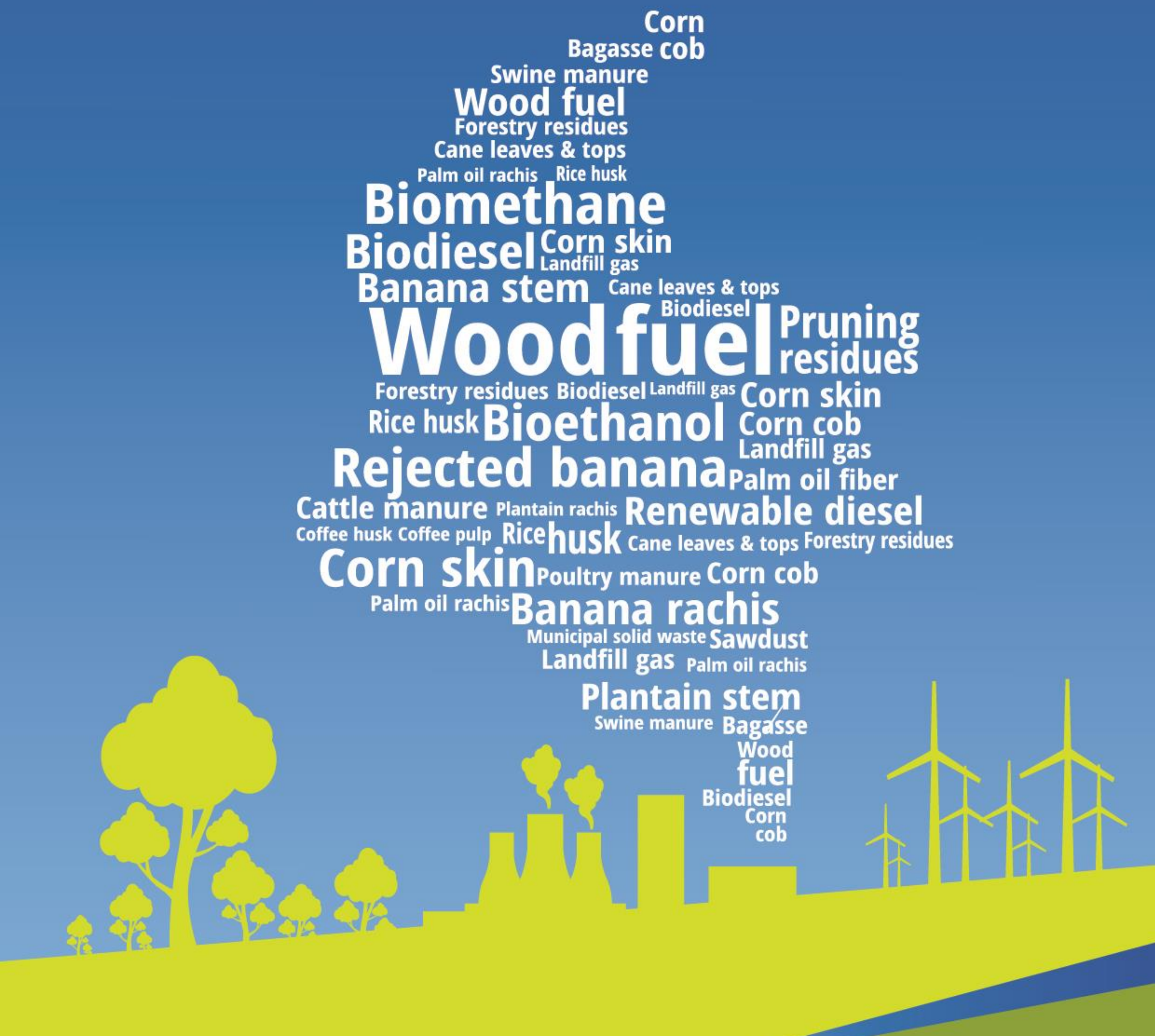
BIOENERGY TECHNOLOGY 2030

Roadmap for Colombia



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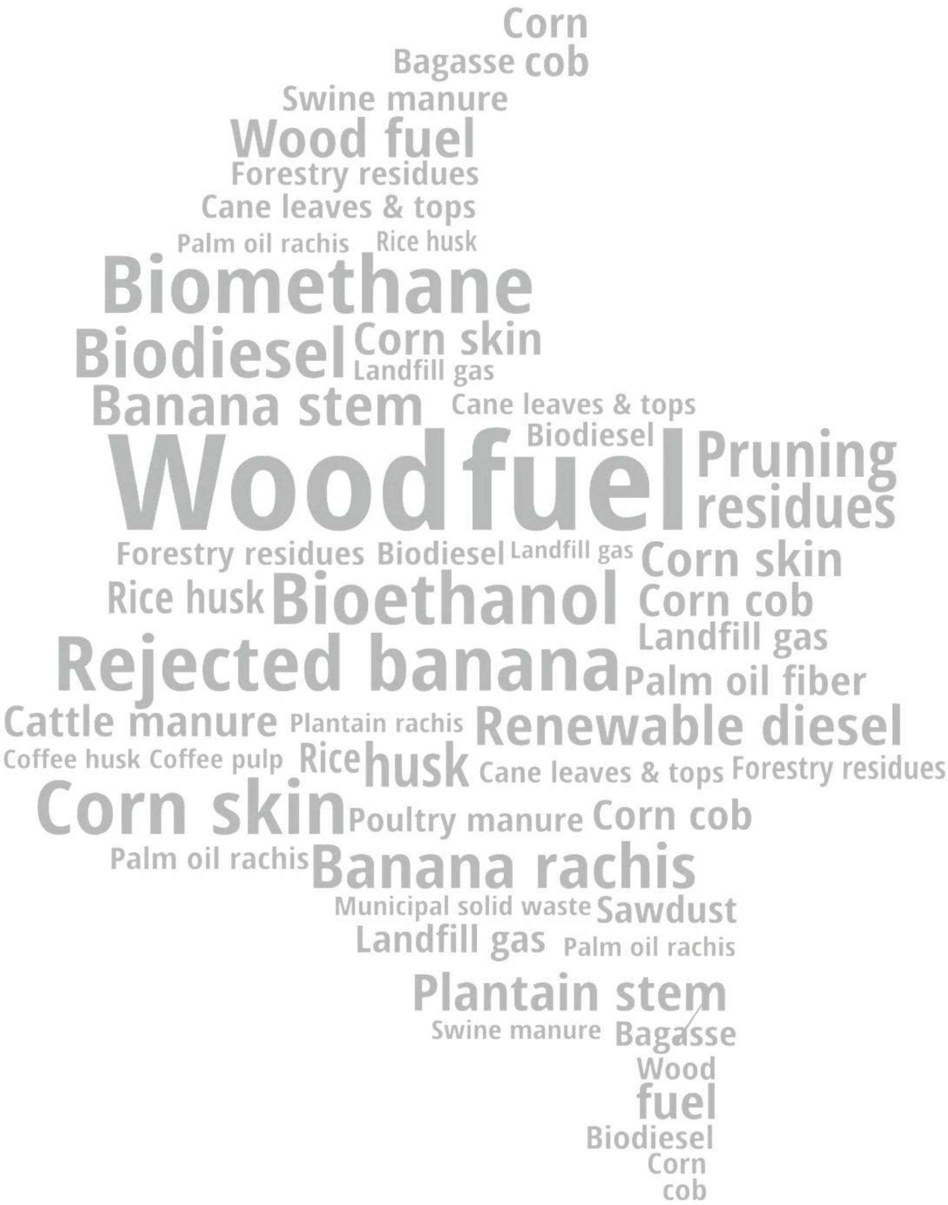

Bioenergy technology roadmap for Colombia

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For more information on this document, please contact:
Miguel Angel Gonzalez Salazar, gnzmln@unife.it

Cover design and layout: José Darío Galvis
Proofreading: Linda March
Photography: Miguel Angel Gonzalez Salazar

Preface

The report of the World Commission on Environment and Development (aka the Brundtland Commission), "Our Common Future" (1987), is often seen as the initial point of a global discussion and worldwide efforts with regard to achieving sustainable development. The Earth Summit at Rio de Janeiro in 1992 was the next step, placing climate change, an important part of any sustainability strategy, internationally on the top priority list. Rio de Janeiro saw the start of the first negotiations to "stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (United Nations Framework Convention on Climate Change, Art. 2).

Nowadays climate change is still a global challenge, which can be only controlled on a mutual basis, with the involvement of all countries or at least the most polluting ones. Up until now this pre-condition has impeded viable treaties. The failure to act to reduce the anthropogenically induced emissions of carbon will not only affect some anonymous groups somewhere, but will hamper prosperity on a local scale worldwide. However, the impacts will not be felt evenly across the world. Some regions and some economic activities will discover that they are more hindered in their development than others.

According to newer research –which confirms older studies– climate change will place at risk small-scale subsistence agriculture and large-scale agricultural production for export. Latin America is exposed to the El Niño Southern Oscillation (ENSO). Recent comparisons of climate model studies suggest the likelihood of global warming leading to the occurrence of more frequent extreme El Niño events in the next decades. The last severe event in 1997-98 resulted in large losses in Latin America. Not only agricultural activities are exposed to ENSO but also hydro power generation, which is of some importance in Colombia.

Colombia is a middle power and the third largest economy in South America. The main export products are fossil fuels, which, under current circumstances, accelerate carbon emissions, and agricultural products like coffee and bananas, which will suffer from a climate that is heating up. Although Colombia is a medium income country, a noteworthy share of the population still lives below the poverty line. Despite these challenges, Colombia has suffered since the 1960s from asymmetric warfare of varying intensity. There is now some hope of coping with the conflict. Although the whole country had been and still is troubled by the conflict, rural areas have been especially thwarted.

Colombia does not only face the previously mentioned challenges. Other unspecified challenges are adding to the list of tasks to be handled by the government and by society. To develop and administer solutions, a comprehensive and well-thought-out strategy (or rather, due to the complexity of the challenges, different strategies) is required. Such strategies shall incorporate information regarding the goals but also ways and means to achieve them.

Research on appropriate governance in modern societies recommends including non-governmental stakeholders in the process of finding societally accepted strategies. Top-down approaches, developed and implemented by the central government, generally lack consideration of the wide range of perspectives and consequences, due to the non-availability of information. Solving emerging conflicts during the implementation phase is often more expensive than somewhat lengthy but fruitful discussion beforehand.

The following report aims at contributing to the discussion on dealing with the aforementioned challenges from an academic point of view and focusing on the Colombian energy system. We have tried to incorporate in the report a wide range of contributions, not only from scientists but also from representatives of the government, industry and NGOs. As the title of the report indicates, bioenergy is seen as a potentially sustainable solution to overcome the aforementioned challenges. Bioenergy is a thought-provoking consideration since it might contribute to reducing the greenhouse gas emissions of the domestic energy system and improve living standards in rural areas. Based on a detailed scenario analysis, we provide some noteworthy insights on what a successful strategy should include to handle the challenges. Looking at the interplay between technology, environment and economy, the report emphasizes that any treatment of the challenges will not result in a simple solution. Thus, the time perspective of any strategy has to be counted in decades and not merely in years, with continuous reflections as to whether the chosen strategies are still appropriate.

We have only touched, in a rather sketchy way, on the hurdles Colombia has to consider while planning for the future. The report will give some interesting insights, which, we hope, will fuel the discussion in Colombia on creating appropriate ways to clear away the impediments it faces.

