MSc Program
Renewable Energy in Central and Eastern Europe

Electricity generation with renewables in Austria - An economic analysis of biomass combustion CHP, photovoltaic, small hydro- and wind power

A Master's Thesis submitted for the degree of
"Master of Science"

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Affidavit

I, **Mag. Robert Schwaiger** hereby declare

1. that I am the sole author of the present Master Thesis, “ELECTRICITY GENERATION WITH RENEWABLES IN AUSTRIA - AN ECONOMIC ANALYSIS OF BIOMASS COMBUSTION CHP, PHOTOVOLTAIC, SMALL HYDRO- AND WIND POWER", 165 pages, bound, and that I have not used any source or tool other than those referenced or any other illicit aid or tool, and
2. that I have not prior to this date submitted this Master Thesis as an examination paper in any form in Austria or abroad.

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Date Signature

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Abstract

The dependency on fossil fuels is growing steadily, putting Europe's energy self-sustainability at massive risk. The recent political disturbances in Russia and Ukraine show how dangerous the situation is. If Russia decided to cut the gas supply, Austria's reserves would suffice for only few months. Meanwhile climate change is under huge progression due to GHG emissions, caused by the excessive use of traditional fuels. Establishing renewable sources of energy is the only way to change this situation. But can renewables prevail at currently low electricity and oil prices?

The first part of this master's thesis covers the Austrian electricity market, economic and legal frameworks. Furthermore a short overview of the realisable RES potentials will be given.

The core of this paper forms the analysis of five existing RES power plants with maximum capacities of 0,5 MW to 4,5 MW, and outputs of 2 GWh to 4,5 GWh, covering biomass combustion, photovoltaic, small hydropower and wind power technologies. The range of size has been chosen by the author because it is considered to be an optimal size for decentralised electricity production, being able to service communities from 1.000 to 2.000 inhabitants. The focus lies on the economic performance of the chosen plants, including dynamic investment calculations and evaluations of the electricity generation costs. Furthermore, sensitivity analyses will test the robustness of the results. In the last section the projects will be compared with traditional fuel based electricity-generating technologies.

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1 INTRODUCTION

Fossil energy sources in these days have already many critics in our society. And although it is known that the use and the extraction of this kind of fuels are causing grave damages to the world and its habitants, the business with oil, gas and coal is still promoted even more than renewable energy. If people Europe-wide were asked randomly, which kind of energy production they would prefer, solar, wind and hydroelectric sources would presumably be the most frequent answers. Hence there is an imbalance between what people think and how they act, because renewable energy has a share of only 16% of worldwide energy production and fossil fuels over 80%. In the author's opinion, the reasons for that situation can of course be found in the long tradition of fossil fuel driven and nuclear electricity production on one hand. On the other hand this is due to the high influence of the nuclear and oil-lobby, not necessarily because of better economic performance. This point gets clear, when looking at the following numbers: Since 1970 255 billion € were spent for coal subsidies and 190 billion € for nuclear power. Renewables have been promoted since the late 1990, taking a share of only 85 billion € (Günsberg et al. 2015: 13).

Since 2009, a radical decay of Europe-wide electricity prices can be seen, which in addition makes it difficult for renewable technologies to come up. In the course of the European Union climate and energy package, launched in 2007, the member states started to launch support systems for RES in form of feed in tariffs or investment capital grants, in order to make RES competitive against conventional generators. This has led to a strong growth of offshore wind park installations in northern Germany, for example. Ironically this has become one of the driving forces, putting pressure on the wholesale electricity price in the German-Austrian market.

However, Austria traditionally covers a high share of the electricity demand with renewable energy. Over 60% of Austria's electricity demand is already covered by hydropower. Other renewable energy sources (RES) contribute approximately 10% to the energy mix; traditional energy carriers and imports from other countries cover the rest (≈20%). In order to reduce the dependency on oil exporting countries and to fight against the climate change, it is highly recommended to substitute conventional energy carriers with renewables. And Austria with its vast river system and abundant wood resources wakes the perception that there is still enough potential for additional RES capacities. (Boltz et al. 2015: 20)

The main RES technologies for electricity production that are installed in Austria are wind power, hydropower, solid biomass and photovoltaic, since they have already reached market standard and economic realisable potentials are available. Unlike conventional power plants, the economic performances of renewable technologies, to a high degree depend on the locations of the sites. This restriction reduces the applicability of each system drastically and makes comprehensive planning necessary before a project can be realised. On the other hand, this could promote rethinking the conventional concept of central electricity production and change into a more decentralised model. The only question is, can RES compete with traditional fossil fuel driven and nuclear electricity production technologies?

1.1 Definition of the research problem and outline of the main research questions

The core objective of this paper is to analyse the economic performance of renewable electricity production projects under the prevailing conditions in Austria. Hence, for the main RES technologies, namely biomass combustion, photovoltaic (PV), small hydropower (SHP) and wind power, existing projects with sizes between 0,5 MWel and 4,5 MWel and outputs between 2 GWh and 4,5 GWh were examined. In the course of this master's thesis, the following questions are going to be answered:

1. *What does the legal and economic framework for RES look like in Austria?*
2. *How much realisable energy potential exists for biomass, PV, SHP and wind, and where in Austria can it be found?*
3. *What are the technical concepts of the analysed plants and how efficient is energy conversion?*
4. *What are the electricity generation costs for the four technologies, and are the chosen projects economically feasible?*
5. *What are the main influencing factors of the electricity generation price?*
6. *Are the projects feasible without subsidy and FITs? If not, which market price would be necessary?*
7. *Is there one RES technology that should be preferred in Austria?*
8. *Can the analysed technologies compete with traditional fossil fuel driven and with nuclear technologies?*

Of course one of the major advantages of RES technologies, compared to traditional energy generators, is the environmental sustainability. But this paper clearly puts focus on the economic performance of RES, thus no ecological assessments of the chosen projects were performed.

1.2 Structure of the master's thesis and methodical approach

The first question will be answered in chapter 2 of this paper, by providing an overview of Austrian electricity market players, price building mechanisms, legal frameworks and subsidy systems. Therefore research of relevant literature and the internet was performed, complemented by reviewing slides and information, gathered during the lectures of the master course *Renewable Energy in CEE* from October 2014 to April 2016 in Bruck an der Leitha, Vienna, Prague and Turkey.

In chapter 3 the prevailing RES potentials in Austria are discussed by describing the results of a study, called *Regio Energy,* which could be found in the internet, provided by the Klima- und Energiefonds.

The spectrum of the analysed technologies in this paper comprises PV, wind power, biomass combustion and small hydropower. In chapter 4, a brief technical introduction will be provided for each technology, in order to give a better understanding of the different characteristics of electricity generation and conversion efficiencies. The information, concepts and relevant data were also retrieved via Internet research and taken from lectures of the master course *Renewable Energy in CEE*.

In chapter 5 dynamic investment calculations for projects of each technology were performed to answer question 4. Therefore mainly the net present value (NPV) concept and the marginal costs concept of long run generation costs (LRGC) were used. These concepts will be described in detail at the beginning of chapter 5. In order to paint a realistic picture and to have real data available, already existing projects were chosen. The main selection criteria have been the following:

- Not older than max 10 years
- 0,5 – 3,5 MWp capacity or annual electricity production 2 – 4,5 GWh per year

These ranges have been chosen because in the opinion of the author they constitute the perfect size ranges for decentralised power production. Plants within these ranges are able to supply communities of 1.000 to 2.000 inhabitants, which can be found frequently in Austria. Moreover, decentralised energy generation is a desirable concept for the future without fossil fuels. To find eligible projects and to get access to the needed data, relevant experts were interviewed and asked for input, concerning further sources. Finally owners and operators of eligible projects were interviewed via e-mail, telephone or directly at the site. Additional information was retrieved via interviews with relevant experts, Internet research or taken from lectures of the master course *Renewable Energy in CEE.*

In a further step in chapter 5, a comprehensive sensitivity analysis will be performed for each plant, to identify the factors that are most crucial for the success of the projects and to answer question 5. Then the results will be compared and two scenarios will be built, in order to analyse whether these projects could be economically feasible without subsidies and feed in tariffs. At the end of chapter 5 the results of the RES analyses will be compared with conventional electricity generation technologies.

2 LEGAL AND ECONOMIC ENVIRONMENT FOR RES IN AUSTRIA

2.1 The European and Austrian electricity market

The European Court of Justice defines electricity as follows: *“In Community law, and indeed in the national laws of the Member States, it is accepted that electricity constitutes a good within the meaning of Article 30 of the treaty….”* (European Court of Justice, C-393/92, Almelo, No 28). Thus electricity is a commodity which is traded on dedicated market places. Due to physical constraints in transmission capacities, a massive limiting factor for electricity flows, and due to the lack of a harmonised method of congestion management, there does not exist one large European electricity market, but rather several national and regional markets. Figure 1 illustrates the main bottlenecks in the European transmission network, causing the establishment of several market regions, in which prices correlate.

Figure 1: Electricity markets in the EU according to E-Control (Ennser 2015)

The interconnection of national power grids of the continental European states (Great Britain, Ireland, Island, Norway, Sweden, Finland and the Baltic States excluded) forms the European network system. It is often referred to as UCTE-network system, because till 2009 it was coordinated by the Union for the Coordination of Transmission of Electricity (UCTE). In 2009 this function was transferred to ENTSO-E (European Network of Transmission System Operators for Electricity). The international exchange of electricity between the national grids within the UCTE grid is mainly used to even out temporary shortages. Large interconnected grid systems have the advantage that the capacities for reserves and unpredictable loads can be kept at a minimum.

Because of technical reasons the Nordic states Finland, Norway and Sweden formed their own network cooperation, which is not synchronised with the UCTE and is coordinated by NORDEL. The same is true for Great Britain and Ireland, whose networks are coordinated by UKTSOA. The electricity exchange between these network systems happens via high-voltage direct-current transmission through several lines in the North and Baltic Seas. (Paschotta 2012)

2.1.1 Players in electricity markets

Looking at the industry value chain in Figure 2, the participants in an electricity market can be roughly divided into competitive and regulated fields. Electricity generators, trading and supplying services are subjects to free market mechanisms. Since transmission and distribution grids are natural monopolies, they have to comply with rigid regulations, in order to ensure non-discriminatory access for all market participants.

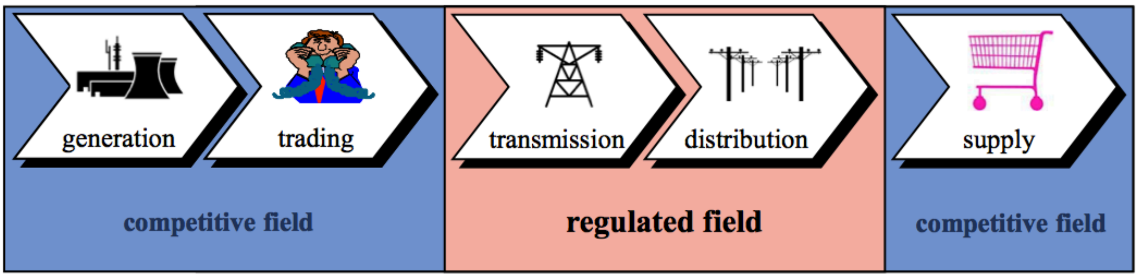


Figure 2: Value chain electricity market (Hofer 2015)

Electricity generators:

Generators in this context are all kinds of power plants that produce electricity and feed it into the public grid. In Austria the range of plant sizes goes from large hydro power plants with peak capacities of several hundreds of MWs, owned by companies like VERBUND, TIWAG or KELAG down to private small photovoltaic installations on roof tops with capacities of few kWs. (Ennser 2015)

Transmission network:

High voltage power lines form the transmission network, designed to transfer bulk power from major generators to areas of demand. Voltages in these networks are typically above 100 kV. The networks have to be extremely robust in order to withstand failures in single and even multiple elements and to continue fulfilling their function. The responsible organs are called transmission system operators (TSOs) or independent system operators (ISOs) and actively manage the systems via dispatch centres. Their main tasks are to keep the amounts of power entering and leaving the grid at balance and to cooperate with interconnected networks and control the load-frequency. (EWEA 2009: 173f)

Distribution networks:

Distribution networks constitute the link between the transmission network and the end customers. They are usually operated below 100kV. Except of RES, very few generators are directly connected to distribution networks, which is called embedded generation or distributed generation. The lower the levels of voltage become, the more the reliability of distribution grids decreases. Grids at 33 kV are expected to lose only a few minutes of connection per year, while domestic customers with a connection at 230 V are expected to lose an hour at least. Distribution networks are operated by DSOs (distribution system operators). The configuration of DSOs is in most cases based on combinations of extreme circumstances (e.g. high ambient temperatures, which reduce the capacity of overhead lines, coupled with maximum demand), in order to ensure that the network conditions always stay within agreed limits. (EWEA 2009: 173f)

Traders and suppliers:

Further major participants in electricity markets are traders and suppliers (retailers). Traders are natural or legal persons that are buying and selling electricity with a view to profit; suppliers are natural or legal persons with the purpose to sell electricity to end-consumers. Trading takes place on stock exchanges or via bilateral contracts, also called OTC (over the counter) contracts. The advantages of stock exchanges are high market transparency, trading of standardised products, anonymous deals, and, since trades are cleared, there is no counterparty risk. On the other hand, on OTC markets tailor-made products can be traded with the downside of respective counterparty risk and limited market transparency. (Ennser 2015)

2.1.2 The Austrian electricity market

Mainly public owned utilities shape the Austrian market. All federal states have their own electric utility companies that are mostly interdependent, because of historically grown alliances and mutual shareholding. Due to the strong relation with electricity generation and sales, DSOs and grid owners have to comply with rigid unbundling rules, based on EU legislation. After the last EU-liberalisation package, strict separation measures like Chinese walls have to be installed between grid operation, generation, trading and sales. Furthermore, Austrian wide operating Verbund AG is worth mentioning, as well as several private companies which started to emerge in 2001, when the Austrian electricity market was liberalised. (VEÖ 2007)

In 2014 Austrian generators produced a total of about 65 TWh of electricity. Figure 3 shows that over 68% of the demand were covered by hydropower (run-of river power plants and pump-storage power plants). Other renewable energy sources contributed approximately 13,4% to the electricity mix; traditional energy carriers and imports from other countries covered the rest. As can be seen, the main part of the generated electricity was fed into the public grid and approximately 12% were generated for own use. The domestic consumption amounts to about 69 TWh without physical exports and pumping (additional 23 TWh). (Boltz et al. 2015: 20)

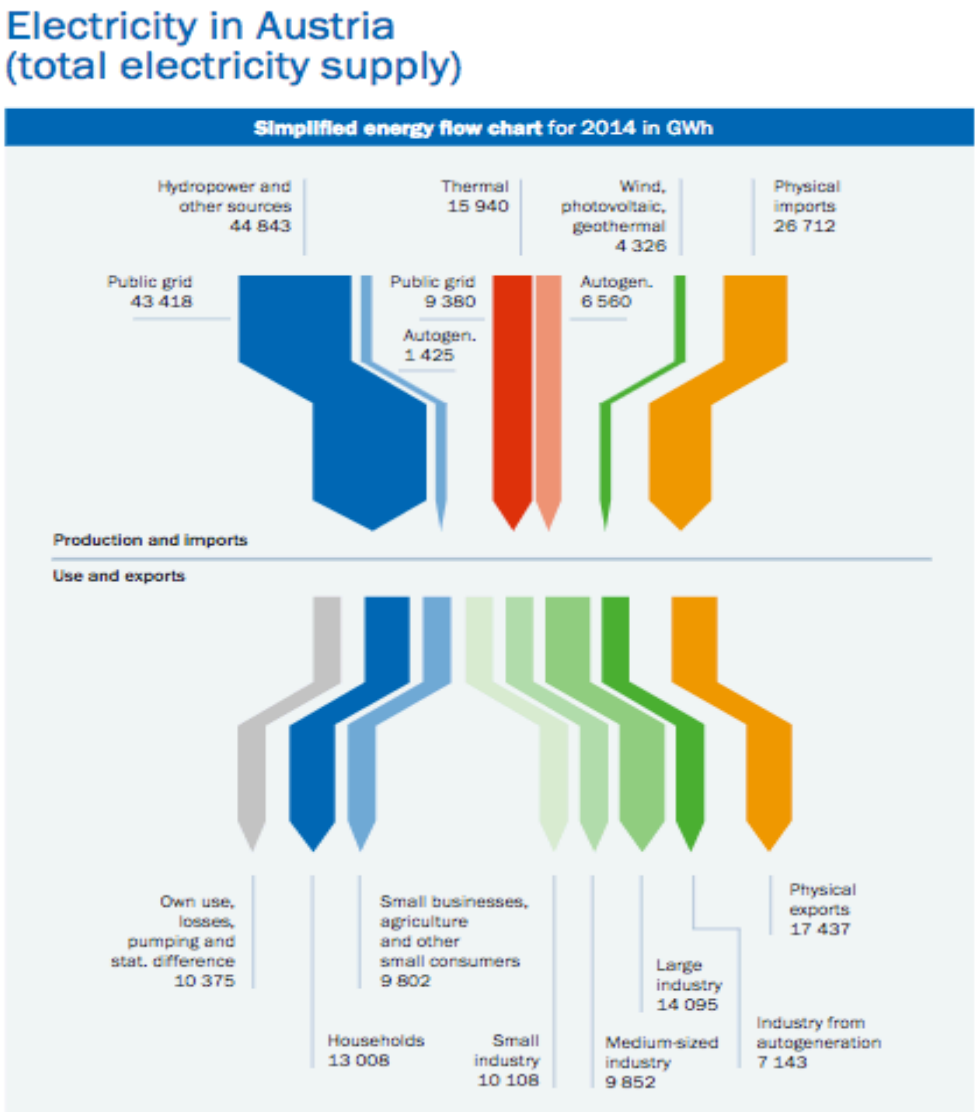


Figure 3: Electricity supply and use in Austria (Boltz et al. 2015)

The Austrian Power Grid AG (APG) operates the high voltage transmission network in Austria (380/220kV) and is responsible for the transport of electricity to 130 lower voltage regional distribution grids. It is certified as ITO (Independent Transmission Operator) and is 100% owned by VERBUND AG. In the year 2014, over 43 TWh were transported via a cable system of 6977 km total length. (Misak 2015)

Before the liberalisation, consumers were supplied by vertically integrated undertakings to whose network they were connected. Nowadays in the course of market liberalisation, suppliers and customers in Austria are organized in balance groups (BGs), in order to guarantee that consumers are able to choose their suppliers freely and to ensure that deals can be settled correctly. These virtual groups have the function to balance injection (procurement schedule, generation) and withdrawal (delivery schedule, demand). Every BG has its own representative (BRP) with the purpose to generate and send the schedules to the APG and the settlement agency. For the control area of APG this is the APCS Power Clearing and Settlement AG, also called balance group coordinator. APCS is responsible for the settlement of electricity and pricing of balance energy. The energy costs on balancing energy are passed on to the members of the BGs. (Ennser 2015)

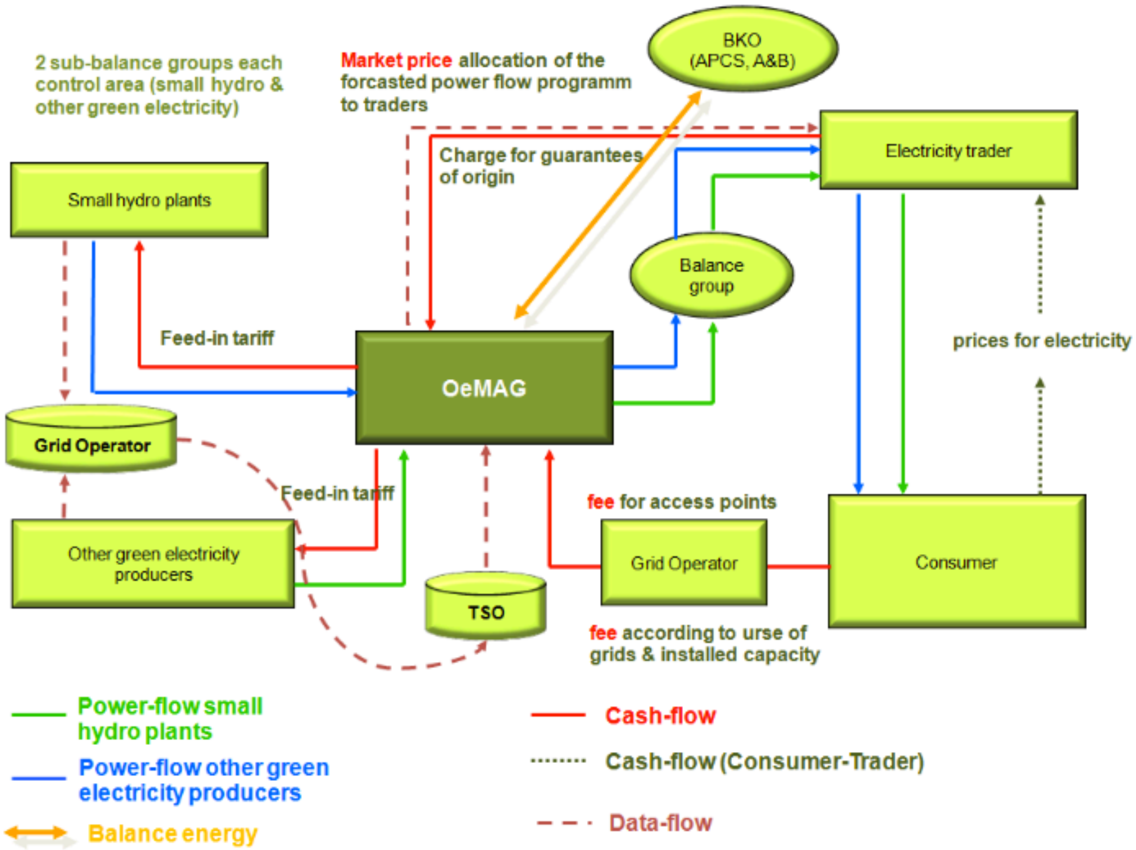


Figure 4: Data-& cash flow scheme of BRP OeMAG (Brandlmaier 2015)

Figure 4 shows how the balance group of RES in Austria is organized. OeMAG, the settlement agency for renewables, is the representative and interface for data-, cash- and power flows between the members of the group. Renewable energy generators sell electricity to OeMAG and receive feed in tariffs. In addition to the market price, traders pay OeMAG charges for guarantees of origin to justify higher prices for consumers who want to buy green energy. The consumer pays the electricity price including taxes and fees to the trader or supplier and fees for access points to the grid operator. In case of wrong electricity scheduling, OeMAG buys balance energy from APCS.

To regulate and control the Austrian market, E-Control, an independent agency under public law, was founded in 2001. Legal legitimation therefore can be found in the Austrian E-Control Act, Electricity Act and the Green Electricity Act. E-Control has the responsibility to set up market rules for the gas and electricity markets and networks, to supervise prices and to enhance transparency on the market. Further tasks are supervision of market competition, controlling of unbundling and supervision of balance group representatives, control area managers and settlement agencies.

2.2 European and Austrian legal framework for energy markets

In general regulations and directives passed by the EU have to be implemented by its member countries on national level within a given period of time. In Figure 5 the hierarchy of legislative acts in the EU is shown, using the example of Austria. National constitutions are the strongest law form (e.g. the Austrian constitution), followed by EU regulations, national law, ordinances and decisions by national legislators.

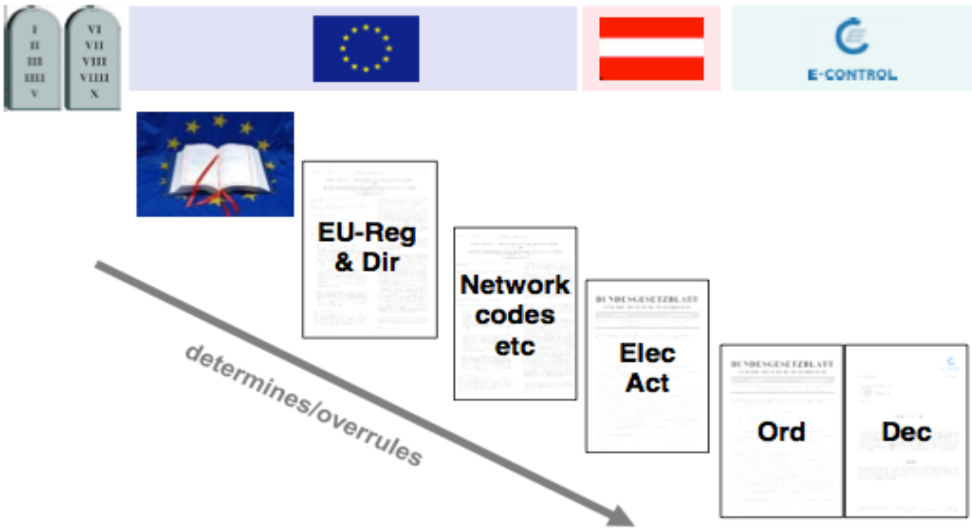


Figure 5: Hierarchy of the legal framework (Ennser 2015)

The following sections aim to outline the main regulations and directives that affect the electricity market in the EU and Austria.

2.2.1 Legal framework at EU level

Around the turn of the millennium the EU saw a strong drive for liberalisation of the energy market. Because of the growing need to establish common rules, binding for all EU members, the European Commission started to promulgate appropriate directives in 1996. In 2009 the 3rd package for liberalisation was passed. The most important directives and regulations for electricity markets and generation are going to be described in the following. (Hofer 2015)

Please note that although liberalisation contains measures for gas too, this paper only deals with electricity-related topics.

Directive 2009/72/EC - rules for the internal electricity market:

This directive aims at establishing common rules for the internal market in electricity. Electricity generation, transmission, distribution and supply, together with consumer protection and competition requirements are regulated here. The directive also lays down rules for the organisation of the sector, monitoring of security of supply, technical rules and the authorisation procedure for new capacity. Unbundling of transmission and distribution systems and its operators together with the installation of an independent controlling body (e.g. E-Control in Austria) are covered too. Moreover market opening is a crucial point. That means all customers are entitled to purchase electricity from the supplier of their choice. (Official Journal of the European Union L 211/55 14.08.2009)

Regulation (EU) 1227/2011 – market surveillance:

This regulation from 2011 determines the prohibition of insider trading and market manipulation and sets general rules for market integrity and transparency. The rules apply to all wholesale energy products, including physical and financial transactions in connection with electricity or natural gas and concern all participants of the energy market. (Official Journal of the European Union L 326/1 08.12.2011)

Regulations (EC) 714/2009; (EC) 838/2010; (EU) 347/2013 – cross-border exchange:

In the first of the above mentioned regulations the conditions for access to the cross-border exchanges in electricity are stated. The goals are enhancement of competition within the internal market, while taking into account national and regional characteristics. This involves the establishment of harmonised compensation mechanisms for cross-border flows of electricity and the allocation of available capacities of interconnections between national transmission systems. Another aim is to secure a well-functioning, transparent wholesale market with high security of supply. (Official Journal of the European Union L 211/15 14.08.2009)

Regulation 838/2010 can be seen as a supplement to 714/2009, recessing the inter-transmission system operator compensation mechanism and the common regulatory approach to transmission charging. (Official Journal of the European Union L 250/5 24.09.2010)

Regulation 347/2013 is an amendment of regulation 714/2009 with reference to guidelines for priority corridors and areas for energy infrastructure projects. (Official Journal of the European Union L 115/39 25.04.2013)

Directive 2012/27/EU – efficiency:

This directive aims at setting up binding measures for the promotion of energy efficiency within the EU in order to reach the energy consumption reduction of 20% by 2020 and to pave the way for further efficiency improvements along the energy supply chain. With these rules, barriers in the energy market and market failures that impede efficiency in the supply and use of energy shall be removed. Member states must integrate the directive into national law by 2014. Measures that enhance energy efficiency include renovation targets for public buildings, the development of efficiency obligations schemes and demand response programmes, as well as the duty to provide consumers with information on their meters and bills and to set up energy audits for large companies. (Official Journal of the European Union L 315/1 14.11.2012)

Directive 2003/87/EC – greenhouse gas emission allowance trading:

To promote the reduction of greenhouse gas emissions (GHG) and therewith indirectly RES generators, a trading system for greenhouse gas certificates was developed by the EU. The idea behind it: facilities only have a certain amount of GHG they are allowed to emit. If they want to exceed that amount, they must buy certificates on dedicated markets. Facilities with zero GHG emissions, i.e. RES, receive certificates for not emitting GHG that can be sold to the market.

Directive 2003/87/EC defines the rules for this trading system. In principle the idea of GHG certificates is a good one, but due to missing sanctions for violations of the rules, the system is not very effective. (Official Journal of the European Union L 275/32 25.10.2003 and Kranner & Sharma 2016)

Directive 2009/28/EC – the RES directive:

By setting individual mandatory targets for all member states, the use of energy from renewable sources shall be promoted, in order to reach the climate and energy targets for 2020. These targets must be achieved across the heat, transport and electricity sectors. Therefore each member state had to establish a National Renewable Energy Action Plan (NREAP), which had to be submitted to the European Commission until 2010. Every state has to report its progress in the implementation process to the commission on a regular basis. (Official Journal of the European Union L 140/16 23.04.2009)

Further important EU-level directives are d*irective 2000/60/EC – Water Framework Directive, European Floods Directive 2007/60/EC and directive 92/42/EEC – promotion of cogeneration power plants*. These directives will be discussed separately in the next section.

2.2.2 Legal framework at Austrian level

The following section discusses the most important acts of the general Austrian framework for the electricity market with focus on RES. This includes acts at federal level (Bundesebene) as well as laws on federal state level (Landesebene).

With the *Electricity Act (Elektrizitätswirtschafts- und -organisationsgesetz 2010, (ElWOG 2010)*, most parts of the EU directive 2009/72/EC and regulation (EC) 714/2009, together with its supplements have been transferred into Austrian law. This act forms the core of the Austrian energy industry.

In addition the *Green Electricity Act (Ökostromgesetz 2012, ÖSG 2012)* constitutes the adoption of directives 2009/28/EC and 2009/72/EC into national law, covering RES-relevant topics. In this law the major mechanisms for RES, like promotion via feed in tariffs and investment subsidies for generators are regulated. It is stated that OeMAG as the central RES settlement agent has the duty to close contracts with generators as long as the annual contingent for new renewable facilities is not consumed. In exchange for green electricity the contractors receive fixed feed-in-tariffs for a fixed period of time (technologies depending on feedstock like biomass 15 years, other technologies like wind and photovoltaic 13 years). By paying the so-called *Ökostrompauschale* and *Ökostromförderbeitrag*, which are parts of the electricity price in Austria, the end consumer is financing the subsidy system.

In the ÖSG 2012 a long-term perspective for renewable electricity production has been brought up for the first time. For the time from 2015 to 2020 the following new construction targets were set: Wind +700 MW, photovoltaic +1200 MW, hydropower +1000 MW and biomass/biogas +200 MW. (Sorger 2013)

Finally, as defined by directive 2009/72/EC, an independent energy market regulator must be installed. Therefore the *E-Control Act (Energie-Control-Gesetz)* was issued to form the legal legitimation for the Austrian energy regulator E-Control. (E-Control 2016a)

Due to the fact that the construction of power plants has an impact on the immediate environment, also laws on federal state- and community level have to be considered.
The most important norms are the *Bundesbauordnung* (federal state building order), *Bundesraumordnungsgesetz* (Regional Planning Act) and the *Bundesnaturschutzgesetz* (Conservation of Nature and of Landscape Act), which are specific for each federal state. On basis of these laws, approvals have to be requested from the responsible local administrator. Violations can add high costs to a project, delay or even abort it. (Baschinger 2015)

2.2.3 Technology specific norms

Especially for the construction of RES generation projects, a couple of technology specific laws have to be considered. In the following section the most important ones are described.

Biomass:

The *ÖSG 2012* regulates the tariff system for electricity from biomass. Power plants that sell electricity and heat are called combined heat and power (CHP) plants. In general, biomass plants are built for the production of heat, electricity or both. Since the energy efficiency of pure electricity generation is very low around 10%-25%, it makes sense to find locations where heat can be fed into a district-heating grid, in order to reach a high total efficiency of up to 90%. (Ortner 2014)

To promote the construction of highly efficient CHP plants, the *KWK-Gesetz (CHP Act)* was issued in 2008, which constitutes the implementation of the EU *CHP-directive*

92/42/EEC into national law. In Austria subsidies of up to 250 €/ kW are possible. (§ 7 KWK-Gesetz)

Biomass plants are depending on the regular delivery of feedstock for example woodchips or industrial waste wood. Austria has very rigid laws concerning the sustainable use of wood. The *Bundesforstgesetze (*federal state forestry law*)* set the rules for any federal state, concerning the locations that can be harvested and the quantity that can be dedicated to energy production.

Another point is the use of the ash from biomass combustion plants, which is considered waste and therefore has to be disposed of. But it can also be used as a fertilizer for agriculture, if it is not from chemically pre-treated wood. The conditions for the use of ash as fertilizer can be found in the respective directive, issued in the year 1998 by the ministry of agriculture and forestry (Bundesministerium für Land- und Forstwirtschaft). (Obernberger 1997: 28ff)

Small hydropower:

The tariff system for electricity from small hydropower is also regulated within the *ÖSG 2012*.
Unlike biomass, hydropower has no dependency on feedstock. The working medium of this technology is water and using water for electricity production does not involve any direct costs. But there are still several ecological measures like fish bypass systems that have to be applied in hydro projects, which can cause high costs.

Over the last decades continuous research in hydraulics, sediment transport and fish ecology has been performed to create an integrative understanding of riverine processes. Based on observed processes in the laboratory and on the field, the *European Water Framework Directive 2000/60/EC* was passed by the EU in 2000. The main focus lies on the preservation and recovery of the "good ecological status" of the aquatic environment. The good ecological status refers to the biological, hydro morphological and chemical elements of ground and surface waters within the same system.

Nowadays run-of river plants or other human interventions heavily influence most of the European river systems. Besides the ecological degradation, the situation creates risks of devastating floods, if the designed discharge of the regulated river is overshot. To tackle this natural hazard, the *European Floods Directive 2007/60/EC* was implemented. (Hauer 2014)

Photovoltaic and wind power:

The tariff systems for PV and wind energy are regulated in the ÖSG 2012, like biomass and hydropower. Since these technologies have relatively low invasive ecological character (no feedstock is needed and no large and complex civil works are necessary), apart from the space needed for large PV plants, no additional technology specific laws are worth mentioning at this point.

2.3 Electricity price

2.3.1 Wholesale market price

As already stated at the beginning of this chapter, electricity is considered a commodity that can be traded on dedicated market places like energy exchanges. The German European Energy Exchange (EEX) is the leading energy exchange, where energy is traded at a spot or long-term basis in form of forward contracts or futures. While the spot market is rather for the coverage of instant electricity shortage, futures and forward markets are used for hedging purposes.

According to economic principle, the wholesale price of electricity depends on the mechanics of demand and supply. The following passage lists the most important factors that influence the demand and supply side.

Supply side: Primary energy prices, CO2 emission allowance prices, availability of power plants, structure of the power plant pool (energy mix), strategy of the generation companies, development of installed capacity over time and political influences are the most important factors to mention.

Demand side: High influence can be observed in the long-term allocation of consumption over time, meaning the general trend of the load. But also the short-term allocation of the consumption, expressed in the peak load - base load ratio strongly affects the price of electricity. (Panzer 2015)

To describe the mechanics of the wholesale electricity price formation the concept of marginal costs will be used in the following passages:

"In economics, marginal cost is the change in the total cost that arises when the quantity produced is incremented by one unit, that is, it is the cost of producing one more unit of a good." (Sullivan 2003: 111)

In the context of the present paper the marginal cost curve is represented by the supplied quantities and prices of all electricity generators in the market. This cost curve is also called the merit order curve. Figure 6 shows the German/Austrian merit order curve in 2014, based on forward prices.

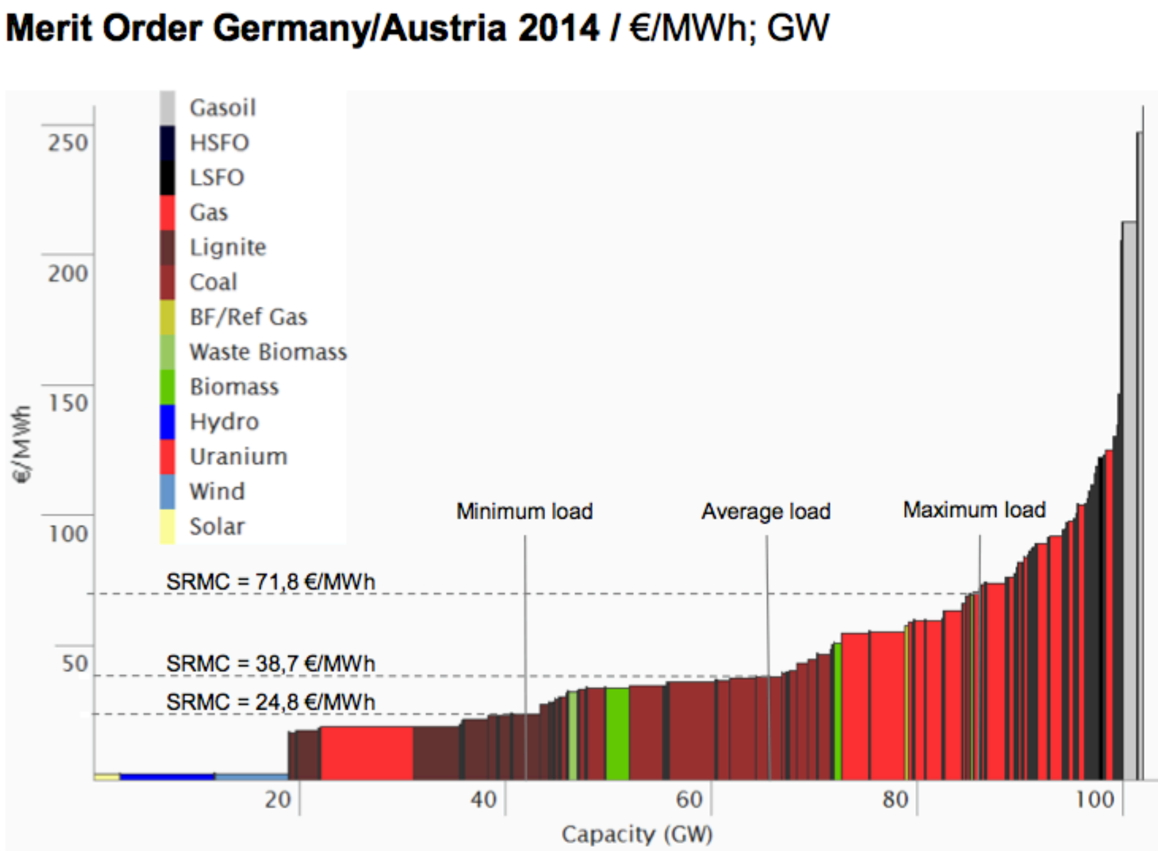


Figure 6: Merit order Germany/Austria 2014 (Wollein 2013)

The x-axis shows the total capacity in GW, available in the market, the y-axis marks the electricity price in €/MWh. Each bar represents the available capacity of a generator and the offered price respectively. As can be seen in figure 6, considering the *short-range marginal costs (SRMC)*, the cheapest energy is produced by hydropower, PV and wind power. These 3 RES technologies can cover almost 20 GW of the demand at prices below 10 € per MWh. Traditional fossil fuel plants and biomass plants produce at much higher costs due to the fact that they depend on fuel or feedstock.

The needed load changes with the electricity demanded by the customers. The *minimum-* to *maximum load* lines in the above figure represent the demand curves at different times. Where the demand curves meet the cost curve, the valid market prices can be found. In this example the price at minimum load settles down at 24,8 €/MWh, at average load 38,7 €/MWh and at maximum load at 71,8 €/MWh.

Nevertheless, the merit order curve changes constantly, depending on the availability of generation sources. With PV and wind power, the system is facing a high degree of uncertainty of supply. According to the *regulation 2009/714/EC and ÖSG 2012*, RES have the highest feed in priority status. That means, whenever RES are producing, TSOs are obliged to take the capacity on the grid and OeMAG is obliged to buy the electricity. This is a tough challenge for APG and other TSOs in the EU, because they must keep the transmission grid at balance. (Wollein 2013)

Recent developments

Since 2011 the EU has experienced constantly decreasing electricity wholesale prices. Currently the average base load price quotes below 2003 levels (figure 7).

Why is the electricity price at free fall? The answer involves a combination of many long-term factors. First to mention is the liberalisation and the increased competition in the electricity market that comes with it. Furthermore the decreasing oil price obviously reduces the costs of fossil fuel fired electricity generators, which puts pressure on the price. In addition to that, broad legally binding efficiency measures shift the demand curve to the left, which results in lower prices.

Figure 7: Development of average market price (EEX) according to §41 ÖSG 2012 (E-Control 2016b)

One influence factor, especially worth headlining, is the merit order effect, caused by the high increase of intermittent cheap RES, i.e. wind power plants in Germany.

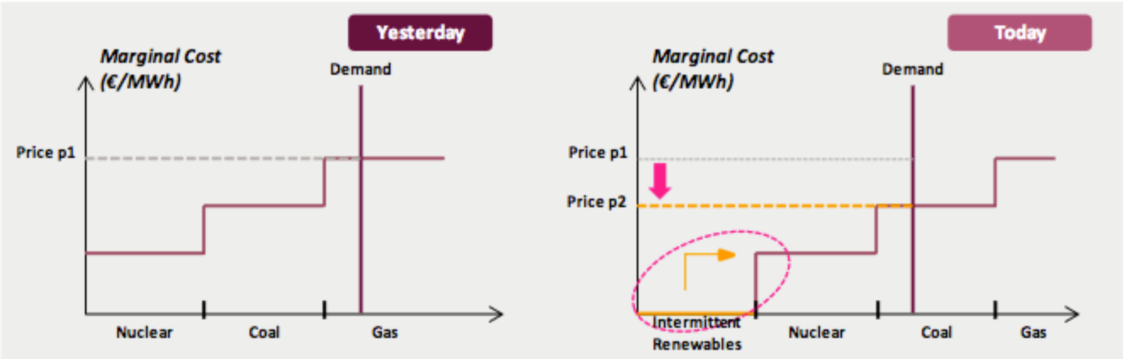


Figure 8: Merit order effect of intermittent RES on the electricity price (Aubard B. et al. 2016: 2)

The left chart in figure 8 shows the situation when no wind is blowing. In the right chart the effect can be seen that wind power enriches the supply curve with cheap electricity and shifts the curve to the right, which causes the price to fix at a lower level.
This effect does not only drive prices down, but also edges out more reliable energy sources for base load and makes severe cost reduction plans necessary for them to survive.

Thus, although meeting the GHG emission targets is a very important task in the EU, it is not negligible that oversupply caused by subsidising intermittent renewables like wind and solar power, brings volatility into the market, which is very difficult to handle for TSOs and increases their costs for balance electricity. (Ruhm & Brenner 2016)

2.3.2 Retail market price

The Austrian retail price consists of 3 parts, where each part accounts for approximately 1/3: Connection charge, wholesale electricity price, taxes and levies. In the following figure the composition of the retail price is described, using an average household from Vienna as an example.

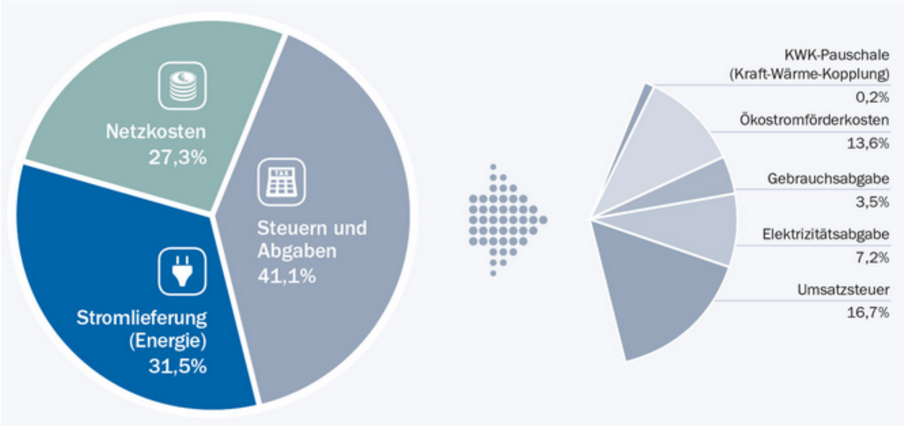


Figure 9: Price composition household customer 3,5 MWh/y, Vienna network area, local supplier as per 28.01.2016 (E-Control 2016c)

The connection charge amounts to 27,3% and the electricity price accounts for 31,5%. Taxes and levies amount to 41,1%, which are split into CHP flat-charge (0,2%), green electricity tax (13,6%), use tax (3,5%), electricity tax (7,2%) and value-added-tax (16,7%).

Taking a closer look at the price components in Austria, it can be seen that taxes and other levies more than doubled from 1998 to 2015 (red line in figure 10), while the electricity wholesale price only increased 19% (light green line). A part of the rapid increase of taxes from 2012 can be explained with the implementation of the Ökostromgesetz 2012.

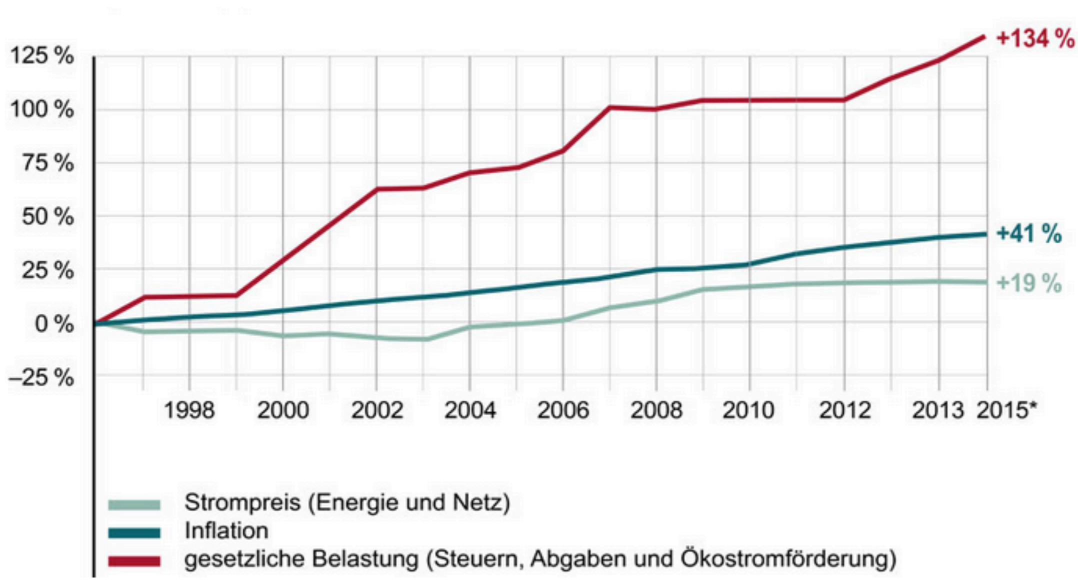


Figure 10: Price (incl. connection charge) - and tax development in Austria (Österreichs Energie 2015)

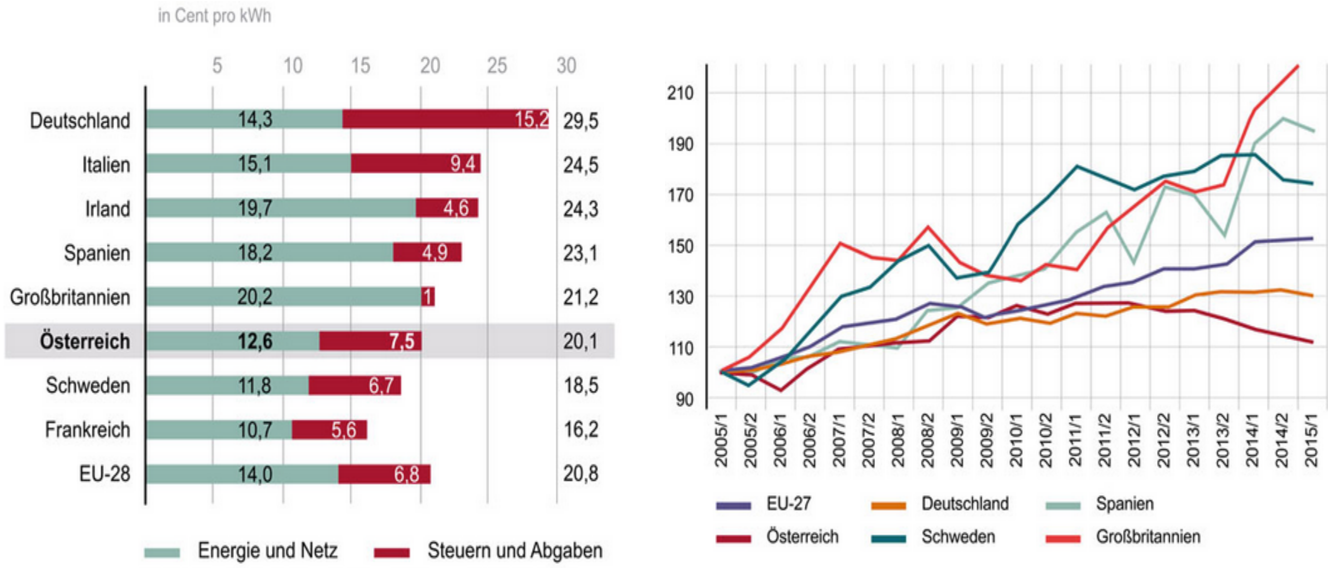


Figure 11/12: Retail household prices in the EU / Price development in Austria (Österreichs Energie 2015)

Figure 11 compares the household electricity prices of 8 EU countries for the first quarter of 2015, based on data from households with a demand of 2.500 to 5000 kWh per year. The Austrian retail price in Q1 2015, with 20,1 Cent per kWh, was slightly below EU average. And figure 12 shows the price development from 2005 to 2015 for five chosen EU countries. Till the first quarter of 2011 Austria's average retail price increased by about 30%. In the following time prices decreased again, leaving a net increase of approximately 10% in 2015 compared to 2005.

2.4 Subsidy- and tariff systems in Austria

2.4.1 **Feed in tariffs** (Brandlmaier 2015)

The basis of the promotion system in Austria is mainly built on feed-in tariffs (FIT). This system provides RES generators with fixed prices and guaranteed access to the public electricity grid for a certain period of time. Founded in 2006, the OeMAG is the central settlement agency for FITs, which are financed out of green electricity tax money. The main advantage of that system is independence from market prices and thus higher creditworthiness in the eyes of banks and higher cash-flow security for investors. Figure 13 gives a comparison of the developments of the market price with FITs from 2007 to 2014.

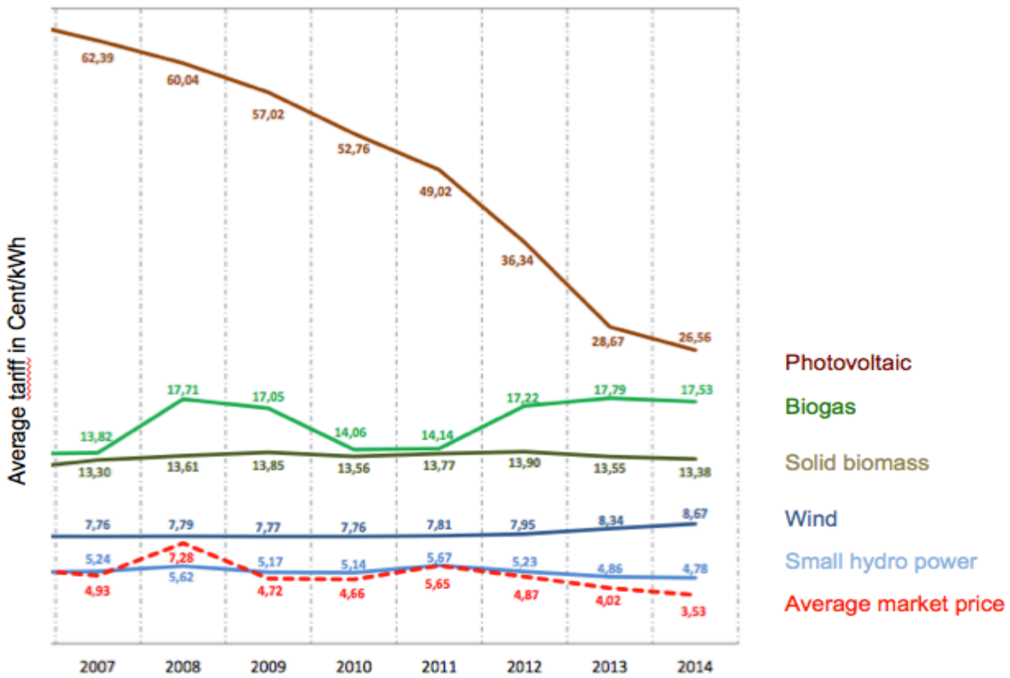


Figure 13: Development of Austrian FITs with average market price (E-Control 2016)

The available subsidy amounts for FITs are fixed on an annual basis via decree by the Austrian government. Initially PV was subsidised with relatively high FITs. Since production costs of PV modules have decreased massively in the last years, also tariffs have been reduced. Except for biogas, the FITs for other renewable technologies have stayed relatively constant.

In 2016, for 5 kWp - 200 kWp PV projects, a contingent of 8 mio € was available. Projects with higher or lower capacities are not subsidised anymore. According to §4

(4) 2 ÖSG 2002, wind power capacity shall be enlarged up to 2000 MWp till 2020. Therefore in 2016 an amount of 11,5 mio € was projected, to supply wind plants with a FIT. For small hydro power a FIT budget of 1,5 mio € was allocated for 2016, which is relatively low, compared to the other technologies. Finally, for solid and liquid biomass projects with electrical capacities bigger than 500 kW, a budget of 16 mio € was available, for smaller solid biomass plants 3 mio €.

Nevertheless, it is questionable if the FIT is an appropriate system, when it comes to sustainability of the market, because it distorts competition, due to the missing of demand and supply mechanisms. In the long run the goal must be that RES can survive without FITs, in order to create a functioning electricity market. But with currently high long-run-generation costs and historically low electricity prices, RES could hardly survive without subsidy.

From that point of view, according to Wolfgang Anzengruber, CEO of Verbund AG, initial investment grants could be a better solution because investments would take place under considerations of economic efficiency, rather than where the highest FITs are paid. (Ruhm, Brenner 2016)

2.4.2 Investment grants

This kind of promotion is also in the program of OeMAG. Small hydropower projects, revitalisation, as well as new ones, with rated capacities smaller than 10 MWp, can apply for investment subsidies. As shown in table 1, there are differences in the granted amounts, depending on the rated capacity of the plant. Moreover, for capacities higher than 500 kW dynamic investment calculations with a discount rate of 6% have to be performed, in order to prove the need for subsidy.

Table 1: Scheme of investment subsidy for SHPP as per 01.01.2016 (Bauer 2016a)

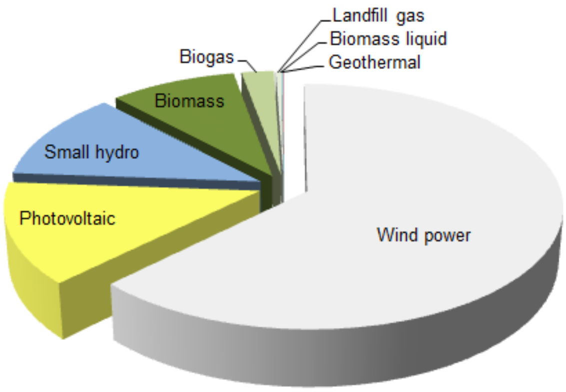
Annual budget for SHPP investment subsidies: 16 mio €				
Rated capacities	**< 50 kW**	**50-100kW**	**500-2000 kW**	**2000-10000 kW**
Subsidy per project = smaller amount of:	1500 €/kW	1500 €/kW or 30% of eligible investment costs	1000-1500 €/kW or 30-20% of eligible investment costs	400 -1000 €/kW or 20-10% of eligible investment costs

CHP plants in general can apply for investment subsidies, according to the *KWK-Gesetz.* Until 2020, 12 mio € are available for new installations and renewal of older systems. The amount is subject to a detailed examination of the project's eligibility and the size. Table 2 illustrates the maximum amounts that can be granted for different plant sizes, as per 01.01.2016.

Table 2: Scheme of investment subsidy for CHP power plants as per 01.01.2016 (Bauer 2016b)

Rated capacities	**100 kW - 1 MW**	**1 MW- 5 MW**	**5 MW- 20 MW**	**20 MW- 100 MW**	**> 100 MW**
Maximum subsidy	250 €/kW	200 €/kW	175 €/kW	150 €/kW	125 €/kW

Finally, in addition to the FIT, PV projects with capacities between 5kW and 200 kW receive investment grants to the amount of 40% of the investment costs, but not more than 375 €/kWp.



	Installed capacity [MW]
Wind power	2,172.20
Photovoltaic	467.30
Small hydro	408.80
Biomass	318.80
Biogas	81.10
Landfill gas	14.80
Biomass liquid	2.70
Geothermal	0.90
Total	**3,466.60**

Figure 14: Installed capacities of RES in Austria as per 31.09.2015 (Brandlmeier 2015)

As can be seen, per 31.09.2015 OeMAG supported an installed capacity of 3,466 MW with FITs or investment grants.

2.4.3 Other subsidy relevant institutions

Kommunalkredit Public Consulting GmbH (KPC) is a central contact point for investors and project owners who are seeking for subsidy possibilities in Austria. Amongst the institution's main objects are the implementation and management of existing promotion programs and consulting in environment- and climate protection topics. KPC bundles all relevant information and helps investors with the application for subsidies from the supporting authorities like the EU, the Austrian federal states or the *Klima- und Energiefonds*.

The applicants can be roughly categorized in private persons, municipalities and firms. For each group, programs with different focuses exist, comprising electricity, heating or building measures amongst others. Private persons and communities, for instance, have the possibility to receive either subsidy from the *Klima- und Energiefonds* or in some cases from the federal states for PV installations, but no combination with subsidies from OeMAG are possible. With respect to firms, mainly isolated electricity production, where no connection to the public grid is possible, is eligible for subsidy. The supported technologies are CHP plants, SHPP, PV, wind power and energy storage. (Kommunalkredit Public Consulting 2016)

3 POTENTIALS OF SOLID BIOMASS, PV, SHP AND WIND IN AUSTRIA (STANZER G. ET ALT 2010)

Renewable electricity production in Austria amounted to round 40 TWh, which is 67% of the total production in 2013. Hydropower has by far the biggest share, but only 8% (5.441 GWh) come from small hydro, followed by the other technologies, as can be seen in table 3. (Biermayr 2014: 9; BMWFW 2015: 66)

Table 3: Renewable electricity production in Austria in 2013 (Biermayr 2014: 9)

Renewable electricity	
Hydropower	39,851 GWh
Biomass (solid, liquid, gaseous)	3,289 GWh
Wind power	3,011 GWh
Black liquors	1,345 GWh
Photovoltaics	582 GWh
Geothermal energy	0.3 GWh
Total amount of electricity from renewables	**48,080 GWh (173.1 PJ)**

And there is still potential to increase the share of RES in Austria, especially when thinking of the high electricity import of 26,7 TWh. In the following section the potentials of solid biomass, PV, wind power and SHP are discussed.

In a joint project called *Regio Energy*, financed by the *Klima- und Energiefonds*, the Austrian institute for urban and regional planning (ÖIR), together with three partners, performed a comprehensive study about the future potentials of RES in Austria. From 2008 – 2009, renewable resources were analysed on a district level. For that purpose three potential types were defined:

- *Technical potential:* Currently possible annual yield with modern standard and state-of-the art technologies, considering possible concurrence with other industries.
- *Reduced technical potential:* Technical potential, including competition with other RES, incorporating protected areas, regional planning aspects and economic considerations.
- *Realisable potential:* Outcomes of three analysed future scenarios, a conservative (mini), a medium (midi) and an aggressive (maxi) scenario

3.1 Solid biomass

Solid biomass can be found in any locations with large wood resources. Looking at the wood harvest of the year 2007, considering the share of combustible material and sawmill side products, a reduced technical potential of 30.760 GWh could be derived from the existing stock. In a further step three scenarios were calculated, to estimate the annual realisable potentials for the years 2012 to 2020.

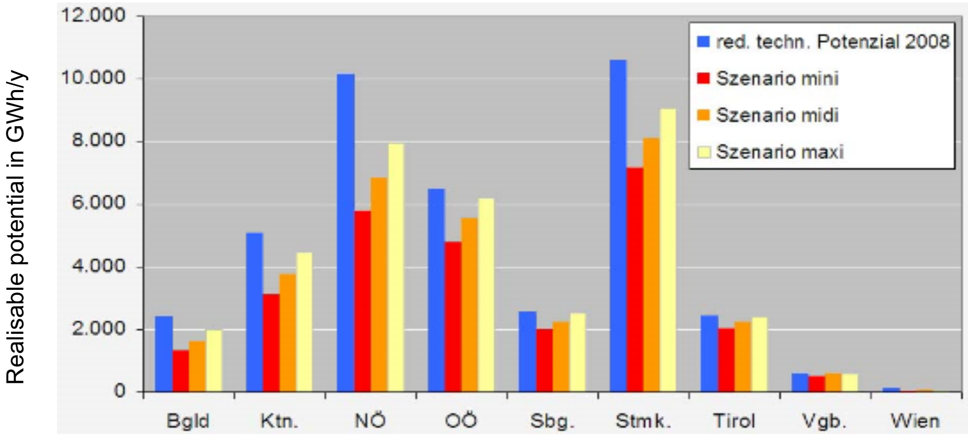


Figure 15: Annually realisable potential of solid biomass per federal state from 2012 - 2020 (Stanzer et al. 2010)

Figure 15 shows the results for the scenarios and the reduced technical potential in 2008 (blue column). The highest potentials in any case can be seen in Steiermark, closely followed by Niederösterreich, which makes these federal states favourable locations for biomass combustion technologies.

3.2 PV

Generally speaking, the highest potential for PV can be found in areas with high values of sunshine hours and strong irradiation at temperatures of around 25°C. These values depend very much on the latitude of the location, the weather and shadowing by mountains or other obstacles.

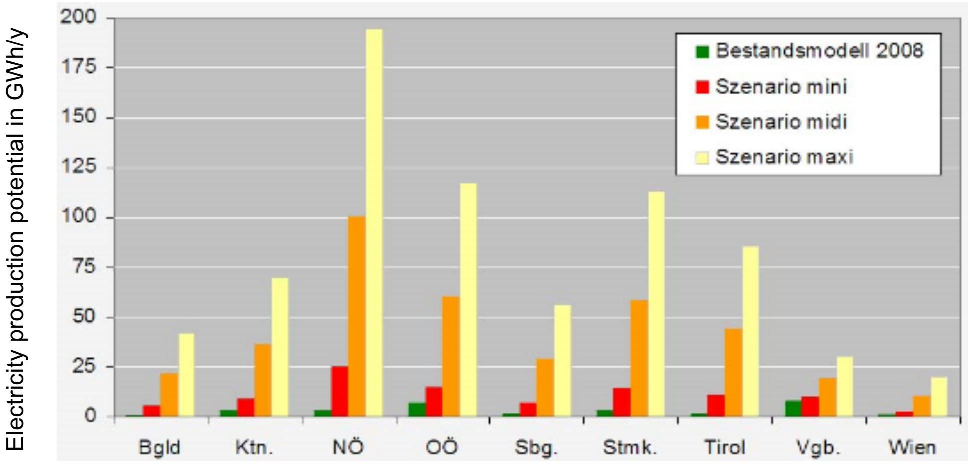


Figure 16: Annually realisable potential of PV per federal state from 2012 - 2020 (Stanzer et al. 2010)

As can be seen in the above figure, in 2008 total Austria generated a relative low annual yield with 25 GWh (sum of green columns). The mini-scenario implies a capacity increase of 6.472 kWp per year (historical maximum added capacity in 2003). Furthermore, the midi-scenario implies an increase of 5 times the historical maximum and the maxi-scenario implies an increase of 10 times this value. The highest realisable potentials can be found in Niederösterreich.

3.3 Small Hydro Power

In this report the technical potential is assumed to depend on four factors: the catchment area, the amount of rain, the relief and the existing duration curves. The highest technical potentials can be found in alpine areas and along the main rivers of Austria, summing up to 75.500 GWh/y, compared to 38.173 GWh/y, produced by an installed hydro power capacity (including large run-of-river and pump-storage pants) of 11,85 GWel. The reduced technical potential follows a similar structural distribution, but with substantially lower values, summing up to 51.300 GWh/y.

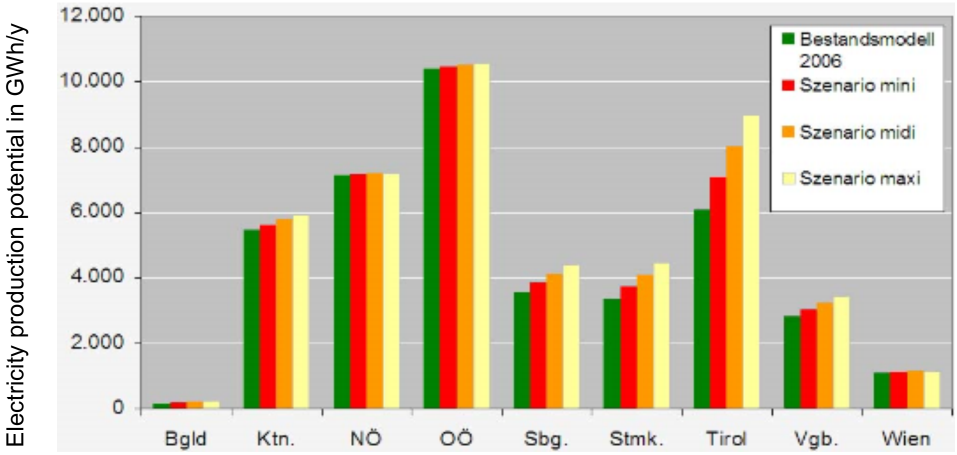


Figure 17: Annually realisable potential of hydropower per federal state from 2012 – 2020 (Stanzer et al. 2010)

In figure 17, again the three scenarios are compared with the reduced technical potential of 2006. With over 10.000 GWh/y, Oberösterreich has the highest realisable future potential, followed by Tirol and Niederösterreich.

3.4 Wind power

Wind power plants can be found mainly in the east of Austria due to very good wind conditions and good accessibility of the sites. 90% of the 2.172 MW of installed capacity are situated in Niederösterreich, Burgenland and Wien. Today mainly whole wind parks are installed (assembly of multiple turbines), rather than only single turbines, because of higher economic efficiency and the scarcity of good wind locations in Austria.

The total area incorporated in the technical potential amounts to 7.300 km². Taking into account protected areas and buffer zones around residential areas, a reduced technical potential area of 2.800 km² remains.

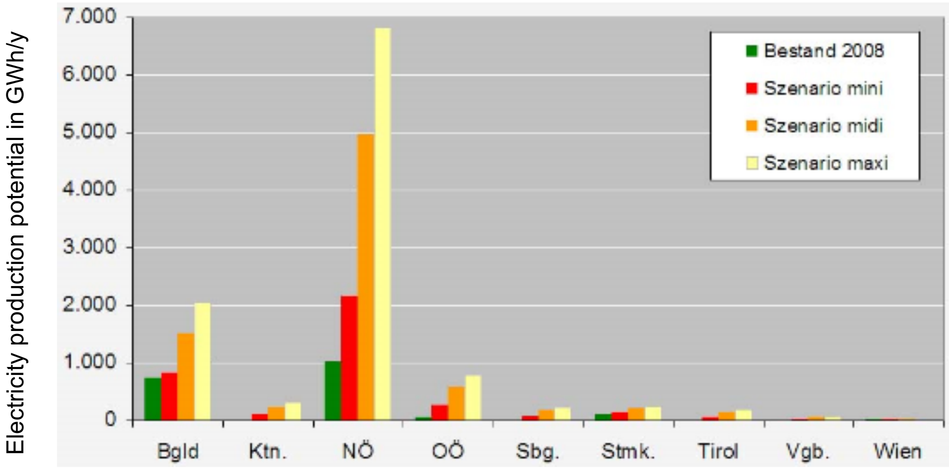


Figure 18: Annually realisable potential of wind power per federal state from 2012 - 2020 (Stanzer et al. 2010)

Unsurprisingly, the main realisable potentials for wind power can be found in Niederösterreich and Burgenland, as can be seen in figure 18.

To sum it up, the highest Austrian-wide potentials can be found for small hydropower and solid biomass. Wind power already utilizes a high portion of the available potential, hence the remaining future potential is relatively low and photovoltaic has by far the lowest potential, due to the rather unfavourable latitude of Austria.

4 TECHNICAL CONCEPTS OF ELECTRICITY PRODUCTION WITH RES

4.1 Solid biomass combustion

4.1.1 Feedstock

A broad set of different fuels exists for biomass combustion. In general any organic material like wood residues, energy crops like willow or poplar and agricultural products or residues like straw or wheat carries a certain amount of energy. The main chemical components of vegetal biomass are carbon, hydrogen and oxygen. The compositions of these elements determine the energy content that is measured by the so-called NCV (net calorific value) and are different for any type of biomass. Contents of sulphur, potassium, chlorine and nitrogen are also found in biomass, but not so much in wood as in agricultural feedstock. These elements contribute directly to harmful emissions into the atmosphere and moreover have a bad influence on the combustion process. For example, ash melting can be caused due to high amounts of potassium. (Ortner 2014)

In this paper wood is the fuel to be discussed because of its good combustion characteristics and its abundance in Austria. However, under certain circumstances other types could also make sense. The following illustration shows conversion factors of the most common wood energy assortments according to the Austrian standards ÖNORM.

Figure 19: Conversion factors of different wood assortments (Francescato 2008: 11)

Generally speaking the cheapest form of wood is roundwood and the most expensive form is pellets. The smaller the parts, the more expensive the feedstock becomes because of the necessary processing steps between harvesting and arrival in the plant. For very small combustion plants log wood is a good choice, where firing of the boiler is conducted manually. When plants reach a certain size, transportation of the fuel into the combustion chamber is automatized. For this purpose wood chips or pellets are best suitable. The typical dimensions of woodchips are between 45mm and 200mm with moisture contents between 20% and 65%.

Wood chips are produced as by-products of sawmills or other wood processing industries, like sawmills or forestry.

The NCVs of the different forms of wood are indicatively depicted in the following diagram. In Austria the main tree population consists of conifer trees with only few deciduous trees. Different species of trees also have different chemical compositions and thus different NCVs and characteristics.

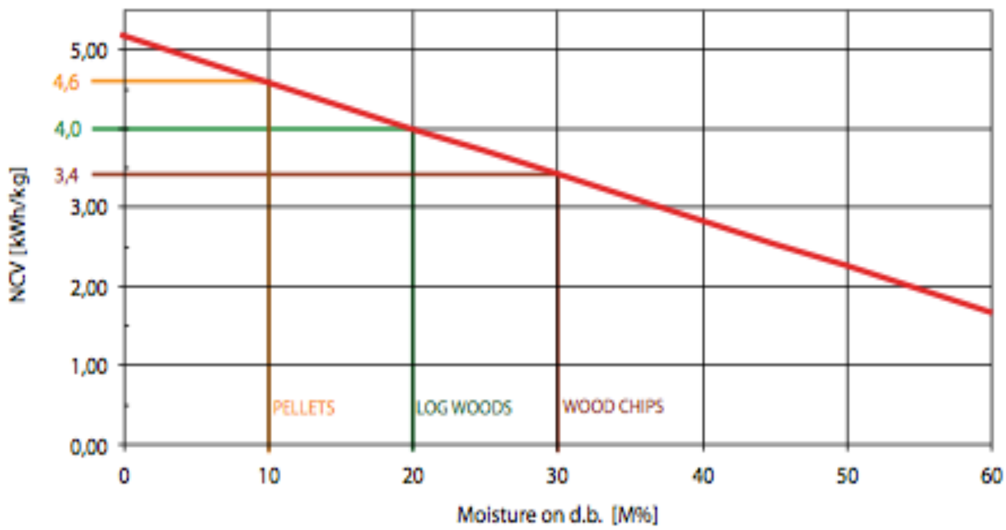


Figure 20: Net calorific value as a function of moisture (Francescato 2008: 25)

The diagram shows the NCVs of different forms of wood which can be used for combustion. The main driving factor determining the NCV is moisture. Wood chips typically have a moisture factor of M30%, and higher, especially if they are produced out of residues. Pellets have the least moisture content due to the pelletizing process, which also includes drying of the material. (Francescato 2008: 21ff)

4.1.2 **Combustion technologies** (Ortner 2014; Pfemeter 2011: 1ff)

For the conversion of biomass into energy several technologies are available. In addition to combustion, gasification and pyrolysis have to be mentioned; in this paper the focus lies on combustion. In a simplified view, the process of a biomass plant producing electricity works as follows:

The fuel is transported mechanically into the combustion chamber, where it decomposes in its components at temperatures of 800°C to 1050°C and reacts with added oxygen. Ashes stay back in a container; hot flue gas consisting mainly of CO_2 and water flows through a heat exchanger and after a strict filtering process gets released into the atmosphere. The heat exchanger produces steam, which drives an engine or turbine, connected to a generator. After passing the turbine the steam flows into a condenser to bring down the temperature to keep the cycle going.

In a CHP power plant (combined heat and power) an additional step is introduced in the above described steam process. After the steam turbine a heat exchanger is set up to feed the local district heating system. The cogeneration mode of course leads to a trade off in electrical power generation in favour of thermal energy.

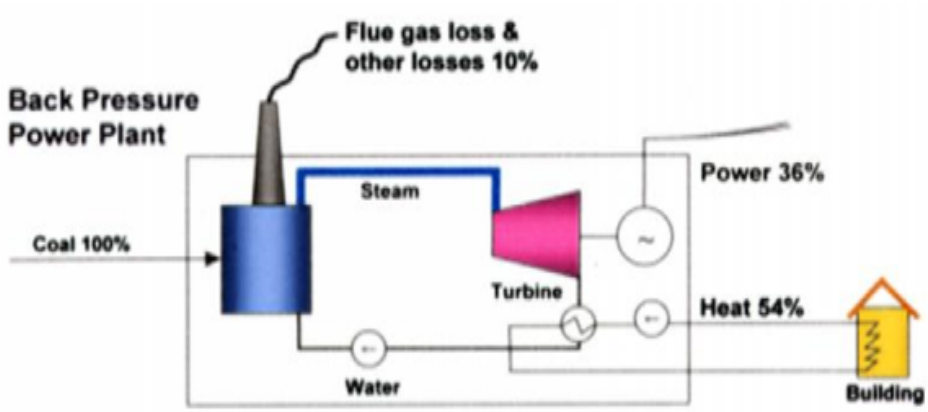


Figure 21: Scheme of a CHP power plant (Pierre et al. 2002: 43)

In the following steps the stations of the process are explained in more detail, together with the most commonly used technologies. For the combustion of wood chips in general, the following different types of combustion technologies can be considered well working: Fixed bed combustion (e.g. grate combustion) and Bubbling (BFB), respective circulating (CFB) fluidized bed combustion.

Fixed bed combustion

In the fixed bed combustion process air is floating through the fuel positioned on a fixed grate, where drying, gasification and charcoal combustion takes place. Various grate furnace technologies are available on the market, like fixed grates, moving grates, vibrating grates etc. Grate combustors are the technology most frequently used for thermal biomass combustion with nominal capacities higher than 100 kW. This is due to its simplicity and the possible use of a wide variety of biomass in terms of size and water content. Moreover the technology is very cheap in investment. A huge disadvantage in comparison with the other technologies is the high combustion temperature of about 900°C to 1050°C, which can cause ash sintering and a higher air inflow compared with the other mentioned technologies. This leads to lower efficiencies.

Bubbling and circulating Fluidized bed combustion

In the BFB the fuel is transported into a bed of inert material like silica sand. Air enters from below and mixes the fuel with sand. This mixture consists of approximately 90% - 98% of the inert material. This leads to a more homogeneous combustion compared to grate technologies and lower temperatures about 800°C-900°C are needed. A positive side effect is lower flue gas volume and lower NOx emissions. The bubbling of the suspension has the advantage of a very intense heat transfer which makes less excess air necessary for combustion and increases efficiency. The size of fuel particles is restricted to a size of below 100mm. The CFB technology uses an additional cyclone fan to increase airflow speed, which causes the suspension circulating in the combustion chamber. Therefore particle size should not exceed 50mm. A big advantage of the technologies is the flexibility with various fuel mixtures and moisture content, for example wood can be mixed with straw. Investment costs are relatively high compared to grate furnaces and the fuel has to undergo pre-treatment, because the combustor is very sensitive to impurities like metals. Moreover start-up time is very long, thus a high amount of full load hours is recommended.

Steam Process

The figure below shows the schematic steam cycle. At stage 1, cool water out of the condenser runs through a pump into the boiler. Energy in form of heat enters the system at stage 2. This stage contains three components: the economiser (water gets preheated), the evaporizer (water converts into steam and expands), the super heater (the steam is brought to a higher temperature to yield more enthalpy out of the cycle). At stage 3 the hot steam enters the turbine at high pressure and drives the shaft of the turbine, which is connected to an AC generator. At stage 4 the steam has already gone through the turbine and lost pressure. Further pressure gets lost in the condenser, where the vapour gets cooled down and condenses. (Ortner 2014)

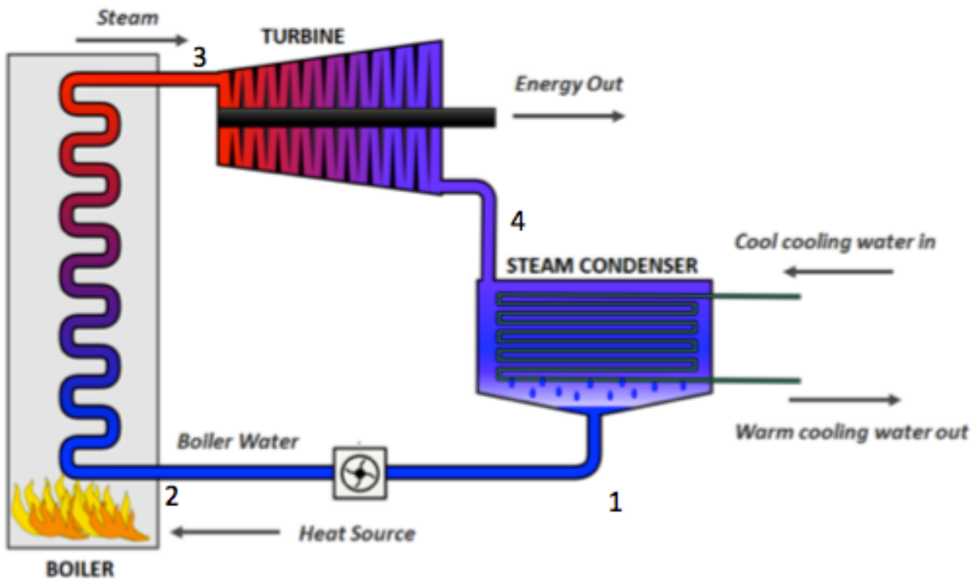


Figure 22: Schematic steam cycle (Delgado Martin 2015)

For biomass CHP plants the most commonly used process is the steam process. A big disadvantage is the low electrical efficiency at low steam pressures and temperatures (15-25% with pure power generation). Thus, only in large facilities high electrical efficiencies up to 35% can be reached. However, small plants (0,5 MWel – 5 MWel) are often operated in back pressure mode with heat extraction and thus have reduced electrical efficiencies.

Organic Rankine Cycle process

The ORC process in principle works similarly to the steam cycle. The main difference is the working fluid (e.g. silicon oil) used. The working fluid has a lower boiling point and thus expands at lower temperatures and pressure than water. Especially in the field of geothermal plants ORCs are often used because of this characteristic and achieve good efficiencies. In biomass plants the technology is mostly found in plants with small electrical capacities and yields efficiencies from 15% to 20%.

4.2 Photovoltaic (Fechner 2015)

The sun bears huge energy potential for the world. The solar irradiation hitting the Earth amounts to about 10.000 times the World's energy demand. Alexandre-Edmond Becquerel, a French physicist, was the first to discover the photovoltaic (PV) effect and in the year 1987 the technology was installed in Austria for the first time. At that time PV was rather at experimental status than standardized. Since then the market has grown constantly and competition between the PV cell producing market leader China, Japan, Korea, Germany, Malaysia, Norway and the USA has brought prices of PV modules to an affordable level for energy industry and even for home use.

The physical principles used in PV cells are the characteristics of two different semiconductors. Negative and positive charged semiconductors are bound together. The negative semiconductor has free negative charged electrons in its structure and the positive charged semiconductor has free positive charged "holes". Wavelengths of approximately 300 nm – 1200 nm in the irradiation of the sun cause electrons to separate from their atoms and move towards the positive-negative junction. When the electron fills the hole, voltage is generated at the positive-negative junction and can be deducted by a wire.

4.2.1 PV cells and modules

Several different types of PV cells are produced, for example thin film cells and solar concentration. But the latter needs a high amount of direct irradiation, which is not given in the examined location and thin film cells' efficiencies are too low for the present purpose.
The commercially most established and therefore dominant technologies are the silicon based mono and multi-crystalline cells. Low material consumption and high availability compared to raw materials needed for other technologies, low weight and compatibility with the electronics industry, are the main reasons for the road of success. While mono crystalline cells are less efficient, multi-crystalline cells are much cheaper in production and hence the majority of produced modules are equipped with this kind of cells.

The smallest unit in the PV technology is the cell. To accumulate energy to a useful amount, cells are interconnected. By default 36 or 72 cells are connected in a series. As a next step these clusters are connected parallel to form a module. The advantage of serial connections is the increase of voltage, while the current stays the same. But if one of the cells has a defect, the whole series drops out. If parallel-connected cells drop out, the rest of the cells is not affected. A negative characteristic of this kind of connection is that with the increase of the number of cells, the voltage stays the same, while current increases. In a further step, identical modules are connected in series to form strings which are connected parallel to form a generator. The modules must be as identical as possible in terms of electric values, to avoid mismatch losses.

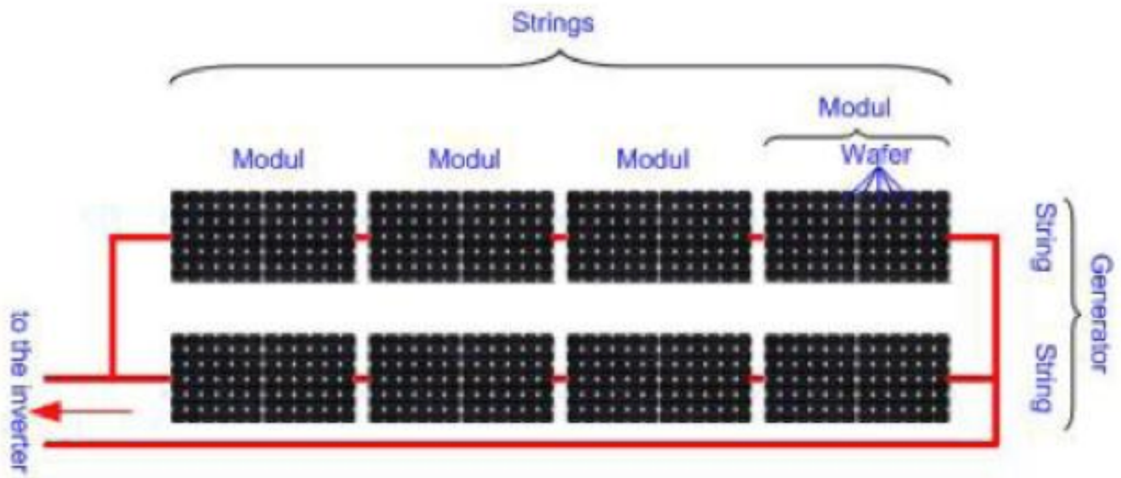


Figure 23: Scheme of a typical PV assembly (Fechner 2015)

To withstand extreme weather conditions and temperatures, modules have to be built with high quality materials, in order to meet life duration of several decades. Therefore the purchase of certified (e.g. IEC/EN 61215 protection class II) modules only is recommended. The same applies to inverters, mounting structures, wiring and other components comprised in the so-called BOS equipment, which is needed for PV operation.

4.2.2 Balance of System (BOS)

The BOS consists of inverters, wiring, monitoring systems, racking and anti lightning measures. Inverters have to be installed to convert the produced direct current into alternating current with 230V and 50HZ, which is used in Austrian local grids. For larger scale plants central inverters are recommended, where all strings are connected to one inverter. For smaller scale systems every single string or module can be connected to one smaller inverter each. To avoid transmission losses inverters should be located as close as possible to the relative unit.

Furthermore, modules have to be mounted on stable stands, which also have to resist harsh weather conditions. For this purpose different systems exist. The simplest versions are fixed stands out of rust-resistant metal with a concrete fundament. A more sophisticated and also more expensive mounting system is a solar tracker, which can adjust the panel automatically to the solar path in one or two axes. In sunny conditions, tracking systems can increase energy output by 30% - 36% in comparison with a fixed mount system. Another possibility to install PV panels is to incorporate them into facades of buildings.

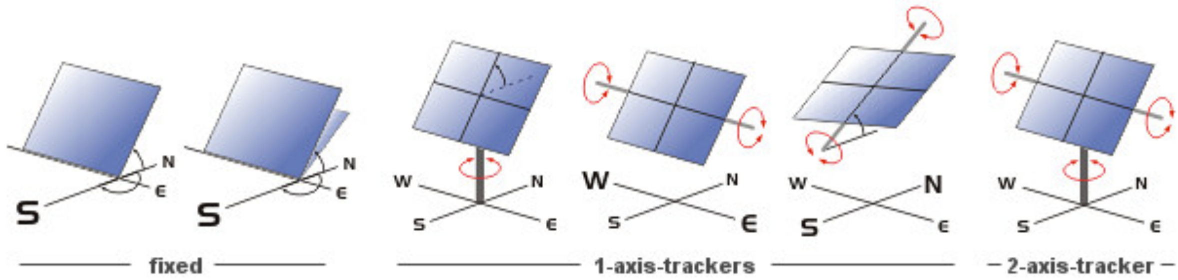


Figure 24: Tracking PV systems (Prekoneta 2016)

At last, monitoring systems are indispensable to observe production and ease error detection.

If no grid connection is possible, stand-alone systems are an option to produce electricity. Isolated PV systems are very expensive, because additional equipment like batteries is necessary. Batteries serve as backup puffer storage for the time the PV panels are not producing energy.

4.3 **Small Hydro** (Hall 2015; Panhauser 2015)

In Europe hydropower plants with a rated capacity of 10 MW are classified as small hydro power plants (SHPPs). For Austria this size is reduced to 2MW.
The principle of SHP is very simple. Water flows downwards from an elevated spot and the kinetic energy drives a turbine, coupled with a generator. The most important variables to calculate the power potential (P) of an SHPP are the available discharge of a river (Q) and the head (H) of the plant. Q is the amount of water that passes a specified metering point, measured in m^3/s and in a simplified view H is the difference in elevation of two particular cross sections in m. Further elements in the equation are gravity (g) and the density of water (ρ), which are given constants.

$$P = \rho * g * Q * H$$

4.3.1 Available discharge (Q), duration curves and head (H)

To assess the available discharge, the whole anatomy of the river has to be analysed, starting with the catchment area. Precipitation in this area is the input into the system, which to some extent gets into the groundwater, evaporates or gets stored in form of snow and ice. The rest gathers in ditches, which flow together and form a river. The fluxes in a system are strongly dependent on the rain regime, the soil and the climate in the catchment area.

Generally speaking, rivers bear less water during wintertime than in summer, spring and fall. Thus, depending on the technology, there is less energy production possible in winter, compared with the other seasons. A way to measure the stream flow of rivers is by solving the water balance equation of a system. Another method is stream gauging, where water level and velocity are measured continuously for a long period of time. Dedicated institutions like eHYD in Austria sometimes provide these data; otherwise separate measurements or computer simulations have to be performed. The data contain the seasonal patterns and dynamics of discharge, which in some further steps get illustrated in a so-called duration curve. The duration curve shows the exceedance frequency of a certain stream flow in days and is unique for every river.

The head is a measure of energy and takes into consideration the different pressure, velocity and elevation of an upstream cross section compared with a downstream cross section. To create river drop in order to make the head usable, dams or weirs can be built (impoundment), tail water level can be reduced (tail water excavation) or the flow gradient can be minimised by diversion, which is the main technique for SHPPs with high head.

In general a rough distinction between low head (<25m) and high head (>25m) SHPPs can be made. Figure 25 shows the schematic arrangement of a low head run-of-river system, consisting of a weir and a powerhouse with turbine and generator.

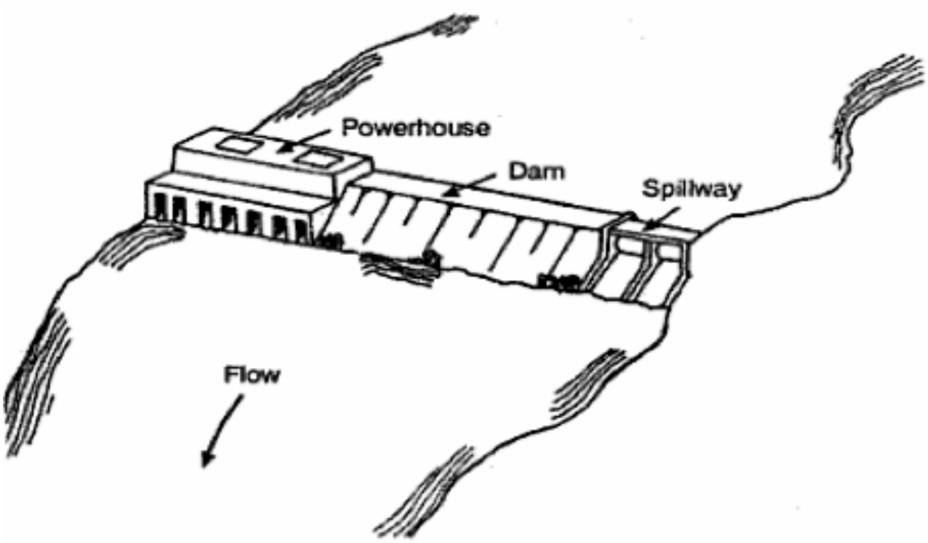


Figure 25: Schematic run-of-river system with Kaplan turbine (Kothari et al. 2008)

Figure 26 shows the typical arrangement of a high head system. At the water intake a diversion weir is installed and in a settling basin the water gets cleared naturally from sediments to protect the turbine against damage. Additionally rakes prevent larger floating material from entering the system. In a further step a channel at low gradient diverts a portion of water from the riverbed into a penstock, which after a high drop leads directly to the turbine into the powerhouse. Afterwards the used water flows back into the river.

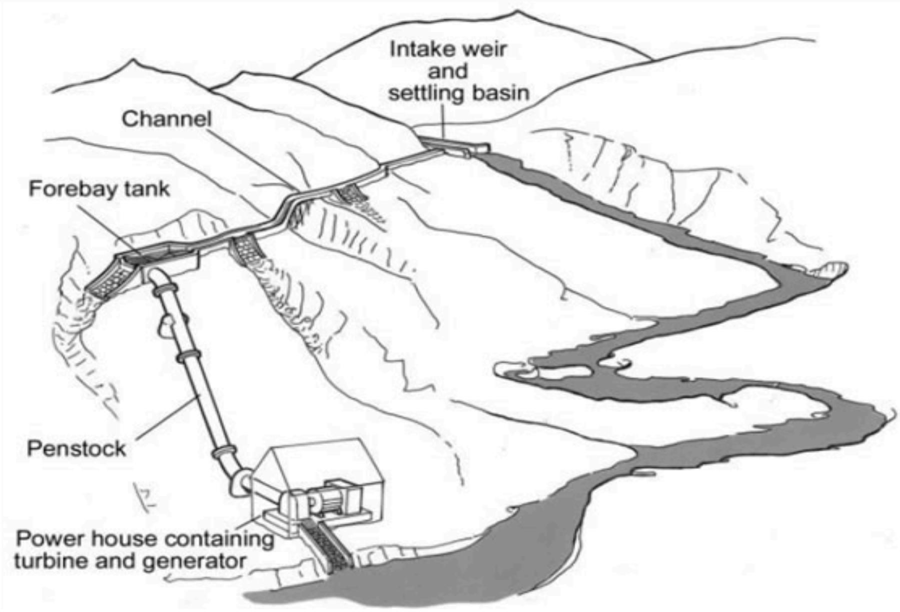


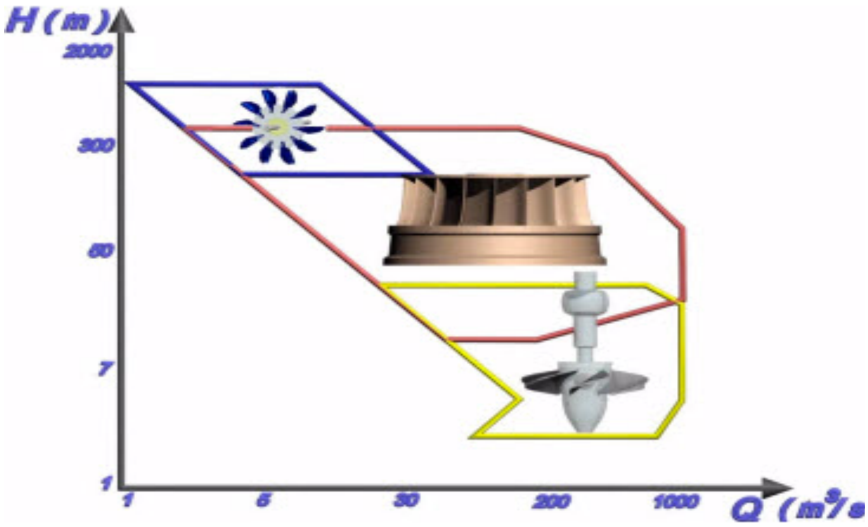
Figure 26: Typical arrangement of a high head system (Gatte M.T. and Kadhim R.A. 2012)

4.3.2 Turbines and generators

In the powerhouse the turbines, generators and control systems are situated. Roughly speaking three designs of turbines exist: the Kaplan, Pelton and Francis turbines. Every turbine has its own operating characteristics and special field of use under which the highest efficiencies and life spans can be achieved.

The Kaplan is classified a reaction turbine and is especially designed for the use in low head run-of-river power plants (5-12m) with high amount of discharge. In most cases the runner blades and the wicket gates are adjustable (double regulated) to keep the rotor speed constant and create higher efficiency. In contrast to the Kaplan turbine, which is an axial-flow runner, the Francis turbine is a radial-flow runner. This application is mainly used in medium head plants (30-100m) with low fluctuation in discharge, where the highest efficiencies are achieved. The water runs through a spiral case and adjustable wicket gate to the turbine with fixed blades. The Francis turbine is not a pure reaction runner like the Kaplan turbine. Some part of the forces comes from impulse action. The Pelton runner is a pure impulse turbine. Water from the penstock is led through one or more jets to hit the runner at high speed. One advantage of this turbine is the high adaptability to the amount of discharge, because the jets can be switched on and off separately. This system works best for high head installations (100-1500m) with small discharge.

Figure 27 summarizes the characteristics of the three different technologies.



Pelton turbine

Francis turbine

Kaplan turbine

Figure 27: Comparison of Pelton, Francis and Kaplan turbines (LearningEngineering.org 2016)

For generators synchronous and asynchronous technologies are the two standard types. Synchronous generators can be used for isolated or grid connected systems, asynchronous generators are for grid parallel operation only. The latter is the cheaper technology because of the simple construction and little required maintenance; moreover, it can be operated at variable rotor speed. However, asynchronous generators need reactive excitation from the grid. Synchronous generators are expensive due to the rather complex construction and the material used. But they are operating more stably under normal conditions and reach higher efficiencies. The frequency of the generator gets synchronized to 50 HZ, which is the standard for the public grid. The synchronous speed of the generator depends on the number of poles, the more poles, the lower the rotating speed has to be. Thus the synchronous generator can be operated with all different kinds of turbine speeds and is used for medium to large power output.

Finally, in order to adapt the output of the generators to the voltage needed by the public grid, transformers have to be installed. The whole equipment gets steered and monitored by central control systems in the powerhouse.

4.4 **Wind** (Krenn 2015)

The principle of energy production with wind as driving medium is very simple. Together with hydropower it is one of the first power sources to be used at large scale. With the beginning of the industrial revolution and the invention of the steam engine, the importance of wind power decreased for some time. But in the last three decades, wind energy for electricity production has won back high importance. (IRENA 2012: 4f)

4.4.1 The theoretical power of wind

The theoretical power wind exerts on a defined surface at 90°can be estimated with the following equation:

$$P = \frac{\rho}{2} A v^3$$

P.............	Theoretical power in W contained in wind
ρ.............	Air density in kg/m^3
A.............	Rotor swept area in m^2 at 90° to wind
v.............	Flow speed of wind

The density of air reflects the mass of air contained in a certain volume and depends on the air pressure and the temperature of the location. The variable v represents the wind speed, measured in meters per second (m/s) and has huge influence on the theoretical amount of power, because P is a function of v^3. The following figure shows the effect an increase of wind speed has on the theoretical power.

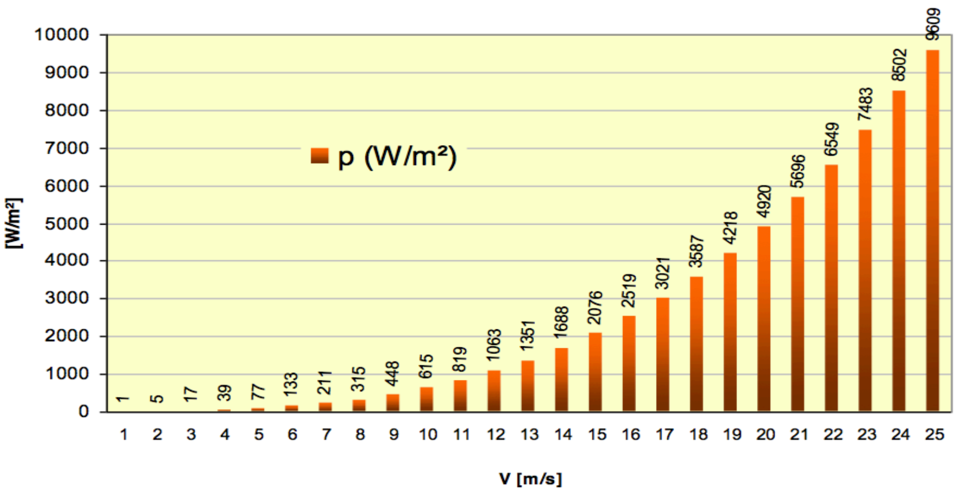


Figure 28: Relation between wind speed and the theoretical power (Krenn 2015)

Wind speed is the most critical variable for planning new wind projects and every location has its own wind characteristics. Hence, before a wind park can be realised, exact measurements of wind speed have to be performed at the chosen location, for at least one year. For this purpose different systems exist to provide detailed wind data.

One technique involves a pole with anemometers at different heights, preferably at minimum 2/3 of the planned hub height. Another technique, called SODAR (sound detection and ranging), sends out sound waves and calculates the phase shifting of the waves, reflected by air molecules. This allows simultaneous wind speed measurements at different heights and even measurements of gusts. A similar technique is used by the so-called LIDAR (light detection and ranging) systems, using bundled light instead of sound waves. Each system has its advantages and comes into use in different situations.

Once enough wind data are collected, the information is processed into wind profiles or so-called frequency distribution tables. These tables can be described with Weibull- or Rayleigh-distributions, where Weibull is used more often, due to the fact that it incorporates different shapes of the distribution curve and thus is more accurate than Rayleigh.

The last variable in the equation is the rotor swept area, that gets hit by the wind at an angle of 90°. The bigger the area, the higher is the power of a system. As can be seen in figure 29, since 1985 the technological standard and the rotor diameters have increased steadily. Modern utility-scale wind turbines sweep diameters of over 100 m and reach capacities of up to 6 MW. (IRENA, 2012: 6)

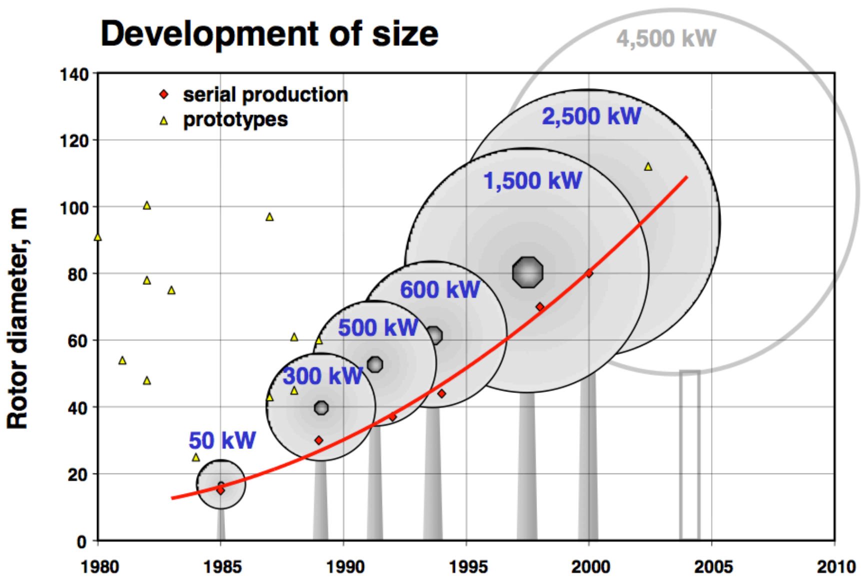


Figure 29: Development of wind system size (Krenn 2015)

4.4.2 Wind power systems

Besides the size and capacity, wind power can be categorized into vertical and horizontal axis systems with one or multiple blades and into on- or offshore systems. For industrial size, the mainly used technology is the three-blade horizontal axis system. Therefore and because of their less significant market share, the aerodynamically less efficient vertical axis systems are not discussed further in this paper.

In most cases not only one turbine is installed at favourable locations, but rather an arrangement of multiple turbines, which then is referred to as a wind park. The advantage of wind parks is that they can use the same infrastructure like roads for site access, buildings and grid connection points.

In figure 30 the main components of different horizontal axis turbine concepts are illustrated.

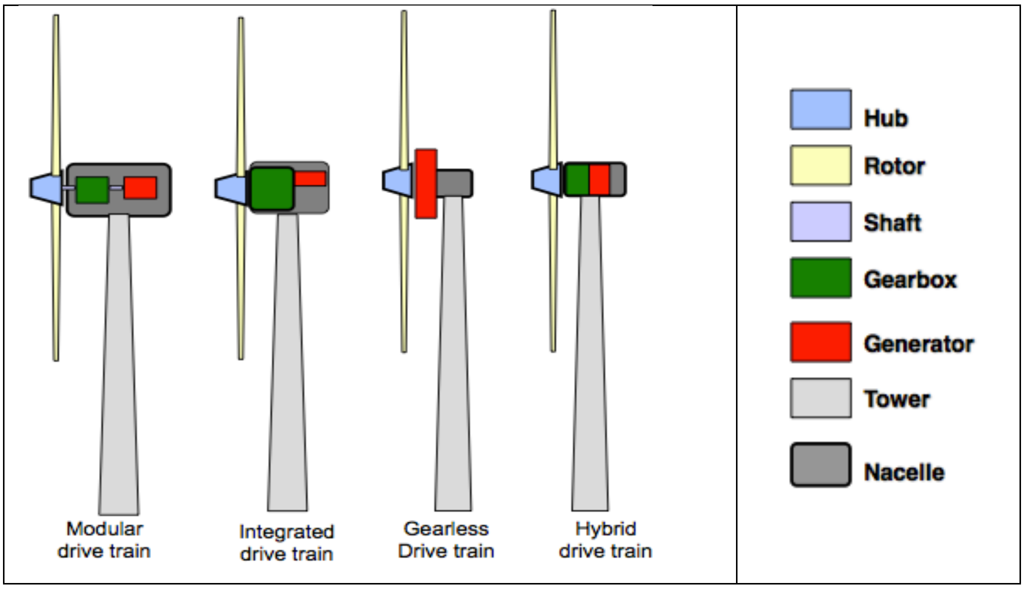


Figure 30: Components of a horizontal axis wind power system (Krenn 2015)

Towers are usually constructed out of steel, concrete or a combination of both, with heights depending on the rotor diameter and wind conditions on the site. Rotor blades are typically constructed out of fibreglass, epoxy resin or reinforced polyester. Strong efforts are put in research for new materials, such as carbon fibre, in order to optimize the ratio of stability to weight and make even larger rotor diameters possible. Via the rotor hub, the blades are connected to the drive shaft and the gearbox or directly to the generator in case of a direct drive system. Gearbox, generator and control systems are housed within the nacelle, a structure made of fibreglass, protecting the equipment.

As can be seen in figure 30, the components can be assembled in different ways. For direct drive systems, due to larger generators, no gearbox is needed, which brings the advantage of higher robustness and less maintenance costs. The other technologies, illustrated in figure 30, need gearboxes to increase the slow but high-torque rotation of the drive shaft to the speed requested by the generator (approximately 1500 rpm). In general the turbine rotor spins at a rate of 10 to 25 revolutions per minute (rpm), depending on the design and size of the turbine. With pitch systems the angle of the blades can be adjusted automatically, in order to control the rotation speed and to fit to the generator.

Similar to hydropower, also for wind power asynchronous and synchronous generators are used. Asynchronous generators must be operated at constant rotation speed with a slip range and need excitation from the grid, but are cost effective. Synchronous generators allow variable rotation speeds, are self-excited and output can be regulated. Therefore the plant can be operated at optimum efficiencies; the design is rather expensive, though.

Finally transformers step up the medium-voltage output of the generators to the voltage needed by the local grid (in general between 10 and 30 kV).

5 ECONOMIC ANALYSIS OF ELECTRICITY PRODUCTION WITH RES

In this chapter biomass CHP, PV, SHPP and wind power are going to be analysed for their economic performance. Generally speaking, the assessed technologies are homogeneous within themselves, in a sense that there are rather small differences in the technical structure PV, for instance, and hence in the cost structure. Thus the assessment of one representative plant for each technology seems enough for the purpose of this paper. As already described in the technology section, SHPP is an exception. For this technology the most common types, namely high-pressure and low-pressure plants, are each covered by one reference plant.

Five existing plants in Austria have been chosen with capacities between 0,5 MWp and 3,5 MWp, generating annual electricity outputs between 2 GWh and 4,5 GWh. The specific ranges of system sizes have been chosen to ensure good comparability of the plants and to eliminate major distortions by economy of scale effects. Presuming that an Austrian average household consists of 2,22 persons (Statistic Austria 2016), consuming round 4.400 kWh per year (Strasser 2013: 9), the specific annual outputs can cover the electricity demands of average Austrian villages with sizes from approximately 1000 to 2000 inhabitants.

In the following sections each plant will be analysed individually, afterwards the results are going to be compared and assessed. The analysis follows the same structure for each plant, starting with the description of the site. Thereafter the plant's efficiencies are estimated, in order to explain and reproduce the energetic output. After the calculation of the output, the cost structure will be analysed, including investment costs, variable costs and taxes. In a next step the economic performance will be analysed by performing a dynamic investment calculation. Finally the results are going to be compared and discussed. The used concepts and methods used for the analysis are described in the following.

5.1 Concepts and methods

For the purpose of finding appropriate existing power plant projects within the set capacity and output spectrum, research in the internet and interviews with experts and operators of several plants have been performed via telephone, e-mail or on site. A list of the interviewed persons can be found in the references. If plant-specific data neither could be found in the Internet, nor could be provided by the operators, the values were estimated with prior fundamental research of literature or interviews with experts from different RES related branches.

For the measurement of economic efficiency, the concepts of long run generation costs (LRGC), a marginal costs concept for the electricity market, and the net present value (NPV) have been chosen.

The NPV in general is a method to translate multiple cash flows, occurring at different times in the future, into one present value. For the calculation, all negative cash flows are opposed to the positive cash flows of a project. Discounting the net cash flows of each period with the discount rate, a rate that represents the costs of capital, and forming the sum of the results, leads to the NPV. Since all five of the assessed projects are operated by limited companies (GmbH), cash flows are assumed to be net cash flows (no VAT) and corporate taxes have to be considered in the calculations. Therefore the basic NPV model including tax on earnings has been chosen to perform the dynamic investment calculation in this paper. (Wöhe et al. 2016: 488 ff)

$$NPV = \sum_{t=1}^{T} \frac{R_t - C_t - tax}{(1+r)^t} - I_0$$

NPV............ Net present value [€]
T .... Investment horizon [y]
t.................. Year-count
R_t .... Revenues in year t [€]
C_t .... Costs in year t [€]
tax .... Tax in year t [€]
I_0 .... Initial investment costs [€]
r.................. Net capital costs (after tax) [%]

The above equation (Wöhe et al., 2016: p.504) shows the formal notation of the used model. Please note that no dismantling costs or revenues are taken into account at the end of the investment horizon, because the plants are supposed to be operated even after this period. In Austria the corporate tax rate (Körperschaftssteuer or KÖSt) amounts to 25%. Multiplying this rate with the tax basis, which consists of all operative profits (earnings before interest rates, depreciation and amortisation or EBITDA) minus depreciation and interest payments for the credit, results in the payable tax amount. (Lüder, 1977: 123)

For the calculation of the discount rate or net capital costs, the weighted average cost of capital (WACC) concept has been chosen. This method combines equity and debt costs in one rate. In order to be consistent, the NPV model including taxes also incorporates an after-tax WACC. This is considered in the following equation. (Kobialka 2015)

$$WACC = \left(\frac{E}{E+D}\right) * r_E + \left(\frac{D}{E+D}\right) * r_D * (1 - tax)$$

WACC..........	Weighted average cost of capital [%]
E	Amount of equity [€]
D.................	Amount of debt [€]
r_E	Equity yield after tax [%]
r_D	Credit rate [%]
Tax..............	Corporate tax (KÖSt) [%]

All assessed projects are financed with equity, debt or a combination of the two. In addition to that, several special financing constructions exist, but a closer look into that topic is beyond the scope of this paper. The expected equity yields for all analysed projects have been assumed, based on Kost (2013: 11). But as a side note it has to be mentioned that equity yield is to a high extent subject to the type of investor and his goals and motivations, which do not necessarily have to be of a monetary nature and can be rather complex to capture in one figure.

Furthermore, the internal rate of return of the projects (IRR) will be calculated, which is actually a special case of the NPV and represents the discount rate, at which the NPV is zero. Also the concept of annuity is used, which is needed to calculate the LRGC. With the annuity method a virtual average constant annual payout over the investment horizon is calculated, taking into account the time value of money. For the calculation the NPV has to be multiplied with the capital recovery factor (CRF), the second term in the equation below. (Wöhe et al. 2016: 496 ff)

$$a = NPV * \frac{r * (1+r)^T}{(1+r)^T - 1}$$

a……………	Annuity
NPV............	Net present value [€]
T	Investment horizon [y]
r..................	Net capital costs (after tax) [%]

The LRGC is a concept used to valuate the electricity costs for additionally installed generation capacities. This figure can be calculated by dividing the annuity of costs by the annual electricity production. (Weissensteiner 2016)

$$LRGC_{el} = \left(\frac{\text{annuity of costs}}{\text{annual electricity production}}\right)$$

Finally sensitivity analyses of LRGCel and NPVs to different economic input factors are performed, by shifting these parameters in 10% steps.

For the sake of completeness, it has to be mentioned that the NPVs and LRGCs of all five projects are valuated back dated, as of the project start dates. Despite FITs, cash flows from 2016 on bear a certain insecurity and are therefore multiplied with an assumed escalation factor, which is based on ECB's long-term inflation target of 2%. Since cash flows till 2016 are already known, this factor does not apply for them.

5.2 Solid biomass

The analyses of this biomass CHP project are based on data provided by Georg Stampfer from Naturwärme Montafon GmbH. Unless otherwise noted, the used data and information relate to this source.

5.2.1 Description of the biomass power plant *Naturwärme Montafon (BM-VBG)*

The assessed biomass power plant is located in the south of Vorarlberg in the area of Montafon. For the operation the special dedicated limited company *Naturwärme-Montafon Biomasse Heizkraftwerk GmbH* was founded. Three local municipalities (Schruns, Tschagguns and Bartholomäberg) together hold 60% of the company's shares, the local forestry fund *Forstfonds des Standes Montafon* holds 20% and the *"MBS Beteiligungs GmbH,* a daughter of *Montafonerbahn AG,* contributes the remaining 20% of the requested 35.000 € of equity. Altogether the project sum amounts to 17 mio €, including 8 mio € for the newly erected local district heating system. The only full time employee of the company is CEO Georg Stampfer. (Excerpt of Austrian companies register FN 285181i) The idea for the project was already born in 2005, but due to objections of neighbours, final approval could only be reached in 2008 after several additional measures, e.g. against noise emissions, have been incorporated in the initial plan. The building phase began in July 2008 and the plant started operating in October 2009.

With round 17 GWh_{th} of heat and round 2,3 GWh_{el} of electricity production per year, approximately 320 public and private households in the region can be supplied with heat via the directly connected 17 km long district-heating grid. The produced electricity gets fed into the public grid and covers the demand of round 500 households. But the plant has not yet reached its full use of the capacity and therefore the company is still trying to convince new customers in the region to use eco-friendly district heating.

According to Ortner (2014) the positive realisation of a biomass combustion project is the double benefit for the involved parties. In the case of Naturwärme Montatfon this is given because from the beginning on, a strong focus of the project has lain on the involvement of the whole region in the value chain. This includes preliminarly the decentralised and independent production of clean thermal and electric energy, by using local resources. Thus, 64% of the used feedstock consist of wood chips from the local forest fund of Montafon and 36% consist of industrial waste wood, mainly from local sawmills. This enhances forest cultivation and protection forest care in the region. It is planned to further increase the number of long–term contracts with additional feedstock suppliers. Three times per year a mobile wood chipper is hired to prepare the delivered wood. On the average, 36.000 m^3 of wood chips are fired per year to generate the needed output. The site has its own loading railroad track, which makes it possible to transport the feedstock directly to the storage area by train, but also roads for trucks exist.

From the storage the wood chips are transported by a wheel loader into a hydraulic stoker system that transports the feedstock into the grate combustion chambers of the two boilers. In 2009 the thermal oil boiler with capacities of 3,2 MWth plus a 500 kWel ORC module and the 4 MWth hot water boiler started operating with the purpose to supply the thermal base load. For peak load and emergency operation, an additional methyl ester (biodiesel) -fired boiler with a capacity of 12 MWth was installed. But the average contribution to the total output per year is rather small and amounts to 660 MWhth, respectively 4% only. The ORC module for electricity generation is connected to the 3,2 MWth boiler, needs little maintenance and is very efficient, if operated in part load. This is especially favourable for the present case; because the plant is operated in heat controlled mode that means electricity can only be generated if heat is produced as well. Heat is only needed in the cold season of the year, thus from May to September, the plant runs at very reduced capacity and in July and August the ORC boiler operates at such low capacity that no electricity is produced.

A possibility to increase the heat production in summer, and therewith the electricity generation, would be district cooling, which is part of further planning. The plant is actually construed for the sales of cooling too, but at present most of the customers' objects do not meet the technological requirements. But also in winter time the plant does not operate at full capacity. During the planning phase of the site, a big hotel was projected in the region with indoor spa and was about to sign a contract with Naturwärme Montafon. According to Stampfer, this big customer would have increased the demand by approximately 25% but unfortunately the project was abandoned and the hotel was not built.

Like almost every process in the plant, the cleaning of the boilers from ashes and dust runs automatically. In addition to that flue gas cleaning takes place in a multistage procedure, involving a multicyclone, an electric filter and a condenser in order to reduce exhaust gases to a minimum. With biomass instead of conventional fuel combustion, approximately 8000t of CO2 eq. are saved per year in the region. Monitoring of all processes is possible out of the control room or online. (Stampfer 2009; Holzkurier 2000)

5.2.2 Efficiency

Theoretically a biomass combustion power plant can operate all the year round, which is 8760 hours per year. In practice the theoretical full load hours (FLH) are less, according to the chosen operating mode and maintenance work that has to be done. The economic feasibility of biomass power plants has a high sensitivity to theoretical FLH. A high amount of operation time is highly recommended in order to stay profitable. The technology is not eligible to function as an additional peak load-serving device, due to relative long starting times. (Ortner 2014)

The ORC of Naturwärme Montafon produces electricity 4567 theoretical FLH per year and heat 3465 theoretical FLH. The additional 4 MWth warm water boiler operates at 1237 theoretical FLH and the methyl ester-fired 12 MWth buffer boiler at 55 theoretical FLH. Broken down to a monthly basis, seasonality comes into focus. During summer months, the production of heat is almost zero and thus also the electricity generation is zero, because Naturwärme Montafon operates in heat-controlled mode. The main purpose of heat-controlled plants is to produce heat in the cold season; that means the plant is not designed to produce electricity alone. Decentralised biomass-fired CHPs with electrical capacities of below 2 MWp, in general are operated in heat-controlled mode. According to Obernberger I. et. al. (2002) p.6, this is due to the low economic and ecological efficiencies of such small systems. In contrast, heat controlled biomass CHPs can achieve over-all efficiencies of up to 90%. Moreover, electricity driven CHPs very often go bankrupt after the expiry of the FIT period and have to be dismantled.

The efficiency of a power plant is the ratio of the amount of energy produced, relating to the energy input. If 40 units of electricity are produced with an input of 100 units, the whole conversion cycle has an over-all efficiency of 40%. The CHP technology is used to improve energy efficiency by producing electricity with an ORC turbine and thermal energy for district heating out of the residual heat of the combustion process. Figure 31 gives an example of the over-all efficiency improvement the CHP technology brings. (Ortner 2014)

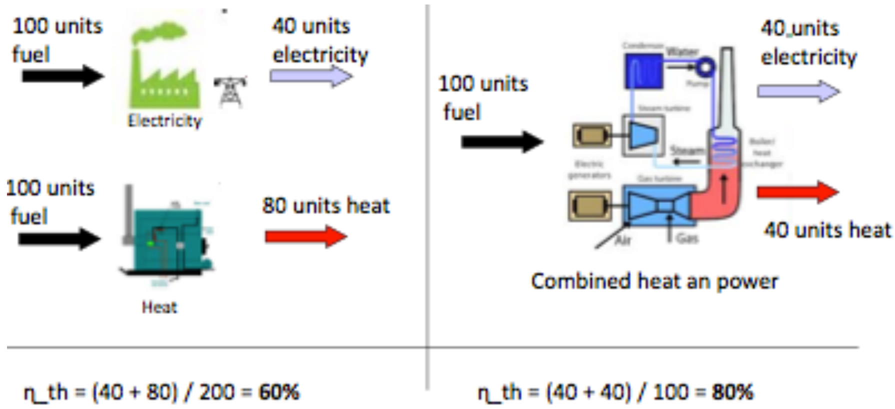


Figure 31: Efficiency improvement via CHP technology (Ortner 2014)

The over-all efficiencies of CHPs are calculated with the following formula (Weissensteiner 2014):

$$\eta = \frac{P_{el} * FLH_{el} + P_{th} * FLH_{th}}{F_{input} * NCV}$$

η	Conversion efficiency power plant [%]
P_{el}	Nominal electric capacity power plant [MW]
P_{th}	Nominal electric capacity power plant [MW]
F_{input}	Fuel input [t]
FLH_{el}	Theoretical full load hours [h]
FLH_{th}	Theoretical full load hours [h]
NCV	Net caloric value of fuel [kWh/t]

In the present case of BM-VBG, using the given values from the previous section, calculations for the ORC module reveal an electric efficiency of round *15%*, a thermal efficiency of 69% and an over-all efficiency of *84%*. The efficiency of the 4 MWth warm water boiler amounts to *88%* and for the methyl ester buffer boiler *90%* are calculated.

5.2.3 Energy output

The energy output depends on the theoretical FLH and the capacity of the observed units. For BM-VBG Georg Stampfer, the director of the analysed facility provided the data that were used to build table 4. Taking the year 2015 as an example, the already mentioned seasonality effect can be seen here very clearly. In June and July no electricity can be produced due to the low heat demand.

Table 4: Heat and electricity output of the wood fired units on a monthly basis in the year 2015 and the average of outputs from 2010 to 2015 (own illustration, data provided by Georg Stampfer 2016)

	Heat	ORC el	Sum	Fuel	Net energy content
	[kWh_{th}]	[kWh_{el}]	[kWh]	[m^3]	[kWh/m^3]
January	2.640.200	430.129	3.070.329	4.808	639
February	2.224.896	365.688	2.590.584	4.847	534
March	2.174.500	312.232	2.486.732	4.122	603
April	1.218.400	200.865	1.419.265	2.724	521
May	1.020.904	67.649	1.088.553	2.276	478
June	580.800	1.523	582.323	1.272	458
July	452.800	0	452.800	758	597
August	493.500	0	493.500	830	595
September	845.296	52.804	898.100	1.397	643
Oktober	1.390.200	256.508	1.646.708	2.753	598
November	1.631.704	279.938	1.911.642	4.598	416
December	2.323.200	380.785	2.703.985	5.586	484
Total in 2015	16.996.400	2.348.121	19.344.521	35.971	538
Average 2010 - 2015	**16.036.337**	**2.283.420**	**18.319.757**	**34.065**	**538**

From 2010 to 2015 the plant produced round 2,28 GWhel and 16 GWhth on the average, with a feedstock consumption of 34.065 m^3. A detailed list of the outputs in the past years and the theoretical FLH can be found in *appendix 6*. The net energy contents in the last column are calculated by dividing the outputs by the fuel inputs. These theoretical numbers are net values and do not include the efficiencies of the plant. Table 5 summarizes the total energy output of the site, including also the methyl ester boiler. These data form the basis for further calculations.

Table 5: Average annual output of Naturwärme Montafon 2010 to 2015 (own illustration, data provided by Georg Stampfer 2016)

	[kWh]	[%]
Thermal wood boiler 3.2 MW	11.087.450	66%
Thermal wood boiler 4 MW	4.948.887	30%
Thermal methyl ester 12 MW	660.667	4%
Thermal output total	**16.697.003**	
Electricity output total	**2.283.420**	

5.2.4 Investment costs

The costs of electricity generation consist of three parts: Capital costs, variable costs and CO2 costs. Capital costs consist of the investment costs for buildings, technical equipment and grid connection, to mention a few. The variable costs contain the fuel price, which depends on the plants' electrical efficiency and the NCV of the used biomass, and the price of maintenance and operation. For renewable energy production in general no CO2 costs appear. But there are small amounts of non-renewable energy needed during the whole process chain like exhaust gases of the wheel loader in the present case. Due to the small impact, the CO2 costs can be neglected in this paper.

To analyse the investment costs, two dimensions have to be considered: the used technology and the size of the facility. Table 6 shows the bandwidth of the investment costs for different biomass technologies. The source of data is a study by Obernberger & Thek, performed in 2008, where he analysed existing state of the art CHP power plants of different technologies in Austria. In terms of economic and technical feasibility, for capacities smaller than 100 kWel, a stirling engine is the best option and according to Ortner (2014), almost 70% of all installed biomass combustion plants, bigger than 2 MWel, are represented by steam turbines. BM-VBG operates a 500 kWel ORC module and thus is best represented by the 650 kWel ORC cycle in the table below.

Table 6: Components of CHP (electricity) related investment costs of biomass CHP plants plus heat related investment costs (based on Obernberger & Thek 2008: 4)

Plant technology		**Stirling engine 70 kWel**		**ORC 650 kWel**		**ORC 1570 kWel**		**Steam process 5000 kWel**	
Buildings & infrastructure	**[€]**	15.000	4,7%	210.000	9,0%	320.000	7,8%	600.000	5,0%
Furnace and boiler	**[€]**	106.000	33,1%	600.000	25,6%	1.170.000	28,4%	4.500.000	37,7%
Gas cleaning	[€]	included		15.000	0,6%	40.000	1,0%	300.000	2,5%
Ash container & conveyor	[€]	included		10.000	0,4%	20.000	0,5%	50.000	0,4%
Heat recovery	[€]	included		30.000	1,3%	30.000	0,7%	280.000	2,3%
Fuel conveyor	[€]	included		10.000	0,4%	30.000	0,7%	130.000	1,1%
Crane	[€]	included		5.000	0,2%	5.000	0,1%	10.000	0,1%
Electric installations	[€]	10.000	3,1%	70.000	3,0%	200.000	4,9%	950.000	7,9%
Hydraulic installations	[€]	14.000	4,4%	50.000	2,1%	125.000	3,0%	1.300.000	10,9%
Steelworks	[€]	included		30.000	1,3%	40.000	1,0%	200.000	1,7%
CHP modules	**[€]**	140.000	43,8%	1.050.000	44,8%	1.675.000	40,6%	2.500.000	20,9%
Planning	**[€]**	35.000	10,9%	213.000	9,1%	367.000	8,9%	931.000	7,8%
Fuel storage unit	[€]	included		50.000	2,1%	100.000	2,4%	200.000	1,7%
Investment costs CHP	[€]	320.000		2.343.000		4.122.000		11.951.000	
Specific IC CHP	**[€/kWel]**	**4.571,43**		**3.605**		**2.625**		**2.390**	
Investment costs heat	[€]	457.000		2.855.000		4.190.000		8.489.000	
Specific IC heat	**[€/kWth]**	**914**		**878**		**548**		**445**	

It can be seen that for ORC almost half of the electricity-related investment costs (44,8%) are represented by the CHP module, followed by the furnace and boiler with 25,6%. The bandwidth of the CHP related specific investment costs ranges from 2.390 €/kWhel for the steam process, to 4.571 €/kWel for the stirling engine. Thus a clear negative correlation of prices to the size of the plant can be observed, in other words, the bigger the plant, the lower the investment costs are.

To generate a holistic picture also the heat related investment costs (the last two lines in Table 6) must be considered. According to Obernberger & Thek the costs of a whole 650 kWel ORC system amount to 4.483 €/kW (3.605 € specific CHP + 878 € specific heat).
The ORC module of Naturwärme Montafon has a thermal capacity of 3,2 MWth and an electric capacity of 500 kWel, which is a quite common relation. But due to the smaller size of the plant assessed in the present paper, the investment costs are rather higher, because of the smaller scale compared to the one analysed by Obernberger & Thek. As an approximation the values for the 650 kWel and 1570 kWel ORC modules in Table 6 are linearly extrapolated. This results in specific CHP related costs of 3.764 €/kWel and 931 €/kWth. By building the sum of the products of the electric and heat capacities with their respective specific investment costs, the costs of round 4.803.600 € can be derived (500 kWel * 3.764 €/kWel + 3.200 kWth * 931 €/kWth).

The total investment costs of BM-VBG amount to 17 mio €, from which the district heating grid takes a share of 8 mio €. 4.803.600 € are the costs for the ORC module and with the remaining 4.196.400 € the 4 MWth warm water system and the 12 MWth methyl ester unit were financed.

Table 7: Composition of total investment costs for Naturwärme Montafon (own illustration, data provided by Georg Stampfer 2016)

ORC system: 3,2 MW_{th} + 500 kW_{el}	4.803.600
Warm water system 4 MW_{th} Methyl ester system 12 MW_{th}	4.196.400
District heating network	8.000.000
Total investment costs	**17.000.000**

5.2.5 Fuel costs

Fuel costs are another main factor for biomass plants. For a positive business plan, long-term contracts of biofuel delivery with one or more participants in the wood industry are crucial, in order to guarantee the coverage of the biomass plant's demand for operation. Moreover a location with short ways of delivery must be chosen, to keep the transport costs affordable. In the technical overview section some types of solid biomass feedstock have already been mentioned. (Ortner 2014) According to Stampfer (2009), approximately 54% of the fuel consist of forest wood chips, delivered by the local forestry at a price of 16,50 €/m^3 and 46% come from local saw mills at a price of

18 €/m^3. These prices are averages from 2009 to 2016 and include transport as well as ash disposal. Thus the weighted price for the fuel-mix is 17,19 €/m^3. The typical water content of the mix is 55% (M55%) with an NCV of round 2.000 kWh/t (see table 8), which is corresponding with an NCV of round 615 kWh/m^3. (Calculation based on Francescato 2008: 26) In the following table a granular picture of the fuel demand of each unit in the plant is shown.

Table 8: Fuel demand for Naturwärme Montafon (own illustration, data provided by Georg Stampfer 2016)

Calorific value fuel mix (M55%)	[kWh/t]	2.000	
Calorific value fuel mix (M55%)	[kWh/m^3]	615	
Methyl ester demand	[t/y]	59	
Wood demand total	[m^3/y]	34.065	
Wood demand ORC	[m^3/y]	**26.013**	**76%**
Wood demand 4MW	[m^3/y]	**8.052**	**24%**

The thermal oil boiler with the ORC consumes 76% of the total wood. In a next step it has to be investigated, how much fuel is consumed for electricity generation in this unit. From 100% of the total ORC energy output, approximately 17% are electricity and 83% are heat (see *appendix 6*). Dividing the fuel-mix price by the product of the NCV and the electric efficiency finally leads to an electricity related fuel price of approximately *18,72 c/kWhel* (17,19 €/m^3/ (15% * 615 kWh/m^3 = 18,72 c/kWhel)).

The fuel price for the heat-producing unit is calculated by dividing the fuel costs per m^3 by the product of the NCV and the thermal efficiency (17,19 €/m^3/ (615 kWh/m^3 * 88%) = *3,2 c/ kWhth*).

To derive the fuel costs for the biodiesel unit, the calorific value of methyl ester and its market price are needed, as well as the conversion efficiency of biodiesel boilers. The market price from 2008 to 2016 on average was 820 €/t (see chart in *appendix 5*), the calorific value amounts to 11.111 kWh/t (Lang X. et al. 2001) and the conversion efficiency is assumed to be 90%, which is standard for oil burners. Thus the fuel costs of *8,20 c/kWhth* can be derived (820 €/t / (90%*11.111 kWh/t) = 8,20 c/kWhth).

5.2.6 Operation and maintenance costs

According to Stampfer, the o&m costs amount to approximately 110.000 €/y. A full service contract is closed with the manufacturer of the boilers, which comprises a periodical maintenance and insurance of the machinery. Further positions are salary of employees and the liability insurance package. In addition to that business interruption insurance is assumed to be in place, which is especially necessary to cover the risk of interruption during the heating season. (Gerhard el. al. 2015: 747f)

To incorporate inflation and other cost increasing factors for the future periods from 2016 on in the NPV and LRGC calculations, an annual escalation factor of 2% is assumed for fuel costs as well, as for o&m costs. That means every year the variable costs increase by the rate of 2%.

5.2.7 Revenues

Electricity sale:

An adequate feed-in tariff (FIT), guaranteed by the buyer of electricity (OeMAG) for a long enough time-span is crucial for the feasibility of the project. In Austria the current support duration for solid biomass is 15y. The tariff very much depends on the type of biofuel that is used and on the installed electric capacity. As already mentioned, the used fuel-mix consists of forest wood chips (54%) and sawmill residues (56%). For 2009 biomass plants firing forest wood chips received a tariff of 15,63 c/kWhel. For the use of sawmill residues, OeMAG calculates deductions from the FIT of 25% which results in 11,72 c/kWhel. Since Naturwärme Montafon is firing a mixture of both, on a pro-rata basis, the FIT amounts to *13,83 c/kWhel* (15,63 c/kWhel * 54% + 11,72 c/kWhel * 46% = 13,83 c/kWhel), see *appendix 1*. Multiplied with the produced electricity (2.28 GWhel), annual revenues of *315.855 €* are derived.

After the FIT period, the produced electricity can be sold at the prevailing wholesale market price. For the analyses of the plant this is assumed to be the average from 2002 to 2016 and amounts to *3,961 c/kWhel,* see *appendix 4*. That leads to annual electricity sales revenues of 90.439 €/y after the expiry of the FIT period.

Heat sale:

According to Stampfer, the revenues out of the sale of heat amount to 9,02 c/kWhth.
The annual total thermal output of the plant amounts to 16.70 GWhth. Due to district heating grid losses, on average only 80% of the produced heat arrive the customers'

objects. Thus only 13,36 GWhth can be sold, which leads to revenues of *1.204.856 €* for heat.

Subsidies:

The Austrian “Kraft-Wärme-Kopplungsgesetz” regulates subsidies for CHP plants. The advantage of CHP plants is the ability to generate energy with high over-all efficiency So-called condensing plants that produce only electricity can achieve only up to 45%. In the present case, subsidies for the whole project amount to 4 mio €.

5.2.8 Depreciation, interest payments and corporate tax (KÖST)

The legal owner of the assessed site is a limited company (GmbH), thus corporate tax has to be paid for earnings. The corporate tax rate in Austria is 25%. The tax base consists of all corporate profits, generated by the company (EBITDA) minus depreciation and interest rates paid for the credit. Depreciation is assumed to be linear for the credit period, which is 25 years.

BM-VBG is financed to almost 100% with debt, plus investment subsidies of 4 mio €. The 35.000 € minimum equity for the foundation of a limited company in Austria are a negligible share of 0,27%. Thus they are not considered in further calculations. The notional credit amounts to 13 mio € and amortizes linearly to zero in 25 years, which is approximately the useful lifetime of a biomass CHP. (NREL 2016)

In *appendix 20* the table with the tax calculations can be found. In the case of BM-VBG, no taxes are paid, because after deduction of depreciation and payment of interest from the EBITDA, no profit is left. The NPV model including tax originally foresees tax revenues, if the company produced losses in a period. But in order to provide a undistorted picture of the plant’s operative business and since BM-VBG is analysed as a stand-alone facility, no tax reduction effects out of losses are taken into account. (Blohm & Lüder 1991: 123)

5.2.9 Financial analysis

To measure the feasibility of the project, the NPV method has been chosen. Therefore all the discounted costs are opposed to the discounted income cash flows. The plant was financed with 100% debt. Banks normally request at least 20% of equity for collateralisation reasons; in this case the 4 mio € of subsidies plus the 35.000 € of equity, needed for the foundation of the limited company, were considered enough for the purpose.

The interest rate of the credit is linked to the money market index 3-month EURIBOR with an assumed margin of 2% p.a., which corresponds to the risk of the project. For further calculations, a fixed credit rate of 2,5% is assumed. That is the average of the 3-month EURIBOR from 2009 to 2016 plus the assumed margin of 2%. For details and historical 3-mont EURIBOR rates, please see *appendix 16*. The loan has a credit period of 25 years, with linear amortisation. In general, because of unsecure income after the FIT period, banks are not willing to exceed that timespan for credit. But in this case since heat selling tariff is rather stable, and takes a much higher share of revenues, banks granted a tenor of 25 years for the credit. (Stampfer 2016; Ortner 2014)

Since there is no significant amount of equity financing, the discount rate for the NPV and LRGC calculations equals the credit interest rate after corporate tax and amounts to 1,88%.

Table 9 summarizes all the given, assumed and derived input parameters, used for the following calculations of NPV and LRGC.

Table 9: Main calculation parameters of BM-VBG

Parameters biomass CHP*	**BM-VBG 0.5 MWel**	
Technical data	**Start**	**2010**
Total capacity el backpressure mode	[kWel]	500
Total capacity th boiler ORC	[kWth]	3.200
Total capacity th boiler warm water	[kWth]	4.000
Total capacity th methyl ester (biodiesel)	[kWth]	12.000
Heat grid transfer losses	[%]	20%
Efficiency ORC electricity	[%]	15%
Efficiency ORC heat	[%]	69%
Efficiency ORC overall	[%]	84%
Efficiency th boiler warm water (WW)	[%]	88%
Efficiency th boiler methyl ester	[%]	90%
Calorific value woodchips M55% a)	[kWh/t]	2.000
Theoretical Full Load Hours el ORC	[h/y]	4.567
Theoretical Full Load Hours th ORC	[h/y]	3.465
Theoretical Full Load Hours th boiler warm water (WW)	[h/y]	1.237
Theoretical Full Load Hours th methyl ester boiler	[h/y]	55
Lifetime power plant = depreciation period = investment horizon b)	[y]	25
Costs		
Investment costs including district heating grid	[€]	17.000.000
Investment costs ORC module	[€]	4.803.600
Investment costs district heating grid	[€]	8.000.000
Fuel costs electricity ORC	[€/kWh_{el}]	0,18717
Fuel costs heat boiler WW	[€/kWh_{th}]	0,03196
Fuel costs heat methyl ester	[€/kWh_{th}]	0,08200
O&m incl. insurance	[€/y]	110.000
Real escalation of o&m and fuel from 2016 on c)	[%/y]	2%
Credit period	[y]	25
Interest rate credit before tax	[%]	2,50%
Corporate tax rate d)	[%]	25%
Discount rate after tax	[%]	1,88%
Debt ratio	[%]	100%
Revenues		
Feed in tariff (OeMAG) e)	[€/kWh]	0,13833
Duration feed-in tariff	[y]	15
Investment subsidies	[€]	4.000.000
Wholesale market price electricity (average 2002-2016)	[€/kW_{e}l]	0,03961
Heat selling tariff no indexation	[€/kWh]	0,09020

* Unless otherwise noted, data were provided by Stampfer (2016) and www.naturwaerme-montafon.at

a) Francescato (2008); see figure 20

b) Calculation based on depreciation information in Austrian companies register 2015 FN 285181i

c) Own assumption based on ECB inflation target of 2%

d) Wirtschaftskammer Österreich (WKÖ)

e) E-Control see *appendix 1* “Overview of FIT different RES technologies 2003-2009”

In this paper the LRGCel for BM-VBG are calculated with the equation presented in the concepts and methods section, complemented with the term of heat exctraction (equation based on Weissensteiner 2014):

$$LRGC_{el} = \left(\frac{\text{ann costs}_{el}}{\text{ann output}_{el}}\right) - \left(\frac{\text{ann revenue ORC}_{th} + \text{ann investment costs ORC}_{th}}{\text{ann output ORC}_{th}}\right)$$

$LRGC_{el}$	Long run generation costs electricity
ann_costs_{el}	Annuity of electricity related costs
ann_output_{el}	Annual electricity output
ann revenue ORC_{th}.......................	Annuity of heat sale revenues, produced by the ORC module
ann investment costs ORC_{th}.........	Annuity of the heat specific investment costs for ORC
ann output ORC_{th}.........................	Annual heat output of the ORC module

At first, the annuity of all electricity related costs is divided by the annual electricity output. The result contains the LRGC for electricity plus heat. In order to filter out the LRGC for electricity, heat extraction has to be considered. Hence, the second term in the above equation, containing heat sales profit and heat specific investment costs has to be deducted. For the calculation of the LRGCel in this case, it makes sense to focus only on the ORC module, because the plant is operated heat driven. As already mentioned in the technology section, pure electricity driven biomass CHP plants have low economic efficiencies and often have to be dismantled, once the FIT expires. But for BM-VBG, considerations about subsidies, which are only granted if CHP technology is applied and of additional profit through electricity sales may have led to the decision to integrate an ORC module in the plant. (Obernberger & Thek 2008: 5) Thus in this paper the LRGCel are calculated for the ORC module as a closed system, capable of being integrated in any other heating plant, not including district heating grid costs and costs for the other boilers.

As can be seen in table 10, the total LRGC of the ORC module, including heat and thermal energy production, amount to *348,39 €/MWh*. To achieve the LRGCel, the heat specific costs and profits have to be deduced, which results in *266,48 €/MWhel.*

Figure 32 has been taken from the presentation of a study performed by Hofbauer (2008). In the chart the LRGC for different CHP technologies are plotted, in dependency of the installed thermal capacity of the system under standardised conditions. It can be seen, that ORC has the highest LRGC for thermal capacities below 8 MWth. The orange diamond in the chart shows the position of the analysed ORC of BM-VBG. The LRGC is higher, compared to the standard situation, which means electricity production of the analysed plant is relatively expensive. One reason therefore is the lower theoretical FLH the BM-VBG ORC operates with. A convergence of BM-VBG's input parameters would drive the LRGC in the direction of the green curve in figure 32.

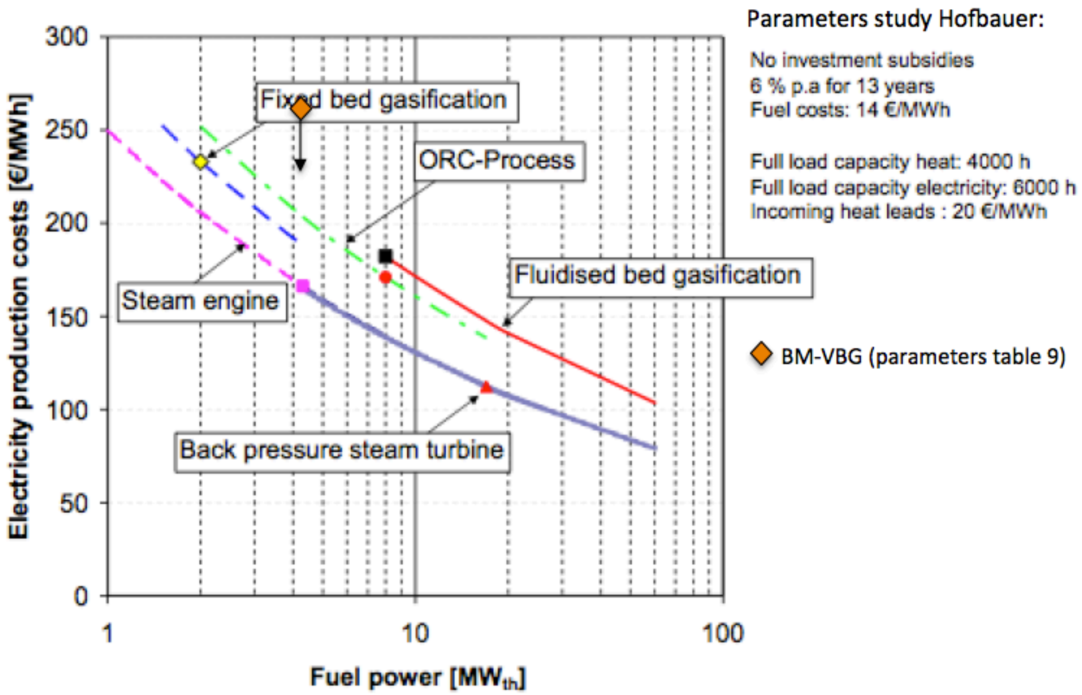


Figure 32: LRGC for biomass CHP technologies in 2008 (Hofbauer 2008: 8ff)

It is a philosophical question, whether the grid costs have to be included for the calculation of the NPV or not. For the purpose of a fair comparison with other electricity producing RES technologies that do not have to invest in costly district heating grids, an analysis without the district-heating grid could be argued. In Austria a very dense electricity distribution network already exists and the investment for connection is rather small, in contrast to the district heating network, which has to be close to heat producing facilities and thus is locally very limited. But on the other hand, for CHP biomass plants, heat and electricity generation are inseparable and therefore infrastructure for the selling of the produced heat must be taken into account for the analysis of the whole project.

The NPV for the whole project, including the district-heating grid is negative and amounts to *-1.277.619 €*. If the district-heating grid were excluded, the NPV would be positive and would amount to *4.840.028 €*. But what was the reason, why the project was realized with a negative NPV? The answer will be given in the next section.

Table 10: Dynamic investment calculation of BM-VBG (own calculation)l

BM-VBG		0,5 MWel
Technical data		
Total capacity el backpressure mode (heating mode)	[MW]	0,50
Total capacity th boiler ORC	[MW]	3,20
Total capacity th boiler warm water	[MW]	4,00
Total capacity th methyl ester (biodiesel)	[MW]	12,00
Theoretical Full Load Hours el ORC	[h/y]	4.567
Theoretical Full Load Hours th ORC	[h/y]	3.465
Theoretical Full Load Hours th boiler warm water (WW)	[h/y]	1.237
Theoretical Full Load Hours th methyl ester boiler	[h/y]	55
Efficiency ORC electricity	[%]	15%
Efficiency ORC heat	[%]	69%
Efficiency ORC overall	[%]	84%
Heat grid transfer losses	[%]	20%
Costs		
Investment costs including district heating grid	[€]	17.000.000,00
Investment costs ORC module	[€]	4.803.600,00
Investment costs district heating grid	[€]	8.000.000,00
Fuel costs per srm M55%	[€/m³]	17,19
Fuel costs electricity ORC	[€/MWh]	187,17
Fuel costs heat boiler WW	[€/MWh]	31,96
Fuel costs heat methyl ester	[€/MWh]	82,00
O&m incl. insurance	[€/y]	110.000,00
Real escalation of o&m and fuel from 2016 on	[%/y]	2,00%
Revenues		
Feed in tariff (ÖMAG)	[€/MWh]	138,33
Heat selling tariff no indexation	[€/MWh]	90,20
Wholesale market price electricity (average 2002-2016)	[€/MWh]	39,61
Investment subsidies for CHP technology	[€/MW]	4.000.000,00
Investment subsidies in % of investment costs	[€/MW]	23,53%
Financing		
Investment horizon	[y]	25
Discount rate after tax	[%]	1,88%
Interest rate debt before tax	[%]	2,50%
Debt ratio	[%]	100%
Corporate tax	[%]	25%
Depreciation period	[y]	25
Capital recovery factor	[%]	5,05%
Energy output		
Output el ORC	[MWh]	2.283,42
Output th ORC	[MWh]	11.087,45
Output th unit 4MWth	[MWh]	4.948,89
Output th Oil unit 12MWth	[MWh]	660,67
Fuel demand warm water 4MWth	[m³]	8.052,12
Fuel demand ORC	[m³]	26.013,34

Dynamic investment calculation including tax

	Year	Discounted CF total	Nominal CF	O&M	Fuel ORC	Fuel 4 MWth	Fuel 12 MWth	Corp. tax	Electr. sale	FIT	Market	Heat sale	Discounted cashflows: Costs ORC	Discounted cashflows: Sale of heat ORC
			A+B+C+D+E+F+G	A	B	C	D	E	F			G		
0	2009	-13.000.000 €	-13.000.000 €										-3.673.341 €	2.234.165 €
1	2010	756.762 €	770.952 €	-110.000 €	-427.396 €	-158.190 €	-54.175 €	0 €	315.855 €	100%	0%	1.204.856 €	-527.505 €	780.556 €
2	2011	742.834 €	770.952 €	-110.000 €	-427.396 €	-158.190 €	-54.175 €	0 €	315.855 €	100%	0%	1.204.856 €	-517.796 €	761.519 €
3	2012	729.162 €	770.952 €	-110.000 €	-427.396 €	-158.190 €	-54.175 €	0 €	315.855 €	100%	0%	1.204.856 €	-508.266 €	742.945 €
4	2013	715.742 €	770.952 €	-110.000 €	-427.396 €	-158.190 €	-54.175 €	0 €	315.855 €	100%	0%	1.204.856 €	-498.912 €	724.824 €
5	2014	702.569 €	770.952 €	-110.000 €	-427.396 €	-158.190 €	-54.175 €	0 €	315.855 €	100%	0%	1.204.856 €	-489.729 €	707.146 €
6	2015	689.638 €	770.952 €	-110.000 €	-427.396 €	-158.190 €	-54.175 €	0 €	315.855 €	100%	0%	1.204.856 €	-480.716 €	689.898 €
7	2016	676.946 €	770.952 €	-110.000 €	-427.396 €	-158.190 €	-54.175 €	0 €	315.855 €	100%	0%	1.204.856 €	-471.868 €	702.514 €
8	2017	651.562 €	755.956 €	-112.200 €	-435.944 €	-161.353 €	-55.259 €	0 €	315.855 €	100%	0%	1.204.856 €	-472.447 €	689.584 €
9	2018	626.630 €	740.661 €	-114.444 €	-444.662 €	-164.580 €	-56.364 €	0 €	315.855 €	100%	0%	1.204.856 €	-473.027 €	676.892 €
10	2019	602.141 €	725.060 €	-116.733 €	-453.556 €	-167.872 €	-57.491 €	0 €	315.855 €	100%	0%	1.204.856 €	-473.607 €	664.434 €
11	2020	578.086 €	709.147 €	-119.068 €	-462.627 €	-171.230 €	-58.641 €	0 €	315.855 €	100%	0%	1.204.856 €	-474.188 €	652.205 €
12	2021	554.459 €	692.916 €	-121.449 €	-471.879 €	-174.654 €	-59.814 €	0 €	315.855 €	100%	0%	1.204.856 €	-474.770 €	640.202 €
13	2022	531.250 €	676.360 €	-123.878 €	-481.317 €	-178.147 €	-61.010 €	0 €	315.855 €	100%	0%	1.204.856 €	-475.353 €	628.419 €
14	2023	508.452 €	659.473 €	-126.355 €	-490.943 €	-181.710 €	-62.230 €	0 €	315.855 €	100%	0%	1.204.856 €	-475.936 €	616.853 €
15	2024	486.058 €	642.248 €	-128.883 €	-500.762 €	-185.344 €	-63.475 €	0 €	315.855 €	100%	0%	1.204.856 €	-476.520 €	605.500 €
16	2025	296.604 €	399.262 €	-131.460 €	-510.777 €	-189.051 €	-64.744 €	0 €	90.439 €	0%	100%	1.204.856 €	-477.105 €	594.355 €
17	2026	278.077 €	381.342 €	-134.089 €	-520.993 €	-192.832 €	-66.039 €	0 €	90.439 €	0%	100%	1.204.856 €	-477.690 €	583.416 €
18	2027	259.875 €	363.063 €	-136.771 €	-531.413 €	-196.689 €	-67.360 €	0 €	90.439 €	0%	100%	1.204.856 €	-478.276 €	572.679 €
19	2028	241.992 €	344.418 €	-139.507 €	-542.041 €	-200.623 €	-68.707 €	0 €	90.439 €	0%	100%	1.204.856 €	-478.863 €	562.139 €
20	2029	224.422 €	325.400 €	-142.297 €	-552.882 €	-204.635 €	-70.081 €	0 €	90.439 €	0%	100%	1.204.856 €	-479.451 €	551.792 €
21	2030	207.159 €	306.002 €	-145.143 €	-563.939 €	-208.728 €	-71.483 €	0 €	90.439 €	0%	100%	1.204.856 €	-480.039 €	541.637 €
22	2031	190.199 €	286.217 €	-148.046 €	-575.218 €	-212.902 €	-72.913 €	0 €	90.439 €	0%	100%	1.204.856 €	-480.628 €	531.668 €
23	2032	173.534 €	266.035 €	-151.006 €	-586.723 €	-217.160 €	-74.371 €	0 €	90.439 €	0%	100%	1.204.856 €	-481.218 €	521.883 €
24	2033	157.159 €	245.450 €	-154.027 €	-598.457 €	-221.504 €	-75.858 €	0 €	90.439 €	0%	100%	1.204.856 €	-481.808 €	512.277 €
25	2034	141.070 €	224.453 €	-157.107 €	-610.426 €	-225.934 €	-77.376 €	0 €	90.439 €	0%	100%	1.204.856 €	-482.399 €	502.849 €

NPV total plant	**-1.277.619 €**
NPV total plant excl. dh. grid	**4.840.028 €**
IRR	0,82%
Total electr generation/y	2.283 MWhel
Total heat generation	16.697 MWhth
Heat generation ORC	11.087 MWhth
LRGC ORC Electricity + Heat (excl. dh. grid)	**348,39 €/MWh**
Heat extraction	81,90 €/MWhth
LRGC (excl. dh. grid)	**266,48 €/MWhel**

Current period

Last period with FIT

NPV of costs electricity	**-15.761.460 €**
Annuity of costs electricity	**-795.511 €**

NPV (revenue ORC_{th}+invest costs ORC_{th})	**17.992.351 €**
Annuity (revenue ORC_{th}+inv costs ORC_{th})	**908.108 €**

$$LRGC_{el} = LRGC_{el+th} - \text{heat extraction}$$

$$LRGC_{el} = \left(\frac{\text{ann costs}_{el}}{\text{ann output}_{el}}\right) - \left(\frac{\text{ann revenue ORC}_{th} + \text{ann investment costs ORC}_{th}}{\text{ann output ORC}_{th}}\right)$$

5.2.10 Sensitivity analysis

During the whole lifetime of a biomass project, some risks have to be faced. In the project development phase, too optimistic business plans and false estimations could cause early bankruptcy in the operating phase. Moreover there is always the risk that permission of the authorities is delayed, for example due to justifiable objections of neighbours, like in the present case. Environmental impact and social assessment analyses have to be performed beforehand to minimize this risk, though. But also if these impediments are overcome, bad project monitoring or project leaders with little experience can increase the project costs dramatically during the implementation phase.

When thinking of the operation phase, several factors influence the profitability of the site. In the following charts the sensitivities of LRGCel and NPV to different economic factors are stressed by shifting these parameters in 10% steps. Naturwärme Montafon has already been operating since the end of 2009; hence the shift of parameters is performed for the periods 2017 to 2034, covering only the future sensitivities of the site.

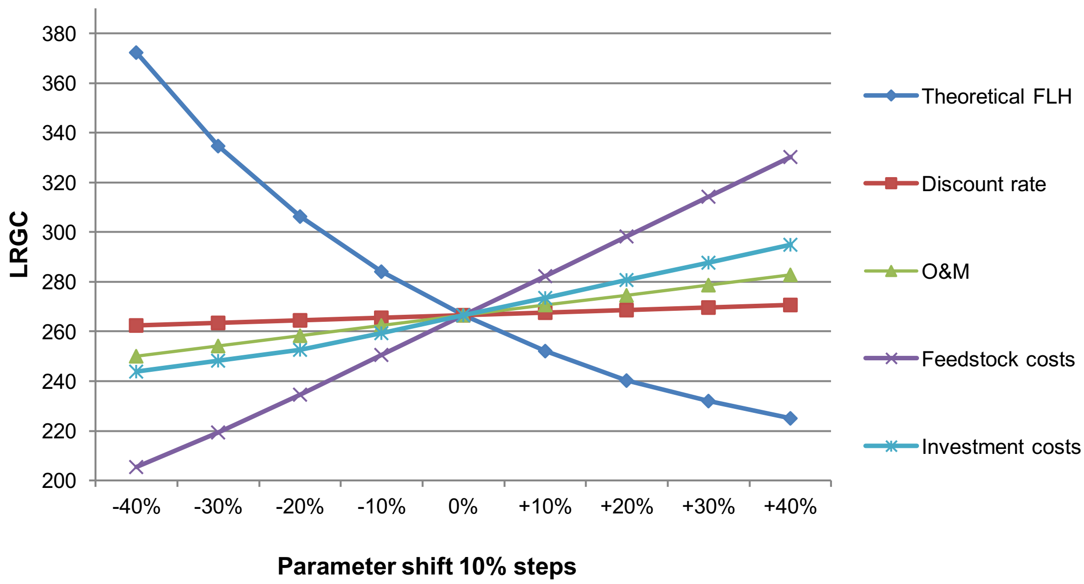


Figure 33: Sensitivity of the ORC's LRGCel to changes of different input parameters (own graph, value table in *appendix 25*)

The highest impact on LRGC can be observed by changing the theoretical FLH. This illustrates the high importance of sufficient demand for heat and electricity. Due to the high linkage of electricity generation to heat production, the theoretical FLH of all wood boilers are shifted with the same proportion. Typical of biomass combustion plants, fuel costs also have a very high impact on the LRGCel and NPV. Even more illustrative the importance of stable fuel costs and long-term supply contracts is shown in figure 34.

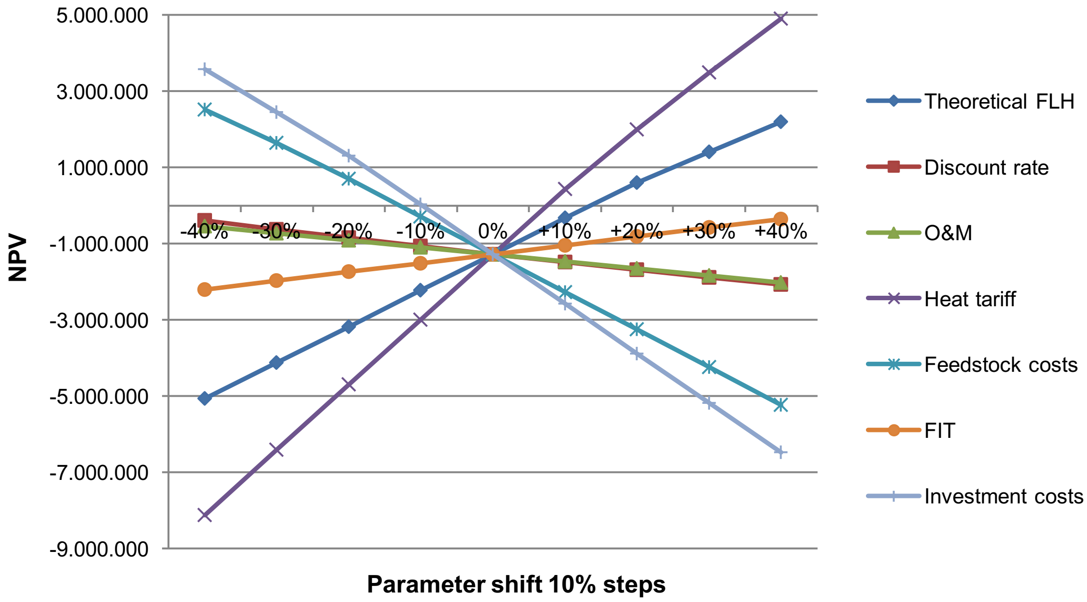


Figure 34: Sensitivity of BM-VBG's NPV to changes of different input parameters (own graph, value table in *appendix 25*)

Shifting the fuel costs down 13% from 17,19 c/kWh to 14,96 c/kWh results in a slightly positive NPV instead of -1.277.619 €. Due to the fact that the main purpose of the assessed site is the generation of heat, the heating tariff has the highest impact on the NPV, even higher than the theoretical FLH. It is interesting that changes of the FIT have a rather moderate influence. This is due to the fact that electricity is not the main product which can simply be explained by the relation of the capacities of 500 kWel to 7,2 kWth + 12 kWth. And even though, due to the scaling of the charts, it looks as if changes of o&m and the discount rate have minor influence on the project, one 10% shift in these parameters changes the NPV by more than 100.000 €.

Taking a closer look to figure 34 reveals a slight skew of the sensitivity lines, when they enter positive terrain. This effect is caused by the corporate tax that reduces revenues and at the same time the NPV.

According to Georg Stampfer, during the planning phase of the plant, a big hotel with a wellness area and swimming pool achieved building approval status and wanted to sign a contract for heat service with Naturwärme Montafon. The energy demand of the Hotel would have brought additional 25% of the whole revenues of the plant.

Unexpectedly the Hotel was not built. Looking at figure 34, an increase of the theoretical FLH of 25% (the amount the Hotel would have brought) shifts the NPV of the plant into positive terrain. In addition to that, originally the investment costs were calculated with 16 mio €. This sum was exceeded by 1 mio €. (Montafoner Standpunkt 2008: 14) In the present case, the sensitivity to the investment costs is of hypothetical nature, since the plant is already in the operating phase. But as can be seen, during the planning- and building phases, incorrect or too optimistic calculations can cause severe problems or at least make the project less profitable.

It appears that a too optimistic calculation of investment costs and the customer base for heat and electricity during the planning phase brought the company into this situation. Already in operation, the main focus has to be the increase of the customer base and, as far as possible, cost reduction measures. Renegotiation of the feedstock price would be another option, but due to fixed contracts this is very difficult. As a last resort the increase of the heating tariff could be considered but this is subject to existing contracts too.

5.3 Photovoltaic

(Please note that the analyses of this PV project are based on data provided by *SOURCE A* under an agreement of strict confidence. Therefore the source of data cannot be specified in this paper. Instead, a list with the names and contact details of all sources will be submitted to Prof. Dr. Bernhard Pelikan. Unless otherwise noted, the used data and information for the analysed PV project relate to this confidential source.)

5.3.1 Description of the analysed PV power plant in Salzburg *(PV-SBG)*

One of Austria's 10 biggest PV power plants lies in central Austria at a latitude of approximately 47° and 1.200 m altitude. Building of the plant started in August 2015 after four years of preparation time. A hired specialist has performed the permission process and communication with responsible public authorities. After several negative expert opinions, with the support of the community next to the construction site, the operators of the plant had the permission to start the construction. In a further step, the three project owners and partners founded a GmbH (limited company) with the purpose to operate the PV plant. The owners of a mountain restaurant close to the site hold 75% of the shares.

With a very favourable hillside situation of 35° facing south, approximately 3,5 acres of space are needed for 3,15 MWp of capacity. The output of the plant amounts to approximately 3,7 GWhel that are fed into the public grid. 1,4 km long cables connect the plant to the nearest network access port.

The substructure for the mounting system of the modules consists of over 3.800 galvanized poles that are rammed 2m into the ground. This is a very mild, convenient solution and goes easy on the soil, because no ground sealing concrete foundations had to be applied. Moreover costs could be reduced thereby.

A very remarkable fact of the project is the value chain; Austrian companies produced the round 13.000 modules, 108 inverters, switch boxes and 80 km of cables. A company from Styria, dedicated to the construction of PV plants performed the civil works. Due to the hillside slope of 35°, the main challenge was the transportation of the 600 t of material to the building site. 25 people were involved in the construction and special machines had to be used. The all-over investment costs from planning to module and construction amount to 3mio €.

To the author's state of information, the main motivations of the operators are the own use of the produced electricity, the increase of energy autonomy in the region, contribution to CO2 reduction and building up an additional source of income. It is a realistic assumption that 10% of the produced electricity is for self-consumption and 90% are fed into the grid.

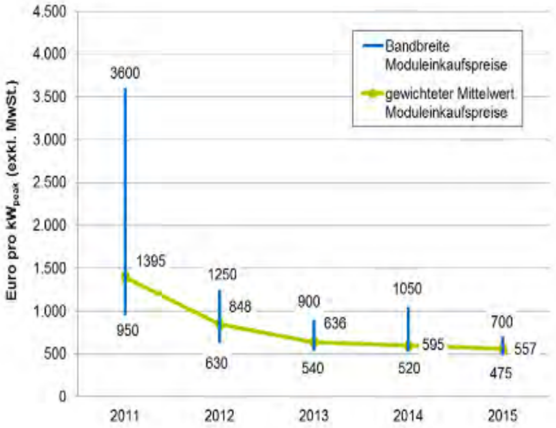
5.3.2 Costs

In PV projects, typically the main drivers of the long-range generation costs (LRGC) are the investment costs, including the following positions:

- PV Modules
- BOS hardware (inverters, rack, wiring, monitoring system, lightning protection)
- BOS soft costs (planning, installation, permission, customer acquisition, grid connection)

Since the mid 80's, the market has grown constantly and competition between the PV cell producing market leader China, Japan, Korea, Germany, Malaysia, Norway and the USA has brought prices of PV modules to an affordable level for energy industry and even for home use. (Fechner 2015; IEA 2014: 9ff).

In Austria the module prices dropped by more than 60% from 2011 to 2015. Figure 35 shows the development of the wholesale prices in Austria. The blue lines represent the bandwidth that is narrowing constantly over the years, and the green line shows the weighted average. Within whole turnkey PV systems >10 kWp, pictured in Figure 36, module prices per kW represent over 43%. The rest is represented by the BOS. The bigger the plants get, the higher is the share of module costs because of economies of scale. Large simple ground-mounted utility-scale projects without tracking systems typically have the lowest BOS costs. (Paula et al. 2016: 108f)



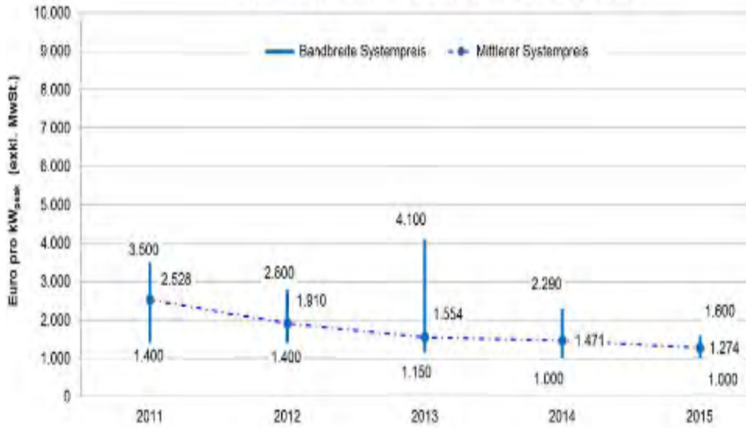


Figure 35: Weighted average and bandwidth of module wholesale prices excl. VAT (Paula et al. 2016: 108f)
Figure 36: Average price and bandwidth of whole installed systems > 10 kW_{peak} (Paula et al. 2016: 108f)

For the assessed 3,15 MW system in Salzburg the turnkey investment costs amount to 3 mio €, respectively 952,39 € per kWp. Given the module price of 2015 in Figure 35 (557 € per kWp or 58,5%), the BOS costs are round 395 € per kWp or 41,5%.

The big advantage of PV power generation is that no fuel or feedstock is needed. Operation and maintenance and insurance costs represent the only variable costs for the operative business. Being exposed to extreme weather conditions, animals, dust and other extreme situations, maintenance is crucial, to keep the energy output at the highest possible level and to secure a long life span. Inverters have to be checked on a daily basis, which can be done automatically. Energy yield must be monitored and the generators should be checked for easily visible defects. At a lower frequency cables and generators should be checked for damages to avoid voltage damages or hot spots by coverage of single cells. (Fechner 2015)

According to Paul Chaloupka, sales director at the Swiss-based PV o&m company named Greentec services GmbH, standard contracts for o&m services cause costs of 8-12 €/MWh for contract durations of 3 to 10 years. For the analysed plant in this paper, he indicated a 10-year contract with 8 €/MWh. Included in the price are cleaning of the modules performance measurements, monitoring of the stored data, hardware checks and repairs of minor defects.

The installed Kioto modules come with a 10-year product guarantee and a maximum degradation of 0,70% p.a. up to 25 years (see product sheet in *appendix 7*). Inverters have a lifetime of 20 years and combined with an o&m contract, risks can be minimized. In addition to that it is recommended to use only certified gear to minimize technical risks. If installed correctly, the rack and sub construction have a lifetime of 20 years. Still, this only covers a part of the risks PV projects are facing and can cause additional costs.

According to Manfred Gutwenger, insurance specialist from Tiroler-Versicherung V.a.G., power plants in general close liability insurance and fire insurance as a basis package. In addition to that, especially constructed all-risk packages exist, including force majeure, political and other unknown risks. Machinery breakage insurances are also quite common. Finally business interruption insurances, linked to the events in the all-in insurance can be closed. Under the circumstances of the present case, it is assumed that the operator has closed liability insurance at a price of 1000 € p.a. and the special PV all-risk insurance at a price of 0,2% of total investment costs (both indications provided by Tiroler Versicherung). Together the whole package can be translated into an average of 2,22 €/kWp per year. Risks emerging from economic factors are going to be discussed further on in the sensitivities section.

To incorporate inflation and other cost increasing factors for the future periods from 2016 on, in the NPV and LRGC calculations an annual escalation factor of 2% for o&m and insurance costs is assumed.

5.3.3 Efficiency

In general subtropical latitudes between 25° and 40° north/south have the highest sunshine duration values up to over 4000 h per year, due to dry and hot weather conditions with clear skies. In higher latitudes weather conditions are unstable, leading to rather low sunshine values. The average sunshine hours per year in central Salzburg (47°north latitude), measured from 1971 – 2000, accounted for approximately 1200 hours. This number constitutes the theoretical maximum possible operating hours per year for the assessed PV plant. In the economic section the theoretical FLH will be calculated by dividing the real output with the nominal capacity. (Boxwell 2016)

The efficiency of a PV power plant depends on the technology of the modules used, the whole BOS and the local conditions. The standard conditions, in which multi-crystalline PV cells achieve the best performance, are 25°C, a 1000 W/m^2 solar radiation (I) and a favourable spectral distribution (depends on the air mass) close to 1,5 (standard IEC/EN 61215). This standard is used to compare it with the conditions of considered locations. To calculate the efficiency of the PV generator (η_{PV}), the ratio of the maximum power output (P_{max}) to the product of the standard solar irradiation power (S) and the collector area (A_{PV}) is calculated. The project owners have decided to install Kioto panels with an efficiency of 15,72% and a needed area of 6,36 m^2/kW (See product sheet *appendix* 7). Inserting the known data in the equation below, a net panel area of 20.034 m^2 can be derived.

$$\eta_{PV} = \frac{P_{\max}}{S * A_{PV}} \qquad \eta_{PV} = \frac{3150000W}{1000W / m^2 * 20034m^2} = 15,72\%$$

Furthermore the performance ratio (PR) measures the degree to which the whole system utilizes the given solar irradiation. This ratio incorporates all losses within the system, caused by unfavourable temperatures, incomplete utilization of the irradiation like shadowing and malfunctions of system components. To calculate the PR, the ratio of the real output of the system to the nominal output ($I*A_{PV}*\eta_{PV}*t_{sol\,max}$) under standard conditions is calculated. (Fechner 2015)

$$PR = \frac{E_{real}}{I * A_{PV} * \eta_{PV} * t_{sol\max}}$$

E_{real} .... real energy output
I .... solar irradiation
A_{PV} .... collector area
η_{PV}.................. module efficiency
$t_{sol\,max}$........ max sunshine hours

Since the assessed plant started to produce in November 2015, no real output data and thus no PR is available yet. But with the projected output of 3,7 GWh, an approximation can be derived, which value the PR must achieve. Therefore the average maximum possible sunshine hours at the site must be measured, combined with a factor that takes shadowing into consideration. In table 11 the average sunshine hours from 1971–2000, provided by ZAMG (Zentralanstalt für Meteorologie und Geodynamik) are listed, already taking into consideration shadowing effects from the surrounding mountains (see figure 37). Using the above formula, with the given data a PR of round 85% can be derived.

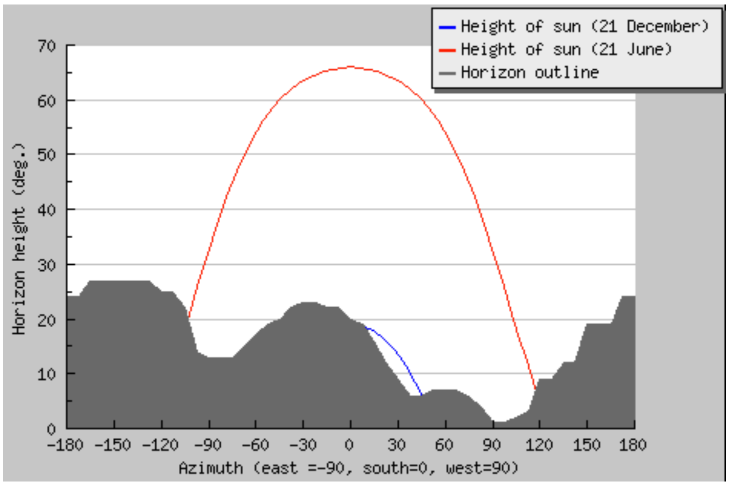


Figure 37: Zenith angle diagram of the PV site (Chaloupka 2016)

Table 11: Sunshine hours without shadowing (ZAMG 2016)

Sunshine hours avg 1971-2000	[h]
January	28
February	66
March	94
April	132
May	169
June	160
July	179
August	188
September	150
October	94
November	56
December	28
Annual total	**1344**

5.3.4 Energy output

To calculate the annual output of the project, the direct irradiation values of the site have to be measured or estimated. According to a forecast of the *SOURCE A*, 3,7 GWh/y are going to be produced. Since no more information could be obtained, in this paper the daily average values of solar irradiation in Innsbruck, measured from 1971-2000, are used as a rough approximation to reproduce the electricity output. Every site has its very unique characteristics but because Innsbruck is located at the same latitude as the assessed site and has a similar shadowing situation due to the surrounding mountains, the comparison shall be good enough for the purpose of this paper.

Table 12 shows the average irradiation on flat surface and at an angle of 43° pointing south which is considered optimal for electricity production at the latitude of 47°. (Boxwell 2016) The next column shows the nominal output per month in kWh/m^2, followed by the real output. Multiplying the nominal output with the PR of 85% derives these values. Finally a total output of round 3,6 GWh can be calculated by multiplying the real output with the surface of the installed panels. This value converges with the prognosis of the operator and translates to approximately 1.140 theoretical FLH per year (3.592MWh output/ 3,15 MWp capacity). Over the years, the annual output is assumed to decrease linearly with the rate of 0,7% (see *appendix 7*).

Table 12: Average irradiation and output in Austria at latitude of 47° from 1971 – 2000 (Boxwell 2016)

Average 1971-2000		**Flat surface**	**43° angle S**	**Output**	**Real output**	**Total output**
		[kWh/m²*day]	[kWh/m²*day]	[kWh/m²*mth]		[kWh/m²*day]
January	31	1,38	2,32	11,31	9,61	192.566
February	28	2,25	3,34	14,70	12,50	250.400
March	31	3,36	4,15	20,23	17,19	344.460
April	30	4,3	4,46	21,04	17,88	358.250
May	31	5,2	4,76	23,20	19,72	395.092
June	30	5,29	4,58	21,60	18,36	367.889
July	31	5,32	4,72	23,01	19,56	391.772
August	31	4,55	4,49	21,89	18,60	372.681
September	30	3,37	3,88	18,30	15,56	311.661
October	31	2,27	3,17	15,45	13,13	263.118
November	30	1,43	2,32	10,94	9,30	186.354
December	31	1,09	1,9	9,26	7,87	157.705
Annual total		**1212,97**	**1341,53**	**210,93**	**179,29**	**3.591.947**

5.3.5 Revenues

In Austrian PV projects, revenues depend on two factors: The amount of electricity output and the FIT. The annual output of the assessed plant has already been calculated in the previous section. According to *SOURCE A*, a FIT of 10 c/kWh could be secured for 13 years. The negotiations started already in 2011, at that time FITs for PV ground mounted sites were granted. In the year 2013 this kind of installation was only subsidised up to 500 KWp, in 2013 and 2015 only up to 200 kWp (see support scheme OeMAG in *appendix 2*). Since 2016 only building-integrated systems between 5 kWp and 200 kWp received a FIT from OeMAG. (OeMAG 2016)

In the present case 90% of the produced electricity gets fed into the grid (revenues 323.275 €), the owner consumes 10%. It is assumed that the alternative price to own use is a business tariff from Salzburg AG and amounts to 16,35 c/kWh (see *appendix 3* for product data sheet). Thus, the own use of 359.195 kWh translates to round 58.728 € of savings and contributes to the investment calculation as indirect revenues. Depending on the annual output, also the revenues decrease over the years at a rate of 0,7% because of module degradation.

5.3.6 Depreciation, interest payments and corporate tax (KÖST)

The legal owner of the PV plant is a limited company (GmbH), thus corporate tax of 25% has to be paid for earnings. The tax base consists of all corporate profits, generated by the company minus depreciation and interest rate payments.

It is assumed that the redemption of the 13-year credit follows a linear schedule and the investment costs are depreciated over a period of 20 years, which is the estimated useful lifetime of the site. (NREL 2016) Own use constitutes indirect revenues that have to be considered in the tax base as well and contribute to the EBITDA. The Austrian finance ministry passed a decree in February 2014, stating that partial own use has to be subject to value added tax (VAT). (BMF-AV Nr. 8/2014, 2014: 14) The Austrian VAT is 20% but for simplification reasons, only one tax rate (25%) is going to be used in the present analysis for all revenues. This leads to a slightly more conservative calculation (see *appendix 21* for tax calculation).

5.3.7 Financial analysis

To measure the feasibility of the PV project, the NPV method has been chosen as the appropriate tool. Therefore all the discounted costs are opposed to the discounted income cash flows. The plant was financed with 20% equity and 80% debt. For the debt share the rate is known and amounts to 2,4% for the duration of 13 years. In general, because of insecure income after the FIT period, banks are not willing to exceed that timespan for credit. For the equity yield a rate of 7% after tax is assumed, based on a study conducted by the Fraunhofer-Institut for solar energy (ISE). (Kost 2013: 11) The WACC serves as discount rate, combining equity and debt costs to one rate, and amounts to 3,32% after tax. The exact calculation can be found in the *appendix 17*.

The investment calculation starts in the year of 2015, when the construction took place. The investment horizon equals the duration of the credit and the FIT period. Table 13 summarizes the input parameters used for the calculations.

Table 13: Main calculation parameters for PV-SBG

Parameters PV *	**PV-SBG 3.15 MWp**	
Technical data	**Start**	**2016**
Nominal capacity	[kW_p]	3.150
Solar irradiation power a)	[W/m^2]	1.000
Collector area needed for 1kW b)	[m^2]	6,36
Total collector area	[m^2]	20.034
Conversion efficiency	[%]	15,72%
Performance ratio	[%]	85%
Annual degradation of modules	[%/y]	0,70%
Theoretical Full Load Hours	[h/y]	1.140
Useful lifetime of power plant (inverter) = depreciation period c)	[y]	20
Costs		
Investment costs	[€/kW]	952,39
Operation & maintenance per year	[€/kWh]	0,008
Insurance package per year	[€/kW_p]	2,22
Credit period	[y]	13
Interest rate credit before tax	[%]	2,40%
Debt ratio	[%]	80%
Expected equity yield after tax	[%]	7%
Corporate tax rate d)	[%]	25%
Discount rate (WACC) after tax	[%]	2,84%
Revenues		
Feed in tariff OeMAG	[€/kWh]	0,1000
Investment horizon and FIT duration	[y]	13
Real escalation of o&m and insurance from 2016 on e)	[%/y]	2%
Alternative electricity Price f)	[€/kW_{el}]	0,0396
Business tariff Salzburg AG incl. VAT (alternative to own use) g)	[€/kW_{el}]	0,1636
Own electricity use	[%]	10%

*) Unless otherwise noted, data and information comes from SOURCE A

a) Fechner (2015)

b) See factsheet in *appendix 7*

c) (Gerhard M. 2015)

d) Wirtschaftskammer Österreich

e) Own assumption based on ECB inflation target

f) Data source: Bloomberg (*appendix 4*)

g) Salzburg AG (*appendix 3*)

In the analysed PV plant the LRGC amount to 99,05 €/MWh, where capital costs take by far the highest part with 77,73 €/MWh. Costs for o&m, insurance including escalation of 2% p.a. and taxes are rather low with 21,32 €/MWh. Since no CO_2 emissions are caused in the power generating process, no CO_2 costs occur.

With the given data, the NPV for the whole project is positive and amounts to 120.767 €. So far the investment can be considered a profitable endeavour because the NPV is positive. In the next section the robustness of the NPV is going to be challenged by performing sensitivity analyses, changing several price-influencing factors. Table 14 gives a detailed view on the performed calculations.

Table 14: Dynamic investment calculation of PV-VBG (own calculation)

PV-SBG		3.15 MWp
Technical data		
Peak capacity	[MW]	3,15
Theoretical Full Load Hours (approximation)	[h/y]	1.140
Costs		
Investment costs	[€/MW]	952.390,00
Operation & maintenance per year10y contract	[€/y]	28.735,57
Real escalation of o&m from 2016 on	[%/y]	2,00%
Insurance costs	[€/y]	7.000,06
Annual degradation modules	[%/y]	0,70%
Revenues		
Feed in tariff (ÖMAG)	[€/MWh]	100,00
Wholesale market price electricity (average 2002-2016)	[€/MWh]	39,61
Business tariff Salzburg AG incl. VAT (alternative to own use)	[€/MWel]	163,6
Financing		
Investment horizon	[y]	13
Discount rate (WACC) after tax	[%]	2,84%
Interest rate debt before tax	[%]	2,40%
Debt ratio	[%]	80%
Equity yield after tax	[%]	7,00%
Corporate tax	[%]	25%
Depreciation period	[y]	20
Capital recovery factor	[%]	9,31%
Energy output		
Electricity output	[kWh/y]	3.591.947
Own use	[%]	10%
Amount fed into grid	[%]	90%

Dynamic investment calculation including tax

	Year	*Discounted CF total*	Nominal CF	O&M	Insurance	Corporate tax	Savings own use	Electricity sale	*Discounted costs*
			A+B+C+D+E	A	B	C	D	E	
0	**2015**	*-3.000.028,50 €*	-3.000.028,50 €						*-3.000.028,50 €*
1	**2016**	*302.603,38 €*	311.197,32 €	-29.310,28 €	-7.000,06 €	-34.531,78 €	58.764,25 €	323.275,19 €	*-68.885,77 €*
2	**2017**	*290.787,96 €*	307.539,25 €	-29.896,49 €	-7.140,06 €	-34.789,36 €	58.352,90 €	321.012,27 €	*-67.913,64 €*
3	**2018**	*279.384,33 €*	303.870,29 €	-30.494,42 €	-7.282,86 €	-35.043,31 €	57.941,55 €	318.749,34 €	*-66.952,69 €*
4	**2019**	*268.378,84 €*	300.190,22 €	-31.104,31 €	-7.428,52 €	-35.293,56 €	57.530,20 €	316.486,41 €	*-66.002,95 €*
5	**2020**	*257.758,28 €*	296.498,82 €	-31.726,39 €	-7.577,09 €	-35.540,03 €	57.118,85 €	314.223,49 €	*-65.064,46 €*
6	**2021**	*247.509,87 €*	292.795,86 €	-32.360,92 €	-7.728,63 €	-35.782,65 €	56.707,50 €	311.960,56 €	*-64.137,24 €*
7	**2022**	*237.621,23 €*	289.081,11 €	-33.008,14 €	-7.883,20 €	-36.021,33 €	56.296,15 €	309.697,63 €	*-63.221,30 €*
8	**2023**	*228.080,37 €*	285.354,33 €	-33.668,30 €	-8.040,87 €	-36.256,01 €	55.884,80 €	307.434,71 €	*-62.316,66 €*
9	**2024**	*218.875,73 €*	281.615,28 €	-34.341,67 €	-8.201,68 €	-36.486,60 €	55.473,45 €	305.171,78 €	*-61.423,29 €*
10	**2025**	*209.996,07 €*	277.863,72 €	-35.028,50 €	-8.365,72 €	-36.713,02 €	55.062,10 €	302.908,85 €	*-60.541,21 €*
11	**2026**	*201.430,55 €*	274.099,40 €	-35.729,07 €	-8.533,03 €	-36.935,18 €	54.650,75 €	300.645,93 €	*-59.670,37 €*
12	**2027**	*193.168,66 €*	270.322,05 €	-36.443,65 €	-8.703,69 €	-37.153,00 €	54.239,40 €	298.383,00 €	*-58.810,77 €*
13	**2028**	*185.200,24 €*	266.531,43 €	-37.172,53 €	-8.877,76 €	-37.366,40 €	53.828,05 €	296.120,08 €	*-57.962,36 €*

NPV	**120.767 €**	
Annuity	11.240 €	
IRR	3,48%	
Electricity generation/y	3.592	MWh
LRGC	**99,05**	**€/MWh**
Capital costs	**77,73**	**€/MWh**

NPV of costs	**-3.822.931,20 €**
Annuity of cost	**-355.800,15 €**

$$LRGC_{el} = \left(\frac{\text{ann costs}_{el}}{\text{ann output}_{el}}\right)$$

$$\text{Capital costs} = \frac{IC * CRF}{FLH}$$

Current period

5.3.8 Sensitivity analysis

The calculated NPV is positive and translates to an IRR of 3,48%. Still there are some risks that have to be considered. A change of only one crucial factor can turn the project into a non-performing business. The following charts show the dependences of the NPV and the LRGC on the most important input parameters, by changing each parameter in 10% steps, ceteris paribus.

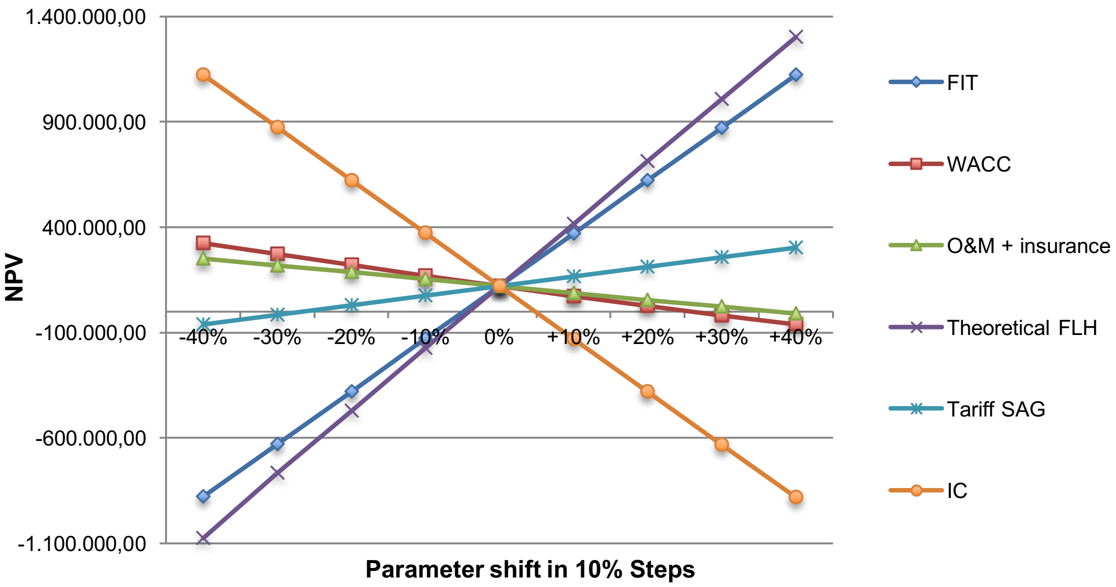


Figure 38: Sensitivity of PV-SBG's NPV to changes of different input parameters for the remaining investment horizon (own graph, value table in *appendix 26*)

Typical of PV technology it can be seen that the NPV reacts most sensitive to changes of the theoretical FLH, investment costs and the FIT. Less than a 10% shift downward in each of these factors is enough loose economic feasibility. Once guaranteed, it is very unlikely that the FIT gets reduced. Thus, this factor is negligible. It shows how fast profitability can decrease after the FIT guaranteed period, though. Actually the FIT curve and the theoretical FLH curve are supposed to match. The reason why this is not the case can be found in the 10% of own electricity use. The mechanism behind it will be explained in the sensitivity analysis of SHPP, where the same effect can be observed.

The sensitivity to a change in investment costs is obviously not an important sensitivity for a running project but during the planning phase this is a well-observed factor. The amount of theoretical FLH is also considered to be a calculable risk due to long-term observation data and insurance. Nevertheless this is the most dangerous technical factor for the project and can be caused by internal influences like malfunctions of the equipment or external influences, like strong hale for instance. The o&m costs already include a price escalation of 2% in the NPV calculation per se, which gives already a conservative view on the development of that factor.

In figure 39, when focussing on the LRGC, the impact of theoretical FLH and investment costs, changes can be seen even more significantly. As already mentioned, especially a decrease of theoretical FLH threatens profitability, since the relation to LRGC is not a linear but rather an exponential one.

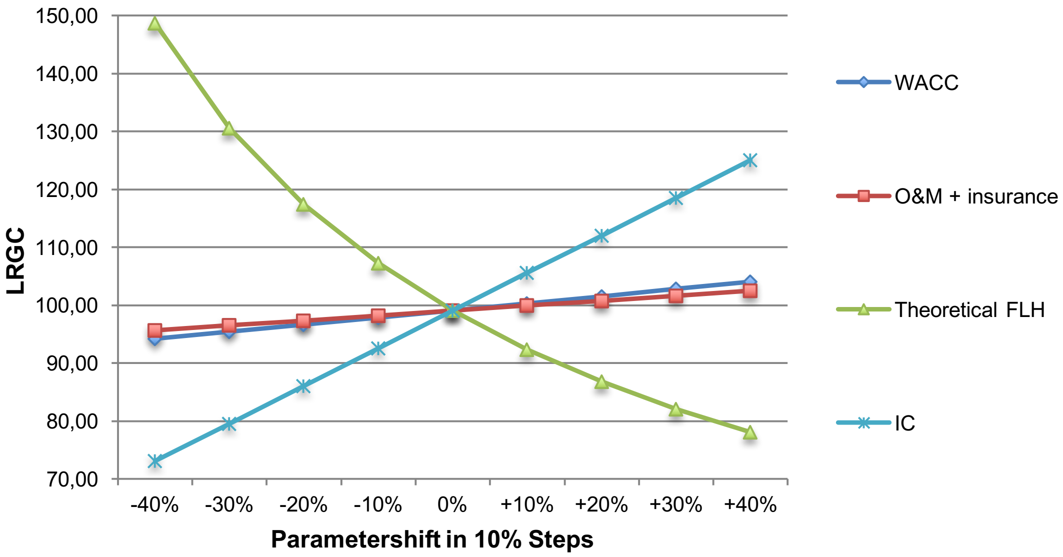


Figure 39: Sensitivity of PV-SBG LRGC to changes of different input parameters for the remaining investment horizon (own graph, value table in *appendix 26*)

One very important factor that is not included in the two sensitivity figures is the own electricity use. The owners of PV-SBG are assumed to use 10% of the produced electricity for their restaurant. Instead of serving the whole electricity demand with external produced power from SAG (16,36 c/kWh), electricity from the PV plant is used directly, saving 6,36 c/kWh (16,36 c/kWh – 10 c/kWh). Without own use the NPV would be at -56.099 €.

To sum it up, the decision to invest in the present project is comprehensible, as far the project owners are willing to take the risk of reducing theoretical FLH and use as much as possible of the produced electricity for their own purpose.

5.4 Small Hydro

Already in the technology section a rough overview of the possibilities to utilize the potential energy of water systems was given. Which kind of technology can be applied for a certain small hydropower project, to a large extent depends on the set of characteristics the chosen location is exposed to. The planning and construction of a SHPP is an interdisciplinary endeavour to a high degree. Civil engineering, hydrology, limnology, engineering and economy, to mention a few, need to work together in good cooperation in order to gain a maximum of energy yield with the least impacts on the environment. But this heterogeneity of different disciplines and interests makes it a real challenge to bring SHPP projects to success. (Pelikan 2015)

For example, as no river equals another in terms of hydrology, morphology and biodiversity, there does not exist a standard design for SHPP because there are too many different local characteristics, the systems have to be adapted. Especially the extent of civil works, the main driver of the energy production costs, is highly affected by the situation of the chosen location. Roughly speaking it can be stated that high head SHPPs, if well accessible, show lower LRGC than low head run of river systems, because much more building effort has to be put in for the power house or fish bypass systems for the latter. Hence, it is impossible to create a representative picture of SHPP in Austria by analysing only one project.

Thus, in the following section an existing new built high head and one new built low head plant with similar electricity outputs are going to be analysed. Still, this is not enough to cover the whole spectrum of systems and their respective LRGCs but it highlights the most prominent features and differences that exist in hydro systems with an output of 3 to 5 GWhel.

Please note that the present paper does not cover revitalisation of existing SHPP with old technologies. Although this is a business case worth mentioning, it would distort the analysis, because additional topics like preservation order have to be considered and the old existing structures often do not allow cost-efficient improvement.

5.4.1 Description of the high head SHPP *Bad Rothenbrunnen in Vorarlberg (HP-VBG)*

(The analyses of this SHPP project are based on data provided by Lorenz Bitsche during an interview directly at the site. Unless otherwise noted, the used data and information for HP-VBG relate to this source.)

The first project is situated in Vorarlberg, an alpine region, where by trend a lot of high head SHPP can be found, due to the favourable circumstances. In 2005 Bitsche Holding GmbH purchased and renovated the Alpengasthaus Rothenbrunnen and some acres of land in the surroundings located at the Matonabach in the middle of the Großes Walsertal. From April 2005 to December 2015, Bitsche Holding bought the water rights for 25 years and built the SHPP under the management of Lorenz Bitsche, the CEO of the legal company himself, with the main purpose to provide the guesthouse with green electricity. The guesthouse consumes approximately 10% of the produced 3,8 GWhel per year; the excess electricity gets fed into the local grid at a FIT of 5 c/kWh to 6c/kWh.

The plant uses the water of the Matonabach with a catchment area of 13,5 km^2. According to Bitsche, on average, the discharge of the mountain creek varies between 200 and 10.000 l/s during the year. With a combination of direct measurements of the Matonabach and hydrological data of the Lutzbach, collected at the gauging station in Garsella for decades, a duration curve of the creek was established. The dimension of the plant was designed to the 100-day discharge at 1.200 l/s, which as a rule of thumb is considered an optimal point in the duration curve, including a residual flow of 15% or a minimum of 100 l/s.

Because Matonabach is a torrent, some physical provisions had to be installed to protect the runner and to keep maintenance efforts low. As a first measure, in order to allow sediments sink down before the water enters the intake, the riverbed is impounded decently, to create a small basin. To prevent bed load from gathering and to preserve the basin, the dam has a scour outlet. Once in a year it happens that after severe weather a dredger has to clean out the basin, though. The weir takes water merely from the surface of the basin and to prevent floating refuse bigger than 2,5 cm from entering the system, a Tiroler weir with a rake is installed, followed by a rake for gravel smaller than 2,5 cm. From the weir, the water flows into a so-called Coanda rake that filters particles bigger than 0,5 mm. This passive device is self-cleaning and no additional electricity or maintenance is needed, since no moving parts are included. Therefore the investment costs are higher than those for a conventional filtering system.

Through an 80 cm diameter penstock and with a length of 560 m, the water flows into the hill-integrated powerhouse at high pressure, where it hits a 5-jet Pelton runner. The net head from the intake to the powerhouse at the bottom of the valley amounts to round 100 m. From the turbine the water flows back into the Lutz. In order to avoid that the noise of the turbine and generator disturbs neighbours on the opposite side of the valley, a syphon was integrated at the outlet.

The pelton runner is connected to a 1000 kVA induction generator, producing alternating current with a voltage of 400 V and a frequency of 50 Hz at 500 rpm (revolutions per minute). 10% of the produced electricity is used for the guesthouse whereas the remaining amount gets transformed to 30 kV and fed into the public grid. For the whole monitoring and steering system of the plant, relay technology was applied at the request of Lorenz Bitsche. He wanted to keep it as simple as possible, because of the lower costs, compared to the digital pendants and as an electrical engineer, he is able to repair the gear by himself in case of damage. For the monitoring of operation, Bitsche automatically receives text messages via phone if the runner stops operating but there is also the possibility to observe some parameters via the Internet.

The relative low investment costs of 1,2 mio € can be explained by the good accessibility of the site, in combination with the simplicity of the construction and the chosen technology. Unnecessary elements like monitors or tiles were left out.

5.4.2 Description of the analysed low head SHPP in Niederösterreich *(HP-NÖ)*

(Please note that the analyses of this SHPP project are based on data provided by *SOURCE B* under an agreement of strict confidence. Therefore the source of data cannot be specified in this paper. Instead, a list with the names and contact details of all anonymous sources will be submitted to Prof. Dr. Bernhard Pelikan. Unless otherwise noted, the used data and information for HP-NÖ relate to this confidential source.)

The second analysed SHPP project is actually a replacement of an abandoned old wooden weir with a bypass channel. But in fact nothing of the old structure, which was bought in 2005 by the operator (a limited company holding), could be used for the new site. In order to execute the building phase in dry, the river was diverted in 2009. After four years of planning and one year of construction, the plant started operating in summer 2010.

The powerhouse of the modern run of river system is situated directly next to the federal highway on property of the holding. This made the construction phase relatively easy, due to the good accessibility for machines and suppliers of equipment. The new weir covers the whole cross section of the river and creates a head of 8,85 m. A state of the art fish bypass shall insure that the fish population of the ecosystem can pass the plant safely. In addition to that, a special system that emits electrical impulses was installed, to keep the fish away from the turbine intake.

A design discharge of maximal 16.000 l/s drives the vertically installed double regulated Kaplan runner with a peak capacity of 1,17 MWel. The residual flow does not fall below the 15% specified in the European water directive. Directly connected to the turbine, the synchronous generator produces 4,2 GWhel per year on average, which get sold at stock exchange linked market prices. Therefore a gearless type, operating at slow speed (300 rpm) was chosen in order to satisfy noise related requirements for building permission. The generated alternate current passes an encapsulated-winding dry-type transformer, where voltage gets increased to 30 KV and 50 Hz. The advantage of this transformer type, compared with a conventional oil transformer is that it needs a relatively low amount of maintenance and no additional fire preventing and ground water saving measures, because no dangerous liquids are involved.

With the help of an innovative programmable logic controller system (PLC), the double regulated Kaplan runner and the whole system can be operated fully autonomous and running processes can be visualized on installed monitors even accessible via Internet at home. Also the cleaning system for the rake at the intake works automatically. Installed web cams, also accessible via the Internet complete the surveillance system. Due to the danger of cyber-attacks and risks, additional security measures had to be installed.

Remarkably, an architect planned the powerhouse with a combination of modern design architecture and purpose building, in order to win the local citizens' acceptance. The total investment costs amount to round 5 mio € (without subsidies of 1,4 mio €), which was financed to 100% with equity of the operator.

5.4.3 Efficiency

Figure 40 illustrates the interdependent relationship of rated discharge, head and the desired output of a SHPP and shows which turbine type works best for a given combination of these parameters. This scheme can also be used to explain the choice of runners for the two assessed projects. With the given discharges and heads, for the low head run-of-river application a 1,17 MWp Kaplan turbine is the most suitable technology and for the high head application a 0,9 MWp Pelton runner fits best.

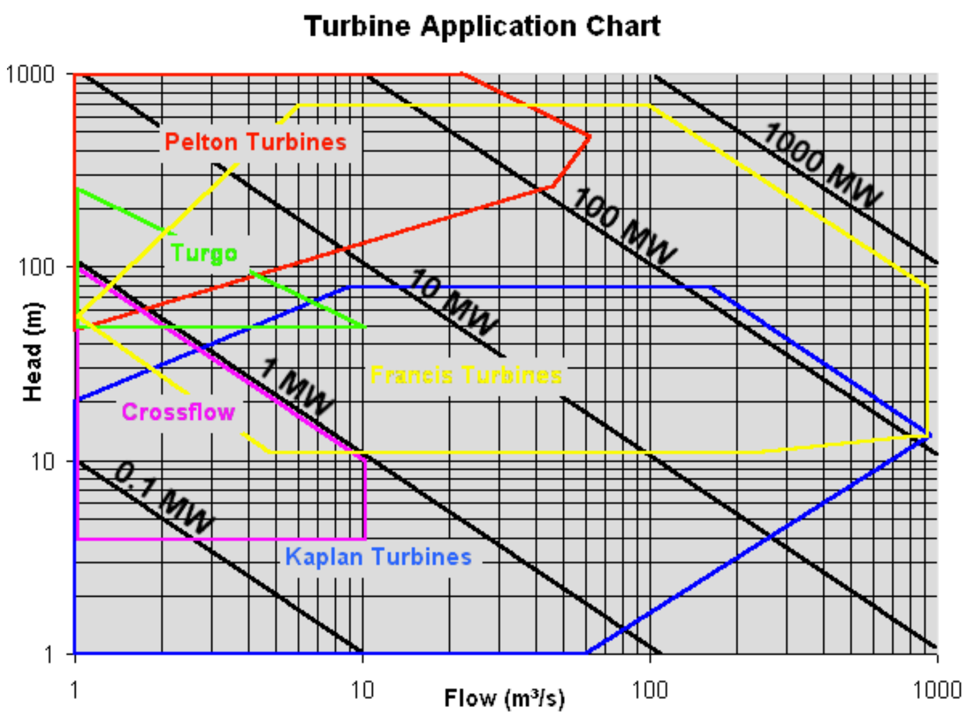


Figure 40: Turbine application chart (Hydroni 2016)

Neglecting the penstock and pipe system, a hydropower system in general consists of 4 technical components: The runner, the generator, the gear and the transformer. To estimate the over-all efficiency, the efficiencies of all components have to be multiplied. As a simplification it is assumed that the generator and the transformer are operating at constant efficiencies, while the efficiencies of the turbines vary with the amount of discharge. Figure 41 shows the efficiency curves of different turbine types in dependence of the percentage of the rated discharge. As can be seen in the chart, the full Kaplan runner (adjustable blades and inlet guide vanes) is more efficient than the Pelton runner in the area above 40% of the design flow. Efficiencies above 90% can be observed often. Pelton turbines have a very steep efficiency curve. Already at 20% of the designed flow, round 85% are achieved. Once full efficiency is reached, it stays relatively stable around 90%. (Pelikan 2015)

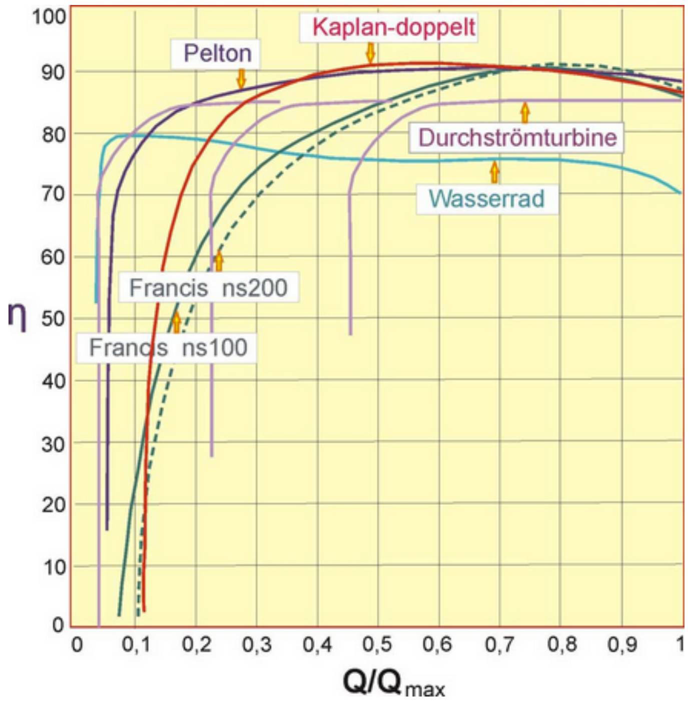


Figure 41: Turbine efficiency chart (Walcher 2016)

Efficiency	**Pelton 0,9 MW**	**Kaplan 1,17 MW**
Generator	88%	93,5%
Transformer	98%	98%
Turbine at rated flow	89%	92%
Total at rated flow	**76,8%**	**84,3%**

Table 15: Over-all efficiencies for the 0,9 MW and the 1,17 MW systems (own estimations based on Panhauser 2015)

To run a turbine at the highest possible conversion efficiency and for higher flexibility, it is quite common that bigger SHPP combine more than one turbine to reach the desired design capacity. For example during winter times, with rather low flows, it makes sense to run only one small turbine. In spring, summer and autumn additional turbines may be operated in parallel, to use the additional flow, up to the rated discharge. The analysed systems in the present paper both are operating with one turbine only.

Table 15 lists the efficiencies of the different components and the total efficiencies of the whole system at rated discharge. In most run-of-river power plants with low head, gearboxes have to be installed to increase the speed in order to fit the generator. Not so in the present case of HP-NÖ, where a gearless synchronous generator, running at

300 rpm is connected to the Kaplan turbine. Also the Pelton runner of HP-VBG works without a gearbox.

5.4.4 Energy output

To calculate the energy output of a SHPP, the equation for power potential presented already in the technology section in chapter 4, has to be multiplied with t. (Panhauser 2015)

$$E = g * \rho * Q_{useable} * H_{rated} * \eta_{total} * t$$

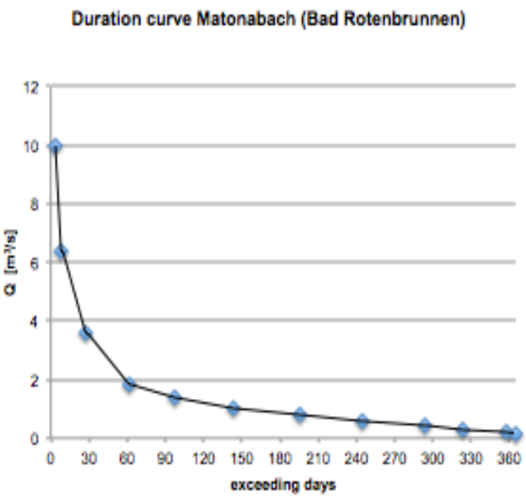
The variable t in the equation represents the exceeding days, converted into hours which will be discussed in this section. The other variables and constants in the equation were already described in the technical concepts chapter.

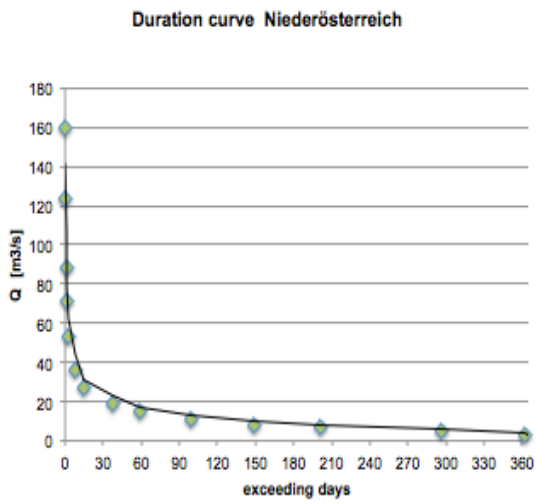
As already stated in the efficiency section, the total efficiency (η_{total}) is calculated by multiplying the turbine efficiency ($\eta_{turbine}$) at given discharge, with the efficiencies of the other components in the process. This results in different total efficiencies along the duration curve.

The characteristics of the rivers in Austria are mainly rain and snow regime driven, with snow storage in winter and snowmelt in spring. But even in a country with a small geographical area, rivers are very different in terms of size, regime and morphology for example. As already described, the best tool to illustrate the stream flow ($Q_{useable}$) in the run of time is the duration curve. (Hall 2015)

According to Lorenz Bitsche, the Matonabach in Vorarlberg, with a catchment area of 13,5 km^2 has a maximum flow of 10 m^3/s for some days in the year and a minimum flow of 200 l/s. Also the discharge of Lutzbach, the river Matonabach flows in, was taken to account. Based on this information, together with the output data and technical data of HP-VBG, provided by Bitsche, a duration curve can be estimated. This can be only a rough estimation of the curve; an exact calculation would by far go beyond the scope of this paper.

The river used for HP-NÖ has a catchment area of approximately 330 km2, a maximum discharge of 180 m^3/s and a minimum discharge of round 350 l/s. The data for the duration curve for the river was extracted out of the hydrographical yearbook 2012. According to *SOURCE B*, this can be taken as an approximation for the plant. But to reproduce the energy output, the values have to be adapted, because there is a smaller creek with a catchment area of 32 km^2 flowing into the main river between the power plant and the gauge of the used data. Therefore the values in the duration curve of the creek were subtracted from the duration curve of the main river. Figures 42 and 43 show the duration curves of the Matonabach and the river in Niederösterreich. Please note that only few data points are available in the yearbook, thus the graphs have been completed via moving average values. For the data tables see *appendix 8 and 9*.





Figures 42 and 43: Estimated duration curves of Matonabach and the river in Niederösterreich (own estimations based on data from eHYD 2015)

In the designing process for a SHPP, an amount of discharge, which is exceeded on 90-120 days during the year, is the recommended value for calculations. This is called rated discharge or design discharge. The design of the turbine for the Matonabach is adapted to the flow that is exceeded on approximately 100 days, that means 1,2 m^3/s. According to *SOURCE B,* the turbine in Niederösterreich is designed relatively large to a rated discharge of 16 m^3/s, which is exceeded on approximately 40 days per year.
It can be seen in the above figures that on some days during the year, the flow exceeds the rated discharge by far. Therefore adequately designed spillways have to be installed to resist floods. (Hauer 2015)

And finally the rated heads (H_{rated}) of the plants amount to 100 m for HP-VBG and 8,85 m for HP_NÖ. It must be mentioned here that for low-pressure power plants the head is not stable and changes with the amount of discharge. But as a simplification this variable is kept constant in the present case of Niederösterreich.

Solving the energy output equation by inserting the correct parameters leads to the outputs presented in tables 16 and 17. In addition to the used discharge, also the total flow of the river ($Q_{available}$) and the required residual flow ($Q_{residual}$) are mentioned in the tables. The turbine efficiencies at different discharges are estimated with the help of figure 41. An efficiency of 0% means that the turbines are switched off because of too much or too little flow.

Table 16: Energy output for the 0,9MW SHPP at different discharge (own calculation)

$Q_{available}$ [m³/s]	$Q_{residual}$ [m³/s]	$Q_{useable}$ [m³/s]	t [h]	H_{rated} [m]	$\eta_{turbine}$	η_{total}	energy output [kWh]
10,00	1,50	1,20	62,4	100	0%	0,0%	0,00
6,40	0,96	1,20	134,4	100	0%	0,0%	0,00
3,60	0,54	1,20	465,6	100	87%	75,0%	411.236,09
1,80	0,27	1,20	835,2	100	89%	76,8%	754.639,43
1,40	0,21	1,19	830,4	100	89%	76,8%	744.049,90
1,00	0,15	0,85	1.104,0	100	90%	77,6%	714.509,92
0,77	0,12	0,65	1.257,6	100	90%	77,6%	626.718,40
0,55	0,10	0,45	1.180,8	100	89%	76,8%	400.089,01
0,40	0,10	0,30	1.185,6	100	85%	73,3%	252.363,52
0,31	0,10	0,21	705,6	100	0%	0,0%	0,00
Total energy production / year in kWh							**3.903.606,28**

Table 17: Energy output for the 1,17 MW SHPP at different discharge (own calculation)

$Q_{available}$ [m³/s]	$Q_{residual}$ [m³/s]	$Q_{useable}$ [m³/s]	t [h]	H_{rated} [m]	$\eta_{turbine}$	η_{total}	energy output [kWh]
160,00	24,00	16,00	4,8	8,9	0%	0%	0,00
124,00	18,60	16,00	4,8	8,9	0%	0%	0,00
88,00	13,20	16,00	14,4	8,9	0%	0%	0,00
71,00	10,65	16,00	9,6	8,9	0%	0%	0,00
53,00	7,95	16,00	38,4	8,9	0%	0%	0,00
35,75	5,36	16,00	129,6	8,9	86%	79%	141.864,39
27,00	4,05	16,00	144,0	8,9	88%	81%	161.292,85
18,65	2,80	15,85	561,6	8,9	92%	84%	651.572,36
15,00	2,25	12,75	518,4	8,9	92%	84%	483.741,08
11,30	1,70	9,61	969,6	8,9	93%	85%	689.005,82
8,50	1,28	7,23	1.190,4	8,9	92%	84%	629.460,61
6,60	0,99	5,61	1.257,6	8,9	91%	83%	510.736,32
4,85	0,73	4,12	2.284,8	8,9	86%	79%	644.402,58
3,40	0,51	2,89	1.555,2	8,9	81%	74%	289.613,68
1,90	0,29	1,62	86,4	8,9	0%	0%	0,00
Total energy production / year in kWh							**4.201.689,70**

Finally the theoretical FLH can be calculated by dividing the output by the design capacity of the power plants. The 0,9 MW facility runs 4320 theoretical FLH, the 1,17 MW site 3588 theoretical FLH.

According to the report “Small Hydropower Roadmap; Condensed research data for EU-27”, conducted by the European Small Hydropower Association from 2009 to 2012, the average theoretical FLH of SHPPs in Austria are around 4500 h. HP-VBG is in line with the report, while HP-NÖ is clearly below this value. This can be explained with the unusually large design of the Kaplan turbine on 40 exceeding days.

5.4.5 **Investment costs** (Frosio 2016)

The biggest position of costs for hydropower plants are investment costs. That includes all the work that has to be performed in the run-up to the construction phase, like initial feasibility studies, hydrological assessments and financing fees, to mention a few. In addition to that, civil works, technical equipment like turbines, generators, transformers and other gear are included in the list. Table 18 shows a granular picture of the investment costs’ composition in general.

Table 18: General list of construction costs for SHPP (Frosio 2016)

<table>
<tr><th colspan="2">Civil works</th><th colspan="2">Hydraulic equipment</th></tr>
<tr><td rowspan="9">30% to 50% of total costs</td><td>Intake structures</td><td rowspan="6">2% to 4% of total costs</td><td>Sluice gates</td></tr>
<tr><td>Basin</td><td>Inlet gates</td></tr>
<tr><td>Supply canal or pipeline</td><td>Flushing gates</td></tr>
<tr><td>Forebay</td><td>Penstock inlet gate/ valve</td></tr>
<tr><td>Penstock</td><td>Stop-logs</td></tr>
<tr><td>Power house</td><td>Trash rake cleaner</td></tr>
<tr><td>Tail race</td><th colspan="2">Engineering</th></tr>
<tr><td>Access roads</td><td rowspan="5">7% to 10% of total costs</td><td>Topographic survey</td></tr>
<tr><td>Accessories works</td><td>Conceptual design</td></tr>
<tr><th colspan="2">Electro-mechanicals suppliers</th><td>Construction design</td></tr>
<tr><td rowspan="8">35% to 55% of total costs</td><td>Hydroelectric units</td><td>Site supervision and performance tests</td></tr>
<tr><td>Control and automation panels</td><td>Operating training and manuals</td></tr>
<tr><td>Switchboard cubicles</td><th colspan="2">Others</th></tr>
<tr><td>Transformers</td><td rowspan="5">About 2% of total costs</td><td>Project management</td></tr>
<tr><td>Electric lines</td><td>Land acquisition</td></tr>
<tr><td>Protection lines cubicles</td><td>Authorisation procedures</td></tr>
<tr><td>Crane</td><td>Financing procurement</td></tr>
<tr><td>Lighting, anti-intrusion, fire detection</td><td>Financial costs</td></tr>
</table>

As can be seen, civil works and electro-mechanical equipment represent the highest cost factors. In contrast to PV or wind power projects, for hydropower only a relative small portion of engineering takes place in the factory, namely the production of the needed hydraulic and electric equipment, like generators, runners, electric panels, pipes, gates, etc. Engineering on site like building the intake structures, canals, penstocks or the powerhouse contribute at least 70% of the costs.

This means that often before appropriate feasibility studies can be performed, the project must be set up and signed already. As a consequence, if the feasibility study turns out to be negative, a considerable amount of money that has been already invested, for instance for topographic surveys, expert's reports, conceptual designing, measurements of the river or planning could be wasted. Thus, pre-feasibility studies with approximate data are performed very often, in order to reduce the risk of false investment.

The investment costs for the 0,9 MW high-pressure SHPP HP-VBG amount to round 1.200.000 € (1.336 €/kW) and the costs for the 1,17 MW low-pressure plant HP-NÖ amount to 5.145.000 € (4.397 €/kW). Although both sites produce similar amounts of electricity, the investment costs for HP-NÖ are more than three times higher compared with those for HP-VBG. To some extent this difference can be explained with figure 44, where it is illustrated that investment costs decrease with the rated head.

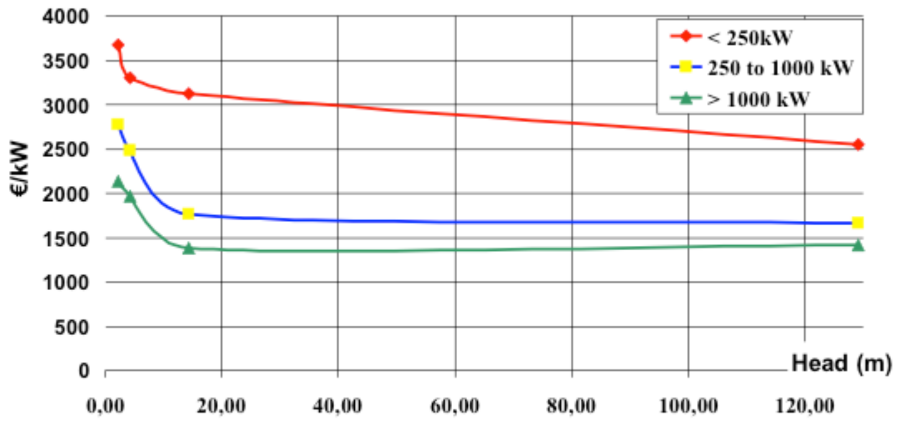


Figure 44: Investment costs for SHPPs as a function of the rated head (Frosio 2016)

The following table shows the composition of investment costs for HP-VBG.

Table 19: Investment costs composition HP-VBG (Bitsche 2016; Steiner 2016)

	HP-VBG	
Civil works	**395.000 €**	**33%**
Tiroler weir & Coanda rake	*200.000 €*	
Penstock	*60.000 €*	
Power house	*135.000 €*	
Turbine and electro-mechanical equipment	**551.000 €**	**46%**
Hydroelectric generating set	*301.000 €*	
Turbine and generator	*250.000 €*	
Hydraulic equipment	**24.000 €**	**2%**
Planning, engineering and other costs	**100.000 €**	**8%**
Grid connection	**130.000 €**	**11%**
Total investment costs	**1.200.000 €**	**100%**

Lorenz Bitsche provided the all-over investment costs and the author estimated the composition. The turbine and generator costs were taken directly from the study performed by Steiner (2016) in his bachelor thesis (see *appendix 10 and 11*). Moreover Steiner investigated costs of about 500.000 € (see *appendix 12*) for the hydroelectric generating set, with a design capacity of 0,9 kW, but in the assessed plant the costs are assumed to be much lower with 301.000 €. This is due to the installation of analogous relay-technology, instead of expensive digital systems.

The costs for the intake system, powerhouse and penstock are assumed to be at the lower end of the costs for civil works that Frosio suggests in table 18. A visiting trip to the plant showed that the whole structure of the powerhouse is kept to an absolute minimum. Furthermore an already existing road made access to the site very easy and transport costs could be reduced, thus 135.000 € seem appropriate. The intake structure seems to be the most expensive part of the civil works, thus 200.000 € were assumed. Planning and engineering, as well as hydraulic equipment was estimated with the help of table 18. According to Bitsche, the installation of the penstock was relatively easy and due to good accessibility, 60.000 € seem to be justifiable assumption. Finally the grid connection costs were assumed to be identical to the ones for HP-NÖ.

SOURCE B provided all the investment cost details for HP-NÖ in table 46.

Table 20: Investment costs composition HP-NÖ (*SOURCE B* 2016)

	HP-NÖ	
Civil works incl. fish bypass system and ground	3.000.000 €	58%
Turbine and electro-mechanical equipment	1.000.000 €	19%
Steel hydraulics construction	315.000 €	6%
Planning, engineering and other	700.000 €	14%
Grid connection	130.000 €	3%
Total investment costs	**5.145.000 €**	100%
Investment subsidies	-1.400.000 €	-27%
Investment costs incl. subsidies	**3.745.000 €**	73%

It can be seen that OeMAG granted investment subsidies of the amount of 1.400.000 €. In order to relief the burden of initial investment costs this support model was chosen instead of the FIT. Compared with the total costs, turbines and electro-mechanical equipment amount to 19%.

Costs for steel hydraulics construction go in line with table 18, those for planning and engineering are above Frosio's suggestion. This can be explained with the high effort that has been put into the architectural appearance of the plant, which was chosen in order to increase the acceptance of the local community.

Other than in HP-VBG, where civil works could be kept to a minimum, in the case of HP-NÖ, civil works constitute the biggest position, which is typical for SHPPs. (Please note that the acquisition of land is included in the 3.000.000 € of civil works here.) Compared with high head power plants, more concrete and material is needed due to the size of the structures. Furthermore, ecological measures like fish bypass systems are very complex and expensive for low-head plants and in this case the special architectural standard increased the costs, too.

On the other hand the accessibility to run-of river sites in Austria is better than to high-pressure sites, because normally they are not that remote. Generally speaking, this leads to the picture shown in Figure 45. Civil works for low-head systems consist of materials to 80% and only to 20% of transport costs. Consequently for high head the situation is the other way round.

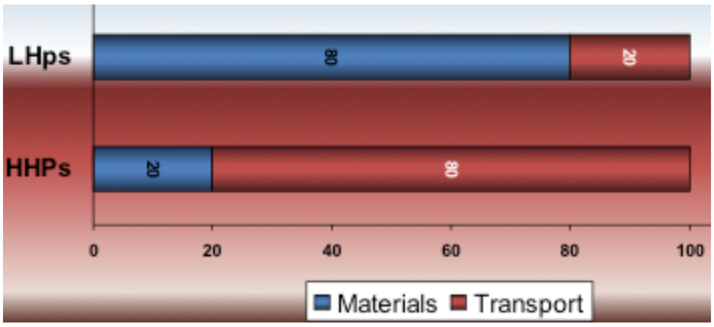


Figure 45: Civil works, influence of transport for low head (LHps) and high head (HHps) systems (Frosio 2016)

Putting HP-VBG into context with figure 45 shows how difficult it is to capture the whole diversity of SHPP projects. Because due to good accessibility of the site in Vorarlberg, transport costs could be minimised, which changes the general picture drastically. In terms of investment costs HP-VBG is an exceptional project and marks a very low point in the bandwidth of investment costs for SHPP. In contrast to that, HP-NÖ is a very costly endeavour and marks the other extreme in the bandwidth of investment costs for SHPP.

5.4.6 **Operation and maintenance costs** (Frosio 2016)

In general, the o&m costs can add up from 1% to 4% of the total investment. Frosio suggests the composition of o&m costs very roughly in Table 21. It also has to be mentioned that the magnitude of these costs depends very much on the design of the plant.

Table 21: General operation & maintenance costs (Frosio 2016)

<table>
<tr><td rowspan="8">**1% to 4% of the total investment**</td><td>Staff</td><td>Fees</td></tr>
<tr><td>1 plant manager</td><td>Water rights</td></tr>
<tr><td>2 people at request</td><td>Land rents</td></tr>
<tr><td>Consumables</td><td>Royalties to local communities</td></tr>
<tr><td>Oils and grease</td><td>Office</td></tr>
<tr><td>Painting</td><td>Administration</td></tr>
<tr><td>Lamps and relays</td><td>Insurance</td></tr>
<tr><td>Spare parts</td><td>Tax</td></tr>
</table>

Although the technologies of the two analysed plants are totally diverse, they are both designed to operate autonomous by which reduces the effort for o&m. While HP-NÖ relies on digital PLC-technology and surveillance cameras, HP-VBG uses old-school analogue technologies in the powerhouse. Concerning the intake, in HP-NÖ a fully automated rake cleaning system is installed, while the Coanda rake in HP-VBG is a so-called passive system that can clean itself and does not need additional time and effort.

According to Bitsche, maintenance for HP-VBG is reduced to changes of oils and greases and once or twice a year the basin at the intake has to be dredged. The owner himself performs periodical inspections of the site and no additional staff is needed. The water rights are saved for 25 years and since the plant stands on the owner's property, no land rent has to be paid. Hence, the o&m costs for HP-VBG are assumed to amount to 1% of the total investment or in absolute numbers 12.071 € per year without tax and insurance.

In addition to the usual insurance package, it is assumed that business interruption insurance is in place for HP-VBG, linked to damages from fire and force of nature, because banks usually request it. The total insurance costs are assumed to be 1,23% of the total investment costs, respective 14.848 €. This is a rough estimation, based on an interview with Manfred Gutwenger from Tiroler Versicherung. The interview was kept very general and no detailed calculations were performed. In table 22 the estimated insurance costs are broken down into the main components.

Table 22: Assumed insurance package for HP-VBG (Gutwenger 2016)

Machinery breakage	0,060%
Force of nature	0,060%
BU force of nature	0,065%
BU fire	0,900%
Fire insurance	0,065%
Legal insurance 1000 € p.a. with percentage share	0,083%
Total in % of investment costs	**1,23%**

According to *SOURCE B*, o&m costs of HP-NÖ amount to 20.000 €. In this amount insurance is already included. Besides the obligatory legal- and fire insurances, an all risk package is in place, including forces of nature and political risks, for instance, but no machine breakage. The major part of the plant stands on private property of the owner company, but partly the structures are obviously erected on the river parcel, owned by the Austrian state. An indexed annual rent of 480 € has to be paid for this.

O&m, and insurance costs are again assumed to increase 2% per year from 2016 on, to incorporate inflation effects.

5.4.7 Revenues

Also in small hydropower the revenues depend on the output of the systems and the tariff at which the produced electricity can be sold. The outputs for the two analysed systems have already been analysed in detail. In the following, the price is discussed.

HP-VBG

The FIT for SHPPs that were approved until 2007 was 6,25 c/kWh for the first GWh per year and 5,10 c/kWh for the next 3 GWh (see *appendix 1*). 90% of the produced electricity get fed into the grid. Multiplying the output with the hierarchized tariff, leads to 189.525 € of direct revenues per year. In addition to that, money can be saved because of 390 MWh (10% of the total output) of own use. The alternative, at which electricity can be purchased in Vorarlberg, is assumed to be 13,047 c/kWh, a basic business tariff, offered by Vorarlberger Kraftwerke AG. (VKW 2016) The savings amount to 50.930 € (13,047 c/kWh * 390,361 kWh).

HP-NÖ

For SHPP two types of subsidies from OeMAG exist. There is the choice between FIT or investment subsidies. As already mentioned in the costs section, the owner of HP-NÖ has chosen investment subsidies. Since the owner himself uses none of the output, 100% of the produced electricity has to be fed into the grid at the prevailing wholesale price. According to *SOURCE B*, it is planned to close a supply contract with a local factory with a high electricity demand. For this purpose a 20 kV direct-line will be installed. The price will be linked to the wholesale price at the stock exchange with an additional margin. For the factory this deal is advantageous, because eco tax and grid costs can be saved and at the same time HP-NÖ can increase the revenues. The following table shows the past revenues of the plant and the assumed average future price.

Table 23: Annual revenues 2010 – 2016 and assumption of future sales price HP-NÖ (own calculation)

Year	**Output** [MWh]	**Price** [€/MWh]	**Revenues** [€]
2010	4.202	48,43 €	203.500 €
2011	4.202	55,71 €	234.089 €
2012	4.202	45,26 €	190.160 €
2013	4.202	39,78 €	167.122 €
2014	4.202	34,10 €	143.269 €
2015	4.202	31,39 €	131.891 €
2016	4.202	24,58 €	103.269 €
2017 - 2049	**4.202**	**39,61 €**	**166.414 €**

Currently the wholesale price for base load electricity is about 25 €/MWh. Round 39,61 €/MWh is the average wholesale base-load price from 2002 to 2016 and it seems to be a valid estimation for the years 2017 to 2049 (see *appendix 4* for price details). Especially the deal with the local factory would bring a portion of security to the future price.

5.4.8 Depreciation and Corporate tax (KÖST)

The owners of both SHPPs are limited companies (GmbH), thus also here 25% of corporate tax have to be paid for earnings. The owner of HP-VBG consumes 10% of the produced electricity for his own which, as in the PV case, constitutes indirect revenues that have to be considered in the tax base as well. Here, too for reasons of simplification, only one tax rate (25%) is going to be applied in the present analysis for all revenues.

Depreciation of both plants is assumed to be linear for the useful lifetime of the systems, which is at least 40 years for both and the notional credit for HP-VBG is linearly amortized to zero in the same period of time. In *appendix 22 and 23* the tables with the tax calculations for HP-VBG and HP-NÖ can be found. (NREL 2016)

5.4.9 Financial analysis

Since all the necessary input parameters have been discussed, the NPV and LRGC of HP-VBG and HP-NÖ can be calculated. Therefore, again all the discounted costs are opposed to the discounted income cash flows in a dynamic investment calculation.

It is assumed that HP-VBG is financed classically with 20% equity and 80% debt with an investment horizon of 13 years. Like in PV-SBG, this tenor is again driven by the FIT period. For equity an expected yield of 8% after tax is assumed. The variable credit rate is linked to the 3-months EURIBOR, to which an assumed risk margin of 1,5% has to be added. For the calculation in this paper, the average 3m-EURIBOR from 2005 to 2016, amounting to 1,57% has been assumed for the whole credit period of 13 years. By adding the risk margin, a credit rate of 3,07% can be derived. Finally the combination of equity and debt costs results in a discount rate of 3,44% after tax. See *appendix 18* for the WACC calculation details and *appendix 16* for the course of the 3months EURIBOR.

HP-NÖ was financed with 100% equity for an investment horizon of 40 years. This time span reflects the minimum useful lifetime of the power plant. Unlike for the other assessed projects, since neither credit, nor FITs are involved, no restrictions for the time horizon exist. However, without any debt in the financing portfolio, an equity yield of 8%, as in the case of HP-VBG is unrealistic. This is due to the fact that costs of equity are much higher than costs of debt. Hence, in this case no expected equity yield is assumed, instead the internal rate of return (IRR) will be calculated in the dynamic investment calculation, to estimate the profitability of the project. In table 24 the input parameters for the dynamic investment calculation are listed.

The LRGC for HP-VBG amount to 47,48 €/MWh, containing investment costs of 29,91 €/MWh. With an NPV of 569.927 €, the project is highly profitable, corresponding to an IRR of 10,28%. The result is not surprising, due to the high cost efficiency of the site. But for the short investment horizon of 13 years, the economic performance is remarkable and must be considered above average.

With the given data for HP-NÖ, the LRGC amount to 39,76 €/MWh, the included investment costs amount to 38,60 €/MWh. That means that the electricity production costs are even lower than those for HP-VBG. The IRR for HP-NÖ amounts to 2,03% after tax.

This situation illustrates one of the difficulties that emerge when comparing different power plants. HP-VBG achieves a yield of 10,28% per year, HP-NÖ only yields 2,03%. Presuming HP-NÖ is financed with the same conditions as HP-VBG, the NPV would be negative at -759.739 € and LRGC amount to 48,26 €/MWh. But in reality the financing circumstances are not uniform and the motivations of the investors and their risk appetite have to be considered. Due to the choice to take the investment subsidy instead of the FIT, HP-NÖ sells electricity at market price and is exposed to a decrease of this price. In this paper a rather conservative future electricity price of 39,61 €/MWh is assumed. Taking into consideration the long remaining useful lifetime of HP-NÖ, the economic performance of the plant can increase significantly, once the electricity price reaches higher levels again. An increase to an average of 55,20 €/MWh, for instance would lead to an IRR of 3,44% (discount rate of HP-VBG) and LRGC of 42,74 €/MWh. So far both investments can be considered profitable, because the NPV, respectively the IRR are positive. Detailed cashflows and the results of both SHPPs can be found in table 25 and 26.

Table 24: Main calculation parameters of HP-VBG and HP-NÖ

Parameters SHPP		*	**HP-VBG 0,9 MW_p**	**	**HP-NÖ 1,17 MW_p**
Technical data			**Start 2006**		**2010**
Nominal capacity	[kWp]		904		1.171
Rated discharge	[m^3/s]		1,20		16,00
Reserved flow	[%]		15%		15%
Rated head	[m]		100		8,70
Gravity on Earth	[m/s^2]		9,81		9,81
Density of water	[kg/m^3]		1.000		1.000
Efficiency generator	[%]	a)	88%	a)	93,5%
Efficiency transformer	[%]	a)	98%	a)	98%
Total efficiency at rated discharge	[%]	a)	76,8%	a)	84,3%
Theoretical Full load hours	[h]		4.320		3.588
Useful lifetime of powe rplant = depreciation period	[y]		40		40
Costs					
Investment costs	[€/kW]		1.336		4.394
Investment horizon (and FIT period for HP-VBG)	[y]		13		40
O&m in % of investment costs excl. insurance	[€/y]	b)	12.071		20.000
Insurance package in % of investment costs	[€/y]	c)	14.882		included in o&m
Real escalation of o&m and insurance from 2016 on	[%/y]	d)	2%	d)	2%
Expected equity yield after tax	[%]	f)	8%		-
Credit period	[y]		13		-
Interest Rate credit before tax	[%]	f)	3,07%		-
Debt ratio	[%]	f)	80%		0%
Corporate tax rate	[%]	e)	25%	e)	25%
Discount rate (WACC) after tax	[%]		3,44%		IRR calculation
Revenues					
Feed in tariff OeMAG (weighted average)	[€/kWh]		0,05395	h)	market price
Duration feed in tariff	[y]		13		-
Investment subsidies	[€]		-		1.400.000
Business electricity tariff Vorarlberger Kraftwerke	[€/kWh]	g)	0,13047		-
Own electricity use	[%]		10%		0%

*) Unless otherwise noted, data source is Lorenz Bitsche

a) Assumptions and calculations based on Panhauser (2015)

b) Assumption based on Gerhard (2015: 763)

c) Assumption based on Interview Gutwenger (2016)

d) Own assumption based on ECB inflation target of 2%

e) Wirtschaftskammer Österreich

f) Assumption based on EURIBOR 3m and interview Schwaiger (2016)

g) VKW (2016)

**) Unless otherwise noted, data provided by *SOURCE B* list

h) Market price 39,61 = average stock exchange price from 2010 to 2016

Table 25: Dynamic investment calculation of HP-VBG (own calculation)

HP-VBG **0,9 MWp Pelton**

Technical data		
Rated capacity	[MW]	0,904
Rated discharge	[m³/s]	1,20
Rated head	[m]	100,00
Theoretical Full Load Hours	[h/y]	4.320
Total efficiency at rated discharge	[%]	76,8%
Costs		
Investment costs	[€/MW]	1.336.000,00
Operation & maintenance costs per year	[€/MWh]	12.071,34
Insurance costs	[€/y]	14.882,04
Real escalation of o&m from 2016 on	[%/y]	2%
Revenues		
Feed in tariff	[€/MWh]	53,95
Alternative electricity Price	[€/MWh]	130,47
Financing		
Investment horizon	[y]	13
Discount rate (WACC) after tax	[%]	3,44%
Interest rate debt before tax	[%]	3,07%
Debt ratio	[%]	80%
Equity yield after tax	[%]	8%
Corporate tax	[%]	25%
Depreciation period	[y]	40
Capital recovery factor	[%]	9,67%
Energy output		
Electricity output	[kWh/y]	3.903.606
Own use	[%]	10%
Amount fed into grid	[%]	90%

Dynamic investment calculation including tax

	Year	*Discounted CF total*	Nominal CF	O&M	Insurance	Corporate tax	Savings own use	Electricity sale	*Discounted costs*
			A+B+C+D+E	A	B	C	D	E	
0	**2005**	*-1.207.133,95 €*	-1.207.133,95 €			0,00 €			*-1.207.133,95 €*
1	**2006**	*169.257,42 €*	175.083,26 €	-12.071,34 €	-14.882,04 €	-38.419,24 €	50.930,35 €	189.525,53 €	*-63.197,36 €*
2	**2007**	*163.092,61 €*	174.513,13 €	-12.071,34 €	-14.882,04 €	-38.989,37 €	50.930,35 €	189.525,53 €	*-61.627,32 €*
3	**2008**	*157.150,66 €*	173.942,99 €	-12.071,34 €	-14.882,04 €	-39.559,51 €	50.930,35 €	189.525,53 €	*-60.091,79 €*
4	**2009**	*151.423,56 €*	173.372,85 €	-12.071,34 €	-14.882,04 €	-40.129,65 €	50.930,35 €	189.525,53 €	*-58.590,21 €*
5	**2010**	*145.903,60 €*	172.802,71 €	-12.071,34 €	-14.882,04 €	-40.699,79 €	50.930,35 €	189.525,53 €	*-57.122,03 €*
6	**2011**	*140.583,33 €*	172.232,57 €	-12.071,34 €	-14.882,04 €	-41.269,93 €	50.930,35 €	189.525,53 €	*-55.686,68 €*
7	**2012**	*135.455,58 €*	171.662,43 €	-12.071,34 €	-14.882,04 €	-41.840,07 €	50.930,35 €	189.525,53 €	*-54.283,61 €*
8	**2013**	*130.513,42 €*	171.092,29 €	-12.071,34 €	-14.882,04 €	-42.410,21 €	50.930,35 €	189.525,53 €	*-52.912,25 €*
9	**2014**	*125.750,19 €*	170.522,15 €	-12.071,34 €	-14.882,04 €	-42.980,34 €	50.930,35 €	189.525,53 €	*-51.572,06 €*
10	**2015**	*121.159,43 €*	169.952,02 €	-12.071,34 €	-14.882,04 €	-43.550,48 €	50.930,35 €	189.525,53 €	*-50.262,47 €*
11	**2016**	*116.734,96 €*	169.381,88 €	-12.071,34 €	-14.882,04 €	-44.120,62 €	50.930,35 €	189.525,53 €	*-48.982,93 €*
12	**2017**	*112.201,42 €*	168.407,44 €	-12.312,77 €	-15.179,68 €	-44.555,99 €	50.930,35 €	189.525,53 €	*-48.002,26 €*
13	**2018**	*107.835,13 €*	167.424,91 €	-12.559,02 €	-15.483,27 €	-44.988,67 €	50.930,35 €	189.525,53 €	*-47.037,83 €*

NPV of costs	**-1.916.502,74 €**
ann of costs	**-185.339,76 €**

NPV	**569.927,36 €**	
annuity	55.116,12 €	
IRR	10,28%	
electr generation/y	3.904	MWh
LRGC (incl cost esc)	**47,48**	**€/MWh**
Investment costs	**29,91**	**€/MWh**

$$LRGC_{el} = \left(\frac{\text{ann costs}_{el}}{\text{ann output}_{el}} \right)$$

$$\text{Capital costs} = \frac{IC * CRF}{FLH}$$

Current period

Table 26: Dynamic investment calculation of HP-NÖ (own calculation)

HP-NÖ — **1,17 MWp Kaplan**

Technical data		
Rated capacity	[MW]	1,171
Rated discharge	[m³/s]	16,00
Rated head	[m]	8,70
Theoretical Full Load Hours	[h/y]	3.588
Total efficiency at rated discharge	[%]	84,30%
Costs		
Investment costs	[€/MW]	4.393.672
Operation & maintenance incl. Insurance	[€/MWh]	20.000,00
Real escalation of o&m from 2016 on	[%/y]	2,00%
Revenues		
Electricity stock price 2010-2016	[€/kWh]	see table 23
Wholesale market price electricity (average 2002-2016)	[€/MW]	39,61
Investment subsidies OeMAG	[€/kW]	1.195,56
Capital recovery factor	[%]	3,70%
Financing		
Investment horizon	[y]	40
Rate of return (equity yield after tax)	[%]	2,03%
Debt ratio	[%]	0%
Equity ratio	[%]	100%
Corporate tax	[%]	25%
Depreciation period	[y]	40
Energy output		
Electricity output	[kWh/y]	4.201.690

Dynamic investment calculation including tax

	Year	*Discounted CF*	Nominal CF	O&M	Corporate tax	Electricity sale	*Discounted cost*
			A+B+C	A	B	C	
0	**2009**	*-3.745.000,00 €*	-3.745.000,00 €				*-3.745.000,00 €*
1	**2010**	*166.429,85 €*	169.809,13 €	-20.000,00 €	-13.691,31 €	203.500,44 €	*-33.020,84 €*
2	**2011**	*185.155,06 €*	192.750,35 €	-20.000,00 €	-21.338,39 €	234.088,74 €	*-39.709,45 €*
3	**2012**	*150.451,96 €*	159.803,85 €	-20.000,00 €	-10.356,22 €	190.160,07 €	*-28.579,74 €*
4	**2013**	*131.514,38 €*	142.525,45 €	-20.000,00 €	-4.596,75 €	167.122,21 €	*-22.696,48 €*
5	**2014**	*111.482,23 €*	123.269,22 €	-20.000,00 €	0,00 €	143.269,22 €	*-18.087,60 €*
6	**2015**	*99.178,27 €*	111.891,04 €	-20.000,00 €	0,00 €	131.891,04 €	*-17.727,65 €*
7	**2016**	*72.339,49 €*	83.269,13 €	-20.000,00 €	0,00 €	103.269,13 €	*-17.374,86 €*
8	**2017**	*120.623,43 €*	141.667,44 €	-20.400,00 €	-4.347,48 €	166.414,92 €	*-21.071,36 €*
9	**2018**	*117.967,61 €*	141.361,44 €	-20.808,00 €	-4.245,48 €	166.414,92 €	*-20.907,39 €*
10	**2019**	*115.364,73 €*	141.049,32 €	-21.224,16 €	-4.141,44 €	166.414,92 €	*-20.746,61 €*
11	**2020**	*112.813,71 €*	140.730,96 €	-21.648,64 €	-4.035,32 €	166.414,92 €	*-20.588,95 €*
12	**2021**	*110.313,54 €*	140.406,23 €	-22.081,62 €	-3.927,08 €	166.414,92 €	*-20.434,36 €*
13	**2022**	*107.863,20 €*	140.075,01 €	-22.523,25 €	-3.816,67 €	166.414,92 €	*-20.282,76 €*
14	**2023**	*105.461,70 €*	139.737,16 €	-22.973,71 €	-3.704,05 €	166.414,92 €	*-20.134,10 €*
15	**2024**	*103.108,06 €*	139.392,55 €	-23.433,19 €	-3.589,18 €	166.414,92 €	*-19.988,33 €*
16	**2025**	*100.801,34 €*	139.041,05 €	-23.901,85 €	-3.472,02 €	166.414,92 €	*-19.845,38 €*
17	**2026**	*98.540,60 €*	138.682,53 €	-24.379,89 €	-3.352,51 €	166.414,92 €	*-19.705,20 €*
18	**2027**	*96.324,93 €*	138.316,83 €	-24.867,49 €	-3.230,61 €	166.414,92 €	*-19.567,73 €*
19	**2028**	*94.153,42 €*	137.943,82 €	-25.364,84 €	-3.106,27 €	166.414,92 €	*-19.432,93 €*
20	**2029**	*92.025,20 €*	137.563,34 €	-25.872,13 €	-2.979,45 €	166.414,92 €	*-19.300,73 €*
21	**2030**	*89.939,42 €*	137.175,26 €	-26.389,58 €	-2.850,09 €	166.414,92 €	*-19.171,08 €*
22	**2031**	*87.895,21 €*	136.779,42 €	-26.917,37 €	-2.718,14 €	166.414,92 €	*-19.043,94 €*
23	**2032**	*85.891,77 €*	136.375,66 €	-27.455,71 €	-2.583,55 €	166.414,92 €	*-18.919,25 €*
24	**2033**	*83.928,26 €*	135.963,82 €	-28.004,83 €	-2.446,27 €	166.414,92 €	*-18.796,97 €*
25	**2034**	*82.003,91 €*	135.543,75 €	-28.564,92 €	-2.306,25 €	166.414,92 €	*-18.677,05 €*
26	**2035**	*80.117,93 €*	135.115,27 €	-29.136,22 €	-2.163,42 €	166.414,92 €	*-18.559,43 €*
27	**2036**	*78.269,56 €*	134.678,23 €	-29.718,95 €	-2.017,74 €	166.414,92 €	*-18.444,09 €*
28	**2037**	*76.458,05 €*	134.232,45 €	-30.313,33 €	-1.869,15 €	166.414,92 €	*-18.330,96 €*
29	**2038**	*74.682,66 €*	133.777,75 €	-30.919,59 €	-1.717,58 €	166.414,92 €	*-18.220,00 €*
30	**2039**	*72.942,68 €*	133.313,95 €	-31.537,99 €	-1.562,98 €	166.414,92 €	*-18.111,18 €*
31	**2040**	*71.237,40 €*	132.840,88 €	-32.168,74 €	-1.405,29 €	166.414,92 €	*-18.004,45 €*
32	**2041**	*69.566,13 €*	132.358,35 €	-32.812,12 €	-1.244,45 €	166.414,92 €	*-17.899,77 €*
33	**2042**	*67.928,20 €*	131.866,17 €	-33.468,36 €	-1.080,39 €	166.414,92 €	*-17.797,09 €*
34	**2043**	*66.322,94 €*	131.364,15 €	-34.137,73 €	-913,05 €	166.414,92 €	*-17.696,39 €*
35	**2044**	*64.749,70 €*	130.852,08 €	-34.820,48 €	-742,36 €	166.414,92 €	*-17.597,61 €*
36	**2045**	*63.207,84 €*	130.329,77 €	-35.516,89 €	-568,26 €	166.414,92 €	*-17.500,72 €*
37	**2046**	*61.696,74 €*	129.797,02 €	-36.227,23 €	-390,67 €	166.414,92 €	*-17.405,68 €*
38	**2047**	*60.215,79 €*	129.253,61 €	-36.951,78 €	-209,54 €	166.414,92 €	*-17.312,46 €*
39	**2048**	*58.764,39 €*	128.699,33 €	-37.690,81 €	-24,78 €	166.414,92 €	*-17.221,02 €*
40	**2049**	*57.268,70 €*	127.970,30 €	-38.444,63 €	0,00 €	166.414,92 €	*-17.204,57 €*

NPV of costs	**-4.546.116,19 €**
ann of costs	**-167.075,40 €**

NPV	**0,00 €**	
annuity	0,00 €	
IRR	2,03%	before tax
electr generation/y	4.202	MWh
LRGC	**39,76 €/MWh**	
Investment costs	**38,60 €/MWh**	

Current period

$$LRGC_{el} = \left(\frac{\text{ann costs}_{el}}{\text{ann output}_{el}}\right)$$

$$\text{Capital costs} = \frac{IC * CRF}{FLH}$$

5.4.10 Sensitivity analysis

The following section concentrates on the parameters that influence the economic performance of both assessed SHPPs. The NPV and LRGC are stressed by shifting each parameter in 10% steps up to a total shift of 40%, respective -40%.

HP-VBG

Since the remaining investment horizon only lasts for two more years, figures 46 and 48 show the sensitivities of the project for the remaining investment horizon of two years. For this short period the influence on the average LRGC and NPV is already reduced. Thus, in order to generate a more holistic picture and to illustrate HP-VBG's risk situation at the time when the project started, the effects of parameter changes for the whole investment horizon are calculated, too.

The theoretical FLH have the highest influence on the LRGC for both observed time horizons, while the sensitivity to o&m and the discount rate is relatively low.

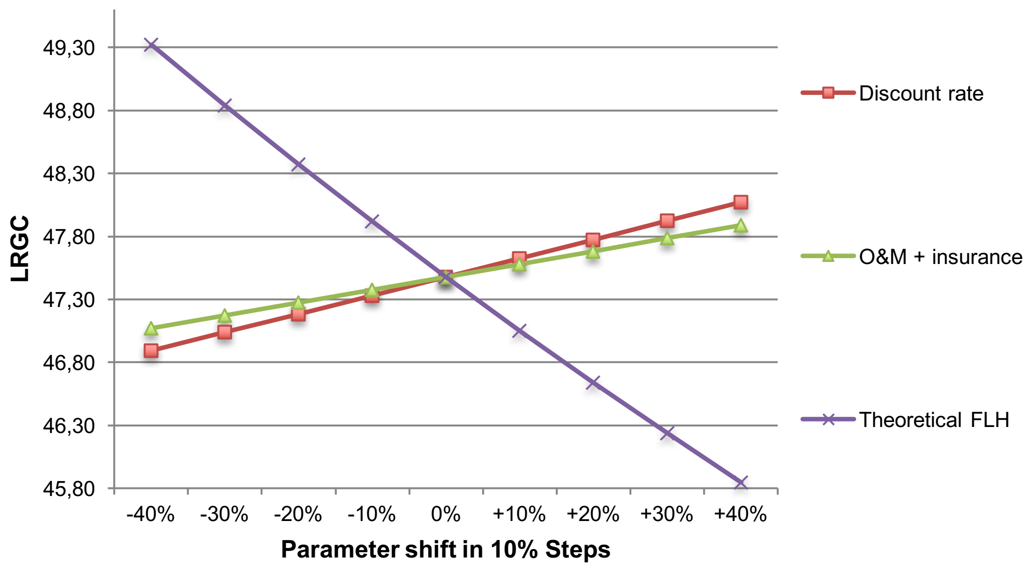


Figure 46: Sensitivity of HP-VBG's LRGC to changes of different input parameters for the remaining investment horizon (own graph, value table in *appendix 27*)

Typical of small hydropower projects the sensitivity to investment costs is rather high. For HP-VBG this is only of hypothetical importance, but in the planning phase of new power plants, this sensitivity has to be watched carefully, because miscalculations of the investment costs have high negative effects in SHPP.

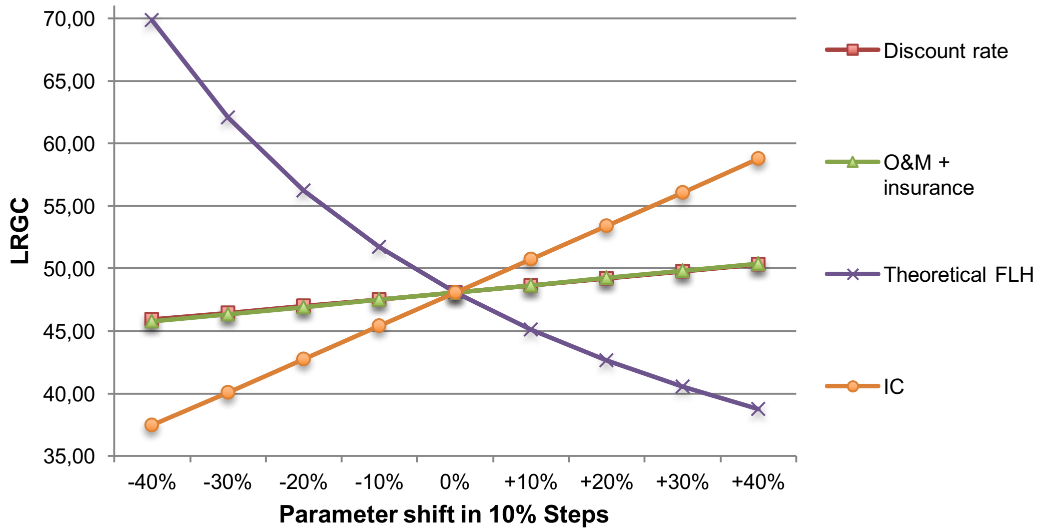


Figure 47: Sensitivity of HP-VBG's LRGC to changes of different input parameters for the whole investment horizon (own graph, value table in *appendix 27*)

For the two-year period observation in figure 48, changes of the discount rate and the alternative tariff of VKW have similar influence, like changes of o&m. Although charted with very high influence in figure 48, a change of the FIT during the operating phase of a project is not realistic in Austria because OeMAG would commit breach of contract. But similar to the investment costs, this factor is crucial in the planning phase of a SHPP project.

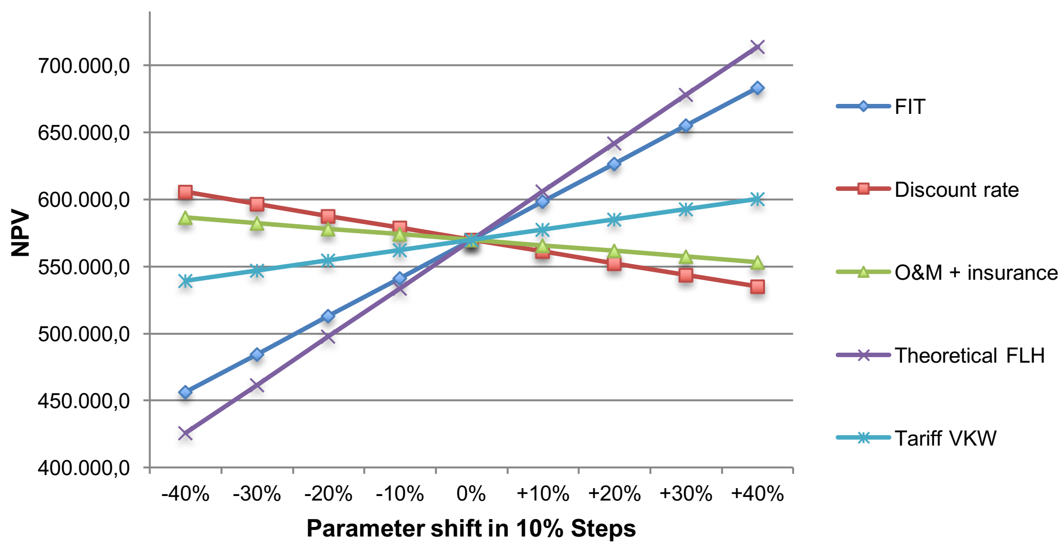


Figure 48: Sensitivity of HP-VBG's LRGC to changes of different input parameters for the remaining investment horizon (own graph, value table in *appendix 27*)

The influence of the VKW tariff is obvious. If this tariff increases, the savings by own use of electricity increase at the same rate.

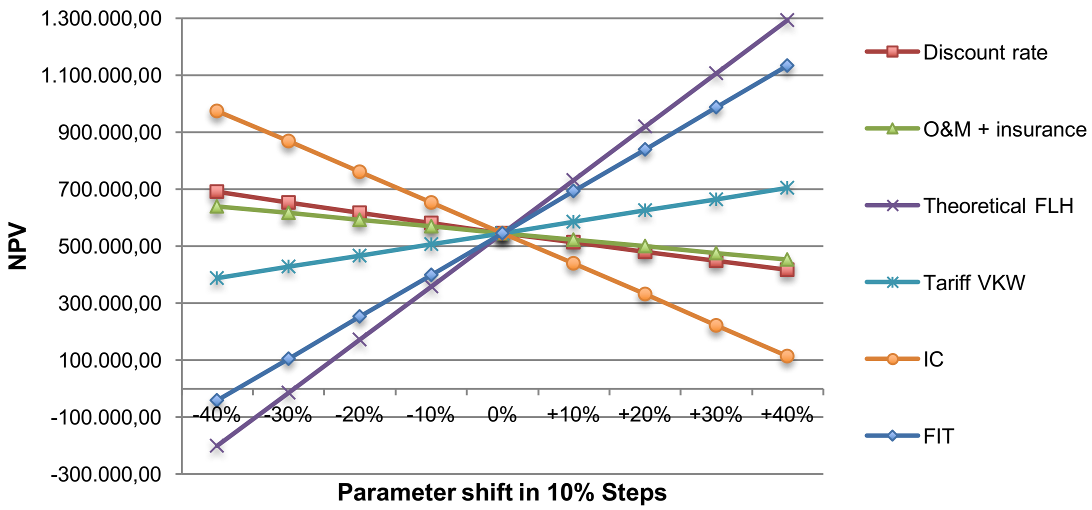


Figure 49: Sensitivity of HP-VBG's LRGC to changes of different input parameters for the whole investment horizon (own graph, value table in *appendix 27*)

HP-NÖ

While HP-VBG shows a high robustness against shifts of the main influencing variables, it looks different for HP-NÖ. The sensitivities of the LRGC show a similar picture with theoretical FLH and investment costs as the main influencing factors.

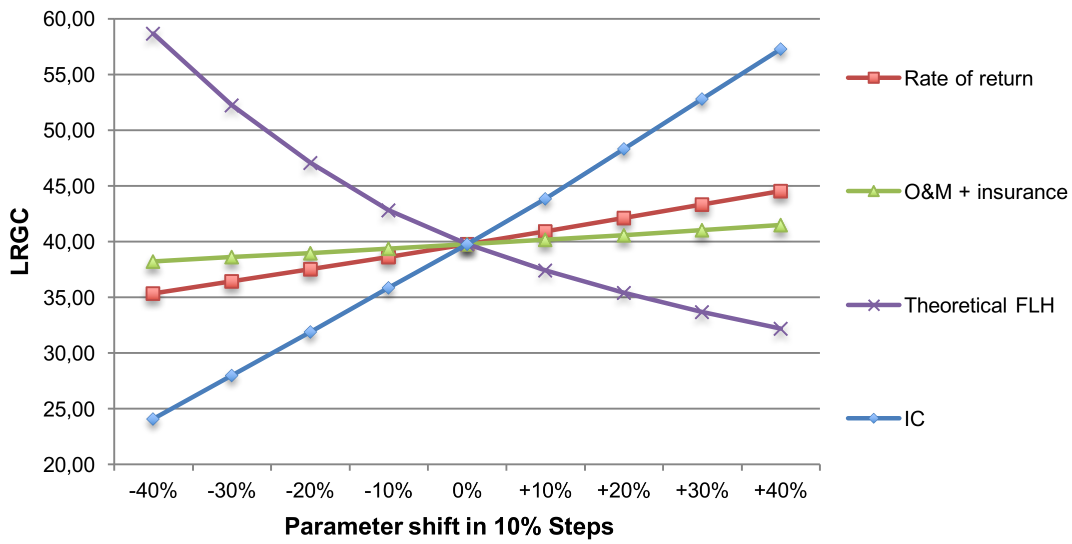


Figure 50: Sensitivity of HP-NÖ's LRGC to changes of different input parameters for (own graph, value table in *appendix 28*)

But with an NPV of 0 €, every cost increase, or revenue reduction means a reduction of the IRR of the investor (2,03% at an NPV of 0 €). With relative stable theoretical FLH in the past, the most important factors to observe for HP-NÖ are the electricity market price and the o&m costs.

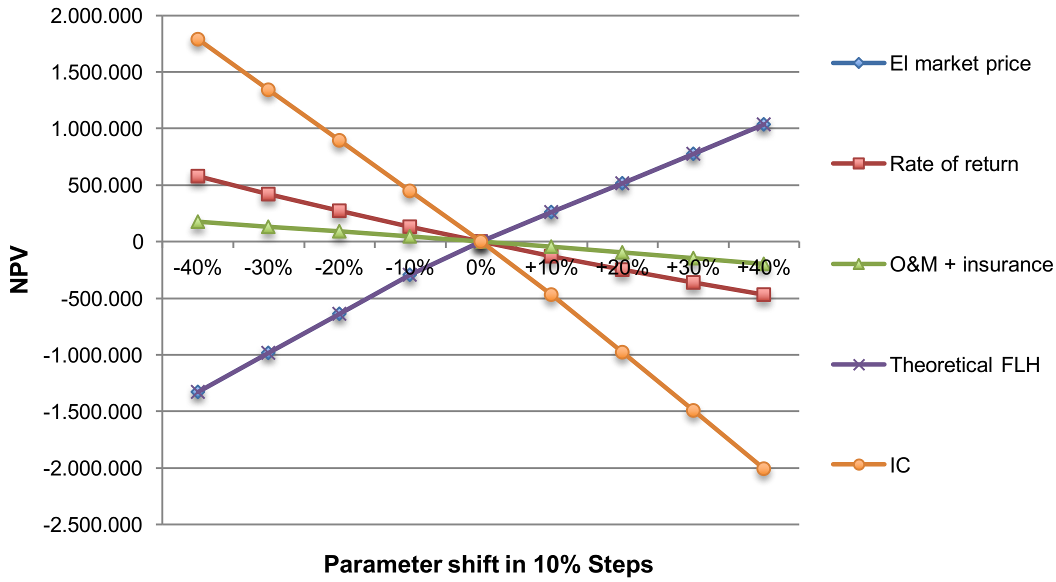


Figure 51: Sensitivity of HP-NÖ's NPV to changes of different input parameters for (own graph, value table in *appendix 28*)

An interesting observation can be made, when comparing figure 49 with figure 51. Since the theoretical FLH multiplied with the electricity price equals annual revenues, a 40%-shift of the FIT must have the same effect as a 40%-shift of the theoretical FLH curves. That means the curves of FIT and theoretical FLH are supposed to match each other, as it is the case for HP-NÖ. But the NPV of HP-VBG shows a higher sensitivity to the theoretical FLH instead. The reason for this effect is the 10% of own used electricity. Savings through own use are only influenced by theoretical FLH and the alternative electricity price from VKW.

5.5 Wind

(Please note that the analyses of this wind power project are based on data provided by the *SOURCE C* under an agreement of strict confidence. Therefore the source of data cannot be specified in this paper. Instead, a list with the names and contact details of all anonymous sources will be submitted to Prof. Dr. Bernhard Pelikan. Unless otherwise noted, the used data and information for W-NÖ relate to this confidential source.)

5.5.1 Description of the analysed wind power plant in Niederösterreich *(W-NÖ)*

In 2009 the planning phase for a new wind park, consisting of 4 turbines with a capacity of 3,4 MWp each in Niederösterreich started. The project had to undergo several examinations before the final building permit was granted. In the end of 2011 the environmental audit was finalized with a positive result. The main concern was the influence of the installations on bird flying routes. Furthermore compliance with regional town and country planning ordinances, like minimum distance to the next residential area, shadowing effects and noise emissions had to be examined. The audit also comprised the adherence to safety zones of nearby located airports.

The site lies in the middle of an agricultural area in the north-east of Niederösterreich at a sea level of 120 to 150 m, with a low degree of roughness and thus good wind conditions from all four cardinal directions. Some hills with an altitude of round 500 m in the north were taken into account in the performed wind studies. In addition to these studies, wind data were provided by already existing parks in the vicinity. Next to the site already 3 other wind parks are located, with enough distance though, in order to avoid bad influence on the performance of the plant, due to wind shadow effects.

The chosen parcel of land is property of the nearby municipality. A contract of lease was negotiated for the duration of the project and in a next step the land was redesignated grassland for wind power. In order to increase the acceptance of the local community, one of the four power plants was financed with a public participation model. Therefore a special operating limited company was founded. This is the power plant that is going to be analysed in the following sections.

The total investment costs of the assessed plant amount to 4.875.000 €. Round 25% of the plant were financed with equity, provided by the citizens of the nearby municipality via silent partnerships and to an extent of 35.000 € by the operating company of the other 3 plants. For the remaining 75% a loan was secured with linear amortisation for the period of 13 years. The minimum duration of the silent partnership was set to 15y with a minimum investment size of 1000 €.

The big advantages for two companies, if they cooperate in the realisation of one joint wind park are economies of scale effects and the corporate use of the same infrastructure. Investment costs and administration costs have to be borne individually by each company, but the remaining maintenance and operation costs, as well as revenues are shared with a relation of 3 to 1.

In 2012 the funding plan was finished and the credit was granted. At the end of the same year, the construction phase began and in 2014, the power plants started production. The produced electricity of the plants gets bundled and transported via an over 10 km long 30 KV cable to the next grid connection point.

5.5.2 Efficiency and energy output

In the technical overview section, the main factors influencing the theoretical power contained in wind were already discussed. To figure out the actual power output of a wind power plant, other factors have to be considered too.

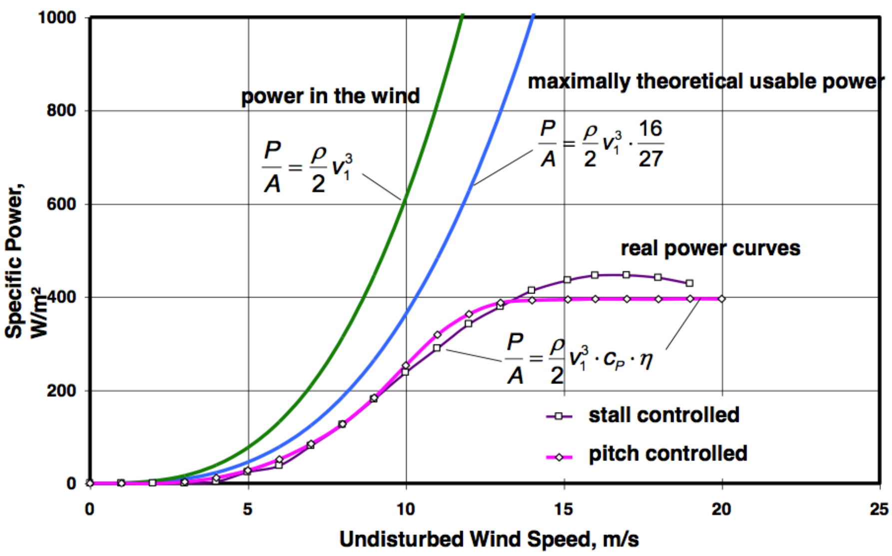


Figure 52: Wind power curves (Krenn 2015)

The green line in figure 52 illustrates the theoretical power of the wind in W/m^2, while the blue line shows the maximal useable power, taking into account the Betz coefficient. According to Betz's law, the maximum power that can be extracted from the theoretical power in the wind in open flow is 16/27 (c_p=59,3%).

Every turbine has a defined cut-in wind speed, at which the turbine starts operating and a cut-out speed, where rotor blades are moved into stall position, in order to slow the rotor speed and to protect the system from overload. For that purpose basically two types of systems exist, namely stall and pitch systems. To describe the real power curve of a specific wind turbine at a particular location, like the ones also depicted in figure 52, the efficiency of the system, also called capacity factor has to be calculated. Dividing the actual output of the turbine in kWh by the theoretical maximum output the turbine could generate, if it ran at its rated capacity for 8.760 h per year, leads to the capacity factor. Therefore the electrical output has to be calculated in a first step.

In most cases the turbine manufacturer delivers the turbine together with the turbine power curve for a given air density and for different hub-height wind speeds. In the present case, the power plant is equipped with a *REpower 3,4M104* turbine with a capacity of 3,4 MWp and a rotor area of 8.495 m^2, installed at a hub height of 128 m. The power curve, provided by the manufacturer *Senvion* is illustrated in figure 53.

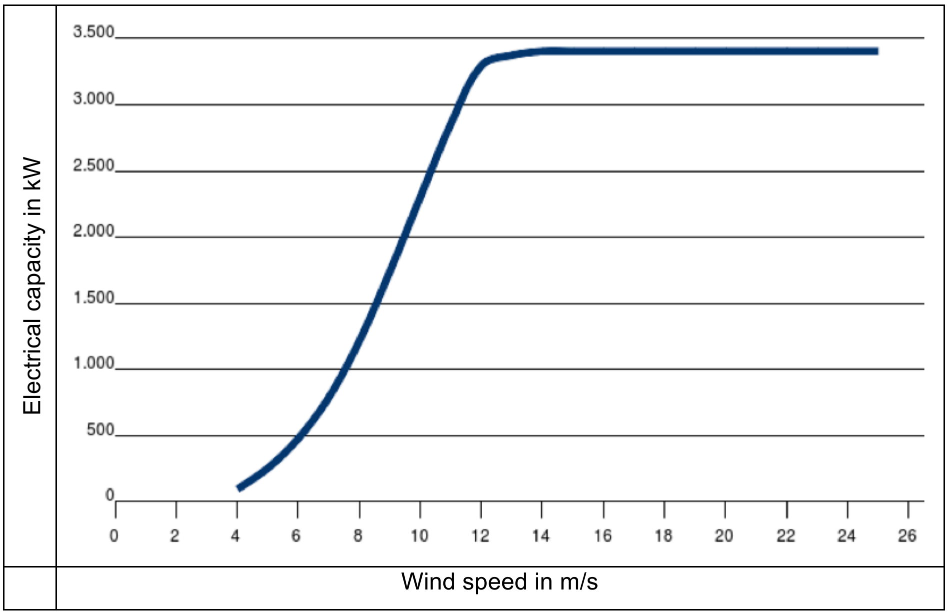


Figure 53: Power curve for the REpower 3,4 M104 turbine (Senvion 2016)

The *REpower 3,4M104* operates at the highest capacity and efficiency at its nominal wind speed, which is 13,5 m/s. The cut-in speed is 3,5 km/h and the cut-out speed 25 km/h. More detailed data can be found in *appendix 13*.

For the calculation of the power production, either a time series of air density data and wind speed or a so-called wind speed frequency distribution of the particular site can be used. The wind speed of the present site, illustrated with blue bars in the following chart, follows a so-called *Weibull distribution* with the shape parameter k and the scale parameter A. The average wind speed amounts to 7,1 m/s. The green line shows the distribution of an earlier built reference plant near the site.

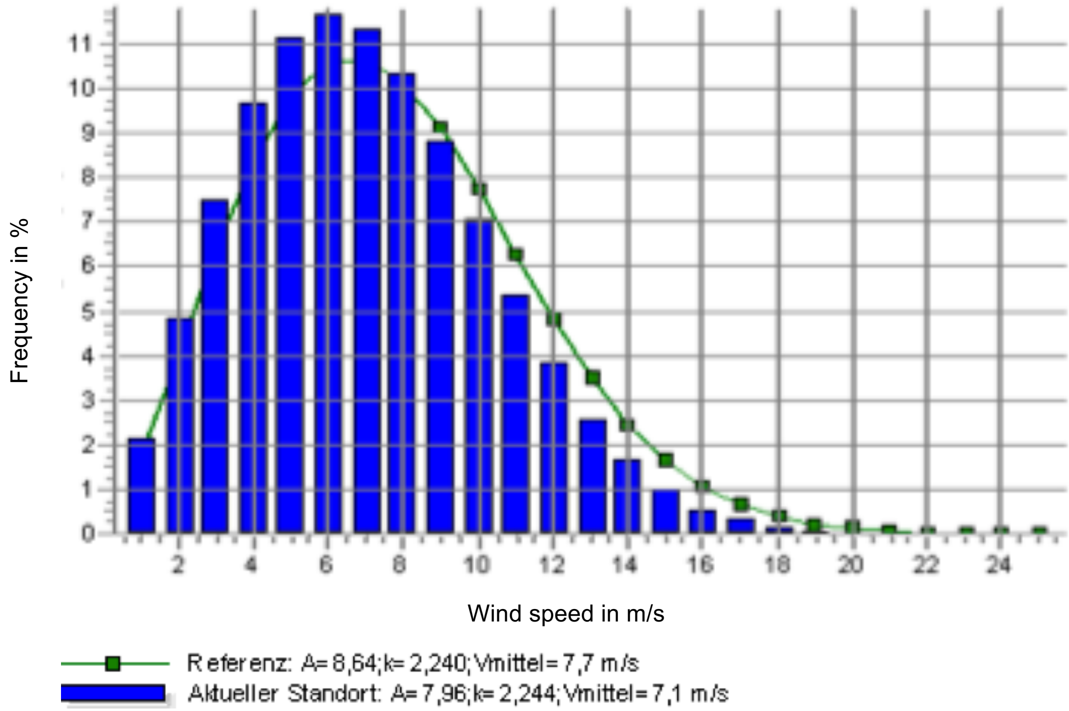


Figure 54: Weibull distribution of the W-NÖ (*SOURCE C 2016)*

Now the output of W-NÖ at free wind flow can be calculated by multiplying the power curve with the given wind speeds. The annual output of the *REpower 3,4M104* amounts to round 9,6 GWh at free wind flow, as can be seen in table 27.

In a next step, performance losses within the turbine itself (manufacturer guarantee <3%) and losses caused by the transformer, cables and wind turbulences have to be considered. Altogether these losses sum up to 4,4%. In addition to that, the wind park effect causes another loss of estimated 9,9%. Incorporating these losses in the calculation leads to a total net output of round 8,3 GWh/y.

Table 27: Annual electricity output of the REpower 3,4M104 (own calculation)

Wind speed	Frequency	Turbine capacity	Turbine output
[m/s]	[h/y]	[kW]	[kWh]
0	16	0	0
1	175	0	0
2	429	0	0
3	648	0	0
4	858	120	103.018
5	972	310	301.432
6	1034	570	589.198
7	981	920	902.630
8	894	1420	1.268.798
9	780	1920	1.496.909
10	613	2520	1.545.264
11	482	3070	1.479.126
12	342	3320	1.134.245
13	228	3370	767.551
14-25	0	3400	0
Total gross output			**9.588.170**
-Wind park effect			-9,9%
-Operating losses			-4,40%
Total net output			**8.258.828**
85% percentile (conservative calculation)			**7.915.750**
Average capacity factor			**26,58%**
Theoretical FLH			**2.328**

For the purpose of a conservative investment calculation, in general not the full total net output, but a percentile is used. For W-NÖ, the 85th percentile was chosen, amounting to 7,9 GWh. That means in 85% of all cases the real output would not fall below this value (see *appendix 14 and 15* for details).

Finally the capacity factor and the theoretical FLH can be calculated. 26,58% is a realistic value for Austria, for most worldwide sites this factor lies between 25% and 50%. The theoretical FLH amount to 2.328 h per year. (Krenn 2015)

5.5.3 Costs

Similar to PV and SHPP, also the costs of wind power production are dominated by the upfront investment costs. Once the system is installed, there are no price risks for fuel costs. There are huge differences between on- and offshore systems. The latter are more expensive and involve much higher costs for the BOS (approximately 50% of the total costs) compared with the land-based systems (approximately 25%). This is due to the added complexity to the structure that has to withstand the harsh maritime conditions. Also the turbines have to cope with a high amount of salt in the air and are more expensive than land-based turbines. In Austria offshore systems are of less importance, thus the following analysis concentrates on on-shore systems. (Moné 2013)

Investment costs

Besides the on- or offshore criterion, investment costs are dependent of the rated capacity and the hub height. In the below charts, the results of a cost study for two capacity classes (P) at different hub heights (NH), performed by *Deutsche Wind Guard* are illustrated.

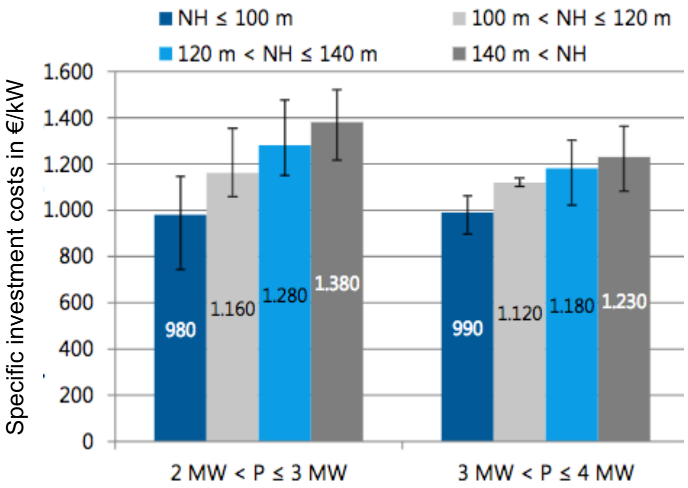


Figure 55: Investment costs for on-shore wind power (Lüers et al. 2015: 17)

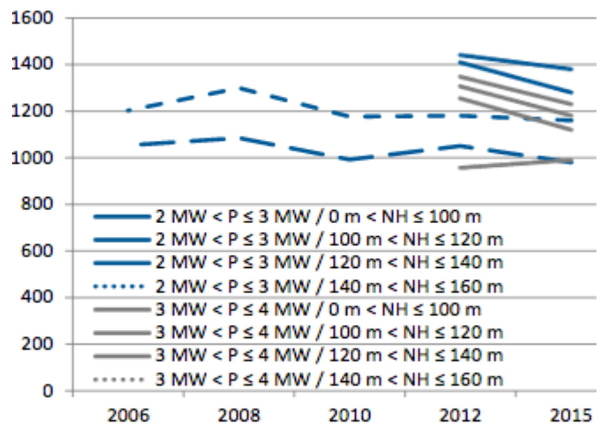


Figure 56: Development of investment costs (Lüers et al. 2015: 17)

It appears that with an increase of the hub height, for both capacity classes the costs increase as well. Moreover, systems with higher capacity seem to be cheaper, compared with the ones with lower capacity. The columns in figure 55 are the results of a sample of 46 land-based wind power plants and the black lines at the top represent the standard deviation that can occur. Figure 56 shows the development of the specific investment costs from 2006 to 2015. (Lüers et al. 2015)

In the next chart, the major categories and their share of investment costs for on-shore wind power projects are presented. As can be seen, the wind turbine takes the biggest share, comprising the tower, rotor blades, gearbox, generator, power converter, transformer and other costs, which mainly consist of civil works and control systems.

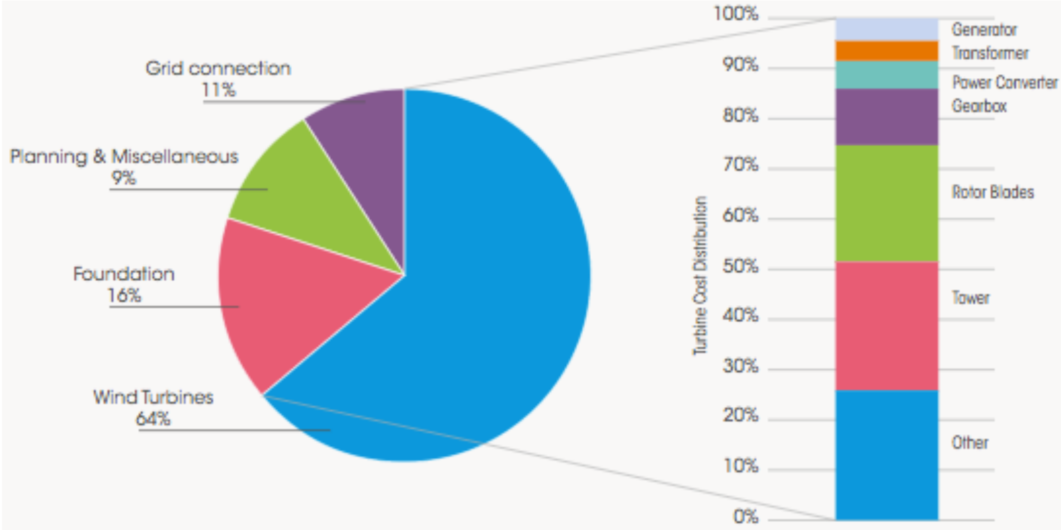


Figure 57: Capital cost breakdown for a typical onshore wind power system and turbine (IRENA 2012: 18)

The remaining 36% are needed for the BOS, consisting of grid connection costs, construction of the foundation and planning costs.

In table 28 the investment costs for the W-NÖ are listed. The turbine, together with the foundation takes 79% of the total costs, which is in line with the above chart. All other costs are ¼ shares that have to be paid for the joint project infrastructure together with the other three plants in the park.

Table 28: Investment costs for W-NÖ (*SOURCE C 2016)*

Turbine, including fundament	3.850.000 €	79%
Grid connection and trafo-station	527.500 €	11%
Planning, access to site, cables, others	342.500 €	7%
Reserves for unforseeable	155.000 €	3%
Total Investment costs	**4.875.000 €**	

Operation and maintenance costs

Operation and maintenance costs are a significant part of the generation costs of wind power and account for 20% to 25% of the total LRGC. All the costs that occur during the operation of a wind park are included in this position. Primarily maintenance, repairing work, payment of rent and grid access charges have to be mentioned. In addition to that, insurance costs and the building of reserves for dismantling after the licensed operation period have to be considered. An important consideration is that o&m costs tend to increase over time. The reason for that is the increasing probability of component failures that mostly occur after the manufacturer's warranty period. (IRENA 2012: 25)

Table 29: Operation and maintenance costs W-NÖ (*SOURCE C 2016)*

Operation costs per year	
Grid access fee	18.105 €
Insurance	5.000 €
Administration	8.000 €
Technical operation	10.000 €
Rent	17.000 €
Phone/ electricity	3.725 €
Reserve	8.000 €
Total per year	**69.830**

Year	**Maintenance**
2013	32.000 €
2014	32.000 €
2015	62.525 €
2016	62.525 €
2017	62.710 €
2018	80.710 €
2019	80.725 €
2020	80.725 €
2021	89.739 €
2022	89.739 €
2023	98.754 €
2024	98.754 €
2025	99.769 €
2026	99.769 €

As already mentioned, due to the exposure of the system to extreme weather conditions, maintenance and repair efforts grow dramatically over time. For W-NÖ a scheduled full maintenance package was signed and the course of the price can be seen in table 29. Operation costs are again assumed to increase 2% per year from 2016 on, to incorporate inflation effects over time.

In general banks request an insurance package containing business interruption. In combination with a full maintenance service contract which reduces the risk of system failures, the insurance costs amount to 5000 € per year.

5.5.4 Revenues

The revenues of wind power depend on two factors: The amount of electricity output and the FIT. The annual output of the assessed plant has already been calculated in the previous section and amounts to round 7,9 GWh/y. According to *SOURCE C*, a FIT of 9,5 c/kWh could be secured for 13 years. Thus the annual revenues sum up to 751.996 €.

5.5.5 Depreciation and corporate tax (Körperschaftssteuer KÖST)

Since the legal owner of W-NÖ is a limited company (GmbH), corporate tax of 25% has to be paid for earnings. The tax base is calculated the same way, as in the analyses of the other RES technologies in the prior chapters. The credit redemption of the 13-year credit follows a linear schedule and the investment costs are depreciated over a period of 15 years. A detailed tax calculation can be found in *appendix 24*.

5.5.6 Financial analysis

With an electrical output of 7,9 GWh the plant produces approximately twice the electricity of the other assessed sites in this paper. This specific plant has been chosen, because the source provided the best data quality. Moreover, according to *SOURCE B*, for analysis purposes, the plant size can be scaled down almost linearly to an output of round 4 to 5 GWh, which is within the target range of the present study, leaving the LRGC at a similar level. A certain deviation to actually existing smaller systems is accepted in this case, because according to Alberici (2014) p13 the range of LRGC for onshore wind systems in the EU is relatively narrow (70 € to 100€). Thus for the present assessment representativeness is given.

To estimate the economic performance of W-NÖ, again the NPV and LRGC are calculated, based on the researched and calculated data. The plant was financed with 25% equity and 75% debt. The credit rate is fixed for the whole credit period of 13 years and amounts to 3%. The equity yield is projected with 8% after tax. Combining the rates by calculating the WACC leads to a project discount rate of 4,25% after tax. The calculation can be found in *appendix 19*. In table 30 the input parameters for the NPV and LRGC calculations are summarised.

In table 31 the results of the dynamic investment calculation are presented. The LRGC amount to 88,04 €/MWh and a NPV of 532.611 € translates to an IRR of 6,34%. Investment costs by nature of wind power take the highest share of LRGC with 63,72 €/MWh. Hence the project can be considered a good investment with a nice buffer for unforeseeable risks. In the next section, the results of the sensitivity analysis are presented.

Table 30: Main calculation parameters of W-NÖ

Parameters Wind *	**W-NÖ 3,4 MWp**	
Technical data	**Start 2014**	
Nominal capacity PV plant a)	[kW_p]	3.400
Hub height a)	[m]	128
Rotor diameter a)	[m]	104
Rated wind speed a)	[m/s]	13,50
Cut-in wind speed a)	[m/s]	3,50
Cut-out wind speed a)	[m/s]	22,00
Park efficiency	[%]	90,01%
Operating losses	[%]	4,40%
Capacity factor	[%]	26,58%
Theoretical Full Load Hours	[h/y]	2.328
Technical lifetime of power plant	[y]	20
Depreciation period	[y]	15
Construction year	[y]	2014
Costs		
Investment costs	[€/kW]	1.433,82
Operation per year	[€/kWh]	69.830
Full maintenance service contract	[€/y]	see table 31
Credit period	[y]	13
Interest Rate credit before tax	[%]	4,5%
Debt ratio	[%]	75%
Expected equity yield after tax	[%]	8%
Corporate tax rate b)	[%]	25%
Discount rate (WACC) after tax	[%]	4,53%
Revenues		
Feed in tariff OeMAG	[€/kWh]	0,0950
Investment horizon and FIT duration	[y]	13
Real escalation of o&m and insurance c)	[%/y]	2%

*) Unless otherwise noted, source is *SOURCE C*

a) See datasheet in *appendix 13*

b) Wirtschaftskammer Österreich

c) Own assumption based on ECB inflation target of 2%

Table 31: Dynamic investment calculation of W-NÖ (own calculation)

W-NÖ		**3,4 MWp**
Technical data		
Nominal capacity	[MW]	3,40
Theoretical Full Load Hours	[h/y]	2.328
Costs		
Investment costs	[€/MW]	1.433.823,53
Operation costs per year	[€/y]	69.830,00
Real escalation of operation costs from 2016 on	[%/y]	2,00%
Maintenance costs	[€/y]	see table 29
Revenues		
Feed in tariff (ÖMAG)	[€/MWh]	95,00
Financing		
Investment horizon	[y]	13
Discount rate (WACC) after tax	[%]	4,53%
Equity yield after tax	[%]	8,00%
Interest rate debt before tax	[%]	4,50%
Debt ratio	[%]	75,00%
Corporate tax	[%]	25%
Depreciation period	[y]	15
Capital recovery factor	[%]	10,35%
Electricity output	[kWh/y]	7.915.750,00

Dynamic investment calculation including tax

	Year	*Discounted CF total*	Nominal CF	Operation	Maintenance	Corporate tax	Electricity sale	*Discounted cost*
			A+B+C+D	A	B	C	D	
0	**2013**	*-4.875.000,00 €*	-4.875.000,00 €					*-4.875.000,00 €*
1	**2014**	*583.564,72 €*	610.007,50 €	-69.830,00 €	-32.000,00 €	-40.158,75 €	751.996,25 €	*-135.833,78 €*
2	**2015**	*555.372,50 €*	606.843,44 €	-69.830,00 €	-32.000,00 €	-43.322,81 €	751.996,25 €	*-132.841,32 €*
3	**2016**	*508.484,16 €*	580.785,63 €	-69.830,00 €	-62.525,00 €	-38.855,63 €	751.996,25 €	*-149.896,77 €*
4	**2017**	*482.914,85 €*	576.574,11 €	-71.226,60 €	-62.525,00 €	-41.670,54 €	751.996,25 €	*-146.926,40 €*
5	**2018**	*458.478,88 €*	572.202,90 €	-72.651,13 €	-62.710,00 €	-44.432,22 €	751.996,25 €	*-144.059,83 €*
6	**2019**	*424.995,96 €*	554.449,07 €	-74.104,15 €	-80.710,00 €	-42.733,02 €	751.996,25 €	*-151.423,74 €*
7	**2020**	*403.429,58 €*	550.162,20 €	-75.586,24 €	-80.725,00 €	-45.522,82 €	751.996,25 €	*-148.003,31 €*
8	**2021**	*382.926,63 €*	545.864,34 €	-77.097,96 €	-80.725,00 €	-48.308,95 €	751.996,25 €	*-144.602,59 €*
9	**2022**	*358.890,99 €*	534.783,31 €	-78.639,92 €	-89.739,00 €	-48.834,02 €	751.996,25 €	*-145.770,75 €*
10	**2023**	*340.545,02 €*	530.439,65 €	-80.212,72 €	-89.739,00 €	-51.604,88 €	751.996,25 €	*-142.240,50 €*
11	**2024**	*318.948,13 €*	519.311,14 €	-81.816,97 €	-98.754,00 €	-52.114,13 €	751.996,25 €	*-142.909,47 €*
12	**2025**	*302.542,15 €*	514.919,83 €	-83.453,31 €	-98.754,00 €	-54.869,11 €	751.996,25 €	*-139.294,72 €*
13	**2026**	*286.517,50 €*	509.742,71 €	-85.122,38 €	-99.769,00 €	-57.362,15 €	751.996,25 €	*-136.166,49 €*

NPV of cost	**-6.734.969,67 €**
ann of cost	**-696.885,54 €**

NPV	**532.611,08 €**
annuity	55.110,71 €
IRR	6,34%
electr generation/y	7.916 MWh
LRGC	**88,04 €/MWh**
Investment costs	**63,72 €/MWh**

Current period

$$LRGC_{el} = \left(\frac{\text{ann costs}_{el}}{\text{ann output}_{el}} \right)$$

$$\text{Capital costs} = \frac{IC * CRF}{FLH}$$

5.5.7 Sensitivity analysis

Figures 58 and 59 offer a similar picture like the analyses of the other RES technologies. A change of the theoretical FLH or investment costs has the highest impact on LRGC and the project NPV.

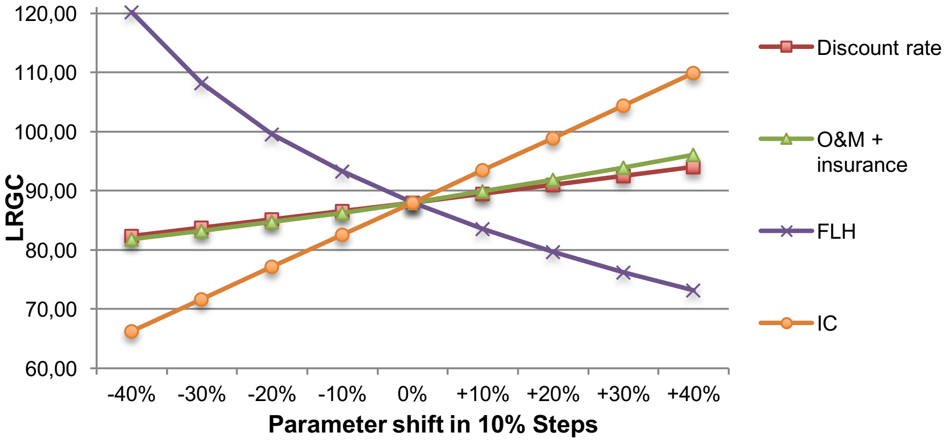


Figure 58: Sensitivity of W-NÖ's LRGC to changes of different input parameters for the remaining investment horizon (own graph, value table in *appendix 29*)

In order to ensure a high degree of capacity utilisation, maintenance is of extraordinary importance in wind power technology. A full service contract already incorporates a high escalation rate over the operating years. However, an increase of the o&m costs over 35% brings the project into negative terrain. But with regular maintenance the risk can be reduced drastically.

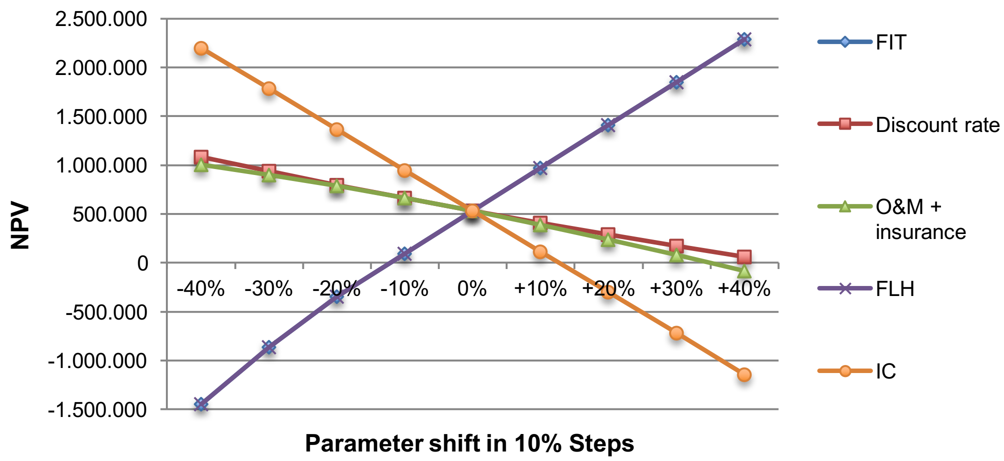


Figure 59: Sensitivity of W-NÖ's NPV to changes of different input parameters for the remaining investment horizon (own graph, value table in *appendix 29*)

5.6 Summary and comparison of the plants

In this section the derived results of the prevenient analyses will be compared in a holistic view. First the concrete situations of the plants are discussed, including a comparison with conventional technologies and RES on EU-level. In a next step a scenario without subsidies and FITs, c.p. will be constructed. Finally the effect of extending the investment horizon and credit period is discussed in scenario 2. Table 32 provides a comprehensive overview.

5.6.1 Comparison of the analysed projects

Looking at table 32, the first decisive difference that can be observed is the amount of theoretical FLH the technologies are operating. The ORC module of BM-VBG operates 4.567 h per year, comparable to HP-VBG with 4.320. While for SHPPs the time of operation is only restricted through the nature of the used rivers, heat led biomass CHPs with sizes around 0,5 MWel are merely restricted by missing demand of heat. Moreover, biomass CHP is the only RES technology that needs feedstock for operation, which can be a bottleneck too. In theory HP-VBG could operate at almost 8.000 h per year, presupposing a stable and sufficient fuel supply and energy demand. Wind and PV are producing electricity intermittently, when the sun is shining or wind is blowing. Therefore these technologies show relatively low theoretical FLH, compared with the other technologies. Hence in this paper SHP is considered to be the RES technology with the highest reliability and flexibility in terms of electricity supply, followed by biomass CHP.

As a consequence, SHPPs and biomass CHPs need much lower system peak capacities to generate the same electricity output like wind and PV. For example, PV-SBG needs an installation of 3,15 MWp to generate 3,6 GWh per year, while HP-VBG produces 3,9 GWh with a capacity of 0,9 MWp.

Comparing initial investment costs of the five systems shows that the high-pressure hydropower plant HP-VBG is the cheapest system with 1,2 mio €. On the other hand, the low-pressure hydropower plant HP-NÖ has very high investment costs, amounting to 5,15 mio €. These projects reflect the heterogeneity of SHP and show the cost bandwidth with the help of two contrary extremes. The opposite can be said about PV and wind power, which are rather standardised technologies. As already mentioned it is acceptable to scale down W-NÖ to 1,7 MWel with an output of round 4 GWh per year. The investment costs then approximately amount to 2,5 mio €. In a relative view, this brings W-NÖ on the second position in terms of investment costs, followed by PV. The most expensive system is BM-VBG, with 9 mio € plus 8 mio € for the district heating grid.

Table 32: Comparison of the analysed RES systems (own calculation)

		BM-VBG 2010 Biodiesel th	BM-VBG 2010 WW th	BM-VBG 2010 ORC th	BM-VBG 2010 ORC el	PV-SBG 2016 - el	HP-VBG 2006 - el	HP-NÖ 2010 - el	W-NÖ 2014 - el
Basis case									
Peak capacity	[MW]	12	4	3,2	0,5	3,15	0,9	1,17	3,4
Theoretical FLH	[h]	55	1.237	3.465	4.567	1.140	4.320	3.588	2328
Energy output	[MWh]	661	4.949	11.087	2.283	3.592	3.904	4.202	7.916
Total efficiency	[%]	90%	88%	84%		15,72%	76,75%	84,30%	26,58%
Fuel driven		y				n	n	n	n
Investment costs	[mio €]	4,14 +8.00 (for district heating grid)		2,98	1,88	3,00	1,20	5,15	4,875
	[€/kW]	na		931	3.764	952	1.336	4.394	1.434
Subsidies in % of IC	[%]	23,53%				-	-	27,21%	-
Discount rate after tax	[%]	1,88%				2,84%	3,44%	2,03%	4,53%
LRGC$_{el}$	**[€/MWh]**	**-**			**266,48**	**99,05**	**47,48**	**39,76**	**88,04**
Investment horizon	[y]	25				13	13	40	13
FIT	[€/MWh]	-			138,33 *	100,00	53,95	market price	95,00
NPV	[€]	-1.28 mio (incl. d.h. grid) *4.84 mio (excl. d.h. grid)*				120.767	569.927	0	532.611
Break even tariff **	[€/MWh]	-			215,70	95,18	33,03	39,61	83,49
IRR	[%]	0,82% (incl. d.h. grid) *8,39% (excl. d.h. grid)*				3,48%	10,28%	2,03%	6,34%

Scenario 1: *No FIT, no investment subsidies, assumed average market price 39,61 €/MWh, c.p.*

		BM-VBG				PV-SBG	HP-VBG	HP-NÖ	W-NÖ
Discount rate after tax	[%]	1,88%				2,84%	3,44%	2,03%	4,53%
LRGC$_{el}$	**[€/MWh]**	**-**			288,33	89,06	44,44	51,84	82,22
Investment horizon	[y]	25				13	13	40	13
Average market price	[€/MWh]	**-**			**39,61**	**39,61**	**39,61**	**39,61**	**39,61**
NPV	[€]	-8.2 mio (incl. d.h. grid) -0.2 mio (excl. d.h. grid)				-1,51 mio	171.855	-1,4 mio	-3,26 mio
Break even tariff **	[€/MWh]	338,64 (incl. d.h. grid)				95,18	33,30	55,92	85,72
LRGC$_{el}$ at break even tariff	[%]	**-**			**300,77**	**98,01**	**43,02**	**55,92**	**85,72**
IRR	[%]	n.a.				n.a.	5,64%	0,31%	n.a.

Scenario 2: *No FIT, no investment subsidies, investment horizon = useful lifetime of powerplant ****

		BM-VBG				PV-SBG	HP-VBG	HP-NÖ	W-NÖ
Discount rate after tax	[%]	1,88%				2,84%	3,44%	2,03%	4,53%
LRGC$_{el}$	**[€/MWh]**	**-**			288,33	67,37	30,29	51,84	68,14
Investment horizon	[y]	**25**				**20**	**40**	**40**	**20**
Average market price	[€/MWh]	-			39,61	39,61	39,61	39,61	39,61
NPV	[€]	-8.2 mio (incl. d.h. grid) -0.2 mio (excl. d.h. grid)				-1,0 mio	1,55 mio	-1,4 mio	-2,93 mio
Break even tariff **	[€/MWh]	338,64 (incl. d.h. grid)				63,19	12,34	55,92	69,44
LRGC$_{el}$ at break even tariff	[%]	**-**			**300,77**	**68,83**	**24,15**	**55,92**	**69,44**
IRR	[%]	n.a.				n.a.	10,33%	0,31%	n.a.

* FIT for 15 years

** Market price of electricity needed to retrieve an NPV of 0 for the project (for BM-VBG including district heating grid, c.p.)

*** Credit period = useful lifetime, credit period for HP-VBG is not extended because this plant is already profitable with 13 years

As can be seen in table 32, BM-VBG received investment subsidies of 4 mio € (23,53% of total investment costs) for CHP technology and has the highest FIT, compared with the other systems. HP-VBG receives the lowest FIT with only 53,95 €/MWh and HP-NÖ sells the output at market price, because investment subsidies of 1,4 mio € were chosen instead of the FIT.

In terms of electricity production the two SHPPs show by far the lowest LRGC, followed by the wind project and PV. The highest LRGC was calculated for BM-VBG, due to relative high investment costs of the ORC module and particularly high fuel costs. When comparing LRGC, they must always be valuated together with the investment horizon of the projects. The longer the investment horizon of the project, the lower the LRGC of the project, c.p.. Thus the most economic energy generator is HP-VBG with LRGC of 47,48 €/MWh for 13 years. BM-VBG is the most expensive electricity producing plant with 266,48 €/MWh for 25 years. But it must not be forgotten that the primary business objective is the production and sale of heat. Moreover, figure 134 also includes biomass CHP plants with much higher capacities driving down the LRGC average through economies of scale and the use of steam turbine processes, which are more efficient and cheaper, compared with ORC turbines (see figure 32).

In figure 60 the LRGC bandwidth of several RES and conventional technologies at realised FLH are shown, based on the produced electricity and the total installed capacity in the EU-28. In order to show the position of the five analysed systems within the EU-28, the LRGCs were plotted into this chart with orange marks. Despite BM-VBG, all systems are clearly within the EU bandwidth. But as already discussed, with higher heat demand and theoretical FLH, the LRGC can be decreased decisively.

All analysed plants except BM-VBG show a positive PV and are therefore considered good investments. With an IRR of 10,28%, HP-VBG is the most profitable endeavour, followed by W-NÖ with 6,34%, PV-SBG and HP-NÖ. The reason why BM-VBG including the district-heating grid is negative, has already been discussed, as well as the measures that can be taken to bring the project into positive terrain. A break-even tariff, at which the NPV of the system reaches 0 € has been derived at 215,70 €/MWh. This figure is obviously of theoretical nature, because OeMAG would not increase the tariff. A more realistic measure would be the increase of the heating tariff or re-negotiation with the feedstock supplier for lower prices.

An interesting observation for the PV project can be made, namely the FIT is lower than the LRGC, and in the four other systems the FIT is higher than the LRGC, which is intuitive, because the costs have to be borne by the tariff. The situation can be explained by the high amount of savings by own electricity use, exceeding the revenues that could be made alternatively by feeding the whole output into the grid

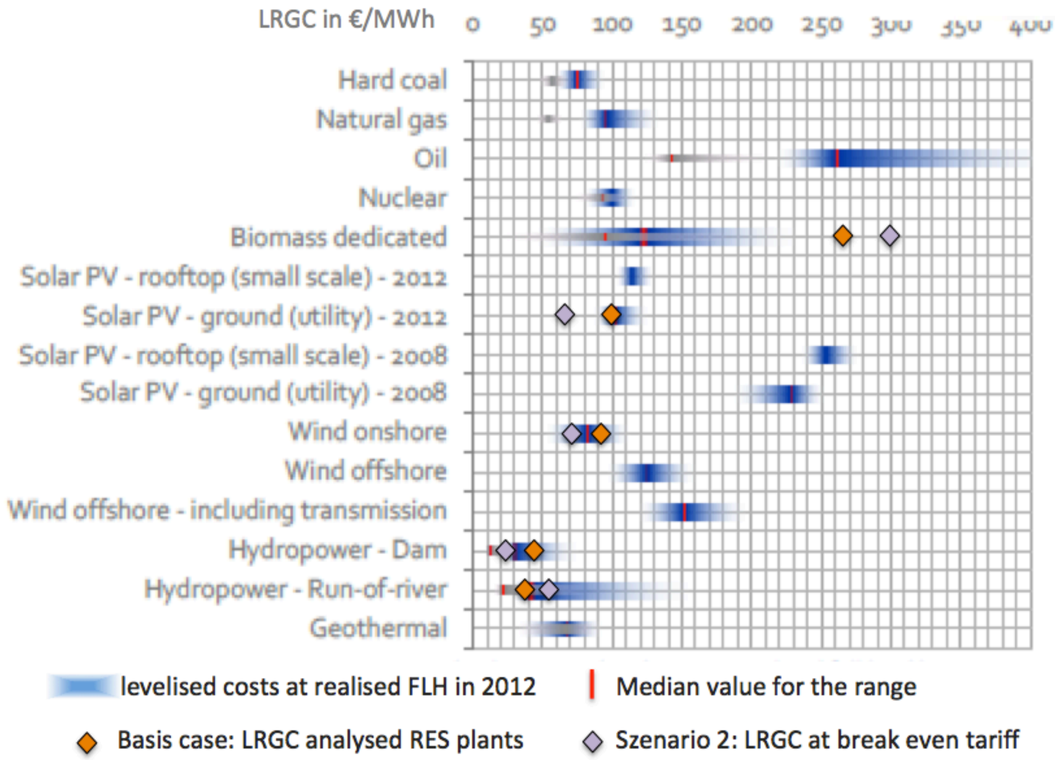


Figure 60: LRGC$_{el}$ at realised FLH in EU 28 (Alberici et al. 2014: 48)

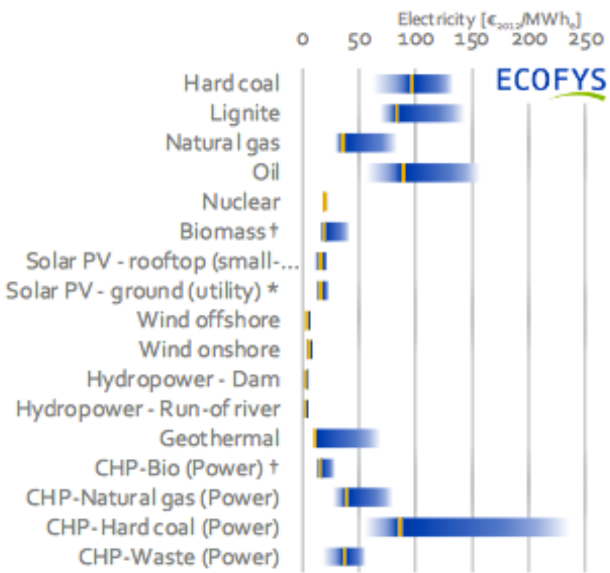


Figure 61: Range of external costs in EU 28, estimated in 2012 (Alberici et al. 2014: 40)

Looking again at figure 60, where the LRGC of RES and traditional technologies are compared, the current situation becomes quite clear. Oil technologies, for instance, are very expensive and are only used as back-up capacities, since they have already been replaced by RES due to the merit order effect. To some extent also natural-gas has already been replaced by RES, due to the high costs of around 100 €/MWh. But although hard coal and nuclear power have higher LRGC than most of the RES in the EU, these technologies are still preferred in several countries. In reality the costs of fossil fuel driven technologies and nuclear power are even higher than suggested in figure 60, because external costs are not included. External costs are costs caused by nuclear accidents or the effects of exhaust gases on climate change, particular matter formation or human toxicity, for instance. Figure 61 shows the outcome of a study, assessing external costs. Taking these costs into account would make the most conventional systems unaffordable. (Alberici et al. 2014: 34ff)

5.6.2 Scenario 1&2, no subsidies or FIT, but longer investment horizon

With the help of subsidies and FITs, RES in Austria are affordable and achieve quite good competitiveness. But as already stated in chapter 2.4.1., FITs distort competition and in the long run RES must be capable to survive without subsidies and FITs. But the currently low oil and electricity prices are serious obstacles on the way to the desired situation.

But how are the economic performances of the five chosen plants in scenario 1, a world without subsidies and FITs? Therefore an average electricity market price of 39,61 €/MWh was presumed (see *appendix 4*). The only plant that would have reached a positive NPV under these circumstances is HP-VBG with 171.855 €. At which market price are the remaining plants feasible? To answer the question, the break-even tariffs are calculated; the results can be seen in table 32. At an average price of round 95 €/MWh all RES but biomass would be feasible.

Now the LRGC at break-even tariff can be compared with those of the base case. The missing of investment subsidies has the highest effect on LRGC, which can be seen for BM-VBG and HP-NÖ. BM-VBG would increase drastically to 300,77 €/MWh, because subsidies of 4 mio € and a high FIT are missing. HP-NÖ sees an increase up to 55,92 €/MWh. For the remaining three plants the LRGC at break-even tariff decrease, compared with the basis case. This is due to the fact that less electricity revenues cause less corporate tax payments.

As in the basis case it can be seen also in scenario 1 that for PV the break-even tariff is lower than the LRGC at break-even. This is again due to the own use of electricity production and at an NPV of 0; this effect can also be observed for HP-VBG.

Finally, in scenario 2 the investment horizon was extended to the useful lifetime of the power plants,. For BM-VBG this is 25 years, thus there is no change, compared to scenario 1. The same is valid for HP-NÖ with an investment horizon of 40 years. For HP-VBG the credit period was assumed to stay the same, because the credit can be paid back much earlier, due to the high economic performance. The investment horizons and credit periods for PV-SBG and W-NÖ were extended to 20 years each. As can be seen in table 32, with this measure, the needed break-even tariffs are reduced dramatically, except those for HP-NÖ and BM-VBG, which were already projected with the useful lifetime in the basis case. Under the circumstances of scenario 2, an average electricity market price of round 70€/MWh would be needed to make all projects but BM-VBG feasible without subsidies and FITs. In figure 60 the five power plants are plotted under the assumptions of scenario 2 with purple marks.

6 CONCLUSION

In a nutshell, the choice to substitute conventional energy technologies with renewables is a must for the whole of Europe and Austria, in order to guarantee a steady and safe energy supply in the future and to stop the climate change. Austria traditionally covers a high share of the electricity demand with renewable energy. The highest remaining Austria-wide realisable potentials can be found for hydropower and solid biomass. Wind power already utilizes a high portion of the available potential, hence the remaining future share is relatively low and photovoltaic has by far the lowest potential, due to the rather unfavourable latitude of Austria.

In this paper five existing RES power plants with maximum capacities of 0,5 MW to 4,5 MW were examined, covering biomass CHP, PV, SHP and wind power technologies. The range of size has been chosen by the author because it was considered to be an optimal size for decentralised electricity production, being able to service communities from 1.000 to 2.000 inhabitants.

After comprehensive analyses, HP-VBG turned out to have the highest economic performance in terms of LRGC, compared to the investment horizon and the IRR. The low-pressure system HP-NÖ has an even lower LRGC, but this has to be valuated together with an investment horizon of 40 years and lower profit for the investor. Wind power takes position three in terms of economic performance. This technology is a little more profitable than PV and shows lower LRGC for the same investment horizon of 13 years. But PV has seen a drastic drop in the main cost driver, namely PV-modules, in the recent years and there is still some cost reduction potential, enhancing higher economic performance in the future. Without own electricity use of 10% PV-SBG would not show a positive NPV. And own electricity use will play a large role in the future PV market in Austria, because no FIT is foreseen any more for ground mounted PV plants, only for building integrated systems between 5 kW and 200 kW. The analysed heat led CHP-plant BM-VBG shows the lowest economic performance. This is mainly due to high fuel costs and the lack of heat demand in the warm months, heat demand being the basic prerequisite for producing electricity.

It could be demonstrated in a scenario analysis, how important FITs and subsidies are for RES. Only HP-VBG shows a positive NPV without FIT. But this plant is an extraordinary example and the high economic performance must be rated far above average. The remaining four plants are highly dependent on tariffs higher than the market price or subsidies. An extension of the investment horizon and the credit period to the useful lifetime would help and an average price of round 70 €/MWh would be sufficient, to make the projects feasible. Only for BM-VBG, a much higher electricity price of 300 €/MWh would be needed. But the direct comparison of BM-VBG's LRGC with those of the other systems is not fair, because the main purpose of this plant is the production and sale of heat, which also has to be taken into consideration. Subsidies for CHP and additional income through electricity sales could have been the motivations to incorporate an ORC module in the plant. In general this is a very smart move, but due to too optimistic dimensioning of BM-VBG the project is currently facing problems.

In terms of electricity generation reliability and flexibility, SHP and biomass are the preferred technologies. PV and wind can only produce electricity intermittently, when the sun is shining or wind is blowing, which reduces the flexibility and reliability of these technologies.

Nevertheless, although some technologies have higher economic performances than others, the question which kind of renewable technology fits best for Austria, is very much depending on the location and economic circumstances, and cannot be answered straightforward with only 5 analysed plants as a basis. It is the opinion of the author that the best solution would be a smart energy mix of all four technologies, complementing each other and utilizing as much of the existing potentials as possible.

Compared with fossil fuel driven and nuclear technologies, some RES show already lower LRGC. Oil technologies have already been degraded to electricity-buffer technologies, due to the merit order effect, caused by cheap wind energy and this is partly valid also for natural gas. Moreover, incorporating external costs, caused by traditional generators, would actually make them unaffordable, but this way of thinking has not yet reached the economy.

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List of abbreviations

APCS	Austrian Power Clearing and Settlement Agency
APG	Austrian Power Grid
BFB	Bubbling fluidized bed
BG	Balance group
BM-VBG	Naturwärme Montafon Biomass CHP in Vorarlberg
BOS	Balance of system
BRP	Balance responsible party
c	EUR Cent
°C	Degree Celsius
CEE	Central and eastern Europe
CEO	Chief Executive Officer
CFB	Circulated fluidised bed
CHP	Combined heat and power
CO_2	Carbon dioxide
c.p.	Ceteris paribus
CRF	Capital recovery factor
d.h.	District heating
DSO	Distribution system operators
EBITDA	Earnings before interest, taxes, depreciation and amortisation
ECB	European Central Bank
EEX	European Energy Exchange
ENTSO-E	European Network of Transmission System Operators for Electricity
e.g.	For example
eq.	Equivalent
et al.	And others
EURIBOR	European interbank offered rate
FIT	Feed-in tariff
FLH	Full load hours
GHG	Greenhous gas
GWh	Gigawatt hours
GWhth	Gigawatt hours thermal
GWhel	Gigawatt hours electric
ha	Hectare
HP-NÖ	Small hydropower plant in Niederösterreich
HP-VBG	Small hydropower plant Bad Rothenbrunnen in Vorarlberg
Hz	Hertz
IRR	Internal rate of return
ISO	Independent system operator
ITO	Independent transmission operator
kg	Kilogram
KPC	Kommunalkredit Public Consulting GmbH
kW	Kilowatt
kWel	Kilowatt electricity

kWh	Kilowatt hours
kV	Kilovolt
kVA	Kilovolt ampere
LCA	Life cycle assessment
LRGCel	Long run generation costs for electricity
mio	Million
m^2	Square meter
m^3	Cubic meter
mm	Millimeter
MW	Megawatt
MWel	Megawatt electricity
MWp	Megawatt peak
MWth	Megawatt thermal
NCV	Net calorific value
NOx	Nitrogen content
nm	Nanometer
NPV	Net present value
o&m	Operation and maintenance
OeMAG	Ökostromabwicklungsstelle AG (Austrian settlement center for RES)
ORC	Organic Rankine Cycle
ÖSG	Ökostromgesetz
OTC	Over the counter
PV	Photovoltaic
PV-SBG	Photovoltaic power plant in Salzburg
PR	Performance ratio
RES	Renewable energy sources
rpm	revolutions per minute
s	Second
SHP	Small hydropower plant
SHPP	Small hydropower plant
SRMC	Short run marginal costs
t	ton
TSO	Transmission system operators
TWh	Terawatt hours
UCTE	Union for the Coordination of Transmission of Electricity
V	Volt
W	Watt
WACC	Weighted average cost of capital
W-NÖ	Wind power plant in Niederösterreich
y	year
ZAMG	Zentralanstalt für Meteorologie

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APPENDIX

Appendix 1: Overview of FIT different RES technologies 2003 -2009

EINSPEISETARIFE FÜR ÖKOSTROMANLAGEN		Tarif in Cent/kWh gemäß BGBl II Nr 401/2006 und BGBl II Nr 59/2008 10 plus 2 (reduzierte) Jahre				Tarif in Cent/kWh gemäß BGBl II Nr 508/2002 13 Jahre
		2009	2008	2007	2006	ab 2003
Windenergie		7,53	7,54	7,55	7,65	7,80
Feste Biomasse (wie Waldhackgut, Stroh)	bis 2 MW	15,63	15,64	15,65	15,70	16,00
	2 bis 5 MW	14,93	14,94	14,95	15,00	15,00
	5 bis 10 MW	13,28	13,29	13,30	13,40	13,00
	über 10 MW	11,08	11,09	11,10	11,30	10,20
Abfall mit hohem biogenen Anteil	SN 17, Tab. 2, Bsp. Rinde, Sägespäne	minus 25 %				minus 20 %
	SN 17, Tab. 1, Bsp. Spanplattenabfälle	minus 40 %				minus 35 %
	Andere 5-stellige SN in Tab. 1 und 2 ÖkoStrG	4,88	4,89	4,90	5,00	2,70
Mischfeuerungen		anteilig				anteilig
Zufeuerung in kalorischen Kraftwerken	Feste Biomasse (Waldhackgut, Stroh)	6,28	6,29	6,30	6,40	6,50
	SN 17, Tab. 2, Bsp. Rinde, Sägespäne	minus 25 %				5,00
	SN 17, Tab. 1, Bsp. Spanplattenabfälle	minus 40 %				4,00
	Andere 5-stellige SN in Tab. 1 und 2 ÖkoStrG	minus 50 %				3,00
Mischfeuerungen		anteilig				anteilig
Flüssige Biomasse	Pflanzenöle, kaltgepresste biogene Öle, RME bis 300 kW	12,48	12,49	12,50	13,00	13,00 (bis 200 kW)
	Pflanzenöle, kaltgepresste biogene Öle, RME über 300 kW	9,48	9,49	9,50	10,00	10,00 (über 200 kW)
	andere flüssige biogene Brennstoffe	5,98	5,99	6,00	6,50	
Biogas aus landwirtschaftl. Produkten (wie Mais, Gülle)	bis 100 kW	16,93	16,94	16,95	17,00	16,50
	100 bis 250 kW	15,13	15,14	15,15	15,20	14,50
	250 bis 500 kW	13,98	13,99	14,00	14,10	14,50
	500 bis 1000 kW	12,38	12,39	12,40	12,60	12,50
	über 1000 kW	11,28	11,29	11,30	11,50	10,30
Biogas bei Kofermentation von Abfallstoffen		minus 30 %				minus 25 %
Deponie- und Klärgas	Klärgas	5,93	5,94	5,95	6,00	3,00 (bis 1 MW)
	Deponiegas	4,03	4,04	4,05	4,10	6,00 (über 1 MW)
Geothermie		7,28	7,29	7,30	7,40	7,00
Photovoltaik	bis 5 kW_p	45,98	45,99	46,00	49,00	60,00 (bis 20 kW_p)
	5 kW_p bis 10 kW_p	39,98	39,99	40,00	42,00	47,00 (über 20 kW_p)
	über 10 kW_p	29,98	29,99	30,00	32,00	

Kleinwasserkraft							
a) Bestehende Altanlagen bis 31.12.2008 b) nach Investitionen mit mindestens 15 % Stromertragssteigerung c) Neubau bzw. mindestens 50 % Stromertragssteigerung	b) Errichtung nach 2007 Vertragsabschluss 2009 (15 Jahre)	c) Errichtung nach 2007 Vertragsabschluss 2009 (15 Jahre)	a) Förderung bis 12/2008	b) NEU 15 Jahre Errichtung 2008	b) ALT Errichtung bis 12/2007	c) NEU 15 Jahre Errichtung 2008	c) ALT Errichtung bis 12/2007
erste 1.000.000 kWh	5,94	6,23	5,68	5,95	5,96	6,24	6,25
nächste 4.000.000 kWh	4,56	4,99	4,36	4,57	4,58	5,00	5,01
nächste 10.000.000 kWh	3,79	4,15	3,63	3,80	3,81	4,16	4,17
nächste 10.000.000 kWh	3,42	3,92	3,28	3,43	3,44	3,93	3,94
25.000.000 kWh übersteigend	3,29	3,76	3,15	3,30	3,31	3,77	3,78
[Einspeisetarif abgestuft nach jährlich eingespeisten Strommengen]							
Kombinierte Strom-Wärmeförderung bei Biomasse-Altanlagen (genehmigt 2003-2004)							
Wärme-Unterstützungstarif möglich (allerdings Maximalbegrenzung)							
WT=ET/4,4-WP							
wobei WP = 2,6 Cent/kWh(th) bei Anlagen bis 10 MW(el) und WT= 1,8 Cent/kWh(th) bei Anlagen größer 10 MW(el), WP 2009: 2,4 Cent/kWh(th)							

[Quelle: Energie-Control GmbH, Februar 2010]

Source: https://www.e-control.at/industrie/oeko-energie/einspeisetarife/einspeisetarife-archiv (2016)

Appendix 2: Overview FIT different RES technologies 2013-2015

EINSPEISETARIFE FÜR NEUE ÖKOSTROMANLAGEN 2013, 2014 und 2015			2013 Tarif Cent/kWh	Degression Gesetz 2014 Tarif Cent/kWh	Degression Gesetz 2 Tarif Cent/kWh
Rohstoffunabhängige Technologien			**Laufzeit 13 Jahre**	**Laufzeit 13 Jahre**	**Laufzeit 13 Jahre**
Windenergie			9,45	9,36	9,26
Photovoltaik[1]	**gebäudeintegriert***	bis 5 kWp	über KLI.EN (Investitionszuschuss)		
		5 kWp bis 500 kWp	18,12		
		5 kWp bis 50 kWp		13,30	11,36
		5 kWp bis 100 kWp		10,86	9,27
		5 kWp bis 200 kWp		9,65	8,24
	auf Freiflächen	bis 5 kWp	über KLI.EN (Investitionszuschuss)		
		5 kWp bis 500 kWp	16,59		
		5 kWp bis 50 kWp		11,97	10,22
		5 kWp bis 100 kWp		9,78	8,34
		5 kWp bis 200 kWp		8,69	7,41
Kleinwasserkraft	**Neuanlagen**	die ersten 500.000 kWh	10,55	10,44	10,34
		die ersten 500.000 kWh	7,59	7,51	7,44
		die nächsten 1.500.000 kWh	6,63	6,56	6,50
		die nächsten 2.500.000 kWh	5,53	5,47	5,42
		die nächsten 2.500.000 kWh	5,22	5,17	5,12
		über 7.500.000 kWh	4,97	4,92	4,87
	Revitalisierung	die ersten 500.000 kWh	8,26	8,18	8,10
		die ersten 500.000 kWh	6,03	5,97	5,91
		die nächsten 1.500.000 kWh	5,22	5,17	5,12
		die nächsten 2.500.000 kWh	3,81	3,77	3,73
		die nächsten 2.500.000 kWh	3,52	3,48	3,45
		über 7.500.000 kWh	3,23	3,20	3,17
Deponie- und Klärgas		Klärgas	5,94	5,88	5,82
		Deponiegas	4,95	4,90	4,85
Geothermie			7,43	7,36	7,28
Rohstoffabhängige Technologien			**Laufzeit 15 Jahre**		
Feste Biomasse (wie Waldhackgut, Stroh)		hocheffizient bis 500 kW	19,90	19,70	19,50
		bis 500 kW	17,91	17,73	17,55
		500 kW bis 1 MW	15,72	15,56	15,41
		1 bis 1,5 MW	15,42	15,27	15,11
		1,5 bis 2 MW	14,92	14,77	14,62
		2 bis 5 MW	14,30	14,16	14,02
		5 bis 10 MW	13,81	13,67	13,54
		über 10 MW	10,94	10,83	10,72
Abfall mit hohem biogenen Anteil		SN 17, Tab. 2, Bsp. Rinde, Sägespäne	minus 25 %	minus 25 %	minus 25 %
		SN 17, Tab. 1, Bsp. Spanplattenabfälle	minus 40 %	minus 40 %	minus 40 %
		Andere 5-stellige SN in Tab. 1 und 2 ÖkoStrG	4,95	4,90	4,85
Mischfeuerungen			anteilig	anteilig	anteilig
Zufeuerung in kalorischen Kraftwerken		Feste Biomasse (Waldhackgut, Stroh)	6,06	6,00	5,94
		SN 17, Tab. 2, Bsp. Rinde, Sägespäne	minus 20 %	minus 20 %	minus 20 %
		Andere 5-stellige SN in Tab. 1 und 2 ÖkoStrG	minus 30 %	minus 30 %	minus 30 %
Mischfeuerungen			anteilig	anteilig	anteilig
Flüssige Biomasse		Flüssige Biomasse	5,74	5,68	5,63
		Zuschlag für Erzeugung in effizienter KWK	2,00	1,98	1,96
Biogas aus landwirtschaftl. Produkten (wie Mais, Gülle)		bis 250 kW	19,50	19,31	19,11
		250 bis 500 kW	16,93	16,76	16,59
		500 bis 750 kW	13,34	13,21	13,07
		über 500 kW	12,93	12,80	12,67
		Biogas bei Kofermentation von Abfallstoffen	minus 20 %	minus 20 %	minus 20 %
		Zuschlag für Erzeugung in effizienter KWK	2,00	1,98	1,96
		Zuschlag bei Aufbereitung auf Erdgasqualität	2,00	1,98	1,96
Mischfeuerungen			anteilig	anteilig	anteilig
Einspeisetarife für rohstoffabhängige Ökostromanlagen nach Ablauf der Kontrahierungspflicht					
Feste Biomasse (wie Waldhackgut, Stroh)		bis 2 MW	12,03	13,00	12,94
		2 bis 10 MW	10,35	11,00	10,95
		über 10 MW	9,95	10,65	10,60
Biogas aus landwirtschaftl. Produkten (wie Mais, Gülle)					
		bis 250 kW	11,44	12,50	12,45
		über 250 kW	9,95	11,00	10,95
		Biogas bei Kofermentation von Abfallstoffen	minus 20 %	minus 20 %	minus 20 %

*Einspeisetarif in Kombination mit Investitionszuschuss: 30% der Investitionskosten maximal jedoch 200 EUR/kWp

Source: https://www.wko.at/Content.Node/Interessenvertretung/Umwelt-und-Energie/-Positionen-/Gutachten_Oekostrom-Einspeisetarife_2014-15_19112013_HPR.pdf, (2016)

Appendix 3: Product sheet business tariff electricity Salzburg AG

GEWERBE OK

STROM FÜRS GESCHÄFT

Gewerbe OK mit drei Preisstufen ist das Basismodell für Gewerbekunden und sonstigen Bedarf ohne Leistungsmessung im Netzgebiet der Salzburg Netz GmbH. Es besteht aus einem Preis pro kWh und einem jährlichen Grundentgelt.

Die Energiestrompreise

	Jahresverbrauch	Grundentgelt/Jahr		Preis/kWh	
	in kWh	**Euro netto[1)]**	**Euro brutto[3)]**	**Cent netto[1)]**	**Cent brutto[3)]**
Small	**bis 1.500**	8,30	9,96	6,9600	8,3520
Medium	**1.500 bis 5.000**	18,80	22,56	6,2600	7,5120
Large	**über 5.000**	28,80	34,56	6,0600	7,2720

Die Gesamtstrompreise

	Jahresverbrauch	Grundentgelt/Jahr		Preis/kWh	
	in kWh	**Euro netto[2)]**	**Euro brutto[3)]**	**Cent netto[2)]**	**Cent brutto[3)]**
Small	**bis 1.500**	76,7720	92,1264	14,5330	17,4396
Medium	**1.500 bis 5.000**	87,2720	104,7264	13,8330	16,5996
Large	**über 5.000**	97,2720	116,7264	13,6330	16,3596

Gültig ab 1. Jänner 2016

1) Die Energiestrompreise enthalten die Kosten für die Herkunftsnachweise des zugewiesenen Ökostroms.

2) Die Netto-Gesamtpreise enthalten die Energiepreise und die Netznutzungs- und Netzverlustentgelte (26,16 Euro/Jahr und 4,19 Cent/kWh), die Gebrauchsabgabe (0,202 Cent/kWh), die Elektrizitätsabgabe (1,5 Cent/kWh), die Ökostrompauschale (33 Euro/Jahr), die Beiträge lt. Ökostromförderbeitragsverordnung (8,062 Euro/Jahr und 1,681 Cent/kWh) und die KWK-Pauschale (1,25 Euro/Jahr), jedoch nicht die Entgelte für Messleistungen.
Alle Zuschläge, Abgaben und Steuern gelten für die Netzebene 7.

3) Die Bruttopreise enthalten 20 % Umsatzsteuer.

STROMKENNZEICHNUNG

gem. § 78 Abs. 1 und 2 ElWOG 2010 und StromkennzeichnungsVO 2011 für den Zeitraum 1.1.2015 bis 31.12.2015

Energieträger	Versorgermix in Prozent
Wasserkraft	86,82
Windenergie	7,89
Feste und flüssige Biomasse	3,50
Sonstige Ökoenergie	1,79
Erneuerbare Energien	**100,00**

Bei der Erzeugung entstanden folgende Umweltauswirkungen	
CO_2-Emissionen	0,00 g/kWh
Radioaktiver Abfall	0,000000 mg/kWh

Die Nachweise stammen zu 63,75 % aus Österreich und zu 36,25 % aus Norwegen.

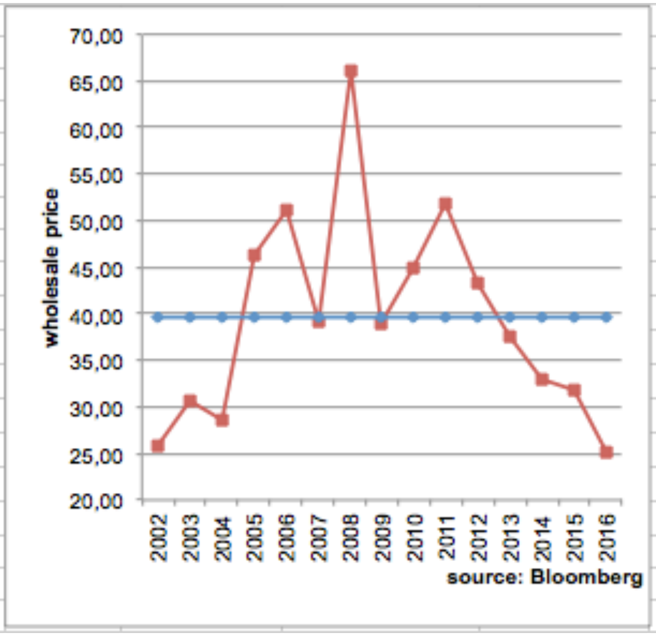
Salzburg AG für Energie, Verkehr und Telekommunikation
Firmensitz: Bayerhamerstraße 16, 5020 Salzburg, Österreich, office@salzburg-ag.at, www.salzburg-ag.at
DVR: 0027685, UID: ATU33790403, Offenlegung nach § 14 UGB, Aktiengesellschaft, Salzburg,
Firmenbuch: FN 51350s, Bankverbindung: Raiffeisenverband Salzburg, IBAN: AT66 3500 0000 0004 5005
BIC: RVSAAT2S, Salzburger Sparkasse, IBAN: AT81 2040 4000 0000 1800, BIC: SBGSAT2SXXX

SALZBURG AG
WO ZUKUNFT INS LEBEN KOMMT.

Source: https://www.salzburg-ag.at/strom/gewerbekunden/gewerbe-ok (26.06.2016)

Appendix 4: Wholesale price development 2002 – 2016

Austrian el wholesale baseload		
	price	average
2002	25,80	39,61
2003	30,70	39,61
2004	28,70	39,61
2005	46,30	39,61
2006	51,10	39,61
2007	39,10	39,61
2008	66,20	39,61
2009	38,90	39,61
2010	45,00	39,61
2011	51,80	39,61
2012	43,20	39,61
2013	37,50	39,61
2014	32,90	39,61
2015	31,70	39,61
2016	25,20	39,61
source: Bloomberg		



Source: Bloomberg (2016)

Appendix 5: Biodiesel price 2008 – 2016

Source: Bloomberg (2016)

Appendix 6: Detail output of Naturwärme Montafon (BM-VBG) from 2010 to 2015

3.2MWth thermal oil boiler + ORC

(Share of total feedstock demand 7.993t = 76%)

	Th output	CapPeak	FLH	El output	CapPeak	FLH
Year	[kWhth]	[kWth]	[h]	[kWhel]	[kWel]	[h]
2010	9.259.100	3200	2893	1.906.368	500	3813
2011	10.542.600	3200	3295	2.200.906	500	4402
2012	10.457.600	3200	3268	2.311.266	500	4623
2013	12.831.800	3200	4010	2.620.427	500	5241
2014	11.716.800	3200	3662	2.312.417	500	4625
2015	11.716.800	3200	3662	2.349.137	500	4698
Average	**11.087.450** **82,92%**		**3465**	**2.283.420** **17,08%**		**4567**

4 MWth warm water boiler

(Share of total feedstock demand 2.474t = 24%)

	Boiler 1	Boiler 2	CapPeak	FLH
Year	[kWhth]	[kWhth]	[kWth]	[h]
2010	3.262.500		4000	816
2011	4.226.700		4000	1057
2012	6.340.300		4000	1585
2013	4.808.600	309.601	4000	1280
2014	4.887.900	284.144	4000	1293
2015	4.327.400	326.215	4000	1163
Average	**4.948.887**			**1237**

12MWth methyl ester boiler

	Boiler 1	Boiler 2	Condensation	CapPeak	FLH
Year	[kWhth]	[kWhth]	[kWhth]	[kWth]	[h]
2013	723.500	227.400	78.100	12000	86
2014	352.400	86.900	77.000	12000	43
2015	268.900	105.800	62.000	12000	36
Average		**660.667**			**55**

Data Source: Stampfer (2016)

Appendix 7: Modules used for PV plant in Salzburg (PV-SBG)

Pure-60 KPV PE NEC 260 / 265 / 270 / 280 PURE poly
KPV ME NEC 280 / 285 PURE mono

kiotosolar.com

MODULDATEN

Type	$Pmpp_{[Wp]}$	$Umpp_{[V]}$	$Impp_{[A]}$	$Uoc_{[V]}$	$Isc_{[A]}$	Wirkungsgrad	Flächenbedarf pro kWp
KPV 260 PE poly	260 Wp	31,10 V	8,37 A	37,99 V	8,90 A	15,73 %	6,36 m²
KPV 265 PE poly	265 Wp	31,60 V	8,40 A	38,01 V	8,94 A	16,03 %	6,23 m²
KPV 270 PE poly	270 Wp	32,18 V	8,42 A	38,33 V	9,03 A	16,34 %	6,12 m²
KPV 280 PE poly PERC	280 Wp	32,61 V	8,59 A	38,82 V	9,13 A	16,94 %	5,90 m²
KPV 280 ME mono	280 Wp	31,42 V	8,95 A	37,98 V	9,29 A	16,94 %	5,90 m²
KPV 285 ME mono	285 Wp	31,86 V	8,98 A	38,02 V	9,43 A	17,24 %	5,79 m²

ELEKTRISCHE DATEN

60 polykristalline Zellen:	156 mm x 156 mm
Anschlussystem:	Tyco-PV4, MC4 - kompatibler Steckverbinder 4 mm²
Max. Systemspannung:	1000 V DC
Leistungstoleranz:	(+ 5 W / - 5 W) Messung: Standard-Testbedingungen
Temperaturkoeffizienten:	poly: Pmpp= -0,405 %/K / Uoc= -114 mV/K / Isc= +4,1 mA/K mono: Pmpp= -0,37 %/K / Uoc= -90,7 mV/K / Isc= +2,85 mA/K
Umgebungstemperatur:	+ 85 °C bis - 40 °C
Kabellänge:	2 x 1000 mm
Bypassdioden:	3 Stk. Tyco SL1515
Leistungsgarantie:	min. 97% im ersten Jahr, danach max. Reduktion um 0,70 % p.a. bis zu 25 Jahren
Produktgarantie:	10 Jahre

TECHNISCHE DATEN

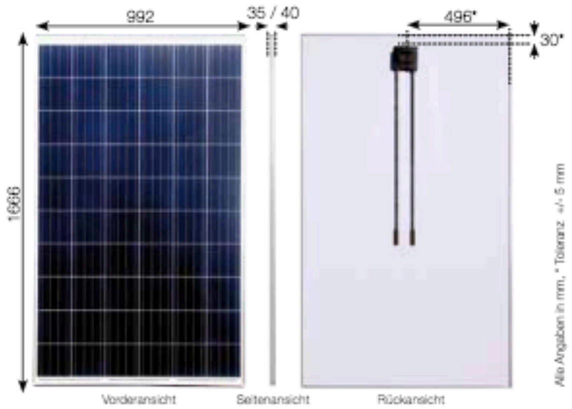
inkl. Alurahmen (nicht eloxiert):	1666 mm x 992 mm x 35 / 40 mm (+/- 2 mm) / (Dosenhöhe 22,5 mm)
Gewicht:	35 mm: 18,50 kg / 40 mm: 19,50
Glasspezifikationen:	Solarglas ESG 3,2 mm mit hochfester Anti-Reflexbeschichtung
Verkapselungsmaterial:	STRE
Rückseitenmaterial:	Isovoltaic
Prüfzertifikat:	IEC 61215 IEC 61730; IP 65, MCS - Zertifikat
Erweiterte Hageltests:	Hagelkorngröße 25 mm, maximale Geschwindigkeit von 46 m/s (165,6 km/h) und Hagelkorngröße 55 mm, maximale Geschwindigkeit von 33,5 m/s (120,6 km/h)
Verpackungskonfiguration:	35 mm: 28 Module / Pal. / 40 mm: 24 Module / Pal.

AUSFÜHRUNG MIT 40MM RAHMEN

- Rahmenkonstruktion für flexible Montagemöglichkeiten
- Einsatz in Gebieten mit hoher Schneelast
- Verwendbar für alle Montagesysteme

STROM SORTIERT

- Exakte 0,1 Ampere-Sortierung
- je String eine Stromklasse
- Strommehrertrag >3%



Neues Rahmendesign

- Rahmen mit Kantenschutz aus Kunststoff
- Robuste Bauweise bei optimalem Gewicht
- Keine scharfen Ecken

Source:[http://www.kiotosolar.com/de/assets/media/downloads/produktdatenblaetter/strom/pure60/KIOTO_SOLAR_DB_PURE60_DE_250416.pdf (2016)](http://www.kiotosolar.com/de/assets/media/downloads/produktdatenblaetter/strom/pure60/KIOTO_SOLAR_DB_PURE60_DE_250416.pdf)

Appendix 8: Estimation of the duration curve for SHPP Bad Rothenbrunnen (HP-VBG)

Duration Curve	**Lutz**	**Scaling**	**Plant VB**
d	[m³/s]		**[m³/s]**
2,6	20	50%	**10,00**
8,2	16	40%	**6,40**
27,6	12	30%	**3,60**
62,4	9	20%	**1,80**
97	7	20%	**1,40**
143	5	20%	**1,00**
195,4	3,5	22%	**0,77**
244,6	2,5	22%	**0,55**
294	1,8	22%	**0,40**
323,4	1,4	22%	**0,31**
357,4	1	22%	**0,22**
365,4	0,8	20%	**0,16**

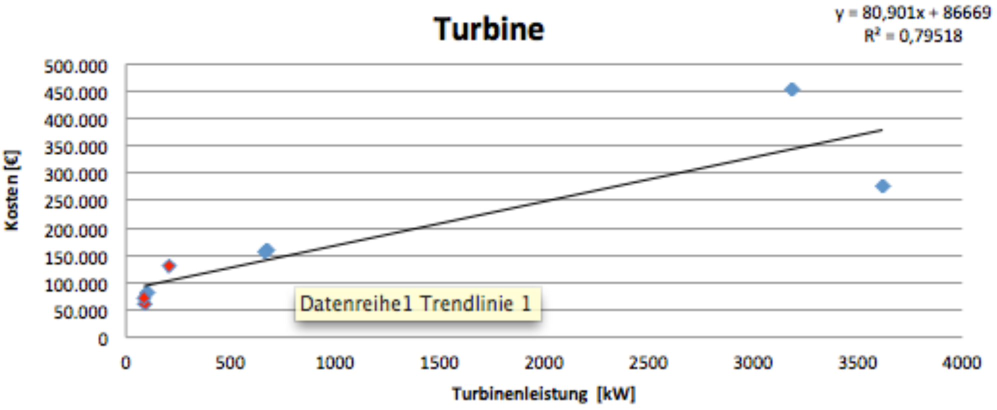
Data source Lutz: eHYD (2015)

Appendix 9: Estimation of the duration curve for SHPP Niederösterreich (HP-NÖ)

Duration Curve	**Main river**	**Creek**	**Plant NB**
[d]	[m³/s]	[m³/s]	**[m³/s]**
0,2	180,0	20,0	**160,0**
0,4	140,0	16,0	**124,0**
1,0	100,0	12,0	**88,0**
1,4	80,0	9,0	**71,0**
3,0	60,0	7,0	**53,0**
8,4	40,0	4,3	**35,8**
14,4	30,0	3,0	**27,0**
37,8	20,0	1,4	**18,7**
59,4	16,0	1,0	**15,0**
99,8	12,0	0,7	**11,3**
149,4	9,0	0,5	**8,5**
201,8	7,0	0,4	**6,6**
297,0	5,0	0,2	**4,9**
361,8	3,5	0,1	**3,4**
365,4	2,5	0,6	**1,9**

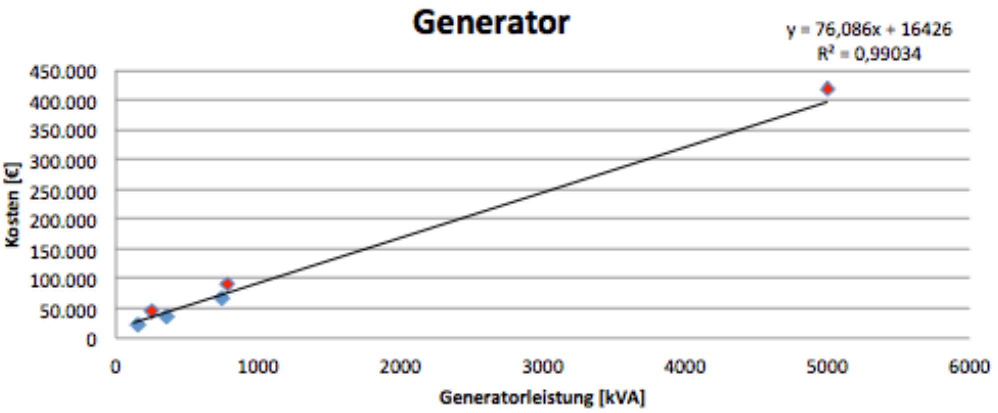
Data source: eHYD (2015)

Appendix 10: Pelton turbine costs estimates



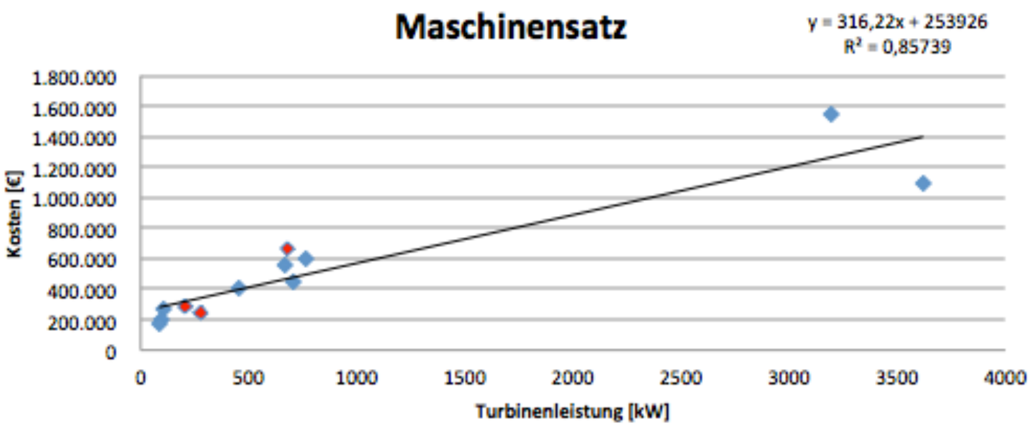
Source: Steiner (2016)

Appendix 11: Generator costs estimates



Source: Steiner (2016)

Appendix 12: Hydroelectric generating set



Source: Steiner (2016)

Appendix 13: Data sheet Senvion 3,4M104 used for W-NÖ

3.4M104

Design data

Nominal power	3,400 kW (LV-side) 3,370 kW (MV-side)
Cut-in wind speed	3.5 m/s
Nominal wind speed	13.5 m/s
Cut-out wind speed	25 m/s
Restart cut-in wind speed	22 m/s
Operating temperature range	-20 – +35 °C

Certification

Hub height	Wind class	DIBt Wind zone
73 m	IEC IB	-
80 m	IEC IB, IEC IIA	WZ 4, GK I
100 m	IEC IIA	WZ 4, GK I

Rotor

Diameter	104 m
Rotor area	8,495 m²
Rotor speed	7.1 – 13.8 1/min (+15 %)
Power control	Electrical pitch

Rotor blade

Blade length	50.8 m
Type	Glass fibre-reinforced plastic (GRP)
Max. chord width	3.9 m

Gear system

Type	Three-stage planetary / spur gearbox
Gear ratio	i = approx. 87
Type of suspension	Three-point contact suspension

Weight

Rotor blade	Approx. 12 t
Nacelle without drive train	Approx. 58 t
Rotor Hub	Approx. 23 t

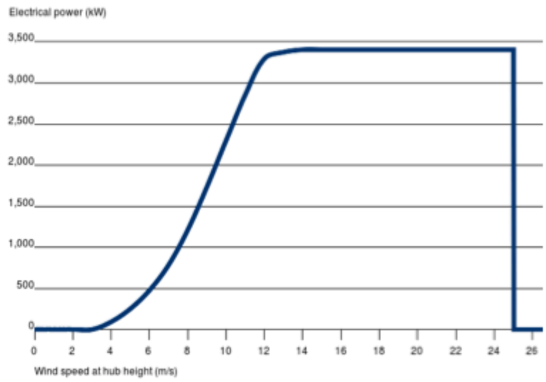
Electrical system

Nominal power	3,400 kW (LV-side) 3,370 kW (MV-side)
Nominal voltage	10/20/30 kV
Nominal frequency	50 Hz
Generator	Double-fed-induction generator
Generator protection class	IP 54
Stator voltage	950 V
Speed range	600 – 1,200 1/min
Converter type	Pulse width modulation IGBTs (liquid-cooled)
Transformer	ITS (Cast resin transformer)

Sound power level

Maximum sound power level	105.6 db (A)

Power curve



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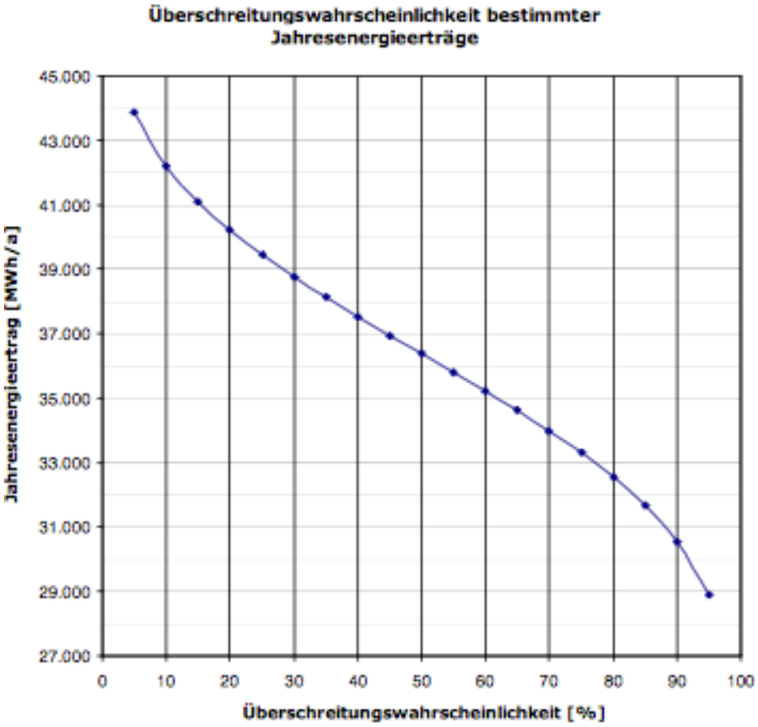
SENVION wind energy solutions

Source: https://www.senvion.com/global/de/wind-energy-solutions/windenergieanlagen/3xm/34m104/, 16.08.2016

Appendix 14: Percentiles of annual output of the whole analysed wind park



P	Jahresenergie-ertrag
[%]	[MWh]
50	**36.375**
55	35.804
60	35.223
65	34.623
70	33.991
75	**33.309**
80	32.549
85	31.663
90	30.548
95	28.896

Source: *SOURCE C* (2016)

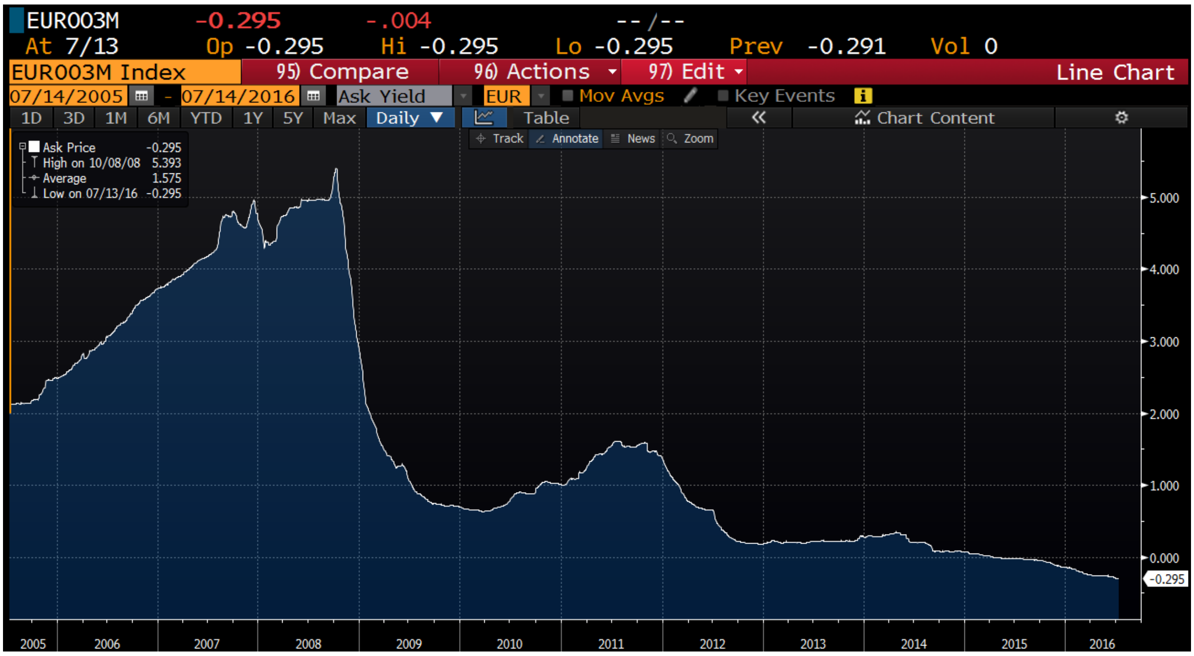
Appendix 15: Percentiles of annual output for W-NÖ (= ¼ of total)

p	Annual output in MWh
50%	9.094
55%	8.951
60%	8.806
65%	8.656
70%	8.498
75%	8.327
80%	8.137
85%	7.916
90%	7.637
95%	7.242

Data Source: *SOURCE C* (2016)

Appendix 16: 3-month EURIBOR - credit calculation Naturwärme Montafon (BM-VBG)

Fixing date	3mEURIBOR
31.12.2015	-0,13
31.12.2014	0,08
31.12.2013	0,29
31.12.2012	0,19
31.12.2011	1,36
31.12.2010	1,01
31.12.2009	0,70
Average 2009 - 2010	0,50

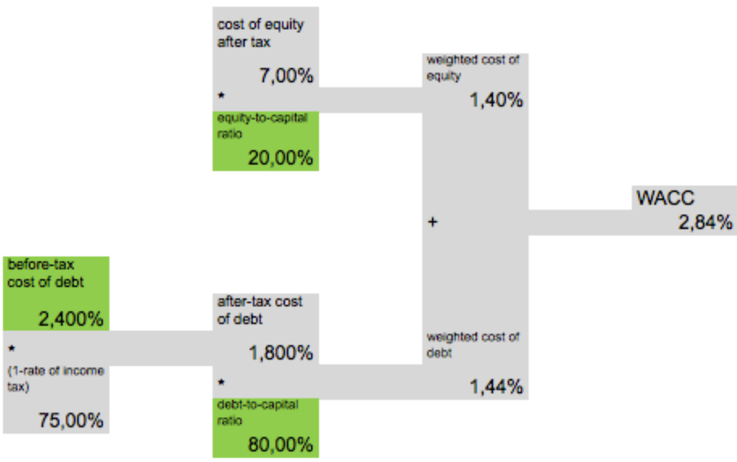


Source: Bloomberg (2016)

Appendix 17: Calculation discount rate (WACC) of PV-SBG

PV-SBG

Investment horizon	13y	
Equity	20%	
Exp market return equity	7%	(Kost C. et alt. (2013, p.11)
Debt	80%	
Debt interest rate fix	2,40%	(provided by SOURCE A)
Income tax (KÖSt)	25%	



Appendix 18: Calculation discount rate (WACC) of HP-VBG

HP-VBG

Investment horizon	13y	
equity	20%	
exp market return	8%	(Kost C. et alt. (2013, p.11)
debt	80%	
EURIBOR 3m	1,57% p.a.	(average 2005-2016)
credit spread	1,5%	(assumption based on consultation of Schwaiger (2016))
Income tax (KÖSt)	25%	

Appendix 19: Calculation discount rate (WACC) of W-NÖ

W-NÖ

Investment horizon	15y
Equity ratio	25%
Exp yield before tax	8%
Debt ratio	75%
Credit rate	4,5%
Income tax (KÖSt)	25%

Appendix 20: Calculation corporate tax BM-VBG

Corporate tax calculation							
year	Corporate tax	Tax basis	EBITDA	Interest rate debt	Depreciation	Credit redemption	Remaining credit
	D * 25%	D = A+B+C	A	B	C		
2009							-13.000.000 €
2010	0 €	-234.049 €	770.951 €	-325.000 €	-680.000 €	-520.000 €	-12.480.000 €
2011	0 €	-221.049 €	770.951 €	-312.000 €	-680.000 €	-520.000 €	-11.960.000 €
2012	0 €	-208.049 €	770.951 €	-299.000 €	-680.000 €	-520.000 €	-11.440.000 €
2013	0 €	-195.049 €	770.951 €	-286.000 €	-680.000 €	-520.000 €	-10.920.000 €
2014	0 €	-182.049 €	770.951 €	-273.000 €	-680.000 €	-520.000 €	-10.400.000 €
2015	0 €	-169.049 €	770.951 €	-260.000 €	-680.000 €	-520.000 €	-9.880.000 €
2016	0 €	-156.049 €	770.951 €	-247.000 €	-680.000 €	-520.000 €	-9.360.000 €
2017	0 €	-158.045 €	755.955 €	-234.000 €	-680.000 €	-520.000 €	-8.840.000 €
2018	0 €	-160.340 €	740.660 €	-221.000 €	-680.000 €	-520.000 €	-8.320.000 €
2019	0 €	-162.941 €	725.059 €	-208.000 €	-680.000 €	-520.000 €	-7.800.000 €
2020	0 €	-165.854 €	709.146 €	-195.000 €	-680.000 €	-520.000 €	-7.280.000 €
2021	0 €	-169.085 €	692.915 €	-182.000 €	-680.000 €	-520.000 €	-6.760.000 €
2022	0 €	-172.641 €	676.359 €	-169.000 €	-680.000 €	-520.000 €	-6.240.000 €
2023	0 €	-176.528 €	659.472 €	-156.000 €	-680.000 €	-520.000 €	-5.720.000 €
2024	0 €	-180.753 €	642.247 €	-143.000 €	-680.000 €	-520.000 €	-5.200.000 €
2025	0 €	-410.739 €	399.261 €	-130.000 €	-680.000 €	-520.000 €	-4.680.000 €
2026	0 €	-415.659 €	381.341 €	-117.000 €	-680.000 €	-520.000 €	-4.160.000 €
2027	0 €	-420.938 €	363.062 €	-104.000 €	-680.000 €	-520.000 €	-3.640.000 €
2028	0 €	-426.583 €	344.417 €	-91.000 €	-680.000 €	-520.000 €	-3.120.000 €
2029	0 €	-432.601 €	325.399 €	-78.000 €	-680.000 €	-520.000 €	-2.600.000 €
2030	0 €	-438.999 €	306.001 €	-65.000 €	-680.000 €	-520.000 €	-2.080.000 €
2031	0 €	-445.784 €	286.216 €	-52.000 €	-680.000 €	-520.000 €	-1.560.000 €
2032	0 €	-452.966 €	266.034 €	-39.000 €	-680.000 €	-520.000 €	-1.040.000 €
2033	0 €	-460.551 €	245.449 €	-26.000 €	-680.000 €	-520.000 €	-520.000 €
2034	0 €	-468.548 €	224.452 €	-13.000 €	-680.000 €	-520.000 €	0 €

Appendix 21: Calculation corporate tax PV-SBG

Corporate tax calculation							
Year	Corporate tax	Tax basis	EBITDA	Interest rate debt	Depreciation	Credit redemption	Remaining credit
	D * 25%	D = A+B+C	A	B	C		
2015							-2.400.022,80 €
2016	-34.531,78 €	138.127,12 €	345.729,10 €	-57.600,55 €	-150.001,43 €	-184.617,14 €	-2.215.405,66 €
2017	-34.789,36 €	139.157,45 €	342.328,61 €	-53.169,74 €	-150.001,43 €	-184.617,14 €	-2.030.788,52 €
2018	-35.043,31 €	140.173,26 €	338.913,61 €	-48.738,92 €	-150.001,43 €	-184.617,14 €	-1.846.171,38 €
2019	-35.293,56 €	141.174,25 €	335.483,79 €	-44.308,11 €	-150.001,43 €	-184.617,14 €	-1.661.554,25 €
2020	-35.540,03 €	142.160,13 €	332.038,85 €	-39.877,30 €	-150.001,43 €	-184.617,14 €	-1.476.937,11 €
2021	-35.782,65 €	143.130,59 €	328.578,51 €	-35.446,49 €	-150.001,43 €	-184.617,14 €	-1.292.319,97 €
2022	-36.021,33 €	144.085,34 €	325.102,44 €	-31.015,68 €	-150.001,43 €	-184.617,14 €	-1.107.702,83 €
2023	-36.256,01 €	145.024,04 €	321.610,34 €	-26.584,87 €	-150.001,43 €	-184.617,14 €	-923.085,69 €
2024	-36.486,60 €	145.946,40 €	318.101,88 €	-22.154,06 €	-150.001,43 €	-184.617,14 €	-738.468,55 €
2025	-36.713,02 €	146.852,06 €	314.576,73 €	-17.723,25 €	-150.001,43 €	-184.617,14 €	-553.851,42 €
2026	-36.935,18 €	147.740,71 €	311.034,57 €	-13.292,43 €	-150.001,43 €	-184.617,14 €	-369.234,28 €
2027	-37.153,00 €	148.612,01 €	307.475,06 €	-8.861,62 €	-150.001,43 €	-184.617,14 €	-184.617,14 €
2028	-37.366,40 €	149.465,60 €	303.897,83 €	-4.430,81 €	-150.001,43 €	-184.617,14 €	0,00 €

Appendix 22: Calculation of corporate tax for HP-VBG

Corporate tax calculation

Year	Corporate tax	Tax basis	EBITDA	Interest rate debt	Depreciation	Credit redemption	Remaining credit
	D * 25%	D = A+B+C	A	B	C		
2005							-965.707,16 €
2006	-38.419,24 €	153.676,94 €	213.502,50 €	-29.647,21 €	-30.178,35 €	-74.285,17 €	-891.422,00 €
2007	-38.989,37 €	155.957,50 €	213.502,50 €	-27.366,66 €	-30.178,35 €	-74.285,17 €	-817.136,83 €
2008	-39.559,51 €	158.238,05 €	213.502,50 €	-25.086,10 €	-30.178,35 €	-74.285,17 €	-742.851,66 €
2009	-40.129,65 €	160.518,60 €	213.502,50 €	-22.805,55 €	-30.178,35 €	-74.285,17 €	-668.566,50 €
2010	-40.699,79 €	162.799,16 €	213.502,50 €	-20.524,99 €	-30.178,35 €	-74.285,17 €	-594.281,33 €
2011	-41.269,93 €	165.079,71 €	213.502,50 €	-18.244,44 €	-30.178,35 €	-74.285,17 €	-519.996,17 €
2012	-41.840,07 €	167.360,27 €	213.502,50 €	-15.963,88 €	-30.178,35 €	-74.285,17 €	-445.711,00 €
2013	-42.410,21 €	169.640,82 €	213.502,50 €	-13.683,33 €	-30.178,35 €	-74.285,17 €	-371.425,83 €
2014	-42.980,34 €	171.921,38 €	213.502,50 €	-11.402,77 €	-30.178,35 €	-74.285,17 €	-297.140,67 €
2015	-43.550,48 €	174.201,93 €	213.502,50 €	-9.122,22 €	-30.178,35 €	-74.285,17 €	-222.855,50 €
2016	-44.120,62 €	176.482,49 €	213.502,50 €	-6.841,66 €	-30.178,35 €	-74.285,17 €	-148.570,33 €
2017	-44.555,99 €	178.223,97 €	212.963,43 €	-4.561,11 €	-30.178,35 €	-74.285,17 €	-74.285,17 €
2018	-44.988,67 €	179.954,68 €	212.413,58 €	-2.280,55 €	-30.178,35 €	-74.285,17 €	0,00 €

Appendix 23: Calculation of corporate tax for HP-NÖ

Corporate tax calculation

Year	Corporate tax	Tax basis	EBITDA	Interest rate debt	Depreciation	Credit redemption	Remaining credit
	D * 25%	D = A+B+C	A	B	C		
2009							
2010	-13.691,31 €	54.765,24 €	183.500,44 €		-128.735,20 €		
2011	-21.338,39 €	85.353,54 €	214.088,74 €		-128.735,20 €		
2012	-10.356,22 €	41.424,88 €	170.160,07 €		-128.735,20 €		
2013	-4.596,75 €	18.387,01 €	147.122,21 €		-128.735,20 €		
2014	0,00 €	-5.465,98 €	123.269,22 €		-128.735,20 €		
2015	0,00 €	-16.844,16 €	111.891,04 €		-128.735,20 €		
2016	0,00 €	-45.355,87 €	83.269,13 €		-128.625,00 €		
2017	-4.347,48 €	17.389,92 €	146.014,92 €		-128.625,00 €		
2018	-4.245,48 €	16.981,92 €	145.606,92 €		-128.625,00 €		
2019	-4.141,44 €	16.565,76 €	145.190,76 €		-128.625,00 €		
2020	-4.035,32 €	16.141,28 €	144.766,28 €		-128.625,00 €		
2021	-3.927,08 €	15.708,31 €	144.333,31 €		-128.625,00 €		
2022	-3.816,67 €	15.266,67 €	143.891,67 €		-128.625,00 €		
2023	-3.704,05 €	14.816,21 €	143.441,21 €		-128.625,00 €		
2024	-3.589,18 €	14.356,74 €	142.981,74 €		-128.625,00 €		
2025	-3.472,02 €	13.888,07 €	142.513,07 €		-128.625,00 €		
2026	-3.352,51 €	13.410,03 €	142.035,03 €		-128.625,00 €		
2027	-3.230,61 €	12.922,44 €	141.547,44 €		-128.625,00 €		
2028	-3.106,27 €	12.425,09 €	141.050,09 €		-128.625,00 €		
2029	-2.979,45 €	11.917,79 €	140.542,79 €		-128.625,00 €		
2030	-2.850,09 €	11.400,35 €	140.025,35 €		-128.625,00 €		
2031	-2.718,14 €	10.872,56 €	139.497,56 €		-128.625,00 €		
2032	-2.583,55 €	10.334,21 €	138.959,21 €		-128.625,00 €		
2033	-2.446,27 €	9.785,09 €	138.410,09 €		-128.625,00 €		
2034	-2.306,25 €	9.225,00 €	137.850,00 €		-128.625,00 €		
2035	-2.163,42 €	8.653,70 €	137.278,70 €		-128.625,00 €		
2036	-2.017,74 €	8.070,98 €	136.695,98 €		-128.625,00 €		
2037	-1.869,15 €	7.476,60 €	136.101,60 €		-128.625,00 €		
2038	-1.717,58 €	6.870,33 €	135.495,33 €		-128.625,00 €		
2039	-1.562,98 €	6.251,94 €	134.876,94 €		-128.625,00 €		
2040	-1.405,29 €	5.621,18 €	134.246,18 €		-128.625,00 €		
2041	-1.244,45 €	4.977,80 €	133.602,80 €		-128.625,00 €		
2042	-1.080,39 €	4.321,56 €	132.946,56 €		-128.625,00 €		
2043	-913,05 €	3.652,19 €	132.277,19 €		-128.625,00 €		
2044	-742,36 €	2.969,44 €	131.594,44 €		-128.625,00 €		
2045	-568,26 €	2.273,03 €	130.898,03 €		-128.625,00 €		
2046	-390,67 €	1.562,69 €	130.187,69 €		-128.625,00 €		
2047	-209,54 €	838,15 €	129.463,15 €		-128.625,00 €		
2048	-24,78 €	99,11 €	128.724,11 €		-128.625,00 €		
2049	0,00 €	-654,70 €	127.970,30 €		-128.625,00 €		

Appendix 24: Calculation corporate tax W-NÖ

Corporate tax calculation							
Year	Corporate tax	Tax basis	EBITDA	Interest rate debt	Depreciation	Credit redemption	Remaining credit
	D * 25%	D = A+B+C	A	B	C		
2013							-3.656.250,00 €
2014	-40.158,75 €	160.635,00 €	650.166,25 €	-164.531,25 €	-325.000,00 €	-281.250,00 €	-3.375.000,00 €
2015	-43.322,81 €	173.291,25 €	650.166,25 €	-151.875,00 €	-325.000,00 €	-281.250,00 €	-3.093.750,00 €
2016	-38.855,63 €	155.422,50 €	619.641,25 €	-139.218,75 €	-325.000,00 €	-281.250,00 €	-2.812.500,00 €
2017	-41.670,54 €	166.682,15 €	618.244,65 €	-126.562,50 €	-325.000,00 €	-281.250,00 €	-2.531.250,00 €
2018	-44.432,22 €	177.728,87 €	616.635,12 €	-113.906,25 €	-325.000,00 €	-281.250,00 €	-2.250.000,00 €
2019	-42.733,02 €	170.932,10 €	597.182,10 €	-101.250,00 €	-325.000,00 €	-281.250,00 €	-1.968.750,00 €
2020	-45.522,82 €	182.091,26 €	595.685,01 €	-88.593,75 €	-325.000,00 €	-281.250,00 €	-1.687.500,00 €
2021	-48.308,95 €	193.235,79 €	594.173,29 €	-75.937,50 €	-325.000,00 €	-281.250,00 €	-1.406.250,00 €
2022	-48.834,02 €	195.336,08 €	583.617,33 €	-63.281,25 €	-325.000,00 €	-281.250,00 €	-1.125.000,00 €
2023	-51.604,88 €	206.419,53 €	582.044,53 €	-50.625,00 €	-325.000,00 €	-281.250,00 €	-843.750,00 €
2024	-52.114,13 €	208.456,53 €	571.425,28 €	-37.968,75 €	-325.000,00 €	-281.250,00 €	-562.500,00 €
2025	-54.869,11 €	219.476,44 €	569.788,94 €	-25.312,50 €	-325.000,00 €	-281.250,00 €	-281.250,00 €
2026	-57.362,15 €	229.448,62 €	567.104,87 €	-12.656,25 €	-325.000,00 €	-281.250,00 €	0,00 €

Appendix 25: Value table for sensitivity analyses biomass BM-VBG

NPV incl district heating grid	Parameter shift								
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	-5.069.099	-4.121.229	-3.173.359	-2.225.489	-1.277.619	-329.748	605.166	1.409.105	2.202.745
Discount rate	-390.993	-621.914	-846.518	-1.065.019	-1.277.619	-1.484.513	-1.685.891	-1.881.933	-2.072.814
O&M	-535.393	-720.950	-906.506	-1.092.062	-1.277.619	-1.463.175	-1.648.731	-1.834.287	-2.019.844
Heat tariff	-8.115.355	-6.405.921	-4.696.487	-2.987.053	-1.277.619	431.816	2.004.563	3.492.752	4.902.957
Feedstock costs	2.514.380	1.642.831	698.000	-289.809	-1.277.619	-2.265.428	-3.253.237	-4.241.046	-5.228.856
FIT	-2.205.615	-1.973.616	-1.741.617	-1.509.618	-1.277.619	-1.045.620	-813.621	-581.622	-349.622
Investment costs	3.584.306	2.445.275	1.300.833	22.381	-1.277.619	-2.577.619	-3.877.619	-5.177.619	-6.477.619

LRGC excl. district heat grid	Parameter shift								
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	372	335	306	284	266	252	240	232	225
Discount rate	262	263	264	265	266	268	269	270	271
O&M	250	254	258	262	266	271	275	279	283
Feedstock costs	205	219	235	251	266	282	298	314	330
Investment costs	244	248	253	259	266	274	281	288	295

Appendix 26: Value table for sensitivity analyses PV-SBG

NPV sensitivity analysis									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	-1.076.026,06	-766.565,09	-470.787,73	-175.010,37	120.767,00	416.544,36	712.321,73	1.008.099,09	1.303.876,46
WACC	325.015,90	271.878,83	220.155,01	169.799,00	120.767,00	73.016,81	26.507,76	-18.799,35	-62.942,31
O&M + insurance	251.916,30	219.128,97	186.341,65	153.554,32	120.767,00	87.979,68	55.192,35	22.405,03	-10.382,30
FIT	-880.359,85	-630.078,13	-379.796,42	-129.514,71	120.767,00	371.048,71	621.330,42	871.612,13	1.121.893,85
Tariff SAG	-61.215,61	-15.719,96	29.775,69	75.271,35	120.767,00	166.262,65	211.758,31	257.253,96	302.749,61
IC	1.124.420,36	873.507,02	622.593,68	371.680,34	120.767,00	-130.146,34	-381.059,68	-631.973,02	-882.886,36

LRGC sensitivity analysis									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	148,65	130,56	117,43	107,22	99,05	92,37	86,80	82,09	78,05
WACC	94,25	95,43	96,63	97,84	99,05	100,29	101,53	102,78	104,05
O&M + insurance	95,66	96,51	97,36	98,21	99,05	99,90	100,75	101,60	102,45
IC	73,05	79,55	86,05	92,55	99,05	105,56	112,06	118,56	125,06

Appendix 27: Value table for sensitivity analyses small hydropower HP-VBG

NPV remaining investment horizon									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	425.689,0	461.748,6	497.808,2	533.867,8	569.927,4	605.986,9	642.046,5	678.106,1	714.165,7
Discount rate	605.643,4	596.615,6	587.654,1	578.758,2	569.927,4	561.161,0	552.458,6	543.819,6	535.243,4
O&M + insurance	586.413,6	582.292,0	578.170,5	574.048,9	569.927,4	565.805,8	561.684,2	557.562,7	553.441,1
FIT	456.239,8	484.661,7	513.083,6	541.505,5	569.927,4	598.349,3	626.771,2	655.193,1	683.615,0
Tariff VKW	539.376,6	547.014,3	554.652,0	562.289,7	569.927,4	577.565,0	585.202,7	592.840,4	600.478,1
IC	1.041.264,5	923.430,2	805.595,9	687.761,6	569.927,4	452.093,1	334.258,8	216.424,5	98.590,3
LRGC remaining investment horizon									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	49,32	48,84	48,37	47,92	47,48	47,05	46,64	46,24	45,85
Discount rate	46,89	47,04	47,19	47,33	47,48	47,63	47,77	47,92	48,07
O&M + insurance	47,07	47,17	47,27	47,38	47,48	47,58	47,68	47,79	47,89
IC	35,80	38,72	41,64	44,56	47,48	50,40	53,32	56,24	59,16

NPV whole investment horizon									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	-200.024	-13.542	172.940	359.423	545.905	732.387	918.869	1.105.352	1.291.834
Discount rate	691.362	653.206	616.275	580.524	545.905	512.376	479.895	448.423	417.920
O&M + insurance	639.445	616.060	592.675	569.290	545.905	522.520	499.135	475.750	452.364
FIT	-42.031	104.953	251.937	398.921	545.905	692.889	839.873	986.857	1.133.841
Tariff VKW	387.912	427.410	466.908	506.407	545.905	585.403	624.902	664.400	703.898
IC	974.147	867.706	760.749	653.447	545.905	438.187	330.338	222.387	114.357
LRGC whole investment horizon									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	69,86	62,08	56,24	51,70	48,07	45,10	42,63	40,53	38,74
Discount rate	45,92	46,45	46,99	47,53	48,07	48,63	49,19	49,75	50,33
O&M + insurance	45,76	46,34	46,92	47,49	48,07	48,65	49,23	49,81	50,39
IC	37,47	40,10	42,75	45,41	48,07	50,74	53,41	56,09	58,77

Appendix 28: Value table for sensitivity analyses small hydropower HP-NÖ

NPV									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	-1.327.499	-982.262	-637.025	-292.019	0	259.001	517.928	776.856	1.035.784
Rate of return	576.919	421.101	273.326	133.110	0	-126.426	-246.565	-360.784	-469.429
O&M + insurance	178.164	133.642	89.119	44.596	0	-46.168	-94.304	-144.267	-195.909
El market price	-1.327.499	-982.262	-637.025	-292.019	0	259.001	517.928	776.856	1.035.784
IC	1.789.910	1.343.444	895.653	447.863	0	-466.249	-975.551	-1.490.051	-2.004.551
LRGC									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
Theoretical FLH	58,65	52,22	47,06	42,83	39,76	37,43	35,43	33,69	32,17
Rate of return	35,36	36,42	37,51	38,63	39,76	40,92	42,10	43,31	44,53
O&M + insurance	38,21	38,59	38,98	39,37	39,76	40,17	40,59	41,03	41,48
IC	24,11	28,01	31,93	35,85	39,76	43,84	48,30	52,80	57,30

Appendix 29: Value table for sensitivity analyses wind power W-NÖ

NPV									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
FLH	-1.444.438	-858.982	-346.384	93.113	532.611	972.109	1.411.606	1.851.104	2.290.602
Discount rate	1.086.020	938.892	797.813	662.481	532.611	407.936	288.201	173.168	62.610
O&M + insurance	1.007.327	902.075	787.871	664.716	532.611	391.555	241.548	82.590	-85.318
FIT	-1.444.438	-858.982	-346.384	93.113	532.611	972.109	1.411.606	1.851.104	2.290.602
IC	2.197.738	1.781.456	1.365.174	948.893	532.611	116.329	-299.952	-716.234	-1.140.929
LRGC									
	-40%	-30%	-20%	-10%	0%	+10%	+20%	+30%	+40%
FLH	120,24	108,22	99,52	93,30	88,04	83,53	79,62	76,20	73,18
Discount rate	82,33	83,72	85,14	86,58	88,04	89,52	91,02	92,54	94,09
O&M + insurance	81,83	83,21	84,70	86,31	88,04	89,88	91,84	93,92	96,12
IC	66,27	71,71	77,15	82,60	88,04	93,48	98,92	104,36	109,91