regulations related to the environment protection as well as other legal liabilities.

In order to realize the above mentioned conditions it is necessary to have permanent engagement of the specialized personnel as the supervisors for each phase of the project. In this manner one has direct control of the project development, which, in the end, results in successful realization of project.

The project is considered finished after a technical review of each phase of the project. After issuing a certificate of technical acceptance, the testing of the plant can begin. Final issuance of permit for operation is issued by the competent authority after completion of this phase of the project.

During the first months of commercial operation of the plant, special attention should be paid to the observation and check of technical parameters of the plant which were provided in the offer by the equipment supplier.

8.2 Technical documentation

To realize the project of construction of small hydro power plants or few of them, preparation of the project documentation should be done in a few phases. The grade of precision of each phase is higher in each further step. Order of preparation of investment-technical documentation in Bosnia and Herzegovina as well as in more European countries is the following:

1. Feasibility Study
2. Basic design or project document
3. Main project document
4. As-built project document

Conditions and way of designing in Bosnia and Herzegovina essentially do not differ from practices in other countries. They shall be described in detail below.

8.2.1 Feasibility Study – elaborate of hydropower utilization

The first step in preparation of investment-technical documentation is preparation of the Feasibility Study. In this phase one makes a rough estimation of hydropower utilization of some watercourse. For this study, an estimation of the hydrological potential, site inspections and selection and a rough estimate of necessary type and amount of equipment are performed.

In principle, the feasibility study is prepared for the entire watercourse or watershed area. It means that hydropower potential of the main watercourse as well as all tributaries is assessed.

In most common cases in Bosnia and Herzegovina the feasibility study is prepared for the state owned electric power company and the local government (canton). This is the common case since award of concession for construction of small hydro power plants with the installed capacity up to 5 MW is in under jurisdiction of the cantons. However, it is possible and, lately it happens, that the construction company is also one of the investors.

Site selection for some small hydro power plant's facilities depends on few factors:

- Accessibility of terrain for some facilities of the power plant (water intake, pressure pipeline, power house),
- Geology,
- Property-legal issues,
- Natural protected areas, resources and cultural and historical areas of interest.

Accessibility to each facility of small hydro power plant is essential in regard to the project costs. Technically speaking, any location in any terrain can be accessed, but the question is how much is necessary to invest for such activity. Therefore the aim is selection of locations which could be accessed in the easiest way. Typically, in practice, it is often necessary to construct new access routes, but with optimal site selection their length could be minimised.

Each study of hydropower utilization can be divided into few parts:

- Hydrology,
- Geology,
- Technology (hydropower part with hydropower facilities).

The hydrology, quantity and quality of flow, of the subject watercourse are analyzed, where quality is defined as the minimum amount of water during the dry season. Into this level of project documentation is entered with the calculation of flow on location of partition profile by utilization of mathematical methods which includes:

- analysis of precipitation on the subject area – watershed,
- calculation of surface drainage at the watershed,
- processing of data from the nearest water-flow measurement station.

By entering all necessary parameters, an estimate of the annual seasonal water flow is obtained. If data about measurements at the water-intake profile of the future power plant do not already exist, then these data shall significantly help in defining of more precise hydrological data.

Site visits can be used for this level of documentation in order to determine geological characteristics of the terrain. If geological maps are available then they could partially provide help in order to more precisely determine the local geology at the project site.

Technological analysis (facility design) presents a summary of previous analyses. Technical parameters for each small hydro power plant follow as result of this part of the study. Simplified economic analyze can be done on the basis of these parameters. In this phase of project design, the allowed error varies in range of ± 35-40%.

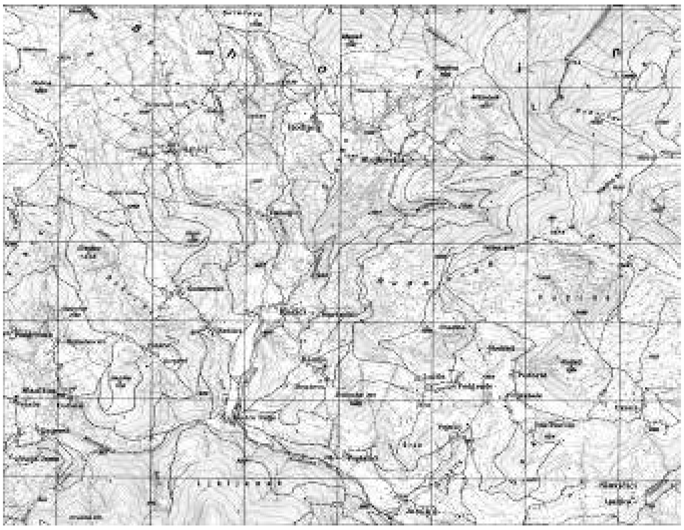

Figure 31: Map of area

8.2.2 Basic design - project

Basic parameters of the utilization of the water resource are determined in the first phase of project documentation preparation. To obtain a concession, as the first actual step towards realization of small hydro power plant construction project, it is necessary to submit adequate technical - investment documentation to the responsible authority that issues the concession. In Bosnia and Herzegovina that documentation is next step in project design called the Basic design,.

Similarly as for Feasibility Study, the integral parts of Basic design are as follows:

- processing or preparation of geodetic and geological data,
- processing or preparation of hydrological data,
- hydropower capacities and utilization.

Data about geodetic and geological characteristics of the terrain obtained from the feasibility study together with submitting other topographic information from cartography are processed for the more detailed in preparation of the Basic design. Topography maps at scales of 1:25000 or more precise up to 1:5000 are used.

Moreover, for this level of designing more precise technical-economic evaluation is made, which implies defining the scope of works, materials and time of equipment. Error degree for this phase of designing varies from ±20-25%.

Except for submitting the application for concession, Basic design also serves for submitting applications for issuing all permits necessary before start of construction.

8.2.3 Main project

Time that is needed for issuing of all necessary permits usually can be used for preparation of Main project. This is technical-investment documentation on which the issuing of the construction permit as the prerequisite for performing of construction works itself is based.

In preparation of this documentation it is necessary to process separately the above mentioned integrities as it is done in previous levels of documentation.

During preparation of this documentation it is recommendable to perform geological investigations at the site of construction of the water-intake building, powerhouse and parts of pressure pipeline route, where a justified doubt that satisfactory information could not be obtained visually exists. Quantities of material, dimensions of construction grips with all necessary parameters are led to the level of precision of ±5%.

Regarding electrical-mechanical equipment, it is necessary to give principal solution of the powerhouse, while real dimensions and resulting quantities of materials and works will be known after tender announcement and selection of the electrical-mechanical equipment. Since each manufacturer of turbines can offer a little bit different technical solution (it is left to their construction freedom), it can be a reason why real quantities of materials and works could be determined just after process of selection of turbine manufacturer and turbine's attached equipment.

Tender documentation is prepared on the basis of this documentation and therefore this documentation has to be clear and precise.

For dimensioning of pressure pipeline of that turbine which is the base for dimensioning of all other electrical-mechanical equipment it is necessary to carry out a detail analysis of hydrological data.

For that purpose in this phase of designing it is necessary to have also the measurement results of the flow at the site of the water-intake building for period of at least one year, so that curve of flow lasting could be determined. The average annual flow is determined on the basis of this curve and the installed flow is adopted on the basis of different analyses. The installed turbine power is determined on the basis of this data and annual power plant output is determined on the basis of the lasting curve. This data together with data about total cost of construction part of the project serves for calculation of technical-economic cost effectiveness of the project.

Of course, the input parameters used for dimensioning of some (main) parts of the power plant - the turbine pressure pipelines with the attached equipment - are more precise if measurements on location of partition profile were done for period of few years. Therefore, if there is no data about measurements, the Investor is recommended to invest money in setting up devices for flow measuring and to perform observing as long as possible. This is possible to be done at the time immediately before preparation of Feasibility Study and then to the preparation of Main project. In normal conditions, it is period of at least one year and a half. Money invested in these measurements is negligible comparing with the total investment, but the effects of the measurements have huge consequences for technical-economic cost effectiveness of the project.

Level of documentation for hydro-mechanical equipment goes to the workshop drawings so that a Bidder for this part of equipment has clearly defined data and parameters.

Figure 32: Map of area with SHPP-s

8.3 Tender announcement and selection of constructors, suppliers and assemblers of equipment

After preparation of the Main project, the following step is its revision. For this task are chosen experienced experts that beside theoretical knowledge above all have practical knowledge in certain fields. The meaning of the revision is to point out possible mistakes in project before approaching to the preparation of tender documents.

Preparation of tender documents is approached after correction of eventual mistakes noticed during revision procedure. This level of documentation in construction part of the project presents shortened version, in which basic features of the project with precisely defined priced bill of quantities are emphasized. Priced bill of quantities has preciseness of ±5%.

In respect of equipment, the level of this documentation reaches event to the workshop drawings so that the Bidder of equipment could have clear image.

In respect of documentation for preparation, delivery and erection of the electric-mechanical equipment, that documentation is on the level necessary for Bidder to have basic data starting from overgrow hydrology to the proposal of actual technical solution. However, each Bidder is left freedom also to offer different solution based on its experience as well as new technical knowledge and achievements.

The evaluation of bids is approached after announcement of tender and collection of bids. The period between announcement of tender and collection of bids should be reasonable. The Investor is recommended that during evaluation of bids engage experts outside of the company. It is usually necessary since very often is applied approach for realization of construction of only one small hydro power plant, so that Investor who can be only one person and not necessarily the company, does not have own expert staff. After clarification of bids, which is in principle necessary, because there are always some questions that should be clarified, two or three bidders are selected, and the next phase is approach into the direct negotiations. The most favorable bidders are selected after negotiations and eventual harmonization of details. Harmonizing contract details includes more precise defining of conditions, deadlines, and financial obligations. After this phase, each of possible contractors approaches to the phase of the realization preparation.

For good performing of works, first of all construction part, it is necessary to perform preparation of works which implies site organization. For that purpose is necessary to prepare the site, necessary machinery and to provide and accommodate the manpower. This is more essential part in terms of construction of more small hydro power plants at one location, which was already the case in Bosnia and Herzegovina. The reason is that concession is awarded for a water flow. It implies construction of two or more small hydro power plants by one or even more concessionaires.

Beside the Contractor, the Investor also has to perform certain preparations regardless of one person or company. The personnel who shall perform supervision on performing of construction works, delivery and erection of equipment as well as supervision on commissioning of small hydro power plant shall be appointed.

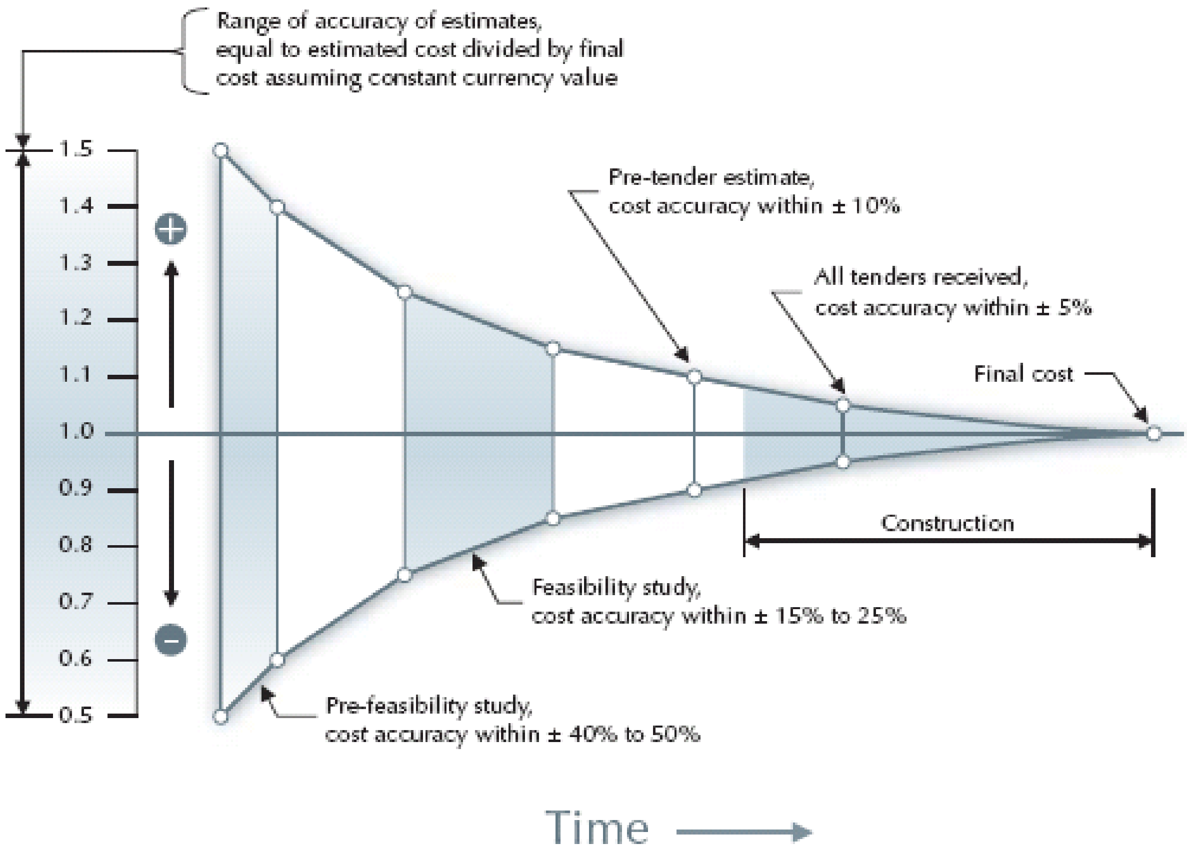

Figure 33: Accuracy of project cost estimates vs. actual costs

8.4 Performing of works during construction of a small hydro power plant

If the Investor wants to have successful realization of the project then they must engage own personnel or skilled personnel outside of their company. These personnel will be responsible for follow up of project realization.

Main task of the team for supervision of construction works performing is follow up of compliance between site works and project documentation. It includes supervision of quality, quantities, and deadlines. Supervisors are obliged to warn the contractor and inform the investor if significant deviation between above mentioned and designed parameters is noticed. This is of course the case if there are unusual deviations that are normal in practice.

Very often cases in practice are also the problems not foreseen in designing phase. In that case it is necessary to coordinate investor, designer and contractor in order to find the solution.

The most common reasons from practice that cause the significant problems are:

- bad estimation/defined terrain geology,
- unpredictable natural occurrences, such as floods, landslides, etc.

Regarding equipment manufacturing in the early manufacturing stage, the most important is to establish that manufacturer respects all conditions of the project documentation, and it first includes:

- fulfillment of technical condition during preparation (certificates of input materials, certificate of the skilled personnel such as welders, performance plans…)
- fulfillment of norms and standards during equipment manufacturing,
- satisfaction of assigned quality parameters from the documentation.

Supervision of quality of the installed material and equipment is permanently done during performing of construction works. E.g. quality of the built concrete is done by taking samples (cube 15x15 cm) and analyses of these samples. Quality control for load of bedding where the pipeline is put down or loading of material around the pipeline after installation is done by measurement of loading with dynamic plate or some other acceptable method. This process is for example done at each 50-100 m of the pipeline route and it is defined by the contract. Results of the above mentioned investigation make an integral part of documentation delivered by contractor when the works are finished.

If some measurements determine that quality of finished works are not good, then it is necessary to take measures for troubleshooting.

After completion of each phase in project realization, representatives of the investor and contractor together conduct test. The aim is again to check performances of the completed work.

For that purpose, for example, pressure test of the pipeline is performed, such as:

- static pressure test and
- dynamic pressure test.

Static test aims to prove that pipeline charged with water has no leakage while dynamic test aims to prove performances of the pipeline in case of the impetuous closing of the pre-turbine valve creating so called recurrent wave in the pipeline which causes appearance of dynamic pressure that is 1,5 times higher than static pressure.

Certainly, before performing of this test it is necessary that basic electrical-mechanical equipment – turbine with the attached mechanical equipment – is assembled. The erection of all electrical-mechanical equipment has to be done under permanent supervision afterward follows the final testing.

Organization of an internal commission for technical check can be approached only after testing of each phase or some works as well as after erection and testing of equipment (this is a task for investor, contractor and supplier and assembler of equipment). Task of this commission is to check again correctness of complete plant and to approve commissioning of trial run of the plant.

Special parameters are observing during the trial run that normally can last from 1 to 6 months depending on results obtained in that period. Those parameters are:

- behavior of basic elements of the plant,
- realization of legal liabilities regarding respect of ecology conditions.

Characteristics that are observed during trial run, but also later during so called commercial operation are the following:

- realization of power of the unit and at the power plant threshold,
- temperatures of all bearings (on turbine, generator, …).

9 REGULATORY AND LEGISLATIVE ISSUES OF sHPP PROJECTS IN MACEDONIA

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9.1 Introduction

Macedonia is a mountainous country with 80 % of the entire territory in mountainous regions. Two percent of the land area is covered by water and the country's 35 rivers, three natural and 50 artificial lakes comprise Macedonia's hydro potential.

The total theoretically exploitable annual energy potential of all rivers is 6,434 GWh. However only 1,370 GWh (22%) of that potential is currently used.

According to the 2003 Annual Report of Electric Power Company of Macedonia-ESM, the total installed energy capacity in Macedonia is 1,444 MW of which 434 MW (some 30 %) produced by HPP, as presented in Figure 34.

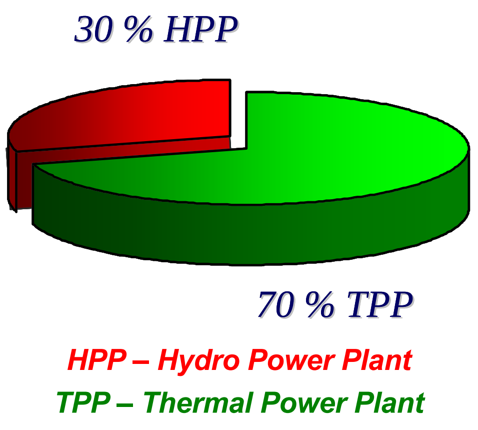

Figure 34: The structure of total installed energy capacity in Macedonia

Figure 35: Existing sHPP in Macedonia

Figure 35 displays the 21 sHPP that represent 35.8 MW installed hydro energy capacity.

In 2003 the total consumption of energy was 7,225.6 GWh of which 953 GWh were imported from neighboring countries. Because the energy consumption is growing every year it is very obvious that Macedonia needs to build new energy capacity to reduce imported energy quantity. Investments in this domain are encouraged.

The basin of the Vardar river is the biggest in the country and has an annual energy potential of 5,193 GWh. Locations of thirteen HPPs that are planned for the Vardar valley are presented in Figure 36. The object of the expansion is to use the entire potential of the Vardar river basin. For these plants, feasibility studies have been completed.

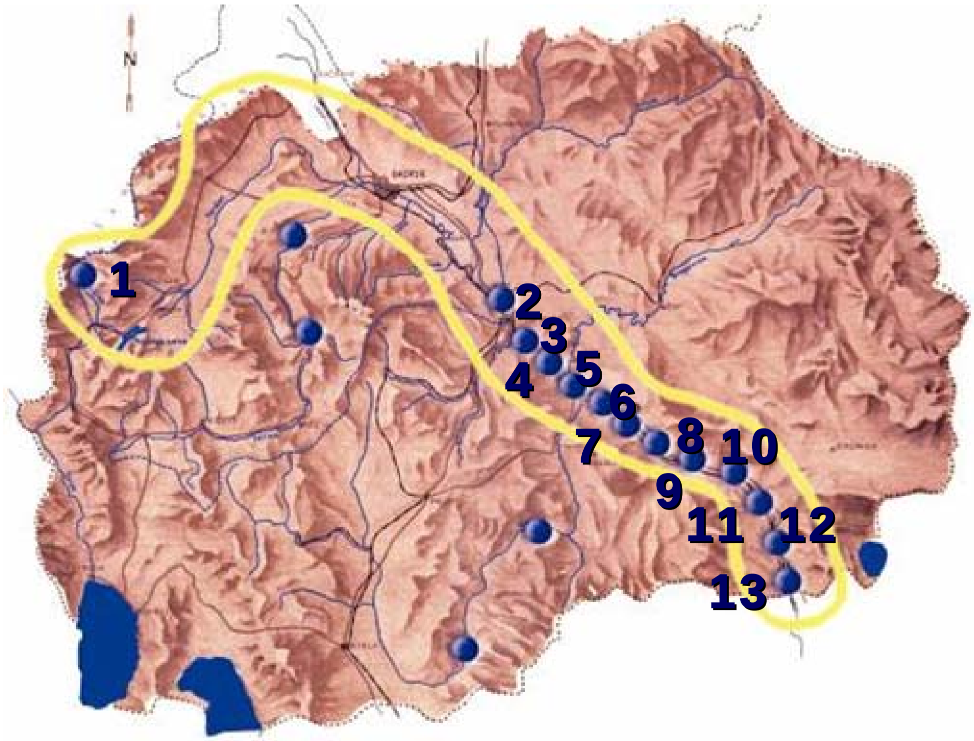

Figure 36: Locations of 13 sHPP planed in Vardar Valley

Another 29 investment projects for sHPP are planned for several locations presented in Figure 37 with different levels of technical documentation (from preliminary assessment to feasibility study). The total planed energy capacity of all of them is 100 MW.

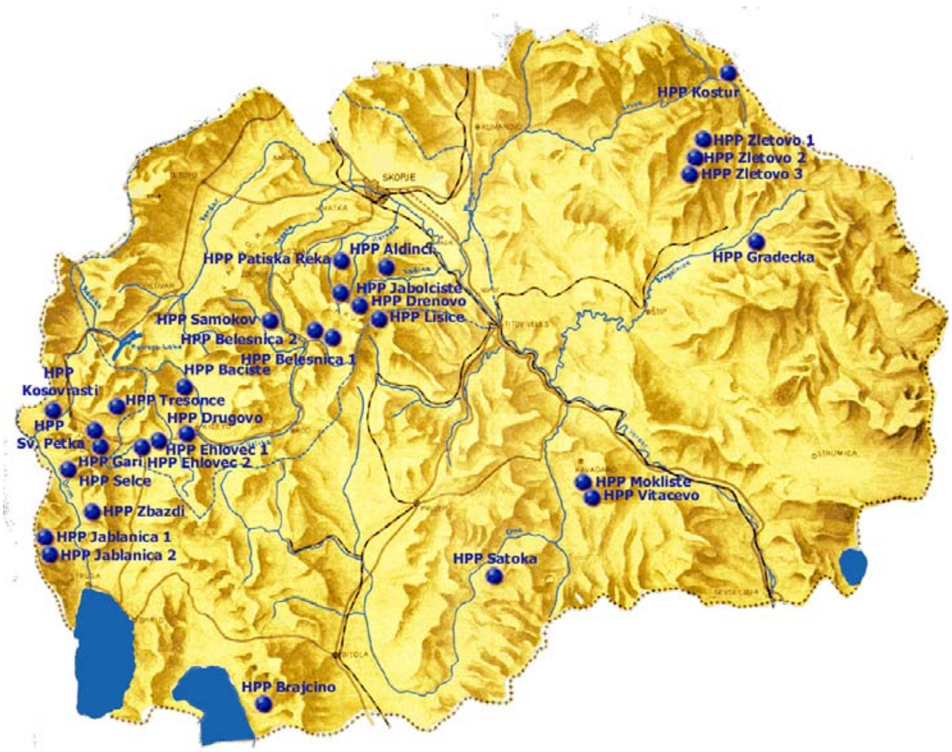

Figure 37: The locations of 29 planned sHPPs in Macedonia (excluding plants in the Vardar Valley)

Macedonia has the first concession project, a project named ROT, for Rehabilitation, Operation and Transfer of 7 existing Small HPP's: HPP Dosnica, HPP Kalimanci, HPP Matka, HPP Pena, HPP Pesocani, HPP Sapuncica and HPP Zrnovci. The concession has been granted to MAKHIDRO for:

- Total investments 20 mil EUR
- Total capacity 30 MW
- Total generation 86 GWh
- Period of concession 11 years

9.2 Attracting Foreign and Private Investors

Macedonia is a poor country in transition and there is no financing of RES installations by the state. Foreign and private investments are needed for realization of sHPP projects. What should foreign investors know about possibility to build and exploit sHPP in Macedonia? Are we prepared for such kind of investments?

Until now all necessary legislation documents are in place:

1. Energy Law (Official Gazette of RM No.47/1997) and Law for modification and amendment of the Energy Law (Official Gazette of RM No.40/1999, No.98/2000, No.38/2002, No.38/2003 and No.40/2005)

2. Law on water (Official Gazette of RM No.4/1998) and Law for modification and amendment of the Law on waters (Official Gazette of RM No.42/2005)
3. Law on concessions (Official Gazette of RM No.25/2002) and Law for modification and amendment of the Law on concessions (Official Gazette of RM No.24/2003)
4. Law on terrain and urban planning (Official Gazette of RM No.51/2005)
5. Law on construction (Official Gazette of RM No.51/2005)
6. Law on environment (Official Gazette of RM No.53/2005)
7. Ordinance regulating conditions, manner and the procedure for issuing, changing and canceling licenses for generating electric power (Official Gazette of RM No.42/2005)
8. Ordinance regulating procedure for acquiring electric-energy approval for connection to the electric power system (Official Gazette of RM No.38/1998) and modifications to the Ordinance (Official Gazette of RM No.78/1998)
9. Ordinance regulating conditions and procedures for electricity price adjustment (Official Gazette of RM No.95/2004 and modification from 2005)
10. Decree on general conditions for the supply of electric energy (Official Gazette of RM No.6/2001)

A paper “Guide for realization of sHPP in Macedonia” prepared by Macedonian Energy Association and issued in October 2005 by Economic Chamber of R. Macedonia, includes all of the above mentioned legislation documents. The paper deals with the key components for project development of sHPP with installed capacity up to 10 MW: plan, location, cost and financing permissions, building interconnection, exploration, maintain and development. About 400 new locations were selected with about 200 MW projected installed capacity and are included in the guide. Project documentation at different levels of detail exists for almost 100 of the potential new small hydro power plants.

The Guide presents the procedure of issuing all permits needed for sHPP realization from 5 national bodies in Macedonia (Ministry of transport and communication, Ministry of agriculture, forestry and water supply, Energy regulatory commission of Macedonia, MEPSO - Macedonian electric power transmission system operator, ESM - Power Distribution Company):

1. Application for urban location of the sHPP to Ministry of transport and communication according Law on terrain and urban planning (Articles 52 and 54, Official Gazette of the RM No.51/2005)
2. Application and issuing permit for concession to Ministry of agriculture, forestry and water supply according Law for modification and amendment of the Law on waters (Article 155, 155b and 156, Official Gazette of the RM No.42/2005). The longest time of concession of using water is:

- o for HPP with installed power lower than 2MW is up to 30 years,
- o for HPP with installed power from 2MW to 10MW is up to 50 years.

3. Application and issuing permit to use the water to Ministry of agriculture, forestry and water supply according Law on waters (Article 31, 32, 35 and 36, Official Gazette of the RM No.4/1998). The conditions and time of using water are regulated with this permit.
4. Application and issuing license for generating electricity to Energy regulatory commission of Macedonia (established in 2002 with Energy Law) according the Law for modification and amendment of the Energy Law (Article 9, Official Gazette of the RM No.40/2005) and Ordinance regulating conditions, manner and the procedure for issuing, changing and canceling licenses for generating electric power (Article 9 and 10, Official Gazette of the RM No.47/2005). License is not applicable when production of electric energy is for individual use, when electric power distribution network is not used.
5. Application for the price of electric energy to Energy regulatory commission of Macedonia according Ordinance regulating conditions and procedures for electricity price adjustment (Article 40, Official Gazette of the RM No.95/2004 and amendment 2005).
6. Application and issuing permit for construction and use of sHPP to Ministry of transport and communication according Law on constructing (Articles 52, 53, 74 and 75, Official Gazette of the RM No.51/2005). For HPP with installed power lower than 2MW the local authorities are issuing this permit.
7. Application and issuing permit for connection to the energy power network to MEPSO according Decree on general conditions for the supply of electric energy (Article 4, Official Gazette of the RM No.6/2001) and Ordinance regulating procedure for acquiring electric-energy approval for connection to the electric power system (Article 18, Official Gazette of the RM No.38/1998 and No.78/1999).
8. The producer signs an Electric power purchase agreement with MEPSO.

9.3 New Energy Law

The Republic of Macedonia has ratified the Energy Charter Treaty and the Protocol of Energy Efficiency with related ecological aspects in September 1998. In the process of joining the EU, Macedonia will accept EU Directives for environmental protection and renewable sources of electric energy (“green energy”). Nowadays the appropriate legislative framework based on the best EU practice is designed through the new Energy Law.

In January 2006 the Draft Energy Law entered the procedure in the Parliament of R. Macedonia and the first discussions were in March 2006. In the law the part of

Directive 2001/77/EC for promotion of RES is implemented. Its fifth goal is to increase the use of RES. Chapter X is dealing with establishing the Energy Agency of R. Macedonia and its responsibilities. The Agency, together with the Ministry of Economy, will prepare a Strategy for use of RES for a period of 10 years and a Realization Program for the strategy for 5 years. The subchapter X.2 deals with goals of the strategy.

The strategy will define the potential of RES in Macedonia and the possibility to use it, the amount and dynamics of RES in the total energy balance, Green Certificates for Qualified electricity producers and the establishment of a market for the Certificates and finally the measures for subvention of qualified electricity producers will be established. The issue of Green Certificates will be implemented with the new Energy Law for production of electric energy from RES in MWh. All electric energy suppliers will be required to bye or to produce a certain amount of renewable energy and Green Certificates. The Energy Agency of R. Macedonia will be the issuer of Green Certificates.

9.4 Conclusion

It is very easy to conclude that in this moment sufficient legislative supports for starting with sHPP projects realization in Macedonia is available. The expected new Energy Law will complete bodies, regulations and supporting documents for RES as Energy Agency, Green certificates etc.

9.5 References

[40] Macedonian Energy Association: Guide for realization of sHPP in Macedonia, Economic Chamber of R. Macedonia, Skopje, 2005

[41] Official Gazette of the RM No.47/1997, No.4/1998, No.38/1998, No.78/1998, No.40/1999, No.98/2000, No.6/2001, No.25/2002, No.38/2002, No.24/2003, No.38/2003, No.95/2004, No.40/2005, No.42/2005, No.51/2005, No.53/2005, No.42/2005

10 PROJECT PREPARATION: Case of CHP

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10.1 Introduction

The whole region of South Eastern Europe is depending on imported fossil fuels. This is a heavy burden for national budget and economy and any increase of use of domestic energy sources will have a positive economic impact. Combined heat and power generation is well-established technology in EU and candidate countries. The share of CHP in total domestic power production ranges between 50 % for Denmark and 6 % for UK. (For Austria this share is approximately 27 %, for Czech Republic 19 %, Slovak Republic 13 %, Bulgaria 11.3%, and Poland 8.3 %). CHP applications can be roughly categorised as large-scale (>50 MW_e) in large public district heating systems and industry, medium-scale plants (5-50 MW_e) in municipal district heating systems, industry and large building complexes, and small-scale applications (5 kW_e-5 MW_e) primarily in small district heating systems, small industries, and commercial sector.

The importance of CHP is increasing, because the electricity consumption is escalating everywhere in Europe but the available production methods are restricted. New nuclear capacity may be expected but a number of existing ones are going to be retired during the years to come. Most economic hydro power resources are already developed and many among the remaining will stay undeveloped for environmental reasons. Use of renewable energy sources, windmills, bio fuel and solar power, are expanding in many countries, but are not sufficient to cover the increasing necessity. Using renewable fuels, however, CHP/DH offers the most efficient way to proceed. In addition, solar heating and waste heat can preferentially be integrated in such systems and DH initiates efficient integration of combined generation of heating and cooling services in a CHP system.

10.2 Stages of the project preparation

The important stage of the project development process is in the beginning the project preparation, which consists of detailed assessment of the site with respect to the following points:

- CHP operation mode
- CHP technology
- CHP capacity
- CHP costs
- CHP financing

To determine the best option for utilisation of CHP on a concrete site, it is first of all necessary to determine the desired effect of the CHP operation on the base of techno-economic analysis. The techno-economic analysis consists of two levels, first being a Preliminary Feasibility Study. This contains several variants of CHP deployment divided in accordance with possible modes of operation and the technology used.

The pre-feasibility study includes the basic technical, economic and environmental performance indicators enabling comparison between individual variants. It is presented to the client, who makes a decision on the preferred variant. This variant is then considered in detail in frame of a Feasibility Study, which allows estimating the investment costs of CHP. Consequently, after the gross amount of investment is revealed, the next step presents the raising of finance by reviewing available financing options and a business plan is developed.

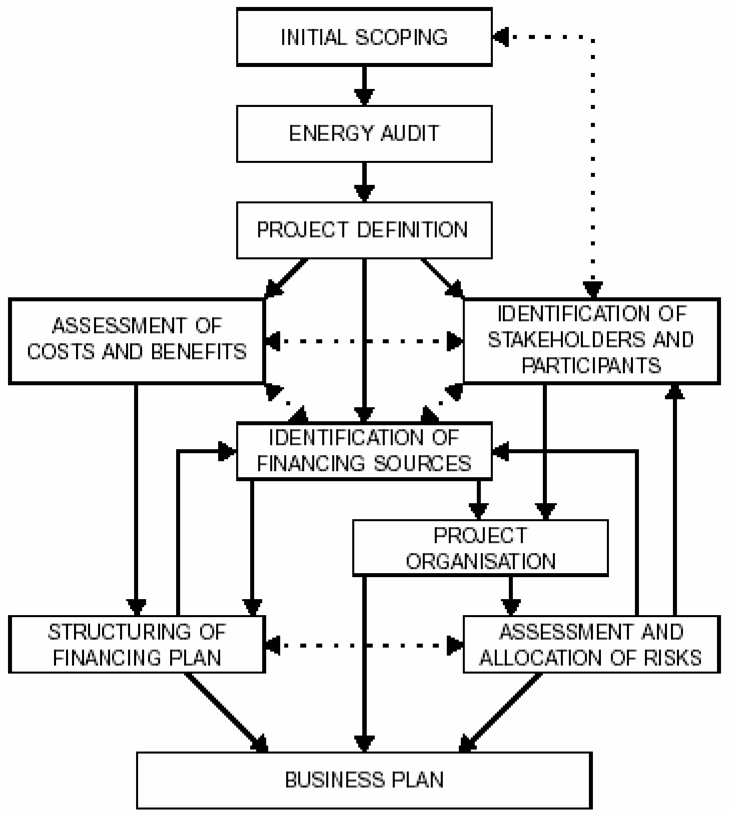

Figure 38: Steps involved in developing project proposal

10.3 Preliminary Feasibility Study

Based on the results of the Scoping Audit, upon identifying facility goals and objectives, the project development process continues with elaboration of a Preliminary Feasibility Study. During this phase, the CHP project developer continues to review the site and to collect detailed information on the energy usage. The economic success of a CHP project depends on the level and reliability of data available:

- Data based on annual volumes provide generally the information, whether the CHP plant is suitable for the prospective investor or whether the classic solution of energy supplies is to be chosen.
- Data based on monthly figures such as the annual heat load curve enable a preliminary sizing of CHP and give a good estimation on whether the plant would eventually meet the client's expectations in terms of investment pay back periods.
- Knowledge of the client's operations enables to determine the effective amount of time the energy supplies are required and provides hence the minimum level of data needed for elaboration of a Pre-feasibility Study.

- Daily and weekly data on energy demand enable to model possible supply diagrams for heat and power from CHP and hence, to define the position of CHP towards the operators of energy networks.
- The assessments of interaction with external players, evaluation of environmental performance, as well as a preliminary financing plan provide the basis for a CHP feasibility study.
- Data on the parameters of energy consumed enable to define the suitable technology.

Before any consideration of CHP is made, potential changes in energy requirements must be checked. Energy saving measures, demand-side management, or changes in processes can not only be cost-effective as stand alone measures but their impact is of high importance with respect to the type, size and economics of the CHP system.

Basically, when proposing the variants, the following factors should be taken into consideration:

- operation mode of the system (i.e. operating electrical and thermal power at any instant of time);
- suitability of the individual type of CHP technology to provide the requested quantity and quality of energy, which is the determining factor for technology selection;
- plant configuration, i.e. number of prime movers and nominal power of each one;
- heat recovery equipment;
- need of thermal storage;
- interconnection with the grid (one-way, two-way, no connection at all).

Furthermore, the availability of heat may lead to investigation of the feasibility of absorption cooling, which will affect the base thermal load and consequently the design of the system.

There should be provided a complete coverage of the electrical and thermal loads at any instant of time with no connection to the grid. This mode requires the system to have reserve electrical and thermal capacity, so that in case a unit is out of service for any reason, the remaining units are capable of covering the electrical and thermal load. This is the most expensive strategy, at least from the point of view of initial cost of the system.

The pre-feasibility study should enable view on energy and economic performance for different configurations of CHP systems (number of units, capacity of each unit, heat recovery equipment, etc.).

10.4 Financial analysis

For the individual variants a shortened financial analysis is to be performed, which provides basic indicators of economic performance. Some of the commonly used financial criteria are as follows:

- Simple payback period
- Return on investment
- Internal rate of return
- Life-cycle cost

This is not a cost-benefit analysis, which should have been performed when the detailed definition of the project was drawn up. The activity described here is merely a listing of all the various costs associated with the project and, most importantly, when they will incur. The purpose of doing this is to be able to make informed decisions regarding sources of finance, which must be appropriately matched to the schedule of expenditure.

Simple payback period refers to the time it takes to repay the installed cost/investment for that CHP by the annual savings, expected to be accrued, by its use. Therefore, when choosing between a conventional and a CHP system, one needs to estimate the incremental installed investment for the CHP system and annual operating cost savings expected to be achieved by it over that for a conventional system. Simple payback period is calculated by dividing the investment with the annual projected operating cost savings.

Life-cycle cost (LCC) of a system is the present value (PV) of all the costs associated with the project over its useful life. Calculations for LCC require the following information:

- Installed equipment cost
- Annual operating costs
- Expected duration of operation
- Discount rate
- Energy cost escalation

Installed equipment and annual operating costs (energy costs plus maintenance costs) have been discussed earlier in the section on economic analysis. When calculating LCCs for various alternatives, it is important to compare these costs over the same period of useful life. If one system has a useful life of 20 years and the other has a useful life of 10 years, the cost of replacing (replacement cost) the second system should also be included in the LCC for that system. Present value functions are available in all major spreadsheet programs.

Even though the initial cost of CHP systems is higher than purchasing all electric power needs and using conventional chillers and boilers for cooling, humidity control and heating needs, the life-cycle cost of the CHP systems is often lower because of the energy cost savings over its useful life of more than 20 years.

The deliverable for this phase is a report containing the main parameters enabling comparison and assessment for several variants of CHP. The individual variants differ in installed capacity, which results from the envisaged modes of operation.

Based on the results, the client can make a decision on which of the examined systems is the most appropriate for their specific needs. The selection of the optimal CHP system should be based on criteria specified by the investors, the future user of the system, considering economic performance, energy efficiency, uninterrupted operation or other performance measures. Any decisions should also take into consideration legal and regulatory requirements, which may impose limits on design and operation parameters such as noise level, emission of pollutants, total operating efficiency.

10.5 Detailed Feasibility Study

The main task of the Detailed Feasibility Study is to closely examine the feasibility of the variant selected by the client in the previous stage – hence to model the CHP plant performance under the specific conditions at the client's site on as detailed level as possible.

This includes modelling of the CHP operation on base of daily and sometimes even hourly load profiles and further refinement of the economic analysis by means of using the actual tariffs related to the site during the specific operation times of the day. There are available specific tools for such refined modelling, such as e.g. the Cogen Master, which can be obtained from Cogen Europe, www.cogen.com.

This technical economic analysis refines the estimation on the suitable capacity and consequently the available specific CHP technologies offered by different manufacturers and suppliers are examined. The basic characteristics of the offered products enable to select those, which are approximately matching the requirements set by the optimum solution. On this base, the investment costs can be estimated with a higher level of preciseness (not by means of the indication values, such as e.g. specific investment costs per kW of installed capacity, but rather by obtaining costs of CHP units of the preferred type from suppliers). Further, the costs of connection to existing networks (fuel, power, water) and side-line devices and the respective investment costs are estimated as well.

When assessing the operation costs and benefits, it is a good practice to perform sensitivity analysis with respect to the development of the outside parameters, such as energy and fuel prices, as well as with regard to changes in the demand on site.

The main reason for performing the analysis is to define the parameters with respect to which the optimal solution is very sensitive. If such parameters exist, a change in the corresponding system features could be examined and proper risk management measures can be taken.

Second reason is to identify possible modifications, which could improve the overall performance of the system, such as e.g. information can be obtained on whether increasing the capacity or introducing energy storage could be advisable.

Third reason for performing the analysis is to reveal the effect of imprecisely known parameters on the optimal solution. Some parameters, such as energy prices, may have a considerable uncertainty.

The information obtained in this way is often so important, that the sensitivity analysis may prove to be equally or even more valuable than the optimal solution itself.

10.5.1 Risk Management

As the next point, the Detailed Feasibility Study should reveal the potential risks and the way in which these can be neglected. The information for this part is based on the Energy Charter application manual "Financing Energy Efficiency", www.encharter.org.

Risk management presents one of the key issues in developing any energy project and involves identifying risks, minimising these risks where possible, and then ensuring that any remaining risks are allocated to those best equipped to handle them. If the current allocation of risks in a project is unsatisfactory, the project developer should consider whether it would be possible to improve the situation by introducing new participants - for example, an insurance company, or an additional equity investor. The three main categories of risk for CHP projects are:

- project implementation risks - the risks of obtaining consents, permits, and other agreements necessary for financial closure;
- technical risks: construction delays, cost overruns, higher-than-expected costs and lower-than-expected production or savings;
- project environment risks that arise from the economic and regulatory or legal factors that together constitute the project environment in which development, construction and operation occurs.

First of all, the implementation risks have to be addressed. This is especially through for a project involving foreign partners, consents might be needed in order for them to have a legal standing to implement, operate, and earn revenues from an energy efficiency project. Depending on local laws, consents may be needed from both central and local governments.

Energy efficiency projects present few difficulties in general and sponsors may face few permission risks other than a license to do business in a country. Permits may be needed for land use, construction of plants, buildings and roads, water supply and waste disposal. Therefore the study should list all additionally needed documents and formal requirements and show how they will be dealt with in frame or the project team, which is to be assigned in further stage of the project. CHP schemes are subject to technical risk during the construction phase and the operation phase of a project. The risks include construction delays, cost overruns during the development or construction phase, sub-optimal performance, higher-than-expected operating costs and changes of energy prices.

The biggest risk facing CHP projects during their operating phase is that the cash benefits are smaller than expected. The technologies employed for a project can have a substantial impact on whether or not the client perceives a project to be risky. In general, proven technologies minimise project risks because their performance is well-documented. Technically-sound project development can reduce risks by reducing the possibility and size of possible losses.

Traditional risk management mechanisms include warranties, turnkey contracts, commercial insurance, letters of credit, and funds for operations and maintenance. Non-traditional mechanisms include special insurance funds and reserve funds. The risk of energy price fluctuations can be hedged by involving utilities in the project development and by contractual means, such as fuel supply contracts and power purchase agreements. However, regardless of the strength of a project's participants, equipment, and design there are always risks that project failures can impose losses. To further minimise client's exposure to risks, a number of risk management mechanisms can be employed that provide contractual and legally enforceable means.

With regard to the project environment risks, the most important issue presents the potentially diminishing market in case when CHP produces heat and electricity for delivery to consumers who present organisationally independent units with regard to the client. At this stage, the risk can be hedged by contractual means, such as long term power and/or heat purchase agreements. The regulatory, legal and political factors,, which determine the project environment, are either subject to the control of host country governments or largely uncontrollable.

The output of this stage of CHP project development is a report extending the Pre-Feasibility study to a document, which enables a definitive decision of the client whether to proceed to the CHP implementation or not. In case, the client decides in favour of the implementation, the data contained in the Detailed Feasibility Study constitute a first basis for evaluation of the project by financing institutions res. grant programmes.

10.6 Raising of Finance

After the client decides to go on with the project, the results from the Feasibility Study, namely the investment costs as well as evaluation of the future operation can be used as basis for the development of a financing structure for the respective project.

At the very beginning, the client has to decide on the allowable ratio of own financing, which in turn leads to defining the amount of finance to be raised.

The start presents the review of available options and selection of those, which are available with respect to the economic and legal standing of the client. Basically, there exists a wide range of options is available for financing CHP projects, including among others:

- Bank loan
- Leasing
- Supplier financing
- ESCOs
- Grants

Commercial banks provide loans to pay for some or all of the cost of installing a CHP system. Availability of this option depends on the credit history and financial statements of the borrower and the cash flow expected to be available to pay the loan amount and the interest on the loan. The borrower also has to be able to provide collateral that the bank will receive if the loan is not paid back. Typically, the loan is paid back by fixed payments (principal plus interest) every month over the period of the loan term, regardless of the actual project performance.

The client may also lease a CHP system. The lease payments may be bundled to include maintenance services, property taxes and insurance. There are many types of leases: capital equipment, operating and leveraged. The general characteristics of a capital lease are as follows:

- Appears on the balance sheet as debt for purchase
- Requires transfer of owner at the end of the lease
- Specifies the terms of future exchange of ownership
- Lease term is at least 75% of the equipment life
- Net present value of lease payments is about 90% of the equipment value

In supplier financing, the supplier of an integrated CHP system or a major component of the system provides the financing for a project. Suppliers could provide financing at attractive low costs to stimulate markets. Supplier financing is very common for energy technologies. Supplier financing is generally suitable for projects up to EUR 400,000.

Energy Savings Performance Contract is a contract in which an energy service company (ESCO) finances the whole project and refinances itself from the energy cost savings. This type of contract provides building owner the assurance of the CHP system performance. It mitigates the risks associated with new technologies for the building owners and allows operation and maintenance of the new system by the ESCO specialists.

Further interesting source of capital present grant schemes, usually launched to promote new technologies that produce overall benefit for the general public. These grants are generally awarded through competitive procurement. Some grants might also be available from environmental programmes and organisations. The grants affect positively the payback period for the projects and very often provide the finally deciding argument for implementing a project. The project developers should hence always try to check their availability for the respective project.

An example of a financing structure of a project is shown in Figure 39.

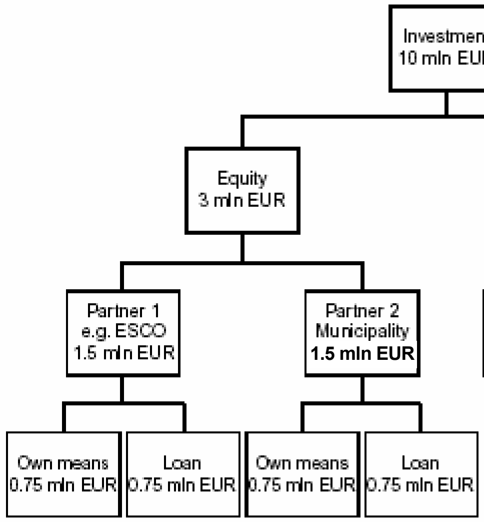

Figure 39: Financing structure – example

The clients prefer financing structures, which include long term low interest loans res. investment subsidy components, therefore the next step should be examination of concrete possibilities for low cost financing in direct contact with the potential financing sources.

10.7 The Business Plan

At this point, the project is to be presented in a transparent and understandable way to potential capital providers. For this reason, business plan is to be produced as the basis for negotiations with the financing institutions in securing the external finance.

A business plan contains the main results from the Feasibility study and provides further all other client and site specific information needed to convince the financing institutions. The business plan should therefore focus on the following areas:

- Client
  - the company
  - activities
  - management
- Project
  - Technical aspects of the project

- o Impact on environment
- o Risk Management
- o Financial Plan

A well structured and written business plan can ‘sell‘ even weaker projects, whereas a confusing business plan works in the contrary way, meaning that even excellent technical solution if presented in a confusing manner could end up with an find no resources. Table 8 presents the most important aspects of a properly structured business plan.

Table 8: The most important aspects of a properly structured business plan

Executive summary	• summary • conclusions
General Indicators	• general profile of the company • energy reduction or cost reduction • commitment of the sponsors to the project • entrepreneurial skills of company managers • preferably audited financial statements • legal and ownership structure of the company • organisational structure
Technical Indicators	• technological solution proposed • efficiency improvement to be achieved • acceptable construction and operation risk
Environmental Indicators	• reduced flue gas emissions • less waste by improved efficiency of the production process • reduced thermal emissions
Project Costs	• detailed investment table: planning, engineering, installation, equipment, management, taxes, customs, contingencies • local costs • foreign costs
Financial Indicators	• commercial and financial track record and prognoses • cost benefit effectiveness (IRR, NPV) • cash flow generating capacity • payback period • self-financing capacity • availability of collateral • flexibility (break-even analysis) • valuation principles • (financial) risk analysis

Note: a separate chapter on market conditions should be considered.

10.8 Conclusion

The CHP together with municipal DH and industrial heat demand has obvious benefits for the environment and the energy efficiency of the region, as recognised in the Green Paper of EU already. From a general social point of view the project is expected to stimulate local economy. However, the key success to the project is a very open and active involvement of the local authorities. In individual countries the energy and the environment authorities with municipalities and industrial companies are in the key position to bring the CHP related benefits available for the citizens. Finally, laying out a well structured, prepared project and written business plan is of crucial importance for obtaining financial resources and future final realization of the project.

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11 Decision Making Process at Geothermal Power Projects

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11.1 Abstract

During all stages of development of a geothermal power plant a series of decisions are necessary. They include early decisions during the exploration phase, such as where to go, how to refine further the plant location, where to drill the exploratory/ production wells, as well as deciding whether proceeding to the field development and plant construction deserves the effort in terms of technical and economical aspects. Establishing a kind of partnership with local community from the early stages of field development is also important. During field development a series of technical decisions should be made including defining power plant type and capacity, sitting production and reinjection wells, and locating surface installations. Managerial decisions such as whether to construct the plant by own resources and subcontracts or through BOT projects are also necessary. During plant operation, the overall organisation structure should be decided such as whether to have one company for both the geothermal field and plant operation or have separate companies. A series of technical decisions are also necessary, such as deciding on a monitoring and maintenance program.

11.2 Introduction

Geothermal power plant development projects include three main stages: exploration, plant development and field exploitation. Each one of them is unique and requires its own decisions at project level, which may be technical, financial or managerial. During the exploration phase the goal is to identify, locate, qualify and quantify the geothermal resources, with earth scientists playing a key role in the decision process, even though the final decision whether to proceed with the power plant construction, is usually taken by top level management. During the plant development stage, engineers play a key role to the decision making process, but the decisions on contractual issues are a responsibility of top level management. During the field exploitation and plant operation stage, engineers have again a key role, but the first decision on the overall organisational structure is a responsibility of top level management.

11.3 Exploration

11.3.1 Where to go at regional level: mapping geology and regional heat flow

The first decision associated with geothermal exploration is to define a target area, promising for geothermal power generation. This decision should be taken after evaluating the geology of the area seeking regions of recent volcanism, or basins with deep aquifers of high temperature suitable for geothermal power generation (e.g. >90°C). These areas are characterized by the presence of hydrothermaly altered rocks (volcanic environment) as well as thermal manifestations, which indicate the presence of deep high temperature fluids. These include warm or hot springs, fumaroles, hot or steaming ground and hydrothermal (phreatic) craters.

The target area for geothermal development may also be defined by measuring regional heat flow from the earth. Areas of high heat flow are associated with high temperature at shallow depth. There are a series of methods which can help to define heat flow. At regional level, these include earthquakes survey, airborne magnetic survey and airborne gamma ray survey. At local level they include flow and temperature measurements of thermal manifestations, as well as measuring local temperature gradient, by measuring temperature within shallow boreholes, or available deep wells.

11.3.2 What to find and where: Geochemical investigation

Geochemical investigation involves sampling of thermal manifestations. Geothermometers will indicate the expected temperature of the deeper geothermal fluids, while classification of surface waters to major geochemical categories may indicate the approximate location of the deeper fluids. Sampling soil near the surface may provide useful information on the location of deeper fluids, as soil concentration of volatile elements or substances such as mercury and ammonia, tends to increase on top of deeper hot fluids.

11.3.3 Where to drill: Geophysical imaging of subsurface formations

The aim of geophysical investigation is to further refine the area targeted for geothermal power generation, and define locations for drilling deep exploration wells, which will prove the existence of the exploitable geothermal resource and define its physical and chemical properties, which will determine the type of the geothermal power plant that should be constructed.

Geophysical investigation includes measuring local temperature gradient, as well as electric resistivity of the subsurface formations. The electric resistivity of the rocks depends on their temperature, fluid presence and its salinity, but mainly on the minerals they include. Rocks with low resistivity are associated with clay alteration, which tend to form the cap rock of deeper reservoirs in volcanic environments. The resistivity measuring methods used in the field are Schlumberger resistivity and Magnetotellutics (MT) with 1-D data inversion. The second has been established as the most popular method for subsurface imaging in geothermal areas due to its simplicity and the quality of information it provides.

Other geophysical methods that may also assist geothermal exploration are mapping the gravity field of the earth and locating the hypocentres of natural micro-earthquakes, which are associated with fracture permeability.

After mapping temperature gradients and obtaining an image of the subsurface formations and main fault zones, sitting of the first well is done in the most promising location. It is important to target a deep fault zone, as faults tend to bring fluids from depth and create fracture permeability. Surface geology can also provide useful information on the location of deep faults.

One excellent method to define deep faults is the reflection seismics survey. Reflection seismics provide imaging of subsurface structures, including deep fault zones. This is the main method used by Italian company ENEL for geothermal exploration down to 3-4 km depth.

11.3.4 Establishment of partnership with local community

Although geothermal energy is a renewable and friendly to the environment energy form, its large scale development is not entirely free from local environmental impact. The environmental impact of geothermal energy depends on practices of the geothermal contractor and on geothermal plant design. Related problems are associated with the chemistry of the geothermal fluids, which can be solved by reinjecting the liquid phase to the deep formations it originated from, and by proper plant design to eliminate the effect of non-condensable gases present in the steam. In any case, and especially during the early exploration phase, escape of steam or hot geothermal brine to the surface or air may be inevitable, which may cause limited localized damages to plants, or a characteristic smell of sulphur in the vicinity of the wells. Other impact may be the appearance of micro-earthquakes, which although not posing any threat at all to people and structures, they may worry local society. A few geothermal projects have been forced to a dead-end due to strong opposition from local community, associated with the above effects of geothermal development.

For the above reasons, in order to a-priori guarantee the success of a geothermal project, apart from providing compensations to agricultural property damaged by geothermal fluids, it is important to establish a kind of partnership with local population. This partnership may include seminars on geothermal energy, exchange of views and discussions with local people on their concerns related to geothermal development, maximizing employment of local people to the geothermal sites and plant, charities and other welfare activities, as well as assisting local community in improving local infrastructure (road works, port facilities, etc.). During subsequent stages of geothermal development this partnership should be extended to lead local development towards a geothermal community exploiting the availability of cheap energy supply. One or more geothermal wells may be dedicated for this purpose.

11.3.5 What is available: Exploration drilling

After the geological, geophysical and geochemical surveys have been completed and after a partnership with local community has been established, then exploration drilling can start. The best location derived from the integration of research date collected until now will be chosen as the site of the first well. The drilling target is defined by geological and geophysical information. Usually a deep fault zone is targeted, or a formation with expected high permeability. The aim of the first well is to prove the existence of the deep geothermal resource, bring the geothermal fluids to the surface and define their physical and chemical properties. During well drilling a series of loggings and pressure tests are performed in order to define the formation properties. Once the target deep zone has been reached, then a production test is performed in order to estimate permeability, and take fluid samples in the surface. Based on the results of the production test, decision is made whether to drill deeper, or not. After the completion of the first well, a long production test is performed in order to define reservoir properties and ability to deliver fluids and define the precise physical properties and chemistry of the produced geothermal fluids.

Once the first exploration well has been successful, the geothermal resource is considered proven. Additional exploration wells may be planned in order to define the extent of the geothermal resource. The geophysical/geochemical data usually define provisional boundaries of the geothermal exploitable zone, and exploratory drilling should target these boundaries in order to investigate them. The number of exploratory wells to be drilled depends on the allocated budget for exploration purposes. The result of the exploration drilling should be estimation of the possible geothermal reserves in terms of MWe of installed power and the expected properties of the fluid in terms of temperature, scaling and corrosion tendency.

11.3.6 Does it deserve the effort: Feasibility Study

After the end of the exploration phase, a key decision should be taken whether to proceed with the development of the power plant or not. For this purpose a technical and economical feasibility study should be prepared. The aim of the study should be to evaluate the technical feasibility of constructing and operating a geothermal power plant, and estimate the expected financial performance of the corresponding investment.

11.4 Plant Development

11.4.1 Size of Plant

The provisional size of plant is defined depending on the electricity needs, available finances and amount of probable resources delineated during the exploration phase.

11.4.2 Production wells

Well sitting and specifications (depth, hole-diameters, casing string) are based on the results of the exploration works. A thorough well testing program is necessary to identify well production characteristics and reservoir properties. The number of production wells depends upon the necessary geothermal fluid mass flow rate output, and on the need to identify enough proven resources. A reservoir engineering study is performed to predict well output behaviour during long term exploitation. The plant size is finalized after the completion of all production wells.

11.4.3 Reinjection wells

Well sitting and specifications is again based on the results of the exploration phase, taking also into consideration new information acquired from subsequent well drilling and testing. Well testing involving injection tests, interference tests and tracers is performed to further define reservoir properties. The reservoir engineering study is updated with the new data.

11.4.4 Type of Plant

Depending upon the available temperature, two main types of geothermal plants are used: ***steam condensing plants*** and ***binary plants***. Steam condensing plants require geothermal water of temperature higher than 150°C. Depending on geothermal fluid temperature and pressure, they can be designed as ***dry steam***, ***single flash*** or ***double flash***. Geothermal binary plants can use water of at least 80-100°C. They tend to have higher efficiency than steam condensing plants at temperatures up to 180°C.

Binary plants use either water or air as cooling fluid. ***Hybrid plants*** combining a steam condensing plant with binary units are also used, aiming in dealing with environmental issues and improving overall energy efficiency.

Depending on which plant type is selected, different equipment is necessary. Main configurations are presented in Figure 40.

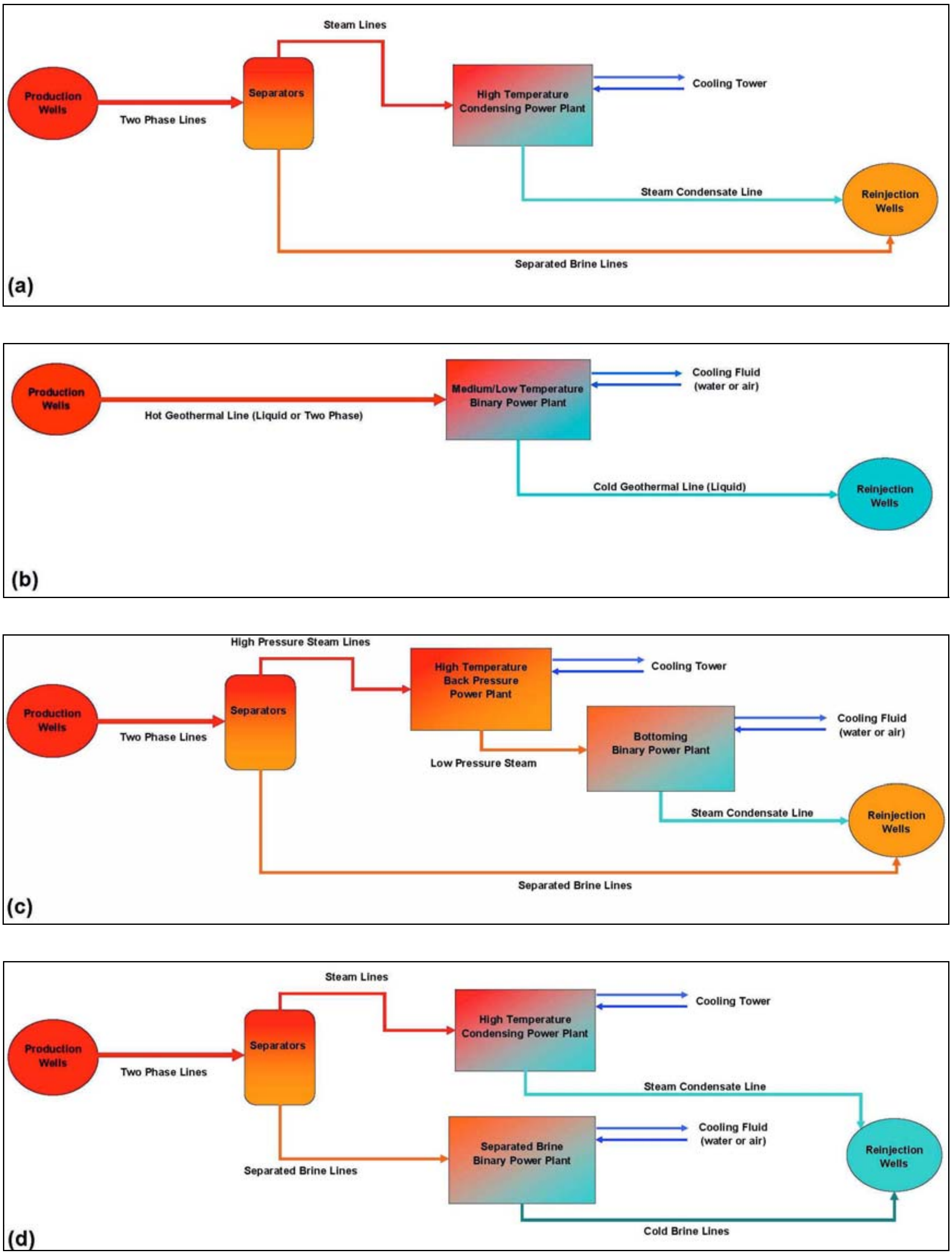

Figure 40: General layout of geothermal power plants: (a) condensing, (b) binary, (c) hybrid with binary bottoming units, (d) hybrid with binary units at the separated brine.

Table 9: Major equipment items of geothermal power plants (adapted from [49])

Equipment	**Condensing** Power Plant	**Binary** Power Plant
Geothermal fluid supply		
Downhole pumps	✓	✓
Wellhead valves & controls	✓	✓
Silencers	✓	–
Sand / particles removal	–	✓
Two phase pipelines	✓	✓–
Cyclone steam separators	✓	–
Steam pipelines	✓	–
Brine pipelines	✓	✓
Brine booster pumps	✓–	✓–
Steam moisture separator	✓	–
Power Plant		
Geothermal heat exchanger	–	✓
Wet steam turbine	✓	–
Dual admission turbine	✓–	–
Organic vapour turbine	–	✓
Condenser	✓	–
Controls / remote control	✓	✓
Condensate pumps	✓	✓
Cooling water pumps	✓	✓
Brine injection pumps	✓	✓
Steam-jet ejector / compressors / vacuum pumps	✓	–
Cooling towers	✓	✓–
Cooling water heat exchanger	–	✓
Cooling air fans	–	✓–

11.4.5 Project financing / contract allocation

When the main plant configuration has been defined, then the decision on how to proceed with the project should be taken. Two main options are available:

The first one concerns contracting the power plant and associated engineering works to one contractor who will provide a turn-key project. These include all works including downhole pumps, but usually excluding production and reinjection wells drilling and completion, which may be allocated to a separate contractor. This decision is made if the geothermal field owner has the necessary geothermal expertise and know-how, and if the necessary funds can be raised. In that case, the risk is taken by the field owner. The project can be financed by either one or a combination of own funds, bank loans, or subsidies from national or EU programmes.

The second, concerns a BOT project. BOT stands for Build-Operate-Transfer. In that case, a specialized company is selected, which will develop and finance the whole plant including production and reinjection wells, operate it for a specified period, say 20 years, and then transfer the plant to the geothermal field owner. In that case, any associated risks are taken exclusively by the BOT company.

11.4.6 Selection of equipment

Decisions on the location of the plant, the separators and the routes of the two phase lines, the steam lines, the separated brine lines and the steam condensate line must be taken at this stage. The corresponding selection depends upon land availability, roads, costs, predicted subsistence zone – if any – location of local settlements. Other major equipment is presented in Table 9. Each one of the components listed in Table 9 must be specified, sized and a supplier must be selected.

11.5 Field Exploitation

11.5.1 Corporate structure

Firstly the structure of the exploitation corporate scheme must be defined. Decision is made whether the geothermal steam supply and power plant should be run by a single body or they should be divided among two companies. A single company is preferred in cases of small plants, but in cases of large plants two companies may operate better. The first one is the geothermal field operator, responsible for the geothermal steam supply and all field management and field development activities. These include drilling and maintaining production and reinjection wells, two phase, steam or brine transmission pipelines, separator plants, reservoir engineering, geophysical and geochemical monitoring, etc. The second one is a power production company, which purchases the steam (or heat) from the former company at an agreed price, while it operates and maintains the geothermal power plant and delivers electricity to the power grid.

11.5.2 Maintenance program

Deciding on a program for regular preventive maintenance is important, depending also on the materials selected for the individual plant components. The scaling and corrosion potential of the geothermal fluids are major factors here. Key aspects that should be decided are allocating a budget on annual basis for operation and maintenance purposes, usually around 5% of the capital costs, and deciding whether to purchase and operate a drilling rig for maintaining existing or drilling additional production/reinjection wells.

11.5.3 Monitoring program

Deciding on a monitoring program during exploitation and allocating the necessary budget is also important in order to study the evolution of reservoir and fluid parameters over time and further decide on the exploitation strategy of the geothermal field, e.g. increase or decrease production rates, change the location of reinjection wells, drilling additional wells, treating the fluid with chemical agents in order to prevent scaling or corrosion, etc. A geophysical and geochemical monitoring program is necessary. The former should include micro-earthquakes, resistivity and gravity data with the aim to predict possible future environmental impact (micro-earthquakes evolution and subsidence), as well as the fluid changes that may take place within the geothermal reservoir. The latter should include chemistry transients of the produced geo-fluids, aiming in predicting future evolution of its scaling or corrosion tendency. In addition pressure, flow rate, temperature/enthalpy transients at the production and reinjection wells should be monitored. The data collected from the above monitoring program, should feed an integrated reservoir engineering and computer simulation task, which should direct the future exploitation strategy of the geothermal field.

11.5.4 Field management

Decisions taken during geothermal plant operation, based on the outcome of a thorough monitoring program may include [53]:

- drilling additional production wells in new areas to offset the generation loss from dying wells due to cold surface water inflow or reinjection returns
- casing-off acid zones or establishing downhole corrosion mitigation to eliminate problems associated with inflow of cold acid fluids
- moving injection wells or limiting injection rate in order to minimize injection breakthrough

- workover drilling and acidizing to encounter scaling in the injection wells
- convert injection from cold to hot, in order to minimize scaling in the injection lines, wellbore and reservoir
- upgrade production facilities to address changing reservoir conditions by including "brine-scrubbing" of steam, and by improving brine separation efficiency.

11.6 Conclusion

Decision making during a geothermal power plant development project is a continuous process, involving all project stages, starting from exploration, continuing with field/plant development and on-going during the power plant operation. Top management decisions should include interaction with local community, going-on or ending the project, financing and contractual issues, as well as corporate structure issues.

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12 ECONOMIC EVALUATION OF WIND POWER PROJECTS

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12.1 Introduction

Investments in any kind of power plant always represent long-term real investments. The purpose of real investments, unlike financial or quasi-financial, is in their productive exploitation for performing certain activity. Bottom line is that every investment is governed by the idea of making profit. The same goes, of course, for RES-e projects. They are aimed at gaining profit through sales of electricity delivered to the power grid. Since renewable facilities are very capital intensive, it is very important to perform cost effectiveness evaluation of such investment. Economic evaluation of RES-e project is based on usual methods of financial decision making, which include project cash flow analysis and determination of profitability indicators, out of which the most usual ones are pay back period, net present value and internal rate of return. The basis for cash flow analysis and relevant profitability indicators calculation is assessment of all expenditures and revenues coming from the proposed project.

The special interest in this paper will be put on the economic evaluation of the wind power projects. It is so due to the fact that among all RES options in Croatia the largest interest currently is in wind energy use for electricity production. Also, potentials for wind energy exploitation in Croatia are high – according to the national wind energy programme ENWIND it equals to about 400 MW of installed capacity and to 800 GWh per year of electricity production capacity [38]. Potentials are assessed in 29 locations.

This paper will give basics for project economic evaluation and explain main profitability indicators. It will address the main expenditures and revenues coming from the wind power projects. Throughout the whole paper theoretical findings will be supported by the example of the possible wind power project WPP Stupišće on the island of Vis, proposed within the Croatian national wind energy programme ENWIND.

12.2 Project economics basics

Economic analyses of investment projects are based on **the progress of future cash flows during the lifetime of the project** and evaluation of project cost effectiveness using various **profitability indicators**.

Lifetime of the project is the duration over which the financial feasibility of the project is evaluated. Depending on circumstances, it can correspond to the life expectancy of the energy equipment, the term of the debt, or the duration of a power purchase agreement. The project life of a well designed wind energy project typically falls between 20 and 30 years.

The basis for every economic analysis is time value of money. Time value of the project is measured by discount rate. It is the rate used to discount future cash flows in order to obtain their present value. The rate generally viewed as being most appropriate is an organisation's weighted average cost of capital. The cost of capital determines how a company can raise money (through a stock issue, borrowing, or a mix of the two). This is the rate of return that a firm would receive if they invested their money someplace else with similar risk. Its determination is actually the source of the most uncertainties related to results of project’s economic evaluation.

12.2.1 The cash flow analysis

The most common and widely used presentation method of project’s economic benefits assessment is a **cash flow analysis**. It is a tabular and graphical presentation of project’s profitability over economic lifetime of the project. Net cash flow represents the estimated sum of cash that will be paid or received each year during the entire life of the project. Simply said, net cash flow is the resulting, actual amount of cash that flows into or out of the company during a period of time, the most usually one year. It can be described with the following equations:

NCF = cash inflows – cash outflows

NCF = – investment + gross income (income from electricity sales) – operating costs – taxes

Above equation is used to calculate net cash flow for every specific year in the lifetime of the project.

For the project owner (investor) the annual economic consequences of the project will depend on the way the project will be financed. There are usually two different ways: equity or debt financing. Equity financing means that company uses its own resources for project financing. Debt financing includes loans, which require company to repay the principal over defined period of time but also periodic (e.g. annual or half-annual) interest on the principal. For the analysis it is necessary to know debt ratio (%), which is the ratio of debt over the sum of the debt and the equity of a project. Apart from debt ratio it is also necessary to know debt term and debt rate of return in order to form a debt repayment plan.

It is also necessary to include income tax in the cash flow analysis. Every country has its own income tax rate and for Croatia it is 20%. It has to be noted that only loan interest are tax deductible. Thus, the tax is calculated by the following equation:

*Tax = tax rate * (gross income – operating costs – depreciation – loan interest)*

Here, “depreciation” should be additionally explained. The capital investments in tangible assets are commonly recovered by company through process called depreciation. Depreciation is the reduction in value of an asset. Depreciation is a tax-allowed deduction included in income tax calculations. There are two most frequently used depreciation models. Straight-line model is the most widely used, while declining-balance could be more attractive since book value of the asset decreases more rapidly to zero or to salvage value. Salvage value is estimated value that an asset will realize upon its sale at the end of its useful life. Straight-line depreciation model assumes that book value of the asset decreases linearly with time. The declining balance method determines annual depreciation charge by multiplying book value at the beginning of each year by a uniform percentage d, which is called depreciation rate.

If all above discussed issues are incorporated in the basic equation for net cash flow, the following expression will be obtained:

NCF= – equity-financed capital expense + gross income – operating expense – taxes – (debt principal + debt interest)

Table 10 gives an overview of all necessary input data for cash flow analysis.

Table 10: Input data for detailed project cash flow calculations

Financing terms		**Economic parameters**		**Expenditures and Revenues**	
Total investment	[€]	Economic lifetime	years	Annual income	[€]
Debt ratio	[%]	Inflation rate	[%]	Annual O&M costs	[€]
Debt interest rate	[%]	Income tax rate	[%]	Periodical maintenance costs	[€]
Debt term	years	Depreciation method	No/SL/DB	Salvage value	[€]

In economic analysis assumptions about future happenings are used. Predictions of future happenings are always incorrect to some degree. Thus, inaccuracy is present in economic calculations. To provide good basis for decision making, sensitivity analysis is usually undertaken. Sensitivity analysis will provide information weather the project remains attractive under the evaluated cost factor changes. Also, it can be determined which cost factor effects profitability indicator the most. General procedure for sensitivity analysis is as follows:

1. Determine which factor(s) of interest may vary from the most likely estimated value.
2. Select the probable range and increment of variation for every factor.
3. Select the profitability factor to be calculated.
4. Calculate the results for every factor.
5. To better interpret the results, graphically display the cost factor versus the profitability indicator.

12.2.2 Profitability indicators

There are three most frequently used profitability indicators. These are net present value, internal rate of return and pay back period. They can be calculated from the results of the cash flow analyses. However, often, to simplify economic evaluation, these indicators are obtained without conducting detailed cash flow analysis.

12.2.2.1 Net present value

Net present value method is by definition an approach used in capital budgeting where the present value of cash inflows is subtracted by the present value of cash outflows. NPV is used to analyze the profitability of an investment or project. To simplify, NPV compares the value of money today versus the value of that same amount of money in the future, after taking inflation and return into account. Net present value method is one of most important methods for estimating profitability and ranking investments. Its objective is to estimate net present value of all previous and future capital values, which exactly means that it will give present value of all savings and expenses during the lifetime of the project.

It is calculated according to the following formula:

$$NPV = \sum_{t=1}^{N} \frac{PV_t}{(1+d)^t} - I$$

where parameters in the above equation are as follows:

NPV	-	net present value
PV_t	-	present value in year t
N	-	project lifetime
d	-	discount rate
I	-	initial (investment) costs

Positive net present value shows that present value of the company (investor) has increased. Regarding to that fact, projects that have negative net present value should not be accepted. If the net present value of the project equals zero, it means that project is able to repay the investment, but the company's value remains the same. Positive net present value of the project means that its profitability is higher then market requires.

12.2.2.2 Internal rate of return

The source of most uncertainties in results of any economic evaluation is in determination of appropriate discount rate. However, it is clear from the above subsection that there is a discount rate for which net present vale equals zero. This discount rate is called internal rate of return and it is marked as R_i in the equation below.

$$\sum_{t=1}^{N}\frac{V_t}{(1+R_i)^t}=I$$

Criterion for project acceptance is that R_i is higher then selected critical value. That means that the projects must compete with other investment options in order to get funding. Internal rate of return actually represents the return that company would earn if they invested in themselves, rather then investing that money abroad. Project will be assessed as profitable if the internal rate of return is at least equal to the company's cost of capital.

12.2.2.3 Payback period

The simple payback period represents the length of time that it takes for an investment project to recoup its own initial cost, out of the cash receipts it generates. The basic premise of the payback method is that the more quickly the cost of an investment can be recovered, the more desirable is the investment. The simple payback method is not a measure of how profitable one project is compared to another. Rather, it is a measure of time in the sense that it indicates how many years are required to recover the investment for one project compared to another. The simple payback should not be used as the primary profitability indicator to evaluate a project. It is useful, however, as a secondary indicator to indicate the level of risk of an investment. A further criticism of the simple payback method is that it does not consider the time value of money nor the impact of inflation on the costs. However, pay back period can be also calculated by taking the time value of money into consideration. It is then referred to as pay-off period and it refers to the time needed to achieve zero net present value of the investment.

12.3 Wind power project economics

Economics of wind power projects (in further text “WPP”) should be evaluated in the same way as any other investment, which has been described in more detail in the chapter 1.2.

The main parameters governing wind power project economics include the following [56]:

- Investment costs;
- Operation and Maintenance (O&M) costs;
- Electricity production/average wind speed;
- Turbine lifetime (lifetime of the project);
- Discount rate.

The first two parameters represent the WPP expenditures, while third parameter represents the WPP revenues gained from electricity sales to the grid. The last two parameters are necessary inputs in any economic evaluation as it has been already shown.

12.3.1 Wind power project expenditures

The main expenditures for WPP are as follows:

- Investment costs;
- Operation and maintenance costs;
- Costs of capital;
- Depreciation;
- Profit tax.

The investment or initial costs most usually include costs for preparing a feasibility study (preparation works at the micro-location like measurement of wind velocity and direction, geological assessment, etc.), performing the project development functions (power purchase agreement, permits and approvals, land rights issues, etc.), completing the necessary engineering (electrical, mechanical and civil design, tendering documentation and contracting), purchasing and installing the energy equipment, the balance of plant (wind turbine(s) foundations(s) and erection, road construction, transmission line, additional substations, transportation costs) and costs for any other miscellaneous items. The energy equipment and balance of plant are the two cost categories showing the strongest dependence on the number of wind turbines that make up the wind farm. Hence, the larger the wind farm, the more relative weight these two categories represent. Table 11 suggests typical ranges of relative costs, for the main cost categories.

Table 11:Relative investment (initial) costs of wind power plant [57]

Cost category	Large Wind Farm (%)	Small Wind Farm (%)
Feasibility Study	<2	1-7
Development	1-8	4-10
Engineering	1-8	1-5
Energy Equipment	67-80	47-71
Balance of Plant	17-26	13-22
Miscellaneous	1-4	2-15

Table 12 gives the example of initial costs assessment for the potential wind power project on the island of Vis - WPP Stupišće (nominal power 6,3 MW). The assessment has been made according to the conceptual design made in 2001.

Table 12: Initial costs in material assets of the 6.3 MW WPP Stupišće [38]

The structure of the investment	HRK[1]
Preparation work on the micro-location	900,000
Project documentation	750,000
Preparation civil engineering work	4,065,000
Equipment, transportation, instalment, etc.	36,784,000
Cable connection 10 kV and 35 kV	3,674,000
Total WPP Stupišće (till grid connection place)	46,173,000
Substation 35/10(20) kV Stupišće	6,372,000
Total	52,545,000

Specific investment costs in this example are approximately 980 €/kW. However, as it can be seen form the Table 12 significant contribution to the overall wind power project costs can be cost of grid connection (cable connection, new substation). It strongly depends on plant's distance form the grid and voltage level of WPP connection. In the case of WPP Stupišće , it is determined that the substation 35/10(20) kV with nominal power 8 MVA is needed as well as additional 10 kV cable connection. With these additional costs, the specific instalment investment costs are approximately 1,100 € per installed kW.

Another type of costs that should be included in calculations are annual operation and maintenance costs (O&M). There will be a number of annual costs associated with the operation of a wind power project, however due to non existence of the fuel costs, they are significantly lower then costs of conventional power plants. O&M costs could include land lease, property taxes, insurance premium, transmission line maintenance, parts and labour, travel and accommodation and general and administrative expenses. For WPP Stupišće maintenance costs are assessed according to all material costs to 1.7% of the investment (equipment and civil engineering work). Labour costs are

[1] HRK is abbreviation for Croatian national currency – 1 € equals approx. 7.5 HRK

assessed according to the 1 employee with annual gross income of 10,000 €. Operation costs are calculated as 0.3% of total investment and miscellaneous costs are assessed to 10 % of personnel costs. O&M costs also include material property insurance which equals to 0.8% of the investment (equipment and civil engineering work).

Costs of capital strongly depend on the way the project is financed. Especially important input parameters are structure and dynamics of the financial means use and terms of their use. For example, for WPP Stupišće debt financing is available to cover 75% of the project cost at an interest rate of 8% in 8 years term.

Depreciation of material assets as well as income tax should also be included in cash flow analysis of wind power project, as it is shown in the previous chapter.

12.3.2 Wind power project revenues

Financial gains of wind power projects are all those benefits that contribute to the economic and financial potential of the project. These are as follows:

- Revenues from electricity sales,
- Revenues form possible tax relieves for WPP construction and delivered kWh,
- Revenues form possible financial support for produced kWh.

The most important are revenues from electrify sales. They are strongly dependant on the amount of the produced electricity and its price. The amount of produced electricity strongly depends on the meteorological conditions and it can vary significantly from year to year. It is thus of great importance to thoroughly examine potential micro-location and to perform measurements of wind characteristics thorough larger number of years. Annual amount of produced electricity should be calculated according to expected wind characteristics. Total electricity produced from wind turbine in specific time period T is determined by the following equation:

$$E_T = T\int_0^{\infty} P_v\, p(v)dv$$

where parameters in the above equation are as follows:

E_T	-	produced electricity amount in time period T [J]
T	-	length of time period [s]
v	-	wind velocity [m/s]
P_v	-	wind turbine power at wind velocity v [W]
p(v)	-	Weibull wind velocity probability distribution function

Apart from wind statistics and micro-location characteristics, for calculation of the possible electricity production it is necessary to have technical data on wind turbine (power curve) and hub height (wind velocity is extrapolated from measurement to hug height). The energy production from the wind equipment can be then calculated based on the power curve of the selected wind turbine and on the average wind speed at hub height for the proposed site also with taking into consideration pressure and temperature conditions at the site. The calculation should also include losses of energy transformation as well as wind potential assessment uncertainty factor (usually 10%).

Apart form the amount of produced electricity, the WPP revenues also strongly depend on the electricity price. It depends on the electricity production price in the power system, on the legislative framework and on the electricity market organisation. In fully liberalised electricity market, electricity could be soled in the prompt market or on the basis of bilateral agreements. The price will depend on the daily load diagram. In every hour, the average electricity price is dictated by the most expensive power production unit in the system. However, in the most European countries, renewable sources are eligible producers with guaranteed favourable purchase price for the total amount of electricity production. This price is either guaranteed in its full amount or prescribed as a price cap on the electricity market price. In the most countries, feed-in tariffs are prescribed for every renewable source and it is aimed to guarantee feasibility of the RES project. Since in Croatia feed-in tariffs are not yet determined, the economic analysis of the WPP Stupišće has been performed with the electricity purchase price that was equal to 90% of the average electricity selling price (0,4745 HRK/kWh in 2001). According to the newest feed-in tariff proposal this price will be equal to 0,57 HRK/kWh for wind power plants larger them 1 MW.

12.3.3 Specific costs and electricity production costs

According to usual initial (investment) costs, specific costs per installed kW of wind power plant can be calculated. The cost per kW typically varies from approximately 900 €/kW to 1,150 €/kW.

The calculated costs per kWh wind power as a function of the wind regime at the chosen sites are shown in Figure 41. As shown, the cost ranges from approximately 6-8 c€/kWh at sites with low average wind speeds to approximately 4-5 c€/kWh at windy coastal locations. The electricity purchase price is crucial for WPP cost effectiveness.

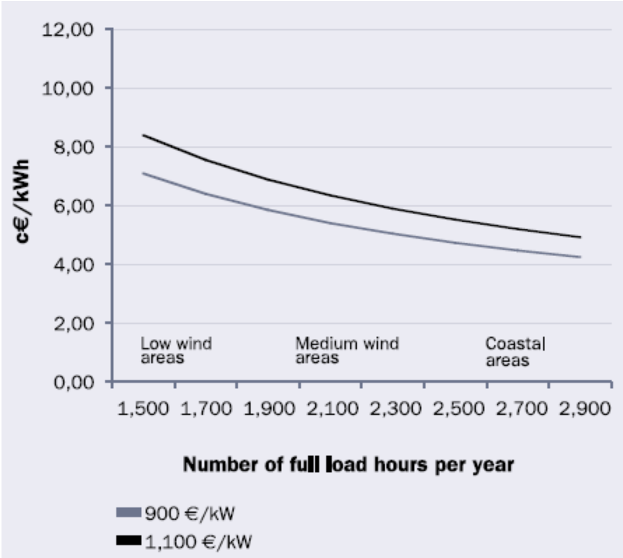

Figure 41: Costs per kWh produced using wind power in dependence of wind regime

Approximately 75 % of total power production costs for a wind turbine are related to capital costs. Thus, wind power plants are a so-called capital-intensive technology compared with conventional fossil fuel-fired technologies such as a natural gas power plant, where as much as 40 % - 60 % of total costs are related to fuel and O&M costs.

Also, the cost of capital, reflected in the discount or interest rate, is a particularly important factor. Since wind power is a capital intensive technology, the economic performance of a wind power project is therefore highly dependent on the level of interest rates, as shown in Figure 42.

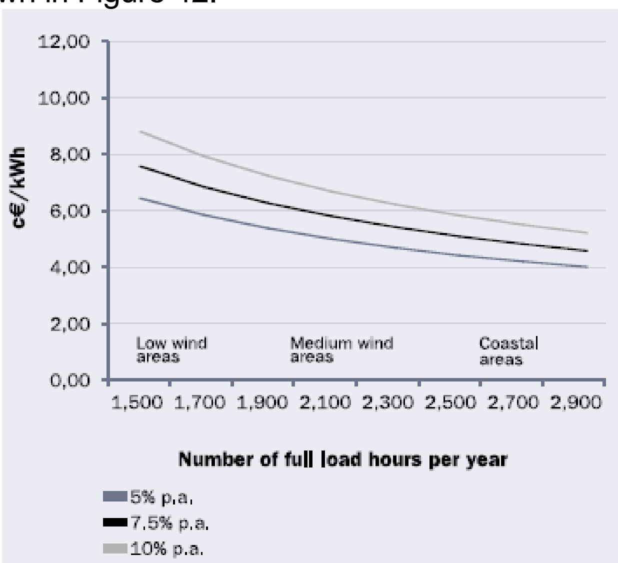

Figure 42: Costs per kWh produced using wind power in dependence of discount rate

12.3.4 Economic evaluation of WPP Stupišće

Preparation works on the micro-location Stupišće have begun in 1996 with first measurements of wind velocity and direction. According to available data, the average wind velocity 20 meters above the ground is equal to 6.73 m/s and average power equals 431 W/m^2. All analyses of the wind potentials are done by WAsP (Wind Atlas Analysis and Application Programme) methodology within the national wind energy programme WINDEN [38].

According to conceptual design, WPP Stupišće will consist of seven NEG Micon wind turbines, each with rated power 900 kW, hub height 55 m and rotor diameter 52.2 m. According to assessed wind velocities at 55 meters height (measurement data extrapolated to this height) and wind turbine power curve, annual net electricity production is assessed to 15,282 MWh.

All input data for economic evaluation of the WPP Stupišće as well as results of the economic evaluation are summarised in Table 13. Although the table is taken from [38], the authors have also performed their own calculation using the RETScreen Wind Energy Project application. The results were very close to these presented within this paper.

Table 13: Overview of input parameters and economic evaluation results [38]

INPUT DATA		
Construction time	year	1
Economic lifetime	year	20
Generator rated power	kW	900
Number of units		7
Total installed power	MW	6.3
Average annual wind velocity	m/s	7.3
Investments – financing mode and terms		
Total investment cost	000 HRK	46,173
Debt ratio	%	75
Debt term	year	8
Debt interest rate	%	8,0
Grace period	half-year	2
Number of debt payments	half-year	16
Required internal rate of return	%	10.0
Electricity production		
Operational hours	h/year	2,426
Electricity production	MWh	15,282
Depreciation (straight-line model)		
Depreciation rate for civil works	%	5.0
Depreciation rate for equipment	%	6.67
Depreciation rate for non material assets	%	20.0

INPUT DATA		
Employment		
Number of employees	person	1
Specific labour costs (annual gross)	HRK/per.	75.000
Operation and maintenance costs		
Maintenance costs (% from investment in civil works and equipment)	%	1.7
Insurance costs (% from investment in civil works and equipment)	%	0.8
Operation costs (% from total investment)	%	0.3
Miscellaneous	%	10
Income tax	%	20
Electricity price	HRK/kWh	0.427
RESULTS		
Pay back period	year	9.8
Internal rate of return	%	8.4
Net present value	HRK	-4,383

As it can be seen the profitability indicators are not very attractive. Net present value is negative and internal rate of return quite low.

However, it is very useful to perform sensitivity analysis of economic evaluation. The most interesting parameter to consider is electricity purchase price, especially since there are still no feed-in tariffs for electricity produced from RES in Croatia. The electricity purchase price has been varied while all other input parameters were kept constant. The results of sensitivity analysis are shown in Table 14. It can be seen that for electricity price 0.57 HRK/kWh (as suggested in the most recent proposal of the tariff system for RES-e), profitability indicators are in that case significantly better, which shows the importance of the favourable price for electricity produced form RES and its impact on the overall project profitability.

Table 14: Sensitivity analysis with variation of electricity selling price [38]

VARIABLE PARAMETER Electricity selling price (HRK/kWh)	NPV (000 HRK)	IRR (%)	SPB (years)
0.380	-9,204	6.51	11.27
0.427	*-4,383*	*8.40*	*9.8*
0.470	0	10.00	8.8
0.522	4,955	11.76	7.8
0.569	**9,445**	**13.29**	**7.1**

12.4 Concluding remarks

Feasibility of the investments made in RES power plants is dependant on the same parameters as for any other power plant, and these are in general investment costs (costs of the construction), operation costs (costs of the electricity production) and electricity purchase price. One of significant characteristics of the market conditions is that investors anticipate as fast as possible return of the investment. Thus, more attractive options seem to be those with lower initial (investment) costs and shorter pay off period. However, RES power plants are highly capital intensive, i.e. characterised by very high investment costs and low operation costs (no fuel costs). Without regulatory support, i.e. favourable guaranteed power purchase price, investments in RES power plants would not be very probable, especially in countries with economies in transition, like Croatia and Western Balkans countries.

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13 INCENTIVES AND BARRIERS FOR RES INSTALLATION PROJECTS IN ROMANIA. GREEN CERTIFICATES MARKET

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13.1 Introduction

The promotion of energy production from renewable energy sources (E-RES) represents an imperative of the current period motivated by: environment protection, increase in energy independency with respect to the imports by diversifying the energy sources as well as economic and social issues reasons.

The 2001/77/EC Directive of the European Parliament and Commission regarding the promotion of electrical energy production from renewable energy sources on the internal market represents the first real action of the European Union to fulfil the requirements imposed for greenhouse gas emission accepted through the Kyoto Protocol.

The E-RES represents the electrical energy produced only from renewable energy plants as well as the percentage of the electrical energy produced by hybrid renewable energy systems, including electrical energy consumed by storage systems of the conventional energy holders, excluding the electrical energy obtained from these systems. In this category, the Romanian Energy Regulatory Authority (ANRE) defines as the Renewable Energy Sources the following energy sources types:

(a) Wind energy;

(b) Solar energy;

(c) Biomass;

(d) Geothermal energy;

(e) Tidal energy;

(f) Hydrogen produced from renewable energy sources;

(g) Hydro power plants with installed power less than 10 MW, commissioned or refurbished starting 2004;

13.2 Legislation

European Legislation

The Directive 2001/77/EC provides new measures concerning the promotion of the electricity produced from RES on the internal electricity market.

Primary legislation in the field of RES

- The electrical energy law no. 318/2003;
- HG no. 1535/2003 assesses the RES potential in Romania and establishes the strategy for RES development in the context of Romania adhesion to the EU;
- HG no. 443/2003 adapts the stipulations of the EU Directive 2001/77/EC (regarding the promotion of electrical energy produced from renewable energy sources) to the conditions specific for Romania;
- HG no. 1429/2004 for approval of the certifying instructions of the electrical energy origin produced by the renewable energy sources;
- HG no. 1892/2004 establishes the promotion system for the electricity produced from RES;
- HG no. 958/2005, modifies the Government Decision no. 443/2003 regarding the promotion of electrical energy produced from renewable energy sources and modifies and updates the Government Decision no. 1892/2004 that establishes the promoting system of electrical energy generation from renewable energy sources.

Secondary legislation in the field of RES

- ANRE Decision no. 23/2004 regarding the procedure for surveillance of guarantees of origin issued for the electricity produced from RES;
- ANRE Decision no. 52/2005 establishes the tariff for the electricity acquisition from the hydro producers which do not have portfolio contracts and for the electricity sold by the producers which participate in the system for E-RES promotion;
- Regulation for Green Certificates Market organization and functioning, approved through the ANRE Decision no. 40/2005;
- ANRE Decision 45/2005 on the allocation procedure for the amount of money collected from the suppliers penalties for quota non-compliance;

- ANRE Decision no. 46/2005 modifies the quota obligation for GC acquisition by the electricity suppliers for the year 2005.

13.3 The system of obligatory quota and green certificates in Romania

Romania has adopted the obligatory quota system combined with the trading system of the green certificates to prices restricted to lower and upper bounds by the ANRE. An obligatory quota is established yearly for the electrical energy producer from renewable energy sources that the suppliers must buy.

The obligatory quota system represents a promoting mechanism of E-RES through acquisition by the suppliers of an obligatory quota of E-RES in order to be delivered to the contracted consumers.

The operation of this mechanism requires the following steps:

- The Regulator Authority establishes a fixed quota of electricity produced from renewable energy sources which the suppliers are obliged to buy;
- The Regulator Authority yearly qualifies the producers of electricity from renewable energy sources in order to receive Green Certificates;
- The Producers receive for each unit of electricity delivered into the network (1 MWh) a Green Certificate, which can be sold separately from the electricity on the Green Certificates Market;
- In order to fulfil their obligation, the suppliers have to own a number of Green Certificates corresponding with the quota of electricity produced from renewable energy sources imposed;
- The Green Certificates value represents an *additional income* received by the producers for the "clean" energy that they deliver into the network;
- The price of electricity sold is determined on the electricity market;
- *The additional price* received for the Green Certificates sold is determined on *a parallel market, separated from the electricity market,* where *the environmental benefits of the "clean" electricity production* are traded.

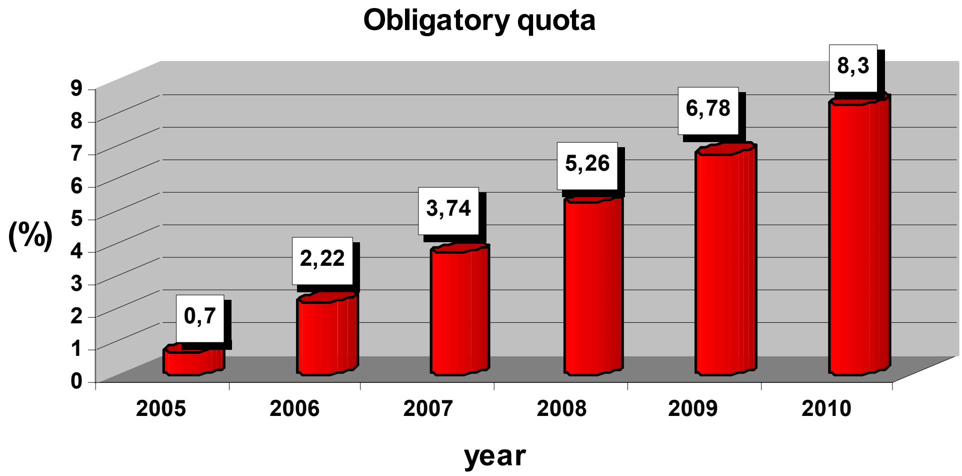

Figure 43: The yearly obligatory quota imposed for electrical energy produced from RES.

The obligatory quota level that will be imposed until 2010 in concordance with the target specified for Romania through the negotiations for adhesion to the European Union regarding the electrical energy proportion produced from renewable energy sources of the internal gross electrical energy consumption is: 0.7% for 2005, 2.22% for 2006, 3.74% for 2007, 5.26% for 2008, 6.78% for 2009 and 8.3% for the period 2010-2012.

Therefore, the number of green certificates necessary to be traded in order to fulfil the obligatory quota is given in Figure 44.

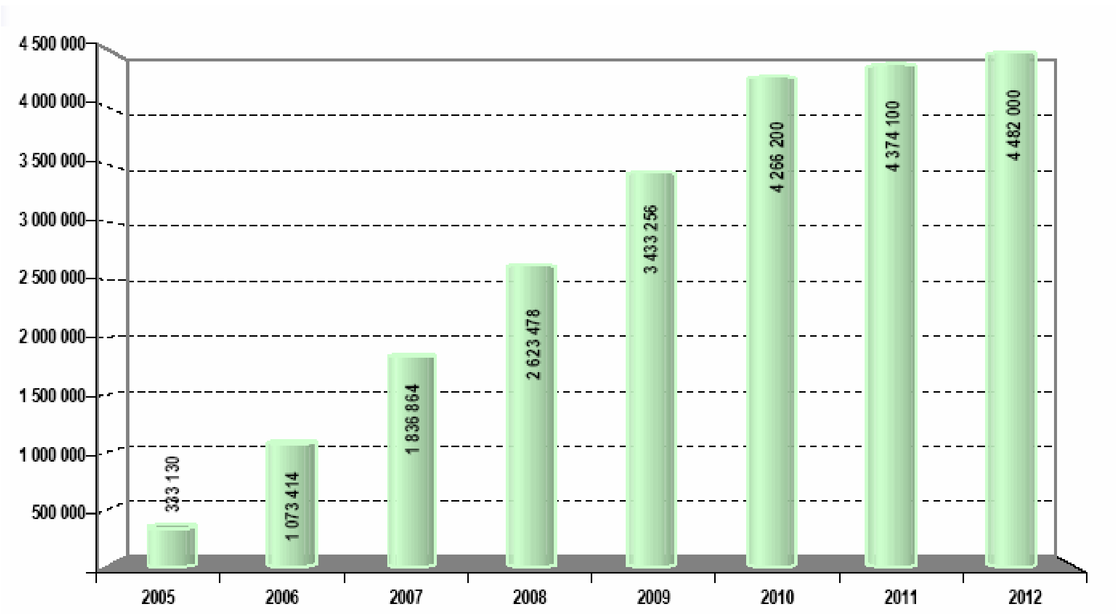

Figure 44: The yearly number of green certificates that have to be traded.

The price of Green Certificates varies in a range established by the Government Decision [Pmin ÷ Pmax]. The minimum price is imposed in order to protect the producers and the maximum price to protect the consumers. This price has been established to a minimum value of €/certificate and a maximum value of €/certificate, calculated to the exchange rate established National Bank of Romania, of the last working day from December of the previous year.

The hydro-producers which do not participate on the green certificates market can sell the electrical energy from units of installed power less than 10MW to distribution companies or suppliers which hold concession contracts for exclusivity rights, at a price of 140.24 lei/MWh for night hours, and 229.87 lei/MWh for day hours.

The producers that benefits, by law, by the promoting system of electrical energy produced from RES can sell their produced electrical energy by regulated contract at a price of 132 lei/MWh.

The value of the green certificates is established by the market mechanisms, either on the bilateral market, between producer and supplier, or on the centralized market administrated by OPCOM.

ANRE is the competent authority that qualifies the producers of electrical energy from RES, in order to participate to the green certificates market. ANRE is charged to supervise the fulfilment of green certificates obligatory quota, and in case of non-fulfilment to apply penalizations.

In the first three monthly trading sessions held so far, 6,342 green certificates was transferred of the 7,608 certificates issued.

If a supplier buys more green certificates then the imposed quota, these can be used in the next year(s) in order to fulfil its quota.

The supplier that reaches the imposed quota will pay to the TSO (Transmission and System Operator) the equivalent of the green certificates not bought, so:

a) In the period 2005-2007 for a value representing one and half of the maximum traded value established legally;

b) Starting with 1st of January 2008 for a value double with respect to the maximum traded value established legally.

13.4 Duties of the Green Certificates System responsible entities

ANRE has the following duties:

- Qualifies the electrical energy producers from renewable energy sources in order to participate in the green certificates market;
- Supervise the fulfilment of obligatory quota by the suppliers;
- Applies penalizations for non-fulfilment of the obligatory quota.

Transmission and System Operator – Transelectrica S.A. collects annually the amounts corresponding to penalizations and allocates them for:

- Buying from producers, at minimum price, the not sold green certificates offered in the market, in years when the offer is smaller than the demand;
- Redistribute the remained funds to the E-RES producers in terms of the number of sold green certificates and type of RES.

Green Certificates Market Operator - OPCOM has the following duties:

- Found and administrate the Register of Green Certificates;
- Register the bilateral contracts E-RES producers and suppliers;
- Register the green certificates market participants;
- Ensure the trading environment for the Centralized Green Certificates Market;
- Determine and publish the green certificates market clearing price (GCMCP) and the number of green certificates traded monthly in the Green Certificates Market (GCM);
- Establish the cash rights and payment obligations for the participants to the GCM;
- Publish monthly the cumulated curves of green certificates offer and demand for the current year.

OPCOM determines:

- the demand curve as combination of all price-quantities blocks from the buying offers, arranged in ascending order, from a single offer;
- the offer curve as a combination of all price-quantities blocks from the selling offers, arranged in descending order, from a single offer;
- GCMCP and the number of the traded green certificates as being the intersection point between the demand and offer curves.

13.5 Green certificates market

Since 2005, in Romania a Green Certificates Market is administrated by OPCOM – the legal person that assures Green Certificates trading and determines the prices on the Centralized Green Certificates Market, performing the functions established by the Regulation for organizing and functioning of the Green Certificates Market (Order no. 15 / 2005 issued by ANRE).

Each electrical energy supplier is obliged to purchase in every year a number of green certificates equal to the product between the value of obligatory quota and the electrical energy supplied to its customers in that year, expressed in MWh.

The yearly green certificates demand represents the number of green certificates corresponding to the legally established yearly quota being calculated as a product between the obligatory quota and the national gross electrical energy consumption of that year:

Number of green certificates corresponding to the legally established yearly quota = Obligatory quota X National gross electrical energy consumption of that year

TSO issues monthly green certificates to E-RES producers for the electrical energy injected into the network, based on a particular procedure certified by the Competent Authority.

The E-RES producers receive for each MWh injected into the network one green certificate.

A green certificate has unlimited validity, being considered “consumed“ if the supplier use it in order to prove the fulfilment of obligatory quota.

The Green Certificates Market is a competitive market, where the GCs afferent to the E-RES are traded on the bilateral contracts market and/or the GC centralized market. The GC transactions on the centralized market are performed monthly, based on the selling / buying offers sent by participants.

The E-RES producers can sell energy on the electricity market, as any other producer, in order to get the market price, and to cover totally the production costs and obtain a reasonable profit it receives for each 1 MWh of electrical energy injected into the network one green certificate that can be traded at a price in the limits imposed by.

The green certificates import/export is allowed only with the countries that are the members of the European Union and that have established contracts with Romania.

The participation to the centralized market is allowed to the E-RES produces, suppliers and consumers that have registered as participants to OPCOM.

A participant can retire by itself from the green certificates centralized market by written notification, signed by the authorized representative of the market participant. The notification must be transmitted at late in the ninth working day of the Trading Month. OPCOM informs the Competent Authority in the quarter of year report about the retired participant.

The Market Clearing Price is determined by the intersection between the offer curve and the demand curve.

The transactions can take place on the green certificates centralized market, in the Trading Day, when: a) the offer curve does not intersect the demand curve; b) the offer is zero; c) the demand is zero.

For the case d of Figure 45, the price is established with formula:

$$\text{GCMCP}=\frac{P\max+P\min}{2}$$

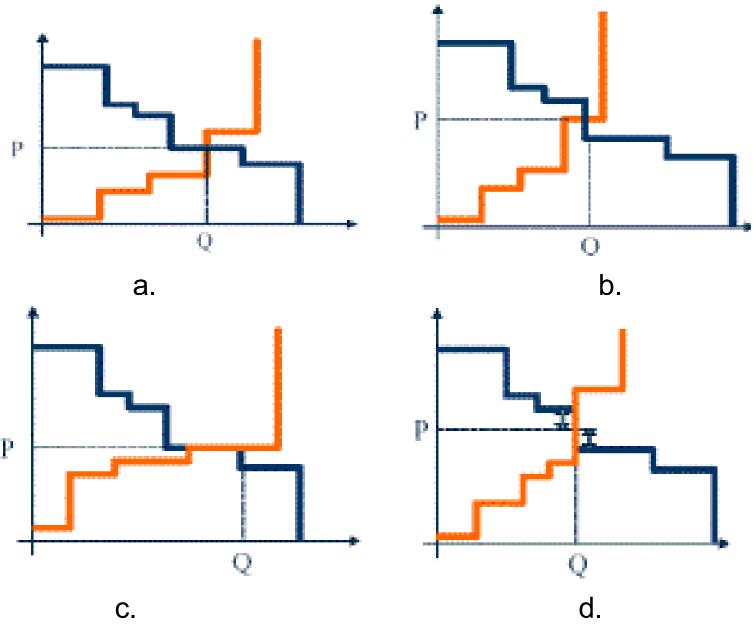

Figure 45: Intersection between offer and demand curves.

The electrical energy production from renewable energy sources is considered priority production for the day-ahead electricity market, which is a central market. The Day Ahead Market Clearing Price is the energy price of RES generation. If, in an hourly interval, the E-RES is not traded (the generation – consumption balance is performed only by the energy traded through bilateral contracts), the producer of E-RES notifies the physical unbalance and receives the price established for such situations.

13.6 Guaranties of origin

For the electrical energy produced from RES at established fixed tariffs by the ANRE, the guaranties of origin are issued monthly, starting with the next month of coming into force of the tariffs.

The guaranties of origin are documents that:

- Specify the renewable energy source that produced the electrical energy, indicating the date, the generation location and the installed power;
- Allow producers to demonstrate that the electrical energy that they sell is produced from RES.

13.7 Documents

The steps that have to be followed by an investor that wish to produce electrical energy from RES are:

(i) Documents issued by the county or local public administrative authority:

- urbanism certificate – contains inclusive stipulations all required certifications;
- construction authorization.

(ii) Documents issued by the electrical networks operator to which the installation is connected:

- placement authorization – issued accordingly to ANRE Decision no. 38/2003;
- grid connecting authorization – issued accordingly to HG no. 867/2003.

(iii) Documents issued by ANRE:

- foundation authorization, accordingly to HG nr. 540/2004; only for installations of installed power less than 10 MW.
- E-RES generation license, accordingly to HG no. 540/2004; only for installations of installed power greater than 250 kW;
- qualification for priority production of electrical energy, accordingly to the ANRE Decision no. 33/2004.

13.8 Situation of micro-hydro power plants in Romania

In Romania, the micro-hydro power plants provide the largest part of the electrical energy produced by renewable sources.

The micro-hydro power plants are entities with power between 100 kW and 10 MW. In 2002, due to a Government decision, Hidroelectrica Company took over, from Termoelectrica Company and Electrica Company, 237 micro-hydro power plants. Altogether, Hidroelectrica Company had in its portfolio 386 of this type of micro-hydro power plants for which the privatization process started in 2003. Hardly, 18 of these have been sold last year. Due to Economy Ministry data, now, evaluation reports are made for 130 micro-hydro power plants, and in this year time, bidding is to be made for selling them. The Economy Ministry privatization program presumes the selling of 150 micro-hydro power plants till 2007. For example, the following group of micro-hydro power plants from the Doftana river drainage basin, Prahova, was recently sold by Hidroelectrica: MHC Prislop, MHC Traisteni 1, MHC Traisteni 2, MHC Negras 1, MHC Negras 2, MHC Tesila 1 and MHC Tesila 2

It has to be mentioned the fact that there are a lot of companies which sell micro-hydro power plants with different characteristics.

The Italian company ESPE has bought from Hidroelectrica five micro-hydro power plants situated on the Firiza river from Maramures county, at the price of 34,7 billions lei, and they engaged to invest 53 billions lei in the next five years for modernizing the units. This is the second package of micro-hydro power plants sold by Hidroelectrica, after the taking over of five units, in Gorj country, by the Institute of studies and hydro-power engineering at the beginning of June.

13.9 Barriers

The installation in Romania of renewable energy sources as well as photovoltaic panels is still in a planning phase. This issues is due, on one hand, to the existence of a great number of hydro power plants, which provided in 2005 electrical energy in proportion of 33.97% of the total consumption, and on the other hand, the inexistence of appropriate incentives.

It should be also mentioned the giant projects, i.e.: commissioning in 2007 of the Group 2 of the Cernavoda Nuclear Power Plant, and 2012 the third group. Due to operating conditions of the nuclear power plant the necessity of new significant investments in hydro power plants arose: building of a pumping-storage plant in the area Tarnița – Lăpuşteşti with an installed power of 1,000 MW, which will be used for power balancing within national power system, as well as a hydro power plant at Măcin, Dobrogea, with an installed power of 875 MW. There is also a preoccupation for development of micro-hydro but the results are still “on stand by”.

The lack of implementation projects of renewable energy systems (especially wind turbines) prove the fact that besides S.C. Hidroelectrica S.A., in Romania there are only two entities holding a license to produce energy from renewable sources. At the same time, we have to mention that actually, in Romania there are two wind turbines in operation: one at Ploiesti – with an installed power of 660 kW and another one at Pasul Tihuta (Bistrita Nasaud), of 250 kW, to which we may add a project which is being implemented of the third wind turbine of 550 kW installed power, Tulcea county.

Although there is a generous legislative frame and an optimist strategy for development renewable energy sources, the actual problems that an investor confronts with are divided in two categories, being determined by the project duration: construction (technical, administrative) and exploitation (connection to the grid and the legislative frame).

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14 RENEWABLE ENERGY SOURCES TECHNOLOGIES INSTALLED ON GREEK ISLANDS

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14.1 Abstract

This paper presents a summary of the current status of renewable energy sources technologies that are installed on Greek islands. The paper also provides results from the evaluation of the economic and environmental impacts of wind power production on the autonomous power system of Crete island.

14.2 Basic Information on Greek Islands

Greece is a country with many dispersed islands in both Ionian and Aegean Sea. Many of them, due to their significant distance from the mainland, are not interconnected with the mainland grid and in many cases each island is a stand-alone system. In few cases some islands are interconnected together to form one stand-alone power system.

Roughly 1,000,000 citizens are living on the Greek islands. The electricity consumption in Greek islands is about 4% the total electricity consumption of Greece. In the islands, the annual demand is increasing by 8%, which is double compared with the annual demand increase for the whole Greece (4%). The Public Power Corporation (PPC) is the operator of the power systems of islands and more specifically its sector called PPC Islands.

Almost all Ionian islands (except some very small ones, Othoni and Ereicousa north of Corfu) are interconnected with the mainland via HV submarine cables. Due to their significant distance from the mainland, the majority of the Aegean islands are not interconnected with the mainland.

There are three groups of autonomous island power systems in Greece:

1. The small autonomous systems with a peak demand less than 6 MW, each.
2. The medium size autonomous systems with a peak load from 6 to 60 MW, each. The power stations on these islands consume diesel and their network is radial.
3. The large size autonomous systems of Crete and Rhodes, that are based on several power production units (steam, diesel and gas turbines) and their transmission network might contain loops.

14.3 Demand and Installed Capacity

Table 15 presents the demand and installed capacity on Greek autonomous island systems. It can be seen that the installed capacity of renewable energy sources (RES) is 11% and the rest 89% is the installed capacity of conventional power sources.

Table 15: Demand and Installed Capacity on Greek Autonomous Islands

Nb	Power System	Maximum Demand (kW)	Annual Energy (MWh)	Installed Conventional Capacity (kW)	Total RES Capacity (kW)
1	Ag. Efstratios	260	945	360	100
2	Agathonisi	120	274	240	0
3	Amorgos	2,740	7,666	2,650	0
4	Anafi	380	804	355	0
5	Andros	9,300	32,613	9,400	1,975
6	Antikithira	90	165	140	45
7	Arkioi	15	22	20	37.5
8	Astipalaia	1,750	4,979	1,600	0
9	Chios	39,700	161,238	38,780	8,400
10	Crete	529,400	2,349,500	695,400	87,270
11	Donousa	180	377	210	0
12	Ereikousa	250	489	270	0
13	Gavdos	8	10	1	20
14	Ikaria	5,900	22,905	6,900	385
15	Ios	4,380	12,563	3,740	0
16	Karpathos	7,800	27,096	9,000	950
17	Kos	57,300	217,824	69,600	8,460
18	Kythnos	1,605	5,629	2,000	777
19	Lemnos	12,900	53,426	15,900	1,140
20	Lesvos	57,500	245,851	49,500	10,058
21	Megisti	410	1,705	390	0

Nb	Power System	Maximum Demand (kW)	Annual Energy (MWh)	Installed Conventional Capacity (kW)	Total RES Capacity (kW)
22	Milos	9,080	33,801	7,600	3,200
23	Mykonos	24,300	66,607	21,200	300
24	Othonoi	250	580	270	0
25	Paros	51,500	157,585	43,250	186
26	Patmos	4,150	13,386	4,380	0
27	Rhodes	126,800	550,385	206,000	555
28	Samos	29,700	118,819	46,080	5,875
29	Samothraki	2,400	7,098	2,200	220
30	Serifos	2,300	6,208	2,000	0
31	Sifnos	4,340	12,209	4,300	60
32	Skyros	3,900	14,202	4,500	140
33	Symi	2,470	9,958	4,350	0
34	Syros	22,100	105,173	20,000	3,540
35	Thira	28,400	85,462	22,200	0
		Total	**4,327,555**	**1,114,986**	**133,694**

14.4 RES Capacity by Type

Table 16 presents the RES installed capacity on Greek autonomous island systems by RES type. It can be seen that the installed capacity of wind energy is 99% and the rest 1% is the installed capacity of all the other RES types.

Table 16: RES Installed Capacity on Greek Autonomous Islands by RES type

Nb	Power System	TOTAL (kW)	Wind (kW)	PV (kW)	Hydro (kW)	Others (kW)	Storage (kWh)
1	Ag. Efstratios	100	100	0	0	0	0
2	Agathonisi	0	0	0	0	0	0
3	Amorgos	0	0	0	0	0	0
4	Anafi	0	0	0	0	0	0
5	Andros	1,975	1,975	0	0	0	0
6	Antikithira	45	0	45	0	0	237
7	Arkioi	38	0	38	0	0	303
8	Astipalaia	0	0	0	0	0	0
9	Chios	8,400	8,400	0	0	0	0
10	Crete	87,270	85,891	442	600	359	0
11	Donousa	0	0	0	0	0	0
12	Ereikousa	0	0	0	0	0	0
13	Gavdos	20	0	20	0	0	237
14	Ikaria	385	385	0	0	0	0

Nb	Power System	TOTAL (kW)	Wind (kW)	PV (kW)	Hydro (kW)	Others (kW)	Storage (kWh)
15	Ios	0	0	0	0	0	0
16	Karpathos	950	950	0	0	0	0
17	Kos	8,460	8,460	0	0	0	0
18	Kythnos	777	665	112	0	0	400
19	Lemnos	1,140	1,140	0	0	0	0
20	Lesvos	10,058	10,050	8	0	0	0
21	Megisti	0	0	0	0	0	0
22	Milos	1,200	1,200	0	0	0	0
23	Mykonos	300	300	0	0	0	0
24	Othonoi	0	0	0	0	0	0
25	Paros	186	176	10	0	0	0
26	Patmos	0	0	0	0	0	0
27	Rhodes	555	555	0	0	0	0
28	Samos	5,875	5,875	0	0	0	0
29	Samothraki	220	220	0	0	0	0
30	Serifos	0	0	0	0	0	0
31	Sifnos	60	0	60	0	0	0
32	Skyros	140	140	0	0	0	0
33	Symi	0	0	0	0	0	0
34	Syros	3,540	3,540	0	0	0	0
35	Thira	0	0	0	0	0	0
	Total	**133,694**	**130,022**	**735**	**600**	**359**	

14.5 RES Share in Energy Demand

Table 17 presents the RES share in energy demand of Greek autonomous island systems by RES type. It can be seen that in the Greek autonomous island systems the share of RES in energy demand is 6 % and the rest 94 % is the share of conventional power sources.

Table 17: RES Share in Energy Demand on Greek Islands by RES type

Nb	Power System	Total Demand (MWh)	RES Production (MWh)	*RES Share* (%)	Wind (MWh)	PV (MWh)	Others (MWh)
1	Ag.Efstratios	945	0	0	0	0	0
2	Agathonisi	274	0	0	0	0	0
3	Amorgos	7,666	0	0	0	0	0
4	Anafi	804	0	0	0	0	0
5	Andros	32,613	5,003	15.3	5,003	0	0
6	Antikithira	165	26	15.8	0	26	0

Nb	Power System	Total Demand (MWh)	RES Production (MWh)	*RES Share (%)*	Wind (MWh)	PV (MWh)	Others (MWh)
7	Arkioi	22	22	100	0	22	0
8	Astipalaia	4,979	0	0	0	0	0
9	Chios	161,238	11,484	7.1	11,484	0	0
10	Crete	2,349,500	205,686	8.8	204,670	0	1016
11	Donousa	377	0	0	0	0	0
12	Ereikousa	489	0	0	0	0	0
13	Gavdos	10	10	20	0	10	0
14	Ikaria	22,905	1,296	0	1,296	0	0
15	Ios	12,563	0	0	0	0	0
16	Karpathos	27,096	1,133	0	1,133	0	0
17	Kos	217,824	N/A	0	0	0	0
18	Kythnos	5,629	639	11.35	586	53	0
19	Lemnos	53,426	841	0	841	0	0
20	Lesvos	245,851	26,010	10.58	26,000	10	0
21	Megisti	1,705	0	0	0	0	0
22	Milos	33,801	N/A	0	0	0	0
23	Mykonos	66,607	N/A	0	0	0	0
24	Othonoi	580	0	0	0	0	0
25	Paros	157,585	0	0	0	10	0
26	Patmos	13,386	0	0	0	0	0
27	Rhodes	550,385	0	0	0	0	0
28	Samos	118,819	8,014	0	8,014	0	0
29	Samothraki	7,098	532	0	532	0	0
30	Serifos	6,208	0	0	0	0	0
31	Sifnos	12,209	78	0.64	0	78	0
32	Skyros	14,202	0	0	0	0	0
33	Symi	9,958	0	0	0	0	0
34	Syros	105,173	0	0	0	0	0
35	Thira	85,462	0	0	0	0	0
	Total	**4,327,555**	**260,774**	**6.03**	**259,559**	**199**	**1,016**

14.6 Energy Cost

Table 18 presents the energy cost in various Greek islands.

Table 18: Energy Cost in Greek Islands

Power System	*Mean Annual cost (Eurocents/kwh)*
Ag. Efstratios	37.21

Power System	*Mean Annual cost (Eurocents/kwh)*
Agathonisi	89.66
Antikithira	172.74
Astipalaia	39.15
Crete	8.06
Donousa	47.57
Ereikousa	49.86
Karpathos	22.13
Kos	16.40
Lemnos	13.29
Lesvos	9.80
Megisti	61.92
Milos	16.43
Othonoi	35.74
Paros	7.54
Samos	8.45
Thira	15.17

14.7 Economic and Environmental Impact of Wind Power Integration in Crete Island

14.7.1 The Crete Power System

The Power System of Crete is the largest isolated system in Greece, with the highest increase in energy demand (8 %) nationwide [63]. In 2000, the peak demand was 435 MW and the consumed energy 2,078 GWh. This is mainly covered by two thermal stations, one in Hania and one in Linoperamata with 20 units and total installed capacity of 490.3 MW. These units comprise steam, diesel, and gas turbines. The steam units cover the base load, while the gas turbines are used to cover the peak at increased costs. The Wind Power currently installed, amounts to 67.35 MW producing approximately 10 % of the energy annually consumed. The installed wind farms are shown in Table 19.

Table 19: Installed Wind Farms on Crete during the year of study

WF No	14.7.1.1 Wind Farm Name	Installed Capacity (MW)
1	PPC-I (TOPLOU)	6.60
2	OAS	0.50

WF No	14.7.1.1 Wind Farm Name	Installed Capacity (MW)
3	ROKAS	10.20
4	IWECO	4.95
5	AIOLOS	9.90
6	MARONIA	25
7	PPC-II (XIROLIMNI)	10.20

In Figure 46, the energy consumption, the wind energy production and the wind power penetration are shown per month.

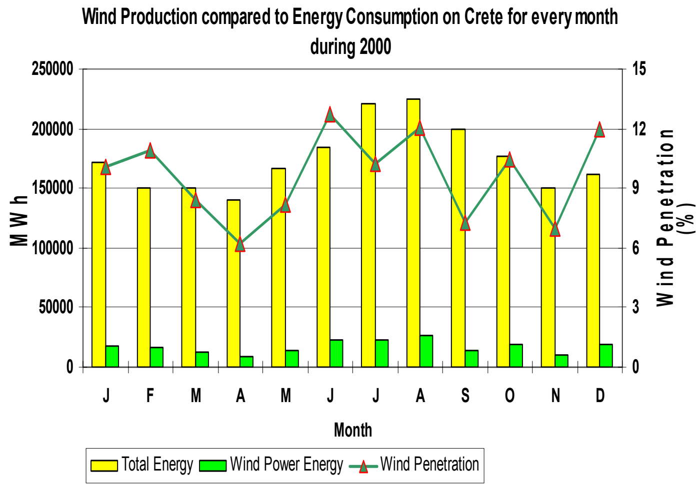

Figure 46: Energy consumption, wind power production and wind power penetration per month in 2000

In Figure 47, the load, the wind production and the wind penetration during the day of the maximum instantaneous wind production (28 Dec. 2000) are shown. As seen in Figure 47, the system can operate with instantaneous wind penetration reaching almost 30 %.

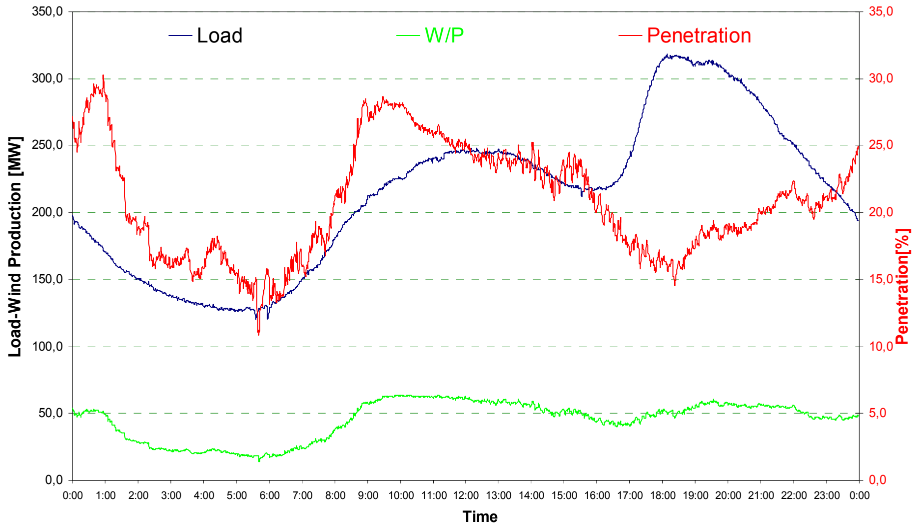

Figure 47: Load, wind production and wind penetration during the day of the maximum instantaneous wind production (28 Dec. 2000)

Table 20 provides summary information about the energy, the load and the RES production in 2000 [64].

Table 20: Summary of energy, load and wind production in 2000

Annual Energy	2078.6 GWh
Peak load	435.4 MW (24/8/2000 at 21.00)
Minimum Load	108 MW (14/3/2000 at 4:00)
Annual Produced Energy by RES	203.5 GWh
Maximum Instantaneous Wind Production	62.7 MW (28/12/2000 at 11:00)
Maximum Wind Penetration	39.2% (10/12/2000 at 6:00)

The minimum wind power production (8,751 MWh) was observed in April, while the maximum in August (27,021 MWh). The maximum monthly wind penetration was during June with 12.7 %.

14.7.2 Economic and Environmental Impact

For the economic assessment of the wind power production in Crete, the actual cost of the fuel consumed for the operation of the system during 2000 including the compensation of the wind power producers is compared to the cost obtained if the same load would be covered by the thermal units alone. It is not considered any effect wind power might have on personnel, capital and management costs, interests, etc.

In order to satisfy the maintenance requirements of the thermal units, the actual unit commitment schedules have been considered with slight modifications, in case units needed to start up when the already committed units were not sufficient to cover the load. In few cases, load shedding was necessary, when the installed capacity of all available units was not enough to cover the load. It was also assumed that the dispatch of the load to the committed units was optimal, thus the economic evaluation of the wind power in Crete is made from the safe side. For the simulation of the economic operation of the system the economic dispatch functions of the MORE CARE system were used. The algorithm employed is the Sequential Quadratic Programming (SQP) [65], a generalisation of the Newton's optimisation method, which uses a quadratic approach of the objective function and linear approximations for the constraints of the problem in order to optimise the non-linear objective function of fuel costs subject to technical constraints. This method guarantees that the solution found is the global optimum in the feasible space, if the objective function is convex.

The analysis was based on hourly average load and production values of the thermal units and the wind parks are recorded in the SCADA system of the Load Dispatch Center of Crete. For the simulation of the economic operation of the system the operational, start-up and shut down costs of each unit were considered. In addition, constraints regarding load balance and losses, min-max limits in the units' production and the rate of change of load at each unit were considered. A minimum amount of 10% spinning reserve was kept at all times.

In Figure 48 and Figure 49 the monthly fuel savings in diesel and heavy oil respectively, as a result of the wind power production are shown. The reduction in diesel consumption is particularly noticeable. This is due to the fact that the base units (basically the steam turbines) consume heavy oil, while the displaced by wind power peaking units (gas turbines) consume diesel.

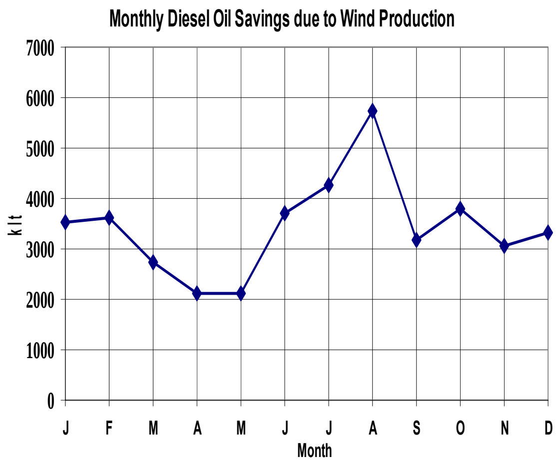

Figure 48: Monthly Diesel Oil Savings due to Wind Production

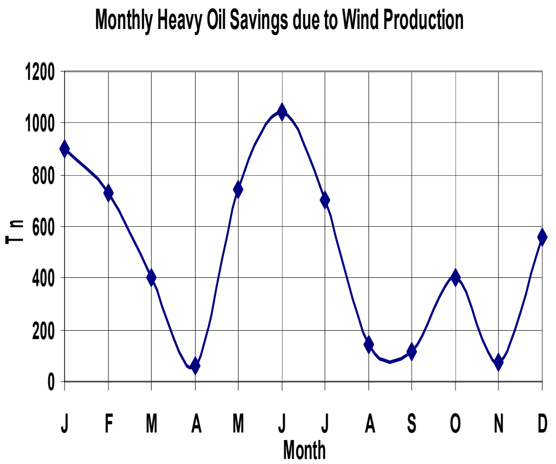

Figure 49: Monthly Heavy Oil Savings due to Wind Production

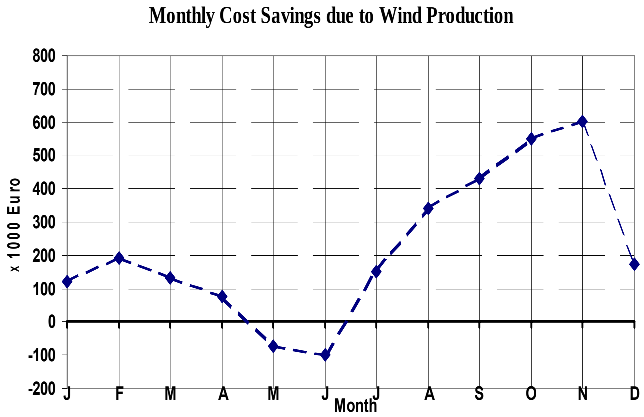

Figure 50: Monthly Cost Savings due to Wind Production

In Figure 50 the monthly cost savings are displayed. It can be seen that they vary from minus 100 to plus 600 k€. These wide fluctuations are attributed to the following factors:

1. Variations of monthly fuel costs. The higher these costs, the higher the cost savings.
2. The type of units available each month. More effective units in maintenance means commitment of less economical units and thus higher cost savings.
3. Load demand and its variations. In case of low load, the more economical base units can satisfy demand at lower cost than the currently applied tariffs for wind power. On the other hand in periods of high load, gas turbines with costs significantly higher than the applied tariffs are committed.
4. Wind power production and its correlation with demand. If the wind power production is high in periods of low load, then economical units are forced to operate at lower than optimal set-points increasing operating costs. On the other hand, high wind power in high load periods reduces significantly operating costs.

5. Technical constraints. It is possible that the system operators need to commit additional units for reliability, or to satisfy reactive power requirements, even if the committed units are not the most economical ones.

Thus during May and June, Wind Power is shown not to be financially beneficial. This is due to the relatively low fuel costs, the availability of all effective thermal units and the fact that the wind power production was rather high at low demand and low at high demand. Comparison between the actual cost of operation including the compensation of wind power producers and the cost of purely thermal operation under the same load and maintenance conditions, calculated optimally, is shown in Table 21.

Table 21: Comparison of actual operation cost versus cost of purely thermal operation (2000)

	Heavy Oil (tn)	Diesel Oil (klt)	Cost (k€)
Actual	263,166.5	283,303	178,505.6
Purely thermal	269,014.3	324,499	181,099.3
Difference	5,847.76	41,196	2,593.7
Percentage savings	2.22%	14.54%	1.45%

It can be seen that in 2000 annual savings of 1.45% are obtained amounting to a total cost of 2.6 Million €. It should be noted that these costs do not include the costs incurred in the system by possible intentional load shedding due to security reasons. For example, with the current thermal installed capacity, if the Wind Parks were not installed, the unserved energy would reach 11.6 MWh in the periods (24/10/2000 at 13:05-13:20) and (10/12/200 at 17:50-19:40) with a maximum load shed of 8.1 MW for 5 minutes. The evaluation of this cost is very complex and can include compensation by the Utility imposed by regulatory measures, special reliability tariffs, etc. A related issue is the economic gains obtained by the postponement of capital investments for the installation of new thermal units or the construction of new thermal stations, in order to maintain a satisfactory degree of reliability in order to cover the load.

Table 22: Annual (2000) reduction of pollutants due to wind power production

	Tn	%
Pollutant Particles	60.07	7.27
SO2	368.49	2.41
NOX	260.7	6.03
CO2	119,42	7.78

Moreover, it is interesting to calculate the environmental benefits from the wind power penetration in the energy production of the Crete power system in 2000. These benefits are summarized in Table 22. In view of the EU commitments to reduce Greenhouse Gas Emissions and other pollutants in the near future, the above effect alone would possibly justify support for a wide exploitation of wind power resources in isolated, island systems and other regions in Europe.

14.8 Conclusion

In this paper the current status of renewable energy sources technologies that are installed on Greek islands are presented, namely the demand and installed capacity, the RES capacity by type, the RES share in energy demand and the energy cost in Greek islands. As a case study, the effects of wind power penetration on the economy of operation of island systems are investigated. The autonomous power system of Crete, the largest Greek island is used as a study case. Based on actual operating data during 2000, it was shown that a purely thermal production system, even following optimal operation, would increase operation costs by 2.6 Million € with the associated GHG emissions. These results indicate that wind power penetration in the Greek islands contributes positively not only in preserving their environment, but also provides significant financial gains for the system.

14.9 References

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15 IMPACT OF ENERGY STORAGE IN THE OPERATION OF HYBRID POWER SYSTEMS IN ISOLATED REGIONS

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15.1 Abstract

Electrical Energy is not conveniently stored in large amounts. In small autonomous systems however, energy storage can critically contribute to the increased penetration of Renewable Energy Sources, such as wind and sun, by increasing the reliability of the power system without significant increase in the operation cost. In this paper, the impact of energy storage, in the secure and economic operation of the Greek island of Kythnos is investigated and ways of exploiting the existing storage devices are proposed.

15.2 Introduction

Electrical energy is not conveniently stored in large quantities. However, storage devices, such as battery banks, flywheels, superconducting Coils (SMES) and pump storage have been used by utilities for load leveling, improvement of power quality and co-operation with renewable energy sources, as described in [66]. In small size, isolated power systems, in particular, energy storage can significantly help in the increase of RES penetration improving at the same time the reliability indices of these systems. This application of energy storage has been studied [67], [68], in order to identify the reliability indices of small, autonomous, hybrid systems with a variety of Renewable Energy Sources (RES) and with or without diesel units.

In Greece there are several islands with a peak demand of 1-5 MW that are operated isolated. These islands are characterized by high operating costs resulting from imported fuel consumed in Diesel units, favorable conditions for exploitation of renewable energies and low demand during winter that constrain this exploitation. In this study, the impact of storage (battery bank) in reducing the operating cost by offering fast reserve, and in increasing the steady state security of the system, in case of machine trip is investigated. The island system of Kythnos is used as a study case.

15.3 The Kythnos Study Case System

Kythnos is a small island with about 2000 inhabitants, within 3 hours by boat from the port of Pireaus. It runs autonomously, having a long history in RES exploitation. It was back in 1982 when the first wind park of Europe was installed with 5 Wind Turbines (WTs) of 20 kW each. Since then, the system has been upgraded with the installation of a 100 kW PV plant, the replacement of the WTs with higher capacity ones of 33 kW each, the installation of a 500 kW WT and a battery bank of 400 kWh/500 kW [69]. All these units are coordinated with the Diesel Power Station of the island via a control system as described in [70]. The Kythnos generating units are summarized in Table 23.

Table 23: Installed Capacity on Kythnos

Quantity	Type of Unit	Capacity
5	Diesel units	5*400=2,000 kW /2,500 kVA
1	Wind Turbine	500 kW
5	Wind Turbines	5*33=165 kW
1	PV Power station	100 kW
1	Battery Bank	400 kWh/500 kW
1	Phase Shifter	600 kVA
1	Compensation bank	8*100=800 kVAr

The total demand of the island in 2002 was 5,630 MWh. The peak demand during summer (August) was 1,605 kW (19/8) and the minimum demand was 120 kW during the early morning hours of October. Typical load curves for winter and summer are shown in Figure 52.

The energy produced by RES during 2002 exceeded 11% of the annual demand (10.2% by the WTs and 1% by the PV). During 2002, there have been times that the (RES) penetration reached 100%, i.e. the system was operating with no Diesel units committed as described in [71]. In Figure 51 the RES penetration for 2002 is shown. It can be seen that the RES penetration exceeded 40% for more than 1,000 hours.

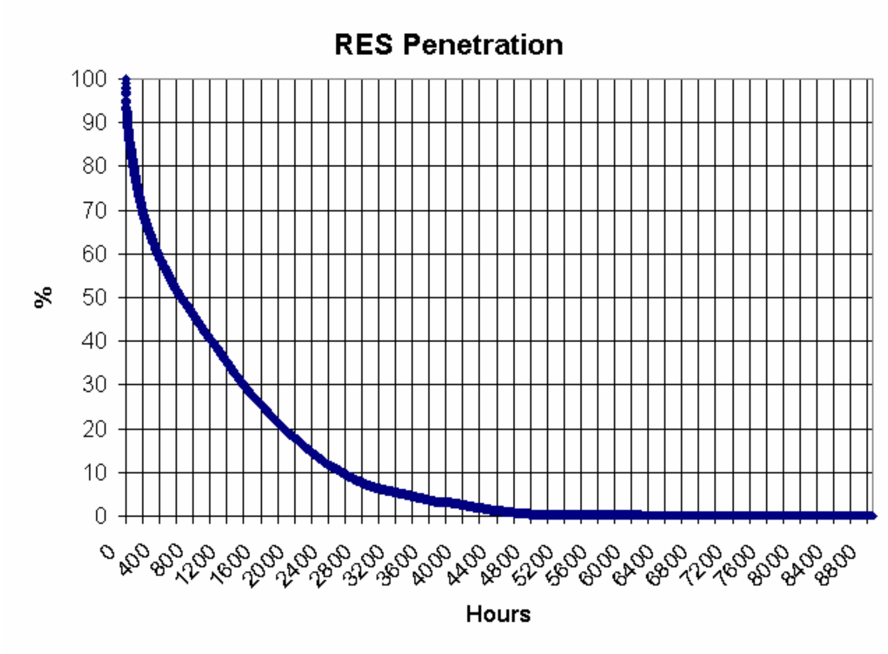

Figure 51: RES penetration curve

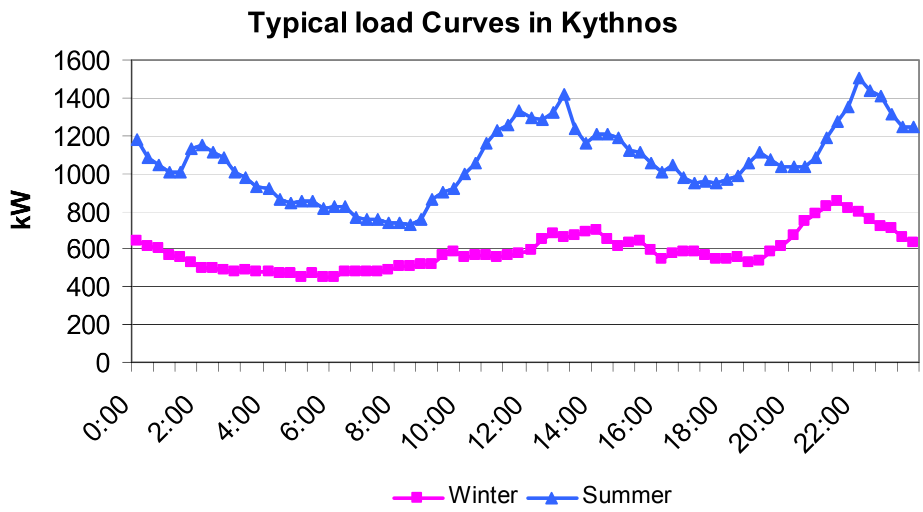

Figure 52: Typical Load Curves from Kythnos

15.4 Proposed Methodology

In order to investigate the impact of energy storage on the operation of Kythnos, three different scenarios regarding the operational scheduling of the five diesel units have been studied. In these scenarios, load and RES production measurements at 20 minutes intervals, as obtained from the SCADA system of the island have been used.

At each time interval, the Economic Dispatch (ED) problem using the Sequential Quadratic Programming (SQP) method described in [72] is solved. This method is a generalisation of the Newton's optimisation method, which uses a quadratic approach of the objective function and linear approximations for the constraints of the problem. The method guarantees that the solution found is the global optimum in the feasible space, if the objective function is convex, as in our case. The objective function takes into account the cost function of each thermal unit (operating cost) at interval t - quadratic for the Diesel units of the island -, as well as start-up and shut-down costs.

In addition, the following constraints are considered:

a) Production covers demand and losses

b) Technical minima and maxima of the diesel units

c) Ramping rates (kW/min) of the diesel units

d) Minimum Spinning Reserve for the Power System.

The demand to be dispatched to the committed diesel units, Edload, is the same in all three scenarios, as defined by:

$$\mathrm{Edload} = \mathrm{Demand} - \mathrm{PV\_prod} - \mathrm{Wind\_prod} \tag{3.1}$$

where

Demand: Load of the system

PV_prod: PV production

Wind_prod: WT production

15.4.1 Operating Scenario 1

Accordingly, the committed units are able to meet the demand (3.1), but also compensate for the uncertainty of load and RES production by maintaining sufficient fast reserve. The amount of spinning reserve compensates uncertainty in load demand (Dem_res), Wind power production (Wind_res) and PV production (PV_res). Therefore, the units to be committed should have sufficient capacity to meet the demand defined by:

$$\mathrm{UCload} = \mathrm{Edload} + \mathrm{PV\_res} + \mathrm{Wind\_res} + \mathrm{Dem\_res} \tag{3.2}$$

It is assumed that the operator accounts for 50% of PV uncertainty, i.e. PV_res is calculated from

$$\mathrm{PV\_res} = \mathrm{PV\_prod} \cdot 0.5 \tag{3.3}$$

It is assumed that the minimum percentage of reserves for wind power is 20% of the nominal capacity of the wind park. This percentage increases linearly to 100% as the wind power production is reduced as depicted in Figure 53.

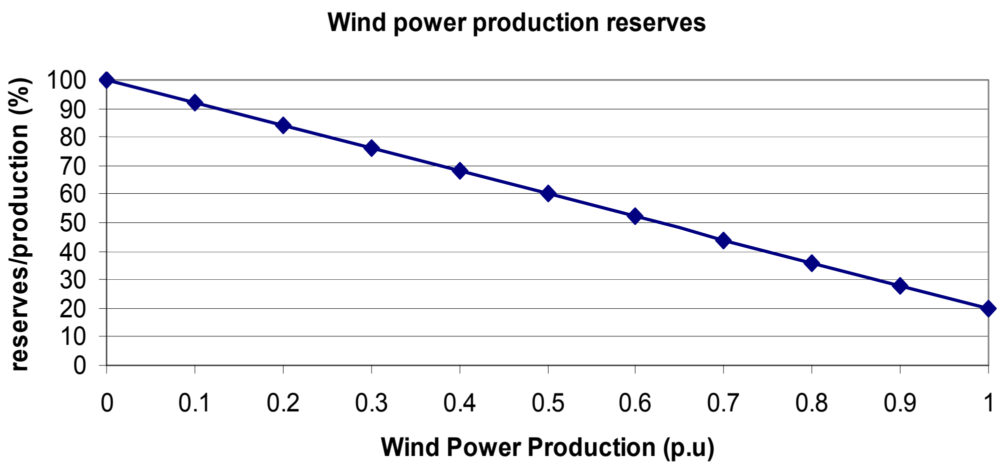

Figure 53: Wind Power Reserves

Thus the reserves to compensate for Wind power production uncertainty are:

$$\mathrm{Wind\_res} = \left[1 - \frac{0.8}{\mathrm{Ins\_wind}} \cdot \mathrm{Wind\_prod}\right] \cdot \mathrm{Wind\_prod} \tag{3.4}$$

where Ins_Wind is the installed capacity of the WTs.

Load uncertainty is based on the findings of the MORE CARE project described in [73], where the short-term load forecasting algorithms for island systems described in [74] have shown during their evaluation presented in [75] a mean square error of 6%.

$$\mathrm{Dem\_res} = \mathrm{Demand} \cdot 0.06 \tag{3.5}$$

Since all the units to be committed are identical, only the number of units to be committed has to be identified. This number (UC_No) is found by dividing the UCload by the maximum output of the units, reduced by a small percentage kept for spinning reserve

$$\mathrm{UC\_No} = \left[\frac{\mathrm{UCload}}{\mathrm{Un\_Cap} \cdot \mathrm{Spin\_perc}}\right] \tag{3.6}$$

where Un_Cap is the nominal capacity of each unit and Spin_perc is the nominal capacity of the diesel unit considering its fast spinning reserve, 0.98 in our application, meaning that the upper 2% of the capacity of the unit is used only for emergency.

15.4.2 Operating Scenario 2

In this case it is assumed that the operator wishes to maintain sufficient spinning reserve not only to cover uncertainties, but also to cover the load, in case of machine trip. Therefore, the committed units are optimally dispatched to meet the Edload (3.1). In case of a machine trip, the rest of the committed units should be adequate to meet the Edload demand. In order to calculate the number of units (Ed_No), the following process is followed.

1. For NumUn=2 to available number of units calculate the maximum available capacity for meeting this requirement

$$\mathrm{LimComm} = (\mathrm{NumUn} - 1) \cdot \mathrm{Un\_Cap} \qquad (3.7)$$

2. Compare Edload with these limits. The lower of them that is higher than the Edload defines the number of units that is sufficient to meet the machine trip requirement.

It should be noted that committing 2 units for very low values of Edload will lead to very low operating points for the diesel units that results in low fuel efficiency and in general decreases their life time. In order to avoid such operating points, it is assumed that the diesel units should be dispatched at a level higher than 30 % of their nominal capacity. Therefore the limit above which 2 units should be committed is assumed to be 60 % of the nominal capacity of the units. For the Kythnos system this level is 240 kW – 60 % of the 400 kW installed capacity. In case only one unit is committed, the technical minimum is 40 kW.

Table 24 shows the number of units according to the Edload for the island system of Kythnos so that the system is adequate in case of machine trip.

Table 24: ED_No and Limits for Kythnos

Limits for Commitment (kW)	ED_No
40	1
240	2
400	3
800	4
1200	5

When the Edload is higher than the capacity of the (available number of units –1) the system is not adequate to meet the total demand in case of machine trip, even if all the units are committed. Therefore in such a case, the demand should be reduced to the above stated capacity, unless energy storage is available. For the Kythnos system this happens when the Edload is above 1,600 kW.

The number of units to be committed is determined as the minimum number of units that satisfies both the spinning reserve and the machine trip limitations, that is the maximum of UC_No –as calculated by (3.6) and Ed_No as defined by Table 24. Compared to operating scenario 1 the number of units to be committed is at least equal. In general, more units need to be operated for more hours than in the operating scenario 1.

15.4.3 Operating Scenario 3

This scenario sets the same demands as the previous scenario, but the operator has a storage device, a battery bank, at his disposal. The operator does not have the total nominal capacity of the battery available, but he knows the lower limit of its available power, i.e. the limit below which the battery bank should not be discharged. It is also assumed that the operator is mainly interested in using the storage device as back-up power during the time necessary to start up a diesel unit, rather than using it as an energy source. It should be noted that for battery banks, the amount of energy derived is decreased when the discharge rate increases as typical battery manuals describe [76].

The limits calculated in operating scenario 2 are modified as follows. ED_No is defined as follows:

1. For NumUn=2 to available number of units

$$\mathrm{LimComm} = (\mathrm{NumUn} - 1) \cdot \mathrm{Un\_Cap} + \mathrm{BattCap} \qquad (3.8)$$

   where BattCap is the capacity of the storage device to provide power during the start–up time of the units in kW

2. Calculate the ED_No using the limits calculated by equation (3.8)
3. Calculate the limit above which a second unit should be committed. The same principle with the operating scenario 2 is followed with the difference that the battery capacity is taken into account. The limit for a second unit to be committed is determined by the maximum of the 60% of the nominal capacity of the units and the BattCap.

From the analysis of the Kythnos data the lower level of the battery bank for the year of study was about 65 % of its nominal capacity. It is assumed that the operator never leaves the battery output fall below that level. This can provide the system with a power of 300 kW for 5 minutes, time that is sufficient for cold starting up one of the units and compensate for the machine trip. Therefore, the output of the battery is higher than the 60 % of the capacity of the units and therefore there is no need to commit two units in case of low load.

Table 25 provides the number of units to be committed in order to face a possible machine trip in Kythnos.

Table 25: ED_No and limits with Energy storage

Limits for Commitment (kW)	ED_no
40	1

300	2
700	3
1100	4
1500	5

As in operating scenario 2, if the Edload is higher than 1,600 kW there will be inability to serve the total load, if a machine trips. However, the battery bank can help in reducing the duration of load curtailment, as well as the maximum load shed decreasing the energy not served at least equivalently to the capacity of the battery bank.

The number of units to be committed is again the maximum of ED_no and UC_No.

15.5 Results

In order to evaluate the economic operation of the three scenarios, the monthly fuel prices and the fuel consumption of each installed unit are taken into account. The operating cost for each scenario is calculated and the results are shown in Table 26. These results are also compared with the actual operation of the system as evaluated using the actual production time series.

In order to evaluate steady state security, the number of 20 minutes intervals, that the system would not be capable to meet demand in case of machine trip is calculated. The results for each of the operating scenarios are shown in Table 27. These results are compared with the number of intervals that the system would not be adequate to meet Edload in case of machine trip when the battery storage is available or not in its actual operation.

15.5.1 Economic Operation

Actual operating cost of the system is 522,856 Euro. Operation costs according to the operating scenarios are summarized in Table 26.

Table 26: Comparison of Economic Operation

	Scenario 1	Scenario 2	Scenario 3
Operating Cost	507,571.5 €	572,305.7 €	511,585.1 €
Difference with actual operation	-2.93 %	+9.46 %	-2.16 %
Difference with cheapest scenario	0	+11.87 %	+0.79 %

These results show that the operating cost can be significantly reduced by optimal Economic Dispatch and lower uncertainty in load and RES power forecast. The latter conclusion is in agreement with results from much larger systems, like Crete, as described in [75]. Scenario 1 is the cheapest scenario, since it sets the least reserve demands and therefore requires the minimum number of units to be committed. In the other two operating scenarios, the number of units to be committed is at least equal to the number of units of operating scenario 1. Committing more units at lower operating points decrease fuel efficiency and increase operating costs. The battery bank increases the limits above which additional units need to be committed. This affects not only the number of committed units, but also the time of operation in order to compensate for the machine trip.

If the battery capacity is equal to the capacity of one of the units, 400 kW in this case, then the limits for committing a new unit should be modified according to (3.8). The number of units ED_No and UC_No are summarized in Table 27. From this table it can be concluded that the number of units to be committed and subsequently the operating cost is the same with operating scenario 1.

Table 27: ED_No and limits with Energy storage equal to the capacity of one of the units

Limits for Commitment (kW)	ED_no	UC_No
40	1	1
400	2	2
800	3	3
1200	4	4
1600	5	5

15.5.2 Steady State Security

Table 28 presents the number of intervals when system is inadequate in case of machine trip.

Table 28: Number of intervals when system is inadequate in case of machine trip

Operation	Intervals	Difference with Actual Operation
Actual (w/o battery)	21,910	0
Actual + battery	2,149	-90.2%
Scenario 1	20,283	-7.43%
Scenario 1 + battery	1,345	-93.86%
Scenario 2	1,672	-92.37%
Scenario 2 + battery	0	-100%
Scenario 3	0	-100%

In actual operation, the number of intervals the system would not have been able to meet the load, in case of machine trip, is 21,910. If the battery bank with 300 kW capacity is taken into account, the system would not be able to meet the demand for 2,149 intervals. Therefore the battery bank reduces the insecure operating points by 90.2%.

The number of intervals that the system is not adequate if operating scenario 2 is used is due to the low values of Edload and the requirement to avoid low operating points. The demand slightly exceeds 1,600 kW only for less than one hour and during this period there is enough Wind Power and PV production so that the Edload is below 1,600 kW. Therefore there is no possibility that the installed units are inadequate to meet the demand due to lack of capacity in case of machine trip.

The battery bank helps in decreasing the intervals that the committed units are not adequate to meet demand in two ways. First by reducing the number of intervals of low operating points without sufficient fast reserve and secondly by decreasing the time of inadequacy, when Edload exceeds 1,600 kW. Since the demand never exceeds 1,605 kW for 2002 and the battery capacity is higher than the limit for low operating point, the system can adequately meet the demand during the time necessary for starting up a new unit, even if the only committed unit trips. Therefore with the proposed operating scenario 3 the number of insecure operating points is reduced to zero.

Moreover, the impact of battery storage if operating scenario 1 is applied is investigated. The results show that the number of inadequate intervals is reduced to 1,345. It is significant to note that the number of insecure operating points can be reduced below the number of the insecure operating points with scenario 2 when the capacity of the storage device is relatively large. However, the possibility of interrupting part of the demand in case of scenario 1 still holds compared to its elimination when operating scenario 3 is used. This possibility is eliminated if the battery capacity is equal to the capacity of one of the units, meaning 400 kW because this is equivalent to have committed a unit with equal capacity with the unit that trips.

15.6 Conclusions

The impact of storage in the economic and secure operation of the system of Kythnos has been investigated. The methodology described can be used for any storage device such as flywheel or pump hydro units if the characteristics for the time and the power that they can supply are known.

It can be concluded that the battery bank helps significantly secure operation of the island by decreasing the number of intervals of inadequacy in case of machine trip. The level of security is greater even when the case that spinning reserve is provided by the diesel units at lower cost. It can be further concluded that the unit commitment of an island system when a storage device is available can be performed in such a way that eliminates the danger of interrupting load in case of machine trip without increasing significantly the operating cost.

The determination of the capacity of the storage device that eliminates the danger of insecure operation without increasing the operation cost is an area of further study. Such a study can be extended so that the cost of the storage device is taken into account so that the payback period is calculated.

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16 PROJECT MANAGEMENT: CASE OF BIOMASS

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16.1 Introduction

The following article presents the project management of a biomass case study. In it, some points specific to biomass projects are addressed, specially the ones regarding fuel issues and financial issues. Similarities and differences between a heating and a CHP project are shown at the end.

As in every other project there are three common phases that have to be thoroughly examined: planning, construction and operation.

16.2 Planning

Planning is the first and the most important process in the project. While selecting the guidelines for the project it is worthwhile taking some additional time for consideration and planning, because mistakes made during this phase can rarely be modified or fixed. A project with poor planning has a risk of becoming an engineering and economic disaster.

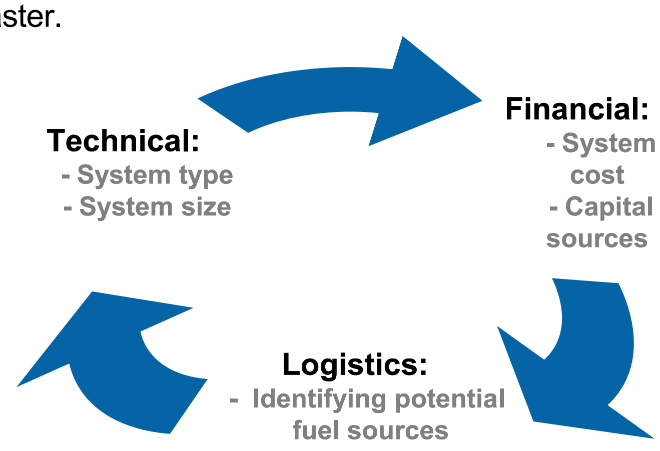

Figure 54: Planning procedures

Trade-offs between technical, financial and logistical issues often don't allow us to build an ideal system. Instead we're forced to iterate the decision making and planning procedure to reach a compromise between wishes, demands and problem constraints in order to reach an optimal system for the given circumstances and conditions.

16.2.1 Technical planning

The size and type of system are the major factors in a biomass heating project, which influence the investment cost and construction process. While small "plug and play" systems are mostly standardized and adapted for residential heating, big systems are usually custom made for the consumer.

16.2.1.1 System type

Several different systems capable of using different kinds of biomass are available on the market. Wood-chip fired and pellet fired systems are most commonly used, while other sources such as straw, corn or biogas have a lower market penetration.

Wood-chip fired systems are very suitable for regions where biomass is abundant and there is a strong wood processing industry presence as the cost of fuel is low. However wood chips are more suitable for the larger systems as regulation is still a problem for small scale automation. Wood chips also require operating a grate furnace which raises the investment costs due to its construction.

Pellet fired systems require a lower investment since the burning takes place in a stoker that is smaller in size (and cost) as compared to grates. Adequate fuel feed is easily achieved with a screw conveyor. Due to a lower investment cost and higher fuel costs such systems are suitable for smaller applications that are not necessarily located close to the pellet source.

16.2.1.2 System size

Size is determined by the heat demand of a building. Generally the older buildings have a bigger demand for heat per surface area. As a rule of thumb an estimate for the yearly heat consumption in Europe is around 50 kWh/m^2 for energy efficient buildings, around 100-120 kWh/m^2 for recent and double glazed buildings and between 150-250 kWh/m^2 and sometimes even more for older buildings. In the latter an investment in insulation is recommended prior to installing a new heating system.

16.2.1.3 Technical planning experience

The most common and everyday mistake that is encountered in heating projects is an oversized system. In order to protect themselves against complaints and lawsuits, designers usually scale up the system by at least one size. Such a system is not operate at an optimal point, which lowers the efficiency and consequentially raises fuel consumption. An investor in this case pays two times for the error - higher investment costs and higher fuel costs.

Another common mistake is oversized storage capacity. This is not a very problematic issue if the stored material is dry, such as pellets. In this case large storage capacity might prove useful for taking advantage of fuel price lows when buying the fuel. However it will surely prove a wrong investment when the material is not dry. Fresh wood chips, if not consumed on time, start to degrade and ferment which causes unpleasant smell.

If there is an existing gas or heating oil system in the building, the investment can be cut in half by keeping the old heating system and installing a biomass system for only 50% of the peak heat demand. As shown in Figure 55 and Figure 56, in this case biomass heating covers the base load which accounts for around 80% of the total yearly heat consumption.. Further improvements can be made by applying thermostatic valves to the radiators or installing a in-floor heating system.

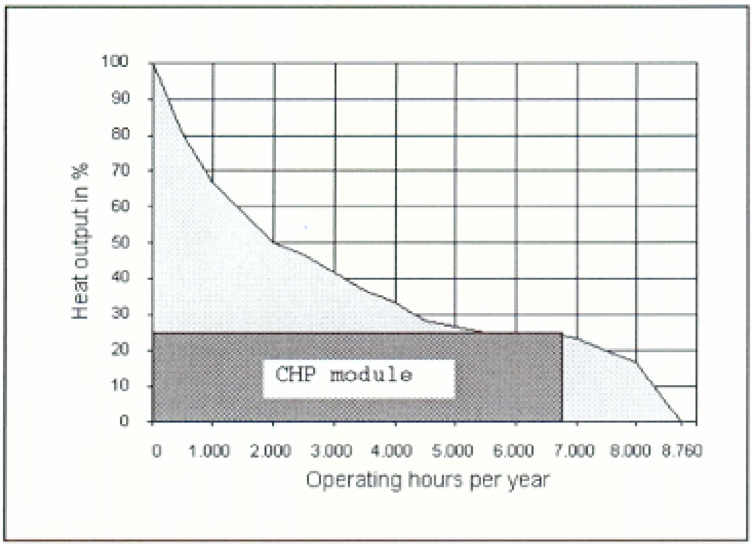

Figure 55: Typical heat demand curve with a possible CHP use (Source: Autocommerce)

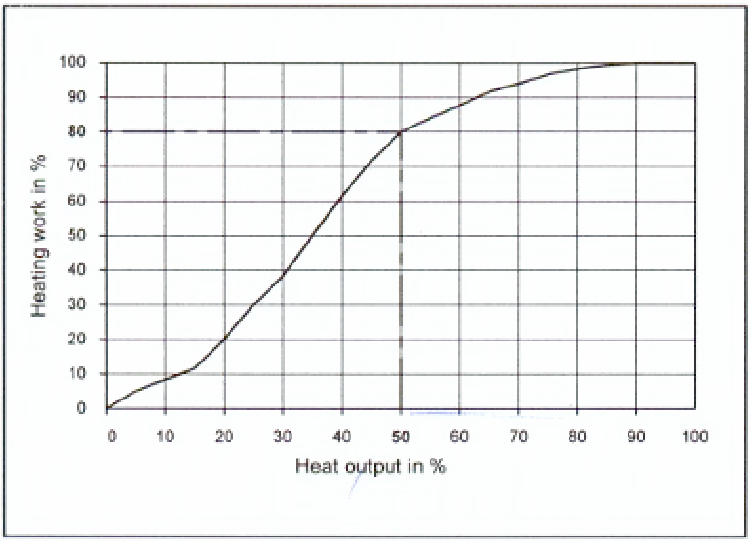

Figure 56: Typical cumulative heating curve (Source: Autocommerce)

16.2.2 Financial planning

16.2.2.1 Identifying system cost

There is a substantial cost difference between pellet fired and wood-chip fired systems as the latter is more complicated. Depending on the fuel sources it is necessary to consider both options in order to choose the most convenient one.

Operation and maintenance (O&M) is a minor consideration in small residential systems where the process is automated, simple and safe. It is however often underestimated in bigger systems where safety demands are much higher. An estimate for the annual O&M cost of a bigger biomass heating plant is between 2% and 3% of the initial investment.

16.2.2.2 Identifying potential capital sources

Renewable energy technologies have several potential capital sources, especially in Western and Central Europe, while the situation is getting better in the Western Balkans. Since the investment in biomass heating technology is very capital intensive, financing is extremely important. There are several local and international "green" funds that are available for investments in renewable energy and offer subsidies or convenient credit rates. Examples of the funds and EU programs are OPET, GEF, ECO Fund in Slovenia, etc. Some of the funds or programs are available solely for the biomass investments.

16.2.2.3 Financial planning experience

Finding the optimal size of the system is crucial for the operational and financial success of the project.

Larger biomass systems are around three times more expensive compared to heating oil systems. As previously discussed, costs can be reduced considerably if one builds the biomass system in the system with an existing heating oil boiler. Heating oil boiler is then used only for peak demand coverage and for the backup.

When different kinds of biomass are available in the vicinity of a heating system it is also suitable to think of some alternative solutions that require a higher investment, but can take advantage of a very cheap fuel. With the flexibility of burning various biomass types one can choose the cheapest fuel from the local farmers such as straw, hay, corn, etc.

16.3 Logistics

16.3.1.1 Identifying potential fuel sources

As transportation represent a major share in the total cost of biomass fuel it is necessary to find fuel sources as close to the facility as possible. It is also necessary that these sources have fuel available and suitable for our system. Some potential fuel sources are:

- Forestry companies,
- Wood processing companies,
- Furniture companies,
- Carpentries, and
- Local farmers.

16.3.1.2 Logistics planning experience

In Western Balkan countries wood pellets are still relatively unknown and there is a high risk of fuel shortages and delivery problems.

Fuel delivery can be as convenient as heating oil or gas. Trucks with pneumatic systems can also deliver pellets, but are not suitable for larger particle fuels.

Figure 57: Transporting wood pellets with a cistern (left), ventilator and filter for pneumatic transport (right)

Having a possibility of acquiring fuel from various sources in vicinity allows us to reduce the risk of running out of fuel.

High oil prices influence the availability of biomass, because of a slow response of supply chain to a market situation.

16.4 Construction

Construction is not a very complicated process as biomass heating systems use the standard elements of conventional heating systems. Smaller residential systems also have a standardized boiler and storage tanks. This is rarely the case in bigger systems.

A major difference between wood and oil heating is the size of a storage tank. As the heating oil energy density is around twice that of biomass and the material and liquid density are also substantially different, a biomass storage tank has to be much bigger. In case of bigger systems a good solution is a covered depot or a silo.

16.5 Operation

The operation of a biomass heating process can be easily completely automated and in this regard doesn't differ from the oil heating system. It can be totally remotely controlled using a Central Monitoring System (CMS), however there are some standards that are present when the system is bigger and when pressurized steam is used. Such systems need constant human supervision.

Generally speaking biomass systems are very robust and require low maintenance. The cost is usually around 2 to 3% of the total investment.

16.6 Differences with power generation or CHP

There is one major difference between a biomass heating project and power generation (or CHP) project. This is system size. Besides a larger system, larger furnaces and storages there is also a higher fuel demand. Since biomass industries are usually very dispersed, it is much harder to find a reliable fuel provider.

Also additional labor force is needed due to higher pressures (heat water, steam) and higher safety standards.

Biomass power generation or CHP is not feasible if the heat consumption is seasonal. That is why most CHP projects are built close to some specific industries where the heat consumption is constant throughout the year. Some very suitable industries are wood processing industry, where the waste from the production process is fuel for the CHP and heat is required for drying, food processing industry, galvanizing…

16.7 Conclusion

As we have shown the key issue in biomass project management is proper planning, while construction and operation don't require any additional know-how.

During planning, it is recommended to avoid over-sizing as the biomass systems are more capital intensive than heating oil ones. We can also save money with refurbishment and utilization of an old heating system and use it for peak coverage. In this case it is advised that the additional system power is only around 50% in order to cut the investment and to supply around 80% of the yearly heat demand. To maintain heat delivery and (or) power production we should also use a variety of fuel sources in order not to run out of fuel.

Despite all the renewable energy subsidies, incentives, programmes and low interest loans available in Western and Central Europe, capital is still an issue in Western Balkans, but the support is slowly growing also in this region.

Key issue in biomass project management is **planning** and the following issues should be taken into consideration:

- Over sizing is costly!
- Old systems can be used for peak coverage.
- Several possible capital sources are available; and
- A variety of fuel sources is suggested.

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