The scientific committee of the bioenergy technology roadmap for Colombia

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This study was prepared by Miguel Angel Gonzalez Salazar as a part of his PhD dissertation thesis at the Università degli Studi di Ferrara (Italy). It was jointly designed, structured and guided by a scientific committee consisting of Mauro Venturini (Università degli Studi di Ferrara), Witold Poganietz (Karlsruhe Institute of Technology), Matthias Finkenrath (Kempten University of Applied Sciences), Trevor Kirsten (GE Global Research), Helmer Acevedo (Universidad Nacional de Colombia) and Miguel Angel Gonzalez Salazar (Università degli Studi di Ferrara). It was reviewed by a group of roadmap experts (alphabetically listed below), who contributed to define a strategic vision and plan to deploy sustainable bioenergy technologies in Colombia and provided valuable inputs. The scientific committee would like to thank all roadmap experts for participating in the surveys and workshop as well as for reviewing and providing comments on the roadmap drafts. This study could not have been carried out without their contribution. The present roadmap represents the scientific committee's interpretation of results from surveys and the workshop complemented with remarks from independent academic researchers and it does not necessarily reflect the opinion of individual experts. The scientific committee would like to thank Helmer Acevedo for organizing and facilitating the workshop in Bogotá and to Carolina Cortés for documenting the discussions and supporting the workshop. Many thanks to the valuable support and cooperation of various external reviewers (listed below) that provided relevant feedback and comments. Finally, many thanks to the Stockholm Environment Institute for granting a LEAP license and for the outstanding technical support, to José Darío Galvis for his help on cover design and layout and to Linda March for proofreading the document.

Roadmap experts

John Ramiro Agudelo – Universidad de Antioquia (Colombia)
Sandra Bautista – Universidad Nacional de Colombia (Colombia)
Carlos Ariel Cardona – Universidad Nacional de Colombia (Colombia)
Daniel Chaves – General Electric (Colombia)
Suani Teixeira Coelho – University of Sao Paulo (Brazil)
Alejandra Corredor – Unidad de Planeación Minero Energética, UPME (Colombia)
Christie J. Daza – Expert on palm oil and derivatives (Colombia)
Claudia Daza Montaño – Energy Research Centre of the Netherlands, ECN (Netherlands)
Fausto Freire – University of Coimbra (Portugal)
María Fernanda Gómez – Royal Institute of Technology, KTH (Sweden) and Universidad de la Sabana (Colombia)
Andrés Gonzalez – Regeneración Ltda. (Colombia)
María Fernanda González Salazar – PE International (Germany)
Carlos Graterón – Fedebiocombustibles (Colombia)
Paola Herrera – Cámara de Comercio de Bogotá (Colombia)
Manoel Regis Lima Verde Leal – Bioethanol Science and Technology Centre, CTBE (Brazil)
Jimmy Lopez – General Electric Global Research (Brazil)
Johan Martínez Ruíz – Asocaña (Colombia)
Juan Pablo Mateus – BioD S.A. (Colombia)
Aymer Maturana – General Electric Global Research (Brazil)
Paulo Cesar Narvaez Rincón – Universidad Nacional de Colombia (Colombia)
Alvaro Orjuela Londoño – Universidad Nacional de Colombia (Colombia)
Clara Ines Pardo – Universidad de La Salle (Colombia)
Juan Fernando Pérez Bayer – Universidad de Antioquia (Colombia)
Julián Andrés Quintero Suarez – Universidad Nacional de Colombia (Colombia)
Javier Rodríguez – Unidad de Planeación Minero Energética, UPME (Colombia)
Angela Adriana Ruíz Colorado – Universidad Nacional de Colombia (Colombia)
Óscar Julián Sánchez Toro – Universidad de Caldas (Colombia)
Mauricio Sierra – Fundación Universitaria Agraria de Colombia (Colombia)
Verónica Paola Villacís – Consultant (Ecuador)

External reviewers

Anselm Eisentraut – International Energy Agency (France)
Steven Farji – World Bank (U.S.)
Juan Fernando Higuita – Empresas Públicas de Medellín (Colombia)

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Executive summary

The importance of using bioenergy for reducing oil dependence and greenhouse gas (GHG) emissions, diversifying the energy portfolio and supporting rural development is been increasingly recognized in Colombia. Against this background, this roadmap provides a long-term vision and goals to sustainably deploy biofuel and biomass technologies in Colombia until 2030. The roadmap identifies barriers to bioenergy deployment and suggests specific actions that should be taken by stakeholders to accomplish the proposed goals. It adopts a methodology from the International Energy Agency for developing technology roadmaps and combines detailed energy modeling with experienced advice from over 30 bioenergy experts from the government, academia, industry and non-governmental organizations.

Based on expert feedback, the roadmap defines two visions, which are translated into two scenarios for detailed evaluation:

- The first vision, which is analyzed in Scenario I, focuses on new technologies and targets their deployment for the production of biomethane, biomass-based power generation and combined-heat-and-power (CHP). It fixes the current mandate for blending first generation liquid biofuels.
- The second vision, which is analyzed in Scenario II, combines new and traditional technologies and targets a combination of new technologies for the production of biomethane, electricity and CHP with further growth of first generation biofuels.

A detailed set of goals, milestones, technologies, policies and barriers are defined for each of the two visions. Long-term goals in the bioenergy area include:

- Biodiesel: increase the quota mandate to B20 in 2020 and B30 in 2030.
- Bioethanol: a) increase the quota mandate to E20 in 2025 and b) implement an E85 fuel program in 2030.
- Renewable diesel: achieve a 10% contribution (on an energy basis) of renewable diesel to the total diesel fuel production in 2030.
- Biomethane: use 5% of biomass residues and 1% animal waste resources nationwide to produce biomethane to be injected into the natural gas network by 2030.
- Power generation and CHP: a) achieve a renewable power target of 10% by 2025, b) use 5% of the biogas from animal waste and municipal water treatment plants nationwide by 2030, c) use 100% of the biogas produced in the water treatment process of biodiesel production plants by 2030, d) use 10% of the municipal landfill gas produced nationwide by 2030.

A detailed energy system model for Colombia is set up and used to evaluate impacts on energy demand, supply, infrastructure and GHG emissions for Scenarios I and II and a baseline scenario that assumes no change in policies or deployment of new technologies. A land use and trade model that is linked to the energy system model is used to estimate land requirements for accomplishing the roadmap targets. A subset of Scenario II (Scenario II with expansion) considers a significant expansion in the cultivation of land beyond the Valley of the Cauca River.

Results for the baseline show significant reductions in the share of bioenergy in the primary energy demand and various sectors. In contrast, Scenarios I and II are characterized by an increased share of bioenergy. In both scenarios, the bioenergy share for power generation and natural gas supply grows to about 6% in 2030. However, the share of bioenergy in the primary energy demand still declines to about 10% in 2030.

Relative to the baseline, in Scenario I, bioenergy-induced emissions reduction amounts to about 11 mio tons of CO_2-eq. and savings in fossil fuels of 2 mio tons of oil equivalent (TOE). The share of bioenergy in road transport remains unchanged. In Scenario I, an increase in land for producing liquid biofuels and woodfuel to 0.67 mio ha by 2030 is expected. Scenario I can accomplish long-term targets with available land and turns out to be the most effective scenario in terms of emission reduction per additional hectare of land.

In Scenario II bioenergy-induced emissions reduction relative to the baseline amounts to about 20 mio tons of CO_2-eq. and savings in fossil fuels of about 4.5 mio TOE (Scenario II with expansion: 22 mio tons of CO_2-eq. and 5.4 mio TOE). The share of bioenergy in road transport grows to 24%. An increase in land for producing liquid biofuels and woodfuel to 1.1 mio ha by 2030 is expected in Scenario II (Scenario II with expansion: 1.3 mio ha). However, emissions reductions per additional hectare of land are about four to five times less compared to Scenario I.

The roadmap shows that the most effective policy measures to reduce greenhouse gas emissions would address power generation and CHP applications, which account for more than 50% in emission reductions. The bulk of these reductions in emissions come from avoiding methane release via landfill gas and biogas from animal waste/wastewater through combustion in reciprocating engines, followed by CO_2 emission reduction in biomass-based power generation, and policies on first generation biofuels (i.e. bioethanol, biodiesel and renewable diesel).

Introduction

In the last 30 years, Colombia has shifted from an agricultural economy to one based on minerals and energy resources. This shift has allowed the country to grow in the last decade at 4 to 5% annually, doubling public expenditure and increasing per capita income by 60% and foreign investment five-fold (Gaviria, 2010; Gaviria, 2012). However, widespread corruption, ineffective policies and weak institutions have hindered better wealth distribution. On top of this, a 50-year armed conflict has resulted in one million casualties, six million civilians internally displaced and thousands of hectares of usurped land (RNI, 2014).

These socioeconomic and political transformations have also brought serious consequences to the energy sector and the environment. Primary and secondary energy demand doubled between 1975 and 2009 (UPME, 2011a), which required a rapid growth of the energy conversion capacity. New coal- and gas-fired power plants were built to reduce the over-dependence on hydro power, which has proven vulnerable to droughts caused by El Niño oscillation. In the transport sector, vehicle ownership grew exponentially while road infrastructure collapsed, which deteriorated mobility in large cities. More people demanding more energy resulted in more pollution. GHG emissions increased 2.5 times between 1975 and 2009 (UPME, 2011a), while the amount of the fresh water supply that is not drinkable has increased to 50% in recent years (UN Periódico, 2014). Deforestation ate up 6.2 million hectares of tropical forest between 1990 and 2010 (an area as large as Norway), which has been mostly replaced by extensive cattle farms (El Tiempo, 2013).

Yet, despite a turbulent and difficult past, Colombia is looking forward to the future. There is hope that peace talks with the main guerrilla groups and ambitious post-conflict reforms might turn around the history of violence and build foundations for a more equitable and prosperous country.

In this context, it is critical to address the challenge of planning a long-term energy system able to ensure: a) energy security, b) clean energy supply to the whole population, c) food and water security and d) enhancement of rural development. Various technology paths have been envisioned to supply energy while reducing GHG emissions: renewables, energy efficiency, fuel switching, distributed power generation & CHP, carbon capture and storage, nuclear, etc. (IEA, 2014a).

While individual measures offer separate benefits, a portfolio of measures is needed at a national level to achieve significant GHG emissions reduction and to fulfill other requirements such as enhancing energy and water security.

This report studies bioenergy, a renewable energy source that, if managed in a sustainable way, might potentially contribute to reducing oil dependence, diversify the energy portfolio, reduce emissions and support rural development. Bioenergy is not a definitive solution though, and multiple barriers exist to exploit it in a sustainable manner. Land use competition, direct and indirect land-use change, deforestation, crops for food vs. biofuels, pressure on water resources and uncertain life cycle emissions are some of the hurdles that need to be carefully addressed. Overlooking these concerns can ultimately lead to poorly managed bioenergy programs and environmental disasters (e.g. clearance of rainforest to plant biofuel crops).

Biomass plays an important role in the energy mix of the country as it is today the second largest renewable energy resource after hydroelectricity. In 2009, biomass contributed 67% of the renewably generated electricity excluding large hydro (69 kTOE), 4.6% of the energy supply in road transport (337 kTOE) and 10% of the overall primary energy demand (3.77 mio TOE) (UPME, 2011a). Colombia is also characterized by a vast theoretical bioenergy potential, ranging between 5 to 18 mio TOE, that remains untapped (Gonzalez-Salazar M. M., 2014a).

While in the last decade Colombia has recognized the importance of bioenergy through various policies and supporting programs, there is a consensus among experts that a long-term vision, a strategic plan and a sustainability scheme to deploy bioenergy in Colombia are missing.

This roadmap attempts to fill this gap. Firstly, it proposes a sound methodology to help address the challenge of defining a long-term bioenergy vision for bioenergy at a national level. Secondly, it identifies barriers to bioenergy deployment and recommends strategies, milestones and actions to be taken by stakeholders to accomplish the proposed goals. Thirdly, it provides a detailed, transparent and objective modeling framework that allows an analysis of the impacts of implementing the long-term goals. This roadmap is ultimately a tool to help turn stakeholder consensus and analytical work into concrete plans that enable sound energy policy-making.

Purpose

This roadmap addresses the challenge of defining a strategic vision and plan to deploy sustainable biofuel and biomass technologies in Colombia for the period 2015-2030. It also analyzes the implications of implementing the roadmap targets for energy supply and demand, associated GHG emissions and land use. It should be regarded as an extension of earlier studies (MRI-UNC-NUMARK, 2010; BID-MME, Consorcio CUE, 2012; Mora Alvarez, 2012), as a proposed methodology to define a long-term vision for bioenergy and as an attempt to initiate a technology roadmapping process that in the future can be updated or continued by governmental agencies.

Scope

The roadmap identifies barriers to bioenergy deployment and recommends: a) strategies, plans and policies to deploy biofuel and biomass technologies in Colombia for the period 2015-2030, and b) actions that should be taken by stakeholders to accomplish the proposed goals. In addition, through detailed modeling, the impacts of achieving roadmap goals are quantified (e.g. substitution of fossil fuels, emissions reduction, land requirements, etc.). Specifically, this roadmap aims at:

1. Identifying effective policies and key technologies in the field of biofuels and biomass-power, and their role in achieving targets to reduce GHG emissions and enhance energy security.
2. Identifying steps to be undertaken to enhance the policy effectiveness and improve the technical, economic and environmental performance of three main bioenergy routes:

    a. First generation biofuel conversion systems currently operating in Colombia (sugar cane-based bioethanol and palm oil-based biodiesel).
    b. Biomass-based heat and power generation (using non-food feedstock, e.g. wood, agricultural residues, biogas, landfill gas, etc.).
    c. Second-generation biofuel conversion systems. Second-generation biofuels are defined here as solid, liquid and gas biofuels produced from feedstocks (biomass/organic matter) that are not used for human consumption.

Roadmapping process

To a large extent, this roadmap follows the methodology proposed by the International Energy Agency (IEA) to develop technology roadmaps (IEA, 2010b). The roadmap was elaborated by combining an energy modeling framework with contributions from experts in the government, academia, industry (e.g. biofuels, sugar cane, palm oil, power generation, etc.) and non-governmental organizations (NGOs). Figure 1 shows the roadmapping process.

The roadmap was developed in three steps. In the first step, the opinions of 30 experts on the future deployment of bioenergy in Colombia were gathered through two surveys. The first survey captured the general perception of experts about the current status of bioenergy in Colombia, the role of bioenergy in future energy goals and the key barriers to further deploying bioenergy in the country. The second survey collected the advice of experts about concrete long-term goals to deploy bioenergy and specific pathways to achieve these goals.

In a second step, experts met in a two-day workshop in Bogotá to discuss the results of the surveys and to provide recommendations and advice. Five bioenergy areas were analyzed: a) bioethanol, b) biodiesel, c) renewable diesel, d) biomethane and e) biomass-based power generation and combined heat and power (CHP).

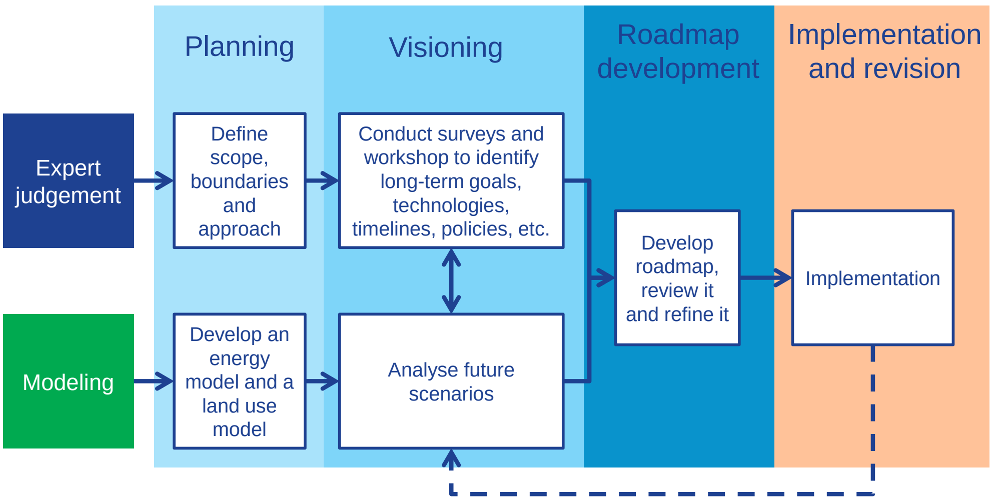


Figure 1. *Roadmapping process adapted from (IEA, 2010b)*

While there was general consensus among experts on the long-term vision for biomethane and biomass-based power generation and CHP, there were opposing views with regard to the long-term vision for transport biofuels (i.e. bioethanol, biodiesel and renewable diesel). As a consequence of this discrepancy, two long-term visions are considered. One vision focuses on new technologies (e.g. biomethane and biomass-based power generation and CHP) and the other combines new and traditional technologies (e.g. first generation biofuels). For each of the two visions a set of long-term goals, milestones, technologies, policies and barriers were defined.

In a third step, independent researchers from academia reviewed the goals and milestones of the two long-term visions and provided complementary remarks and suggestions. Subsequently, expert advice was supported by modeling and scenario analysis to evaluate the impacts of implementing the two visions. For this purpose a very detailed model of the country's energy demand, conversion and supply, energy policy, land use and environmental performance was created and validated using available statistics. A methodology framework to estimate future energy requirements was developed integrating sound data of end-use consumption profiles, technology performance, price forecasts, weather conditions, etc. Then, the potential impacts associated with each long-term vision (e.g. substitution of fossil fuels, GHG emissions reduction, land requirements, etc.) through till 2030 were quantified and compared to a baseline scenario.

It is important to note that the estimations presented in this report involve various uncertainties, e.g. unavoidable unpredictability of future events, limited information of model parameters, limited knowledge about the model structure as well as known and unknown limitations of the mathematical model because of gaps in knowledge, computational limitations or methodological disagreements. One important source of uncertainty relates to the fact that models are calibrated using the latest available statistics, which correspond to the year 2009 and predate the present study by five years. Results should not be regarded as forecasts but rather as outcomes of scenario analyses. Hence, they are potential representations of future storylines subject to particular conditions.

Finally, it is expected that the long-term goals, milestones and action items identified in this roadmap will be revised and adjusted by policy makers and local authorities and lead to an implementation program.

Report structure

This roadmap is divided into three chapters. Chapter A describes the current status of bioenergy in Colombia and presents details of the roadmap vision, i.e. the set of goals, milestones, barriers and action items identified for the different bioenergy technology areas. Chapter B presents the modeling process and methodology used to evaluate the implications of implementing the roadmap targets for energy supply and demand, associated greenhouse gas emissions and land use. Chapter C presents the impacts of implementing roadmap targets obtained from models; it also includes a discussion and draws some conclusions.

Chapter A. Roadmap vision

Highlights Chapter A

1

Key identified reasons to support the deployment of bioenergy technologies: a) to promote rural development, b) to enhance energy security and c) to reduce GHG emissions.

2

Key identified technology areas: a) bioethanol, b) biodiesel, c) renewable diesel, d) biomethane and e) power generation & CHP.

3

Two long-term visions are considered: the first vision focuses on new technologies (e.g. biomethane and power generation & CHP) and the second vision combines new and traditional technologies (e.g. first generation biofuels).

4

Long-term goals by area:

- Biodiesel: increase the quota mandate to B20 in 2020 and B30 in 2030.

- Bioethanol: increase the quota mandate to E20 in 2025 and implement E85 in 2030.

- Renewable diesel: achieve a 10% energy contribution in the total diesel fuel in 2030.

- Biomethane: use 5% of biomass residues and animal waste to produce biomethane by 2030.

- Power generation & CHP: a) achieve a renewable power target of 10% by 2025, b) use 5% of the biogas from animal waste and municipal water treatment plants by 2030, c) use 100% of the biogas produced in the water treatment process of biodiesel production plants by 2030, d) use 10% of the municipal landfill gas by 2030.

5

Various actions are required: a) implement new regulations and policies, b) implement incentive programs and financial mechanisms, c) mitigate technical and environmental risks and d) implement a bioenergy sustainability scheme.

A.1. Current status of bioenergy in Colombia

Overview

Current use of biomass for energy purposes in Colombia can be divided into four main categories. Firstly, and more predominantly, it is used in the form of wood and charcoal as a traditional fuel for cooking and water heating (see national energy balances (UPME, 2011a)). Secondly, it is used in the form of cane bagasse and palm oil residues as a fuel in boilers and cogeneration power plants to provide heat and power. Thirdly, it is used after conversion in the form of bioethanol and biodiesel as road transport biofuels. Other forms of using biomass for energy purposes have been explored to a much lesser extent as demonstration or pilot projects with varying degrees of success. These forms include among others: a) use of landfill gas and biogas for in situ heat or power production, b) biomass gasification and combustion in reciprocating engines and c) methane collection from wastewater treatment plants for heating.

Biomass plays an important role in the energy mix of the country as it is today the second largest renewable energy resource after hydroelectricity. In 2009, biomass contributed 67% of renewably generated electricity excluding large hydro (69 kTOE), 4.6% of the energy supply in road transport (337 kTOE) and 10% of the overall primary energy demand (3.77 mio TOE) (UPME, 2011a). The historical demand for biomass in the form of wood, cane bagasse[1] and biomass residues[2] has remained relatively constant since 1975, ranging between 3.72 and 4.47 mio TOE (see Figure 2). However, its contribution to the primary energy supply has significantly reduced from about 26% in 1975 to 10% in 2009. In contrast, the contribution of natural gas has grown from 10% to 22% in the same period. The reduced contribution of biomass relative to other fuels is the consequence of a combination of factors including increasing urbanization, higher access to electricity and natural gas services nationwide and an increased deployment of fossil fuel-based thermal power plants.

Colombia is also characterized by a vast bioenergy potential that remains untapped. Various studies have recently estimated a theoretical biomass energy potential, ranging between 5 and 18 mio TOE, depending on the assumptions (Gonzalez-Salazar M. M., 2014a). From this potential, a fraction ranging between 1 and 10 mio TOE might be technically available at current conditions and constraints for energy exploitation.

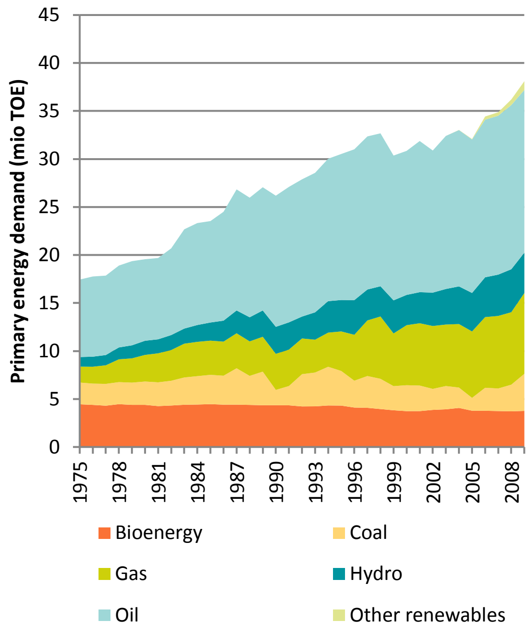


Figure 2. *Primary energy demand and contribution*[3]

Regulations

The Ministry of Mines and Energy (MME) leads and coordinates policy making and regulations in the energy sector in Colombia and is supported by various governmental agencies such as the Mining and Energy Planning Unit (UPME), the Electricity and Gas Regulation Commission (CREG), the Institute of Planning and Promoting of Energy Solutions in Non-Interconnected Zones (IPSE). While UPME and IPSE are in charge of capacity planning and support of policy making, CREG regulates power and gas tariffs. Recognizing the importance of biomass, the MME and its affiliated agencies have adopted several policies and programs in the last decade aimed at encouraging the deployment of bioenergy technologies. Examples include obligatory blends for bioethanol and biodiesel (Laws 788 of 2002 and 939 of 2004 and Decree 4892 of 2011), policy guidelines for the promotion of biofuels production (Conpes 3510 of 2008) and programs on the promotion of the efficient and rational use of energy and alternative energies (Law 697 of 2001, Resolution 180919 of 2010, Law 1715 of 2014). This support to bioenergy has been driven by the government's rationale to generate rural employment, enhance rural development, diversify the energy portfolio, reduce carbon emissions in the transport sector and decrease dependence on oil (DNP, 2008).

[1] Includes bagasse from sugarcane but excludes bagasse from jaggery cane
[2] Palm oil residues

[3] Data taken from (UPME, 2011a) and further adapted. Imports of oil-based secondary fuels are converted into primary energy.

Wood

Similarly to other developing countries, wood and charcoal have been traditionally used in Colombia for cooking and water heating. In 2009 the demand for wood amounted to 2.48 mio TOE, of which 56.2% was used in the rural residential sector, 5.5% in the urban residential sector, 24.5% for the production of charcoal and the remaining 13.8% in the agricultural and industrial sectors (UPME, 2011a). Colombia's forest coverage is large (~ 69 mio ha), reaching more than 60% of the country's land surface (IDEAM, 2010). In 2009, 13.6 mio m^3 of roundwood were produced, mostly extracted from primary forests and to a lesser extent from plantations (FAO, 2012). However, according to IDEAM's estimations, about two fifths of logging is illegal, which indicates that wood is not only extracted from allowed areas but also from protected forests and national parks (IDEAM, 2010). Using wood for cooking in traditional stoves is a very inefficient process. UPME estimates an average energy efficiency of 10% by using wood for cooking in urban residences and as low as 2.5% in rural residences, although there are acknowledged uncertainties in this estimation (UPME, 2011a; UPME, 2011b; UPME, 2011c). On the other hand, charcoal is produced by slow pyrolysis by heating wood in ovens in the absence of oxygen. Typical energy efficiencies of the charcoal conversion process are about 72% as described by UPME (UPME, 2011a; UPME, 2011b; UPME, 2011c). Illegal production of charcoal exists, but its dimension is unknown. It is a serious cause of deforestation, which has reportedly destroyed natural forests in various regions (IDEAM, 2010).

Sugar cane and bioethanol

Driven by energy security concerns and the ambition to reduce emissions in the transport sector, in 2004 Colombia implemented a bioethanol blending mandate (Decree 4892, Laws 788 and 939). This mandate defines a blending of 10% bioethanol by volume (E10) that must be used in road transport gasoline fuel. The mandate is accompanied by tax incentives for selling bioethanol and importing process machinery. Biofuel blends, tax incentives, quality standards and biofuel prices are regulated by the government through the Ministry of Mines and Energy. Production of bioethanol reached 334 mio liters in 2009 (167 kTOE), which contributed 2.3% of the overall energy demand in road transport (UPME, 2011a). Demand for ethanol requires an installed production capacity close to 2 mio liters per day.

Bioethanol is currently produced using sugar cane as feedstock. In contrast to other countries, in Colombia the climatic and soil conditions allow the cultivation of sugar cane throughout the entire year and not in sessional harvests (e.g. zafra). Sugar cane is cultivated on a large scale only in the Valley of the Cauca River on the western side of the country, where yields as high as 120 tons/ha are commonly obtained. In 2009 sugar cane cultivation in this region amounted to 217 kha, of which 38% was exclusively allocated to sugar production and 62% to co-production of sugar and bioethanol (BID-MME, Consorcio CUE, 2012).

Two thirds of the cane fields are manually harvested while only one third is mechanically harvested. For this reason, about 70% of the cane fields are burned before harvesting to facilitate the collection of stalks. After harvesting, the remaining burned residues (leaves, tops, etc.) are left on the field for soil replenishment, while stalks are transported to the mill. In the sugar cane mill, cane is crushed and cane juice, bagasse, tops and leaves are extracted. The juice is used to produce sugar and ethanol, and the bagasse is partly used to produce steam in boilers and CHP plants and partly used as raw material in paper mills. The cane mill is mechanically driven by steam turbines fed with steam produced in bagasse-fuelled boilers.

The cane juice is purified, filtrated and evaporated to produce molasses. This is followed by a crystallization and centrifugation process, in which sugar crystals are formed and separated from molasses. Molasses are then converted into bioethanol in a continuous process via microbial fermentation, distillation and dehydration. This is a mature, commercially available process that yields 0.093 tons of sugar and 0.019 tons of bioethanol per ton of sugar cane (without leaves) (BID-MME, Consorcio CUE, 2012). By-products of the ethanol production process include wastewater, vinasse and CO_2. While wastewater is treated via surface-aerated basins (lagoons) before release, CO_2 is vented into the atmosphere. Vinasse, on the other hand, is collected and concentrated by removing water, yeast and organic matter. Concentrated vinasse is then used for compost, while water, yeast and organic matter are recirculated into the fermentation reactor (BID-MME, Consorcio CUE, 2012). This process offers a significantly lower vinasse production (0.8-3 l-vinasse/l-ethanol) than the ferti-irrigation approach used in Brazil (8-12 l-vinasse/l-ethanol).

Palm oil and biodiesel

Biodiesel was introduced in Colombia in 2008 through a blending mandate of 5% by volume (B5) in road transport diesel, which subsequently increased by 2013 to levels ranging from 8 to 10%, depending on the region. Blending proportions of biodiesel, tax incentives, quality standards and prices are regulated by the Ministry of Mines and Energy in a similar fashion to that for bioethanol. Production of biodiesel reached 276 mio liters in 2009 (167 kTOE), which contributed 2.3% of the overall energy demand in road transport (UPME, 2011a). An installed production capacity of 1.8 mio liters per day is currently required to supply the growing biodiesel demand.

Biodiesel is currently produced using palm oil as feedstock. Palm oil is widely cultivated across the country, but most representative plantations are located in the eastern, northern and central regions of the country. The cultivated area in 2009 accounted for 337 kha, of which 66% corresponds to full productive plantations and 34% to developing plantations not ready for exploitation (BID-MME, Consorcio CUE, 2012). The palm oil-cultivated area has been boosted since the introduction of the biodiesel blend mandate, and today Colombia is the fifth grower worldwide. Typical yields are about 20 tons of fresh fruit bunches (FFB) and 3.5 tons of oil per ha, which are higher than alternative oil crops (BID-MME, Consorcio CUE, 2012).

Fresh fruit bunches are cut from palm trees and transported by animal traction or by truck to palm oil extraction mills. In these mills, the fresh fruit bunches of the palm are crushed, producing palm oil and residues. Part of the residues (e.g. fiber, stone) is commonly used as fuel in steam boilers to provide heating, while the other part of the residues (e.g. rachis) is returned to the field for soil replenishment. The process to convert palm oil into biodiesel is commercially available and consists of oil refining, continuous transesterification and biodiesel purification steps. The reported biodiesel yield can be as high as 4530 liters per ha (BID-MME, Consorcio CUE, 2012). Sub-products of the palm oil extraction mill include palm kernel oil and meal, which are used as animal feed. Sub-products of the biodiesel conversion process include glycerol, soap and refined oil, which are used as feedstock in the cosmetics and pharmaceutical industry. Wastewater is produced at palm oil extraction mills and biodiesel production plants. Wastewater is treated via surface-aerated basins (lagoons), which significantly reduces the biochemical oxygen demand (BOD) but does not capture methane, which is released into the atmosphere causing a negative environmental impact.

Biomass-based power generation and combined heat and power (CHP)

Today two main cases of biomass-based power generation and CHP exist in Colombia, i.e. cogeneration in the sugar cane and the palm oil industries. The first case relates to the use of steam turbine power plants using bagasse as fuel to generate process steam and power. Steam is mainly used for two purposes: 1) to feed steam turbines driving knives, shredders and other equipment need for processing and 2) to feed bioethanol distillation towers. The technology for cogenerating electricity at sugar cane facilities is well established worldwide. In principle, it consists of power conversion technology entailing a bagasse-fired boiler, a steam turbine, a pump and a steam condenser. However, details of the process configuration vary from site to site. Various sugar mills use back-pressure steam turbines designed to meet power needs, in which steam exiting the turbine is extracted at pressures above atmospheric. This configuration is characterized by poor efficiencies that cover in situ power needs but generate no surplus power (Macedo & Leal, 2001). In some cane mills, cogeneration power plants using condensing-extraction steam turbines are used. This is a superior configuration that has the capability of extracting steam at one or more points along the expansion path of the turbine to meet process needs. Non-extracted steam continues to expand to sub-atmospheric pressures, thereby increasing the efficiency and power generated compared to the back-pressure configuration. Electrical efficiencies range from 5 to 10% for the back-pressure configuration and from 10 to 30% for the condensing-extraction configuration. Today, the average electrical efficiency of bagasse-based power plants in Colombia is about 24%, while the CHP efficiency ranges between 45% and 65% (BID-MME, Consorcio CUE, 2012). The first cogeneration power plant at a sugar mill able to sell surplus power to the grid began operation in the Incauca sugar mill in the early 1990s with a 9 MWe of installed capacity (XM, 2013). By 2009 there were six cogeneration power plants in operation and two planned, totaling 58 MW of installed capacity and generating 0.6 TWh (BID-MME, Consorcio CUE, 2012; XM, 2013)

The second case relates to the use of steam turbine power plants using palm residues in palm oil extraction mills. Steam is used in two processes: 1) sterilization of fresh fruit bunches (FFB) and 2) digestion of fruits in steam vessels with mechanical agitation to separate off the oil from the solid material. On the other hand, power is required to mechanically crush the FFB and separate oil from solid material as well as to drive other mechanical equipment. In this application, the most common technology is the back-pressure steam turbine cogeneration plant with a boiler fed with palm residues and occasionally with coal. In some sites no steam turbine is used. Instead, process steam is directly supplied by the boiler, while electricity is either bought from the grid or generated in a diesel engine. No data regarding palm oil extraction mills using condensing-extraction steam turbines is found. Depending on the configuration, typical electrical efficiencies range from 5 to 15% and CHP efficiencies range from 30% to 65%. The overall installed capacity is unknown, but the power generation in 2009 reached 0.2 TWh (BID-MME, Consorcio CUE, 2012).

A.2. Roadmap vision of deploying bioenergy in Colombia

A.2.1. Overview

In order of importance, roadmap experts consider the three following reasons critical to supporting the deployment of bioenergy technologies in Colombia:

1. To promote rural development
2. To enhance energy security
3. To reduce greenhouse gas emissions

In addition, experts consider that further deployment of bioenergy should be one of the top three national energy targets to be implemented by 2030, the other two targets being increased energy efficiency nationwide and increased power coverage in non-interconnected zones (NIZ). Five bioenergy technology areas are considered fundamental for future deployment in Colombia: a) bioethanol, b) biodiesel, c) renewable diesel, d) biomethane and e) biomass-based power generation and combined heat and power (CHP). Some of them have already been deployed to a certain extent in the country (e.g. bioethanol, biodiesel, biomass-based power generation and CHP), while others have not been commercially explored yet (e.g. renewable diesel[4] and biomethane).

Experts unanimously agreed on the long-term vision of some bioenergy technology areas but disagreed on others. While there was general consensus among experts on the long-term vision for biomethane and biomass-based power generation and CHP, there were opposing views with regard to the long-term vision of liquid transport biofuels (i.e. bioethanol, biodiesel and renewable diesel). Experts consider that advanced liquid biofuels (e.g. cellulosic ethanol, biodiesel from microalgae and other advanced routes) are not expected to become commercially available in Colombia before 2030 and that first generation liquid biofuels (biofuels produced from feedstocks that are used for human consumption, e.g. cane-based bioethanol, palm-based biodiesel, palm-based renewable diesel, etc.) will continue being produced in the future. The opinions of experts particularly differed on the levels of blend mandates to be implemented in the future. On one hand, some experts advocate a significant growth in the production of first generation liquid transport biofuels by increasing blend mandates.

On the other hand, other experts consider that any further increase in the production of first generation biofuels might worsen the conflicts of land use and food vs. biofuels and are in favor of fixing the current blend mandates. As a consequence of the mentioned dilemma, this roadmap considers two different visions:

- **Vision focusing on new technologies**: this targets the deployment of new technologies for the production of biomethane, electricity and CHP and fixes the current blend mandate of first generation liquid biofuels.
- **Vision combining new and traditional technologies**: this targets a combination of new technologies for production of biomethane, electricity and CHP with further growth of first generation biofuels (i.e. bioethanol and biodiesel and renewable diesel).

A detailed set of long-term goals, milestones, technologies, policies and barriers are defined for each of the two visions and are described as follows.

A.2.2. Long-term goals of the bioenergy technology roadmap

Long-term goals are quantifiable targets classified by bioenergy technology area for the two visions. Goals for the vision focusing on new technologies cover biomethane and power generation and CHP, while goals for the vision combining new and traditional technologies cover all bioenergy technology areas. The long-term goals for bioethanol, biodiesel and renewable diesel aim at significantly increasing the quota mandates relative to fossil fuels in the transport sector (see Table 1 and Figure 3). A second goal for bioethanol is the launch of a new E85 fuel program by 2030. These goals reflect an interest in decreasing fossil fuel dependency and reducing carbon emissions in the transport sector through the use of first generation biofuels already deployed in Colombia (with the exception of renewable diesel, which has not been commercially deployed yet). On the other hand, the goals for biomethane, power generation and CHP are considered novel targets. These goals aim at multiple directions, including: a) implementing advanced biofuels such as biomethane, b) implementing a renewable power target and deploying novel technologies such as biomass-based power plants, co-firing and gasification plants and c) increasing the exploitation of residual biomass (e.g. biogas from animal waste and water treatment plants, landfill gas, etc.) for energy purposes. These novel goals show not only an interest in decreasing oil dependency and carbon emissions but also in using advance biofuels and biomass technologies that offer lower life cycle GHG emissions and land use than first generation commercial biofuels.

[4] The Colombian national oil company, Ecopetrol, has already started analyzing the production of renewable diesel in dedicated or co-processing plants in the country (Ecopetrol, 2013).

Table 1. *Set of long-term goals and milestones*

Vision	Bioenergy area	Long-term goals	Milestones
Vision combining new and traditional technologies	**Biodiesel**	• Increase the quota mandate from B10 to B20 (20% biodiesel in blend by volume) in 2020 and to B30 in 2030 for all diesel-fuelled vehicles	• Gradually increase the biodiesel quota mandate. Start in 2015 and reach B20 in 2020 and B30 in 2030 • Ensure that all new diesel-fuelled vehicles commercially available in Colombia can operate with blends higher than B10 by 2017 • Ensure satisfactory operation of aging diesel-fuelled vehicles with blends higher than B10 by 2017-2020
	Bioethanol	• Increase the quota mandate from E10 to E20 (20% anhydrous ethanol in gasohol by volume) for gasoline-fuelled vehicles and motorcycles in 2025 • Implement an E85 (85% anhydrous ethanol in gasohol by volume) fuel program in 2030	• Gradually increase the bioethanol quota mandate. Start in 2015 and reach E20 in 2025 • Ensure that all new gasoline-fuelled vehicles and motorcycles commercially available in Colombia are flex-fuel vehicles (FFV) as of 2017 • Ensure satisfactory operation of non-flex-fuel aging vehicles with mid-level ethanol blends (>E10) by 2017-2020
	Renewable diesel	• Achieve a 10% contribution (on an energy basis) of renewable diesel in the total diesel fuel production in 2030	• Gradually increase the contribution of renewable diesel in the total diesel fuel production. Start in 2015 and reach 10% in 2030
Vision focusing on new technologies	**Biomethane**	• Use 5% of biomass residues and 1% of animal waste nationwide to produce biomethane to be injected into the natural gas network by 2030	• Gradually increase the exploitation of residues and animal waste for biomethane production. Start in 2015 and reach goals in 2030
	Power generation and CHP	• Supply 10% of the national electricity demand from renewable energy sources (excluding hydro > 10 MWe) by 2025. This target includes the following sub-targets: ○ Use 5% of the biogas from animal waste and municipal water treatment plants nationwide for energy purposes (electricity, heat or CHP) by 2030 ○ Use 100% of the biogas produced in the water treatment process of biodiesel production plants for energy purposes by 2030 ○ Use 10% of the municipal landfill gas produced nationwide for energy purposes by 2030	• Increase the renewable target from 0% in 2015 to 10% in 2025 ○ Gradually increase the exploitation of biogas from animal waste and municipal water treatment plants. Start in 2015 and reach 5% in 2030 ○ Gradually increase the exploitation of biogas in biodiesel production plants. Start in 2015 and reach 100% in 2030 ○ Gradually increase the exploitation of landfill gas. Start in 2015 and reach 10% in 2030

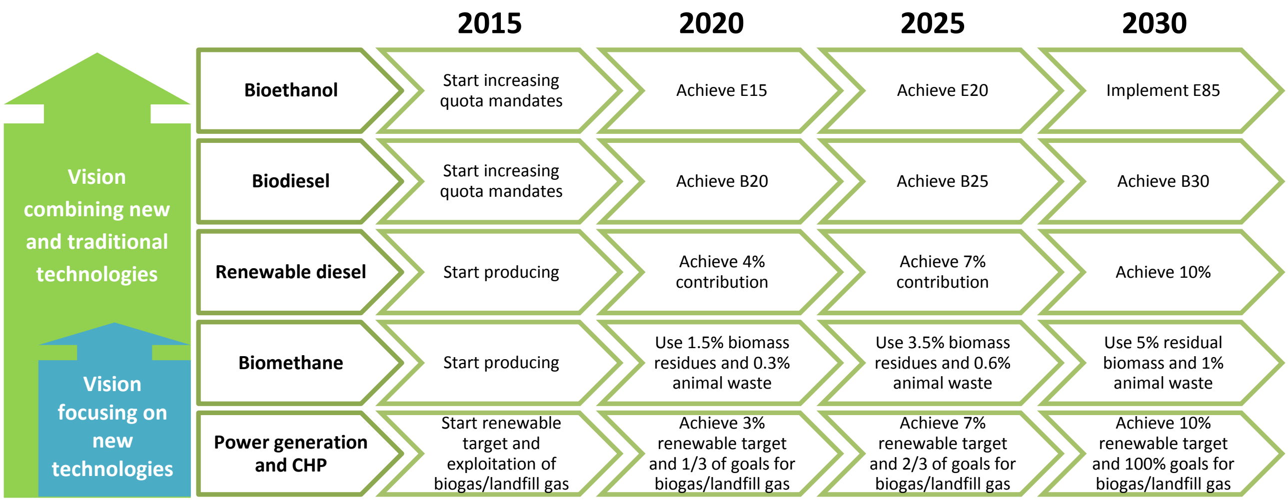


Figure 3. *Timeline of goals*

A.2.3. Milestones of the bioenergy technology roadmap

Milestones are intermediate steps required to accomplish the long-term goals. Details of the milestones classified by bioenergy area for the two visions are also shown in Table 1.

Most of the identified milestones are quantifiable measures. Examples include gradual increases in the biofuels quota mandate (i.e. achieve B20 in 2020 and B30 in 2030), in the renewable target in power generation (i.e. reach 10% renewables in 2025), in the contribution of renewable diesel to total diesel production (i.e. reach a 10% contribution in energy in 2030) and in the exploitation of residual biomass (i.e. exploit 5% of the biomass residues and 1% of animal waste in 2030). In addition to these quantifiable milestones, there are other critical qualitative milestones. Two examples are given for the biodiesel and bioethanol areas. For bioethanol, a set of qualitative milestones is required to make sure that an increase in the quota mandate is feasible. These milestones include ensuring that non-flex-fuel aging vehicles with mid-level ethanol blends (>E10) can successfully operate and that all new gasoline-fuelled vehicles and motorcycles are flex-fuel. Similarly, for biodiesel, a set of qualitative milestones is required to ensure that aging and new diesel-fuelled vehicles can operate with blends higher than B10 as targeted in the long-term goals.

Certainly, there are barriers and gaps in knowledge that might thwart achieving the long-term goals and milestones. The next sections discuss in detail the barriers and gaps in knowledge identified by experts, as well as the recommended action items necessary to overcome them and achieve the goals.

A.2.4. Barriers to implement the bioenergy technology roadmap

Various regulatory, market, technological and public acceptance barriers are identified for accomplishing the long-term goals and milestones.

A.2.4.1. Regulatory barriers

The regulatory barriers to accomplish the goals of the two visions are classified by bioenergy area and shown in Table 2. For biofuels already deployed in the country (i.e. biodiesel and bioethanol), most of the regulatory barriers relate to the lack of a centralized and consolidated authority issuing regulations, defining non-political mechanisms and long-term policies that allow further growth. For the particular case of biodiesel, the lack of regulations and mechanisms for monitoring and controlling the quality of biodiesel at all stages of the supply chain represents another critical barrier.

For power generation and CHP, the lack of an effective regulatory framework and pricing scheme that supports the deployment of renewable energy, distributed and small-scale power generation and CHP represents the largest barrier. It is important to note that up to the date of writing this report, a new legislation on power generation and CHP has been approved (Law 1715 of 2014). As this law has not been regulated yet, the scope and potential impacts of it are not covered in this report. Hence, it is acknowledged that some of the barriers and actions identified in this report might be already addressed by Law 1715.

For other biofuels such as renewable diesel and biomethane, there are currently no regulations or incentives to encourage deployment.

Table 2. *Regulatory barriers*

Vision		Bioenergy area	Regulatory barriers
Vision combining new and traditional technologies		**Biodiesel and bioethanol**	• Currently biofuel regulations are separately defined by different authorities including the Ministry of Mines and Energy, the Ministry of Agriculture and the Ministry of Environment • There is a lack of national long-term targets for biodiesel and bioethanol. Additionally, current biofuel policies are strongly influenced by the political agenda of the government and pressure from third parties (e.g. industry, foreign countries, trading partners, etc.) • There is a lack of regulations and mechanisms for monitoring and controlling the quality of biofuels (particularly of diesel) at all stages of the supply chain • Policies regulating flex-fuel vehicles and vehicles operating high biodiesel blends in Colombia are contradicting and not supportive of further growth in biofuels[5]
Vision combining new and traditional technologies		**Renewable diesel**	• While some regulations have been recently issued (e.g. (MME, 2014)), there are no current incentives to encourage the deployment of renewable diesel
Vision combining new and traditional technologies	Vision focusing on new technologies	**Biomethane**	• There is a lack of an effective regulatory framework, technical standards and an attractive pricing scheme that supports the transformation of residues or waste into alternative biofuels (e.g. biomethane) for energy purposes • There is lack of regulations or incentives to avoid emission of methane (e.g. biogas) to the atmosphere or use it for energy purposes • A barrier for alternative biofuels to substitute and compete with coal (actually the cheapest fuel for industrial use available in the market) is the lack of environmental regulations to penalize coal combustion (source of particulate matter, SOx, NOx, short-lived climate pollutants, etc.)[6] • While in theory the National Fund for Royalties[7] can fund projects associated with biogas/biomethane, in practice it is very difficult. The main reason is that projects proposing only technology transfer are rejected and are required to prove local innovation for support. As Colombia is in an early stage of R&D, fulfilling the requirements of technology transfer and local innovation for alternative biofuel projects might be challenging. Nonetheless, there are successful examples where technology transfer stimulated innovation, such as the biodiesel industry that started importing equipment and currently develops some processes locally.
Vision combining new and traditional technologies	Vision focusing on new technologies	**Power generation and CHP**	• There is the perception among utilities, investors, regulators and policy makers that hydro power is the best solution (i.e. available, cheap and clean), even though it is very climate-dependent and it might compromise grid reliability and vulnerability • There is lack of an effective regulatory framework and an attractive pricing scheme that supports distributed generation beyond bagasse large-scale cogeneration in sugar mills • According to the existing regulation, cogeneration power plants cannot apply for the "reliability charge" incentive[8], which is a stimulus for power generation units able to guarantee the reliability of the system. Therefore, there is a competitive disadvantage compared to the large-scale power generation units (e.g. hydro and thermal power plants), which can effectively apply for this incentive • Despite the fact that cogeneration power plants can currently sell power surplus to the grid, so-called "self-generators"[9] (<10 MWe) are not allowed. However, it is difficult to estimate the real potential and impact of "self-generators", as the installed capacity is unknown • The government is not willing to promote or subsidize technologies that are more expensive than hydro power plants, arguing that the overall emissions related to power generation are low compared to other sectors[10].

[5] Despite decrees 2629 (Alcaldía de Bogotá, 2007) and 1135 (Alcaldía de Bogotá, 2009) defining the mandatory use of flex-fuel vehicles in Colombia as of 2012, decree 4892 (MME, 2011) overruled them and defined a voluntary use of flex-fuel vehicles.

[6] One example of lack of regulations and incentives for promoting alternative biofuels occurs in brick factories, which are allowed to burn any type of fuel (mainly coal, but also diesel fuel, wood and even tires) to produce heat with no regulation on emissions. In this case, alternative biofuels are the least used option because they are less polluting but commonly more expensive.

[7] Fondo Nacional de Regalías; see details in (DNP, 2014).

[8] Cargo por confiabilidad; see details in (CREG, 2014).

[9] Auto-generadores; see details in (UPME, 2004).

[10] In fact, GHG emissions associated with power generation in 2004 were 15 mio ton of CO_2 -eq., which accounted for 8.5% of the total emissions in the country (IDEAM-UNDP, 2009).

A.2.4.2. Market barriers

Market barriers for the two long-term visions are summarized by bioenergy area in Table 3. The principal market barrier for the two long-term visions is the economics of various biomass conversion processes, which are not currently competitive with fossil-based alternatives without subsidies (IEA, 2012b). This barrier is more severe for advanced biofuels and technologies such as biomethane, biogas and renewable diesel than for mature technologies (e.g. first generation biofuels, biogas, etc.). Other market barriers include: a) unfavorable pricing schemes and market conditions, b) vulnerability to the international price of oil and commodities and c) market restrictions to deploy certain technologies. An example of unfavorable pricing schemes and market condition occurs for power generation and CHP as a consequence of regulatory barriers. In this case small-scale power plants are unable to sell power surplus and benefit from incentives, which prevents them from competing with large-scale hydro power plants. An example of vulnerability to the international price of oil and commodities occurs for biodiesel and bioethanol. The reason is that the pricing scheme of biodiesel and bioethanol, ruled by the government, links their local price to the international price of oil, commodities (e.g. palm oil and sugar) and the exchange rate. This makes the local price vulnerable to macroeconomic trends. Finally, examples of market restrictions to deploying certain technologies also occur for biodiesel and bioethanol. In particular, for economic and technical reasons, car manufacturers are not willing to produce or import vehicles able to operate the proposed biofuel blends.

Table 3. *Market barriers*

Vision	Bioenergy area	Market barriers
Vision combining new and traditional technologies	**Biodiesel**	• The cost of producing biodiesel is currently too high to compete with diesel fuel without governmental support • Car manufacturers are currently not willing to produce or to import vehicles able to operate blends with more than 7% biodiesel (by volume). The position of car original equipment manufacturers (OEMs) regarding biodiesel blends is mixed. While many car OEMs support up to B5 (mainly European), others support up to B20 (National Biodiesel Board, 2014). Most of the OEMs supporting up to B5 do not extend the warranty if equipment is damaged by higher blends, unless models are tested on biodiesel blends. In addition, engine manufacturers will not test the impact of biodiesel blends on legacy models. • Market conditions to exploit by-products or sub-products of the palm oil or the biodiesel industry (e.g. biomass-based chemicals, biogas, etc.) are suboptimal • The competitiveness of biodiesel is affected by high volatility in price, which in turn is driven by the price of oil and commodities and the exchange rate
	Bioethanol	• Car manufacturers are currently not willing to produce or to import flex-fuel vehicles to Colombia, arguing that it is a niche market • The cost of producing ethanol is currently too high to compete with gasoline without governmental support • The competitiveness of ethanol is affected by the volatility of international prices of oil and sugar and the exchange rate
	Renewable diesel	• Long-term goals for biodiesel might create competition for feedstock, in particular for palm oil
Vision focusing on new technologies	**Biomethane**	• The cost of producing biomethane either from biogas or syngas might be too high and noncompetitive with the cheapest fuels available in the market (coal for industrial use and natural gas for residential use)
	Power generation and CHP	• The current market for cogeneration power plants (particularly at capacities below 20 MWe) is almost inexistent. There are two potential causes for this: i) small and medium enterprises (SMEs) demanding heat and power are not willing to make significant investments and ii) current process economics are not favorable to self-producing heat and power and selling power surplus to the grid. • While some experts consider that the low price of electricity is a market barrier, the fact is that the electricity price in Colombia is relatively high compared to that of neighboring countries and only behind Brazil and Chile in South America (EIA, 2010)

A.2.4.3. Technological barriers

The technological barriers classified by bioenergy area for the two visions are described as follows.

Bioethanol

- Lignocellulosic bioethanol is not expected to become commercially available in Colombia before 2030, although it is a topic of joint research between Ecopetrol and the National Renewable Energy Laboratory (NREL) (Ecopetrol, 2013).
- Alternative feedstocks to produce bioethanol (e.g. jaggery cane, cassava and red beet) are not expected to be competitive in the short term with cane-based bioethanol in Colombia. There are various reasons for this reasoning, including:
    a. Jaggery cane is a non-concentrated, artisanal industry with limited opportunities to profit from economies of scale. Thus, production costs are high and logistics are difficult.
    b. Despite its small-scale production characteristics, cassava-based ethanol has been tested in Colombia by the national oil company, Ecopetrol (Ecopetrol, 2013). However, the project was cancelled as minimum profitability requirements were not achieved. In contrast to sugar cane, cassava does not provide a by-product that can be used as an energy source.
    c. Red beet-based ethanol by Maquilagro S.A. has also been tested in Colombia with poor results (El Tiempo, 2014). The reasons in this case were low productivity and non-economic performance.
- The results of testing mid-level ethanol blends in aging vehicles in Colombia are not fully acknowledged by all stakeholders. In 2009 the Universidad Tecnológica de Pereira jointly with the Ministry of Mines and Energy and Ecopetrol started testing E12, E15 and E20 in four vehicles. After five years of testing, it was claimed that mid-level ethanol blends did not present serious threats to the operability of gasoline-fuelled vehicles in Colombia (Asocaña, 2010; Asocaña, 2013; Portafolio.co, 2012). However, these claims have been questioned by the car industry and some sectors of academia. One of the main reasons for this skepticism is that previous international experiences using or testing such blends in non-flex-fuel aging vehicles are not conclusive[11]. Moreover, results from test programs in other countries are often contradictory and show that potential impacts of mid-level ethanol blends on an aging fleet are site-specific and strongly dependent on vehicle technologies.
- Other barriers that are not strictly due to the lack of technological maturity but to limited technology transfer or to unsound technological practices exist and hinder a further deployment of bioethanol. These barriers include:
    a. Lower productivities (~70-80 ton-cane/ha) are expected from cultivating cane in regions other than the Valley of the Cauca River, for the following reasons: i) there is limited infrastructure and skilled labor, ii) the soil is not optimal for cane production and ii) new cane varieties should be developed.
    b. Of the cane fields in Colombia, 70% are burned before harvesting to facilitate the collection of stalks (BID-MME, Consorcio CUE, 2012). In this way tops and leaves that could be used in a power plant are wasted, and their combustion generates GHG emissions.
    c. Cane-based bioethanol is currently transported from processing plants in the Valley of the Cauca River to end users throughout the country by diesel-fuelled trucks over long distances rather than by pipeline.

Biodiesel

- Alternative feedstocks to produce biodiesel (e.g. Jatropha curcas, soy, sunflower, algae, etc.) are not expected to be competitive in the short term with today's palm-based biodiesel in Colombia.
- Some issues associated with the production and use of biodiesel remain unsolved:
    a. Tailpipe NO_x emissions increase in reciprocating engines using biodiesel (Demirbas, 2009), which

[11] An example of the use of mid-level ethanol blends in an aging fleet occurred in the late 1970s at the beginning of the Proalcool program in Brazil. In-use vehicles operated ethanol blends of 15% in 1979 and 20% in 1981 without modifications. This was possible because in-use vehicles were manufactured with no emissions or fuel economy requirements (ORNL, 2007). This trend changed in the 1980s, when Proalcool promoted the modification or development of vehicles to run with higher ethanol blends. Other countries have started testing the impacts of mid-level ethanol blends on an aging fleet with contrasting results. In 2003 Australia commissioned a test program by the Orbital Engine Company, which found that materials used in vehicles (similar to Tier 1 vehicles in the U.S.) were not sufficiently compatible with E20 to satisfactorily operate over the lifetime. The U.S. Department of Energy (DOE) initiated in 2007 a test program to assess the impacts of E15 and E20 on tailpipe, evaporative emissions, catalyst and engine durability, vehicle drivability and operability, vehicle and engine materials, as well as on infrastructure material compatibility. Test results indicate that the use of mid-level ethanol blends in 86 Tier 2 vehicles (produced after 2004): a) did not present signs of corrosion or wear in the power train (DOE, 2010), b) did not produce higher exhaust emissions (NOx, CO and NMVOC) compared to aging vehicles on ethanol-free fuels (NREL, 2012) and c) presented a lower fuel economy, lower in proportion to the lower energy density (NREL, 2012). These results have, however, been challenged by the Coordinating Research Council (CRC), an organization founded by automobile and oil companies in the U.S., which also conducted durability tests in 28 aging vehicles running with E15 and E20 (CRC, 2012; CRC, 2013). CRC results claim that E15 could damage valves and valve seals in 2001-2009 vehicles and have been criticized for using a questionable methodology (Bevill, 2012).

might become a significant barrier to expansion.

b. Tailpipe particulate matter and ozone are the most impactful pollutants in the main cities of Colombia (Ruiz Ramos, 2006). While a reduction in particulate matter is expected from using biodiesel blends (Demirbas, 2009; Kousoulidou, 2008), such a decrease remains yet to be proved in the field[12].
c. Biodiesel experiences oxidative degradation over time as a consequence of the high concentration of fatty acids with double bonds. These antioxidant additives might negatively affect the emissions and engine performance (Kalam, 2002; Gan, 2010; Rizwanul Fattah, 2014; Pullen, 2014).
d. The emission of ultrafine particles in reciprocating engines using biodiesel remains to be tested.
e. Best practices on wastewater treatment (e.g. biogas capture and use of residues for energy purposes) are not commonly employed.
f. The majority of methanol used for biodiesel transesterification is produced via petrochemistry, which adversely affects the life cycle emissions of biodiesel (Verhé, 2011).
g. Glycerol obtained as a by-product of the transesterification process presents a limited quality, which requires additional processing to be commercialized (Macario, 2011).
h. Biodiesel crystallization might occur, causing fuel filter clogging and impeding the flow of fuel in cold weather (NREL, 2012).

- There is concern that car manufacturers will not be willing to offer vehicles able to operate with blends containing more than 10% biodiesel by volume. However, various references state that diesel fuel can be substituted by maximum 20% biodiesel with no or minor engine modifications (NREL, 2009; Minnesota Department of Agriculture, 2009; Verhé, 2011), although certain manufacturers do not extend the warranty if equipment is damaged by such blends. Biodiesel can also be used pure, but in this case it does require engine modifications (NREL, 2009). International experiences on the extent to which biodiesel should be blended with diesel fuel is non-conclusive. While in the European Union the majority of blending is in the range 4-7%, in some U.S. states (e.g. Illinois, Minnesota) up to B20 has been successfully used, fulfilling the ASTM D6751 standards and with limited operability issues (NREL, 2009; Verhé, 2011).
- Other barriers that are not strictly due to lack of technological maturity but to limited technology transfer or to unsound technological practices exist and hinder a further deployment of biodiesel:
  a. There is uncertainty about the environmental benefits of using biodiesel as a transport fuel in the Colombian context. Results from a number of studies show that GHG emissions of biodiesel blends strongly depend on land use change, fertilization schemes as well as waste and wastewater treatment practices (BID-MME, Consorcio CUE, 2012; Castanheira, 2014). The influence of land use change is particularly large and significant differences in GHG emissions are expected for biodiesel from palm oil produced in different land types (e.g. cropland, savanna, scrublands, tropical rainforest, etc.). These differences might translate into uncertain environmental benefits if additional land for cultivating palm oil occurs in high carbon stock land (e.g. primary forest, tropical rain forest, etc.) and if waste and wastewater treatment processes are not sustainable.
  b. Some current practices are detrimental to the environmental benefits of biodiesel. Examples include: i) coal and diesel fuel are used to supply heat in biodiesel production plants, ii) feedstocks to biodiesel processing plants and biodiesel to demand users are transported in diesel-fuelled trucks over long distances rather than by pipeline and iii) methane and CO_2 are commonly released from water treatment plants in biodiesel processing plants.

<u>Renewable diesel</u>

- Large-scale processing plants producing renewable diesel (hydrotreated vegetable oil) have begun operation in recent years (IEA, 2011). In addition, the Colombian national oil company, Ecopetrol, has already started analyzing the production of renewable diesel in dedicated or co-processing plants in the country (Ecopetrol, 2013). However, these technologies should demonstrate robust performance and reliable operation in the Colombian context to support expansion (IEA, 2011).
- Processing plants producing renewable diesel might compete with biodiesel production plants for feedstocks, particularly palm oil. Alternative feedstocks are not expected to be competitive with palm-based in the short term. However, processing plants face the challenge of being able to produce renewable diesel from alternative feedstocks (e.g. waste animal fat, vegetable oils, etc.) in the case of palm oil being not sufficient, too expensive or not available.

[12] Various studies have experimentally tested the influence of palm-based biodiesel blends on particulate matter by diesel engines in Colombia. However, results are non-conclusive. While Salamanca et al. (Salamanca, 2012) found a reduction in particulate matter as a function of the biodiesel added to diesel fuel, Rojas et al. (Rojas, 2011) found no significant difference in particulate matter between diesel- and B15-fuelled engines.

- Hydrogen required in the process is produced via petrochemistry, which negatively affects the life cycle emissions of renewable diesel (IEA, 2011).
- Given that the final fuel delivered to end-users of reciprocating diesel engines would contain diesel fuel, biodiesel and renewable diesel, a careful blending is required (NESTE OIL, 2014).
- Similarly to the case of biodiesel, additional land for cultivating palm oil is required to achieve the proposed goals. Then, concerns about land competition, crops for food vs. biofuels and single crop farming remain unsolved.

<u>Biomethane</u>

- Although biomass gasification is a mature technology (IEA, 2012a), it still needs to prove operability, reliability and quality standards in the Colombian context. Additionally, the combination of gasification, syngas clean-up, methanation and upgrade processes increases its complexity. A slow implementation of gasification technologies is expected, given the slow process of technology transfer and demonstration occurring in Colombia. Another challenge of gasification is the production and further use of tars, which remains unsolved.
- An important challenge to ensure the operation of biomethane process plants is to fulfill the quality standards of pipeline natural gas (e.g. pressure, water content, contaminants, etc.). In particular, careful attention should be paid to removing CO_2, water, hydrogen sulfide and its oxidation products (Stamatelatou, 2011).

<u>Power generation and CHP</u>

- While renewable power generation (excluding large hydro) is not new in Colombia[13], considerable technological challenges are expected from increasing the renewable target to 10% in 2025. These challenges include:
    a. A significant increase in installed capacity of renewable power is necessary. This additional capacity needs to be carefully planned to ensure a safe planning reserve margin and should therefore account for a typically lower availability factor of renewable power technologies compared to base load power plants.
    b. Renewable power must ensure robust performance, reliability and economic feasibility in the Colombian context.
    c. Sustainable operation of biomass-based power generation must be ensured. This means that the volumes of feedstock to run the power plant are assured.
    d. There is a lack of local companies developing renewable power generation and CHP technologies. However, both technology transfer and local manufacturing and R&D are necessary to ensure continuity of projects.
- Some past experiences using biomass-based energy technologies in the country were not successful. Examples include:
    a. A small-scale cogeneration system installed in 1969 in Capote Field burning wood residues ceased operation as a consequence of non-sustainable wood management and the subsequent depletion of resources (AENE, 2003).
    b. An incinerator of municipal residues installed on the island of San Andrés ceased operation because of an insufficient volume of residues.
    c. The installation of a wood gasifier in Necoclí (Antioquia, Colombia), a non-interconnected zone (NIZ), ceased operation because the town eventually gained connection to the national grid (Cuevas, 2013).
- Various facilities using biomass for energy purposes currently employ obsolete technology, which, in many cases, aim at disposing of biomass residues rather than producing energy efficiently.
- Many companies producing large amounts of residues (e.g. agriculture, forestry and wood industry, livestock, etc.) have limited knowledge of technologies for power generation and CHP. This gap in knowledge contributes to undermining the trust in implementing these technologies.
- The following barriers associated with the exploitation of biogas and landfill gas were identified:
    a. While to a certain extent biogas has been produced via biodigestion and used for in situ heating in the porcine industry (CNPML, 2009), experience on biogas use for power generation and CHP is limited in Colombia. Similarly, the landfill gas collected in various landfill sites is commonly flared or vented and, to a very limited extent, used for power generation (most likely due to the high cost of electricity).
    b. While the energy potential of biogas from livestock and agro-industrial waste has recently been estimated (CNPML, 2009), there is a lack of studies estimating the energy potential associated with biogas production in water treatment plants nationwide.
    c. The economic viability of projects exploiting biogas and landfill gas for power generation and CHP would strongly depend on size. Most likely not all projects of this kind would prove feasible.

[13] Up until 2009 the installed capacity of renewable power generation excluding large hydro was 852.5 MWe, of which 519 MWe corresponds to small hydro, 205 MWe to bagasse CHP, 18.4 MWe to wind and 110 MWe to waste. In total, the renewably generated electricity amounted to 1.2 TWh (UPME, 2011a).

A.2.4.4. Public acceptance barriers

Public acceptance barriers can be divided into three categories: a) lack of acceptance of the current regulatory framework, b) overlooking benefits associated with bioenergy and c) lack of acceptance of new technologies (see Table 4). Various stakeholders including end-users, smallholders, farmers and sectors of academia consider the current regulatory framework and commercialization scheme of biofuels (viz. bioethanol and biodiesel) to be inappropriate. On the other hand, the benefits of distributed generation and CHP are not perceived by sectors of the government, utilities and investors mainly because large hydro is considered the best option. Regarding new technologies, such as biomethane and renewable diesel, there is a perception that there is lack of collaborative projects between OEMs, utilities, SMEs and universities.

A.2.5. Action items to implement the bioenergy technology roadmap

In order to overcome barriers and achieve the envisioned long-term goals and milestones for the two visions, various action items are required. The multiple action items are divided into: a) sustainability, b) regulatory, c) financing mechanisms and business development and d) technological.

A.2.5.1. Sustainability action items

Bioenergy is considered an alternative energy to reduce greenhouse gas emissions, decrease oil dependence, enhance rural development and diversify the energy matrix. However, significant concerns need to be addressed to make use of bioenergy. Hurdles include the presumed negative environmental impact, land use competition, crops for food vs. biofuels, direct and indirect land use change, deforestation, pressure on water resources, etc. In the Colombian context, additional concerns need to be considered. A 50-year armed conflict resulted in massive internal displacement of civilians, farmers and indigenous communities by illegal armed groups. Abandoned land was usurped, illegally traded and used for agriculture, mining and other purposes (UNDP, 2011). In addition, public policies ruling rural areas have historically privileged large landholders over small farmers and have supported low productivity activities (e.g. extensive cattle farms) with limited capacity to create jobs (UNDP, 2011). Therefore, a more symmetric and democratic land distribution that allows a more productive and environmentally friendly use of rural land should be a priority. The deployment of bioenergy technologies should be bound to ensure not only environmental and economic benefits, but also rural and social development. The inclusion of all stakeholders, particularly small- and medium-scale farmers, in the decision-making process of deploying bioenergy technologies is therefore essential. In this context, the victims and land restitution land law (Law 148) issued in 2011 in Colombia (MIJ, 2011) is certainly a step in the right direction.

<u>Sustainability criteria</u>

There is scientific consensus that sustainability requirements and certification schemes are necessary to monitor environmental and social sustainability of bioenergy policies (GBEP, 2011a). Certification schemes also offer several advantages to biomass growers and bioenergy producers. On one hand, certification schemes ensure a credible standard to demonstrate benefits to tax payers and authorities. On the other hand, stakeholders can be recognized for the environmental, social and economic sustainable production of bioenergy. Strategic planning of land use should be emphasized to avoid deforestation, loss of biodiversity, displacement of communities, water and soil pollution, increasing gap between rich and poor and overall negative impacts. Various national and international initiatives and approaches for the sustainability certification of bioenergy have been recently proposed and developed worldwide.

More than 15 different certification schemes were identified in (Scarlat, 2011), which can be classified into the following categories: a) approaches with mandatory sustainability requirements, b) certifications for crops used as feedstock, c) national biofuel certifications and d) international biofuel certifications. Despite the rapid development of certification schemes globally, there is a lack of harmonized methodologies across approaches (Scarlat, 2011). Nevertheless, a general consensus on bioenergy sustainability criteria and a globally accepted GHG calculation framework is found in the Global Bioenergy Partnership (GBEP) (GBEP, 2011a). GBEP has developed a set of 24 sustainable indicators for the assessment and monitoring of bioenergy sustainability at a national level. This set of indicators has recently been tested in various countries, including Colombia (FAO-GBEP, 2014). Lessons learnt from testing the GBEP indicators in Colombia include: a) testing confirmed the usefulness of GBEP indicators to inform policymakers about the sustainability of bioenergy in the country and b) GBEP indicators are data and skills intensive; therefore, stakeholder engagement is necessary to get access to key data, process and interpret results. Although a dedicated effort to select and define bioenergy sustainability criteria for Colombia is certainly beyond the scope of this study, an exploratory scheme on the sustainability of bioenergy is suggested. This sustainability scheme also aims at mitigating the multiple public acceptance barriers identified in Section A.2.4.4.

Table 4. *Public acceptance barriers*

Vision	Bioenergy area	Public acceptance barriers
Vision combining new and traditional technologies	**Biodiesel and bioethanol**	• While the current regulatory framework is designed to ensure a minimum profitability to local biofuel producers by controlling the biofuel price and the blend mandate quota, it does it at the expense of higher costs to consumers. • Biofuels used in Colombia are typically characterized by having lower energy content than corresponding fossil fuels. However, the current biofuel pricing system does not acknowledge this effect, which results in higher costs per unit of energy for end-users compared to fossil fuels. • The current regulatory framework does not include mechanisms to protect the interests of consumers. • Subsidies and other benefits are granted even though local biofuel producers are not subject to a verifiable increase in rural jobs, increase in rural development in areas producing bioenergy, or reduction in life cycle GHG emissions. • Subsidies to biofuels do not have a deadline or a gradual phase-out, which does not encourage local biofuel producers to become price-competitive over time. • There is a serious concern with land use competition, the dilemma of crops for food vs. biofuels and the dependence on single crop farming (e.g. cane for producing bioethanol and palm oil to produce biodiesel). In the particular case of palm oil, there is concern that crop expansion in the last decade involved the forced migration of farmers, indigenous communities and ethnic minorities, deforestation and loss of biodiversity. • There is concern over the existing business model, in which farmers cultivating palm oil on a small scale sell their production to large commercialized companies. While the farmers must take financial risks for cultivating the plant, only the commercialized companies have access to governmental aid (El Espectador, 2013). • There is concern among end-users about the malfunction and failure of legacy or new vehicles caused by the increasing biofuel quota mandate. In the particular case of biodiesel, there is concern about the poor quality of the blend distributed in some regions. • Some stakeholders consider electric mobility a more effective way to reduce GHG emissions in the transport sector than biofuels. • There is a lack of communication and divulgation of results related to biofuels among universities and research institutions.
	Renewable diesel	Renewable diesel presents several advantages compared to biodiesel, e.g. higher energy content, higher cetane number, no detrimental effect on final boiling area, possibility to use current infrastructure. However, if palm oil is used as feedstock, the concerns about land competition, crops for food vs. biofuels and single crop farming remain unsolved.
Vision focusing on new technologies	**Biomethane**	• There is a lack of collaborative projects on biomethane production among OEMs, experienced companies, local utilities, SMEs and universities. • There is the perception among some stakeholders that collecting 5% of the residues and animal waste resources for biomethane production is not feasible, the reasons being difficult logistics and unfavorable process economics.
	Power generation and CHP	• The benefits of distributed generation (e.g. reduction in distribution losses) and cogeneration (e.g. energy savings, reduced consumption of fossil fuels) are not known, perceived or acknowledged by sectors of the government, utilities and investors. • There is concern about the risk of deforesting and clearing tropical forests to supply wood for biomass-based power plants. • There is the perception that the power market is dominated by large utilities, which do not easily allow small producers to sell their power surplus and compete in the market. Additionally, there is a lack of collaborative projects among OEMs, experienced companies on renewable power generation, local utilities, small and medium power producers and universities. • There is the perception that using biogas from water treatment plants is less impactful than other options, e.g. reducing GHG emissions from raising cattle.

It is strongly recommended, however, that environmental authorities take a leading role in defining a more detailed framework for bioenergy certification schemes in Colombia and consider lessons learnt from pilot testing the GBEP indicators in the country. The following proposed bioenergy sustainability scheme is recommended to be bound to the long-term goals defined in this roadmap:

- Biomass conversion to electricity, heating or cooling should reach a minimum requirement for GHG savings, for example of 40% relative to fossil fuels in 2015, 50% in 2020 and 60% in 2025.
- Biofuels should reach a minimum requirement for GHG savings, for example of 40% relative to fossil fuels in 2015, 50% in 2020 and 60% in 2025.
- GHG savings should include emissions from cultivation, processing, transport, distribution and direct land use changes. Indirect land use changes (ILUC) must be included, but only after the scientific community reaches consensus on a sound accounting methodology. Methodology to calculate GHG savings should be widely recognized by the scientific community; examples include the Renewable Energy Directive 2009/28/EC of the European Union (EC, 2009a; EC, 2009b), the GBEP framework for GHG life cycle analysis of bioenergy (GBEP, 2011b), the Roundtable on Sustainable Biofuels GHG Calculation Methodology (RSB, 2011), among others.
- Land categories excluded for bioenergy production include: a) natural parks and protected forests, b) tropical forests, native rain forest and wooded land, c) highly biodiverse ecosystems (wetlands, swamps, páramos, biodiverse savannah, etc.) and d) land with high carbon stock.
- Forests used to supply wood to energy projects (e.g. power generation, biofuels, biomethane, etc.) should comply with the certification of the Forest Stewardship Council (FSC), which is the best certification currently available (Leonard, 2010). Tropical forests or forests with indigenous vegetation must not be replaced by tree plantations. Tree plantations are monocultural fields of imported species, which provide relatively few jobs, increase the use of pesticides and negatively impact water cycles (Meadows, 1997). It might be advisable to use tree plantation only in eroded or degraded land.
- Biomass conversion and biofuels production must ensure that the quality of groundwater and surface water remains at high standards (a 5-day carbonaceous BOD[14] below 2 mg/L) for human consumption, small-scale farming and fishing. In addition, it is advisable that these processes must regularly report their associated water footprint, which is the total volume of fresh water used.
- Monitoring and reporting is mandatory and should be rigorously supervised by environmental authorities.
- Additional economic and tributary incentives should be given to conversion of waste, residues, non-food cellulosic and lignocellulosic biomass into energy.
- The participation of local indigenous communities (natives, Afro-Colombians and members of other minorities) in the decision-making and the environmental planning process of projects affecting their land, resources and communities must be secured and protected. This in accordance with the United Nations Declaration on the Rights of Indigenous People adopted in 2007 (UN, 2007). Thus, permits to use land for bioenergy purposes fulfilling environmental requirements must be jointly evaluated by indigenous communities, and regulatory and environmental authorities.
- As it is expected that biofuels and bioenergy will become more price-competitive over time, subsidies and economic incentives should not be indefinite and should start declining by 2015.
- Access to subsidies and tributary incentives should be subject to a verifiable increase in rural jobs, and rural development (e.g. increase in rural GDP, infrastructure, etc.) in areas producing bioenergy, reduction in life cycle GHG emissions, protection of water sources and biodiversity and non-use of land categories excluded from bioenergy production.
- It is advisable to jointly revise and re-design the current biofuel regulatory framework with representatives from consumers, smallholders, farmers and academia. Topics to address include: a) appropriateness of subsidies, b) pricing system, c) mechanisms to protect the end-users, d) responsibilities of local biofuel producers to ensure sustainable operation, reduce GHG emissions, increase rural jobs, etc.

A.2.5.2. Regulatory action items

Regulatory action items classified by bioenergy area for the two visions are summarized in Table 5. For bioethanol and biodiesel, it is firstly advisable to unify and centralize the definition of policies, regulations and long-term goals. It is also necessary to modify the existing policy framework (viz. to enable E20 in 2025, B30 and E85 in 2030, to implement a flex-fuel framework, to regulate the compliance of a sustainability scheme) to achieve the proposed long-term goals.

[14] Biochemical oxygen demand

Table 5. *Regulatory action items*

Vision	Bioenergy area	Regulatory action items
Vision combining new and traditional technologies	**Biodiesel and bioethanol**	• It is advisable that policies and regulations for biofuels are jointly created by the Ministry of Mines and Energy, the Ministry of Agriculture, the Ministry of Transport and the Ministry of Environment, or alternatively by a new institution, with members from these ministries, that centralizes actions and policies. This offers various benefits: a. It would unify the official position of the government towards biofuels. b. It would define a clear and unambiguous set of national long-term goals for biofuels, aiming at improving the sustainable development of the country. c. It would centralize the definition of standards and rules (e.g. the bioenergy sustainability scheme), aiming at reducing the political influence of third parties on biofuel policies. d. It would encourage a multidisciplinary discussion within the government to address biofuels from an energetic, agricultural and environmental perspective. • It is required to implement a regulatory framework enabling: a) a gradual increase in quota mandate to B20 in 2020, E20 in 2025 and B30 in 2030 and b) the implementation of an E85 fuel program in 2030. • It is required to implement a clear and definitive regulatory framework to force the introduction of flex-fuel vehicles (FFV) as of 2017. It would ensure that all new vehicles and motorcycles commercialized in the country are FFV and can satisfactorily operate with any blend of ethanol and gasoline. This regulatory framework should also force the introduction of diesel-fuelled vehicles able to operate blends higher than B10. Additionally, it would be advisable to design this framework in such a way that it does not block introduction of other vehicle alternatives, such as electric and hybrid vehicles. • It is advisable to implement a regulatory framework to supervise and verify that local biofuel producers comply with the requirements of the sustainability scheme. It is also necessary, particularly in the biodiesel case, to control the quality of the biofuel at all stages of the supply chain.
	Renewable diesel	It is required to implement new regulations and legislation to enable the deployment of renewable diesel targets by 2030.
Vision focusing on new technologies	**Biomethane**	It is required to modify existing regulations and legislation to: a. Enable the implementation of biomethane targets by 2030. b. Stimulate the substitution of highly-pollutant coal by biogas/biomethane in various sectors either by penalizing emissions, by offering incentives (tariff exemption for importing/developing equipment, tax reduction, support for demonstration projects, etc.) or by combinations thereof. c. Create a mechanism to stimulate an efficient use of biomass residues and animal waste (urban and non-urban) for energy purposes. Potential solutions include price bonuses for effective waste management solutions, tariff exemption for developing equipment, tax reduction for imports, support for demos, etc. d. Control and monitor the disposal of organic waste in landfills.
	Power generation and CHP	• The most appropriate framework to support a new power generation and CHP policy is the national renewable energy auction. It is considered the most appropriate because it respects the principle of equal opportunity and competitiveness among different technologies (a characteristic of the Colombian electricity framework), it limits the risk for investors and it increases the predictability of the renewable energy supply (IRENA, 2013). However, it should be carefully designed and acknowledge the experiences of other countries in order to avoid failures (e.g. favoring large players, discontinuous market development and risk of underbidding (IRENA, 2013)). • It is required to modify existing regulations and legislation to: a. Enable the implementation of a 10% renewable target by 2025, biogas and landfill gas targets by 2030. b. Allow “self-generators” to sell power surplus to the grid. Additionally, it is advisable to estimate the actual installed capacity to evaluate the real impact of “self-generators”. c. Allow cogeneration power plants to apply for the reliability charge incentive. d. Allow the implementation of clusters of hybrid power plants (combination of different technologies, e.g. wind, small-hydro and biomass) to increase availability, reliability and risk mitigation not by power plant but by cluster. e. Stimulate the capture and use of biogas produced from animal waste, municipal water treatment plants and biodiesel plants either by penalizing emissions or offering incentives. f. Stimulate the capture and use of municipal landfill gas either by penalizing emissions or offering incentives.

For power generation and CHP, it is recommended to implement a renewable energy auction scheme, modify the existing policy framework to enable a renewable target of 10% in 2025 and stimulate the deployment of distributed generation, CHP, biogas, and landfill gas. For biomethane, it is appropriate to stimulate an efficient use of residues and encourage the substitution of highly pollutant coal in order to achieve the targets by 2030. Finally, for renewable diesel, a new policy is required to enable the implementation of a 10% energy contribution by 2030.

A.2.5.3. Action items on financing mechanisms and business development

Action items on financing mechanisms and business development are summarized in Table 6. In general, it is recommended that incentive programs to encourage the use of bioenergy through tax incentives and the local development of technologies are implemented. These incentive programs aim to reduce the production costs of bioenergy technologies, improving the efficiency of supply chains and conversion processes, improving the national competitiveness and supporting the local development of machinery, equipment and R&D. For this purpose it is crucial to seek partnerships with OEMs, utilities, SMEs and universities to build demonstration and pilot projects, etc. Additionally, new initiatives for providing services and energy solutions (e.g. Energy Service Companies –ESCOs–) are required to support the incipient industry of distributed power generation.

A.2.5.4. Technological action items

Technological action items by bioenergy technology area are described as follows. Technologies recommended for deployment by bioenergy technology area are summarized in Figure 4.

Bioethanol

- It is recommended to further deploy cane-based bioethanol with continuous fermentation and vinasse recirculation, subject to compliance with the sustainability scheme. The main benefit of vinasse recirculation with yeast and organic matter separation is a lower vinasse production (0.8-3 l-vinasse/l-ethanol) than the ferti-irrigation approach used in Brazil (8-12 l-vinasse/l-ethanol) (BID-MME, Consorcio CUE, 2012). Additionally, it is recommended to continue deploying water treatment plants for effluents to ensure high quality standards for groundwater and surface water.
- A satisfactory operation of non-flex-fuel aging vehicles and motorcycles with mid-level ethanol blends (> E10) must be ensured. It is recommended to start a well-coordinated test campaign involving all stakeholders, i.e. government, car and oil industry, biofuel producers, universities, standards organizations and end-users. Further recommendations include:
  a. Test a statistically representative sample of the existing vehicle fleet. For instance, 86 and 28 vehicles were respectively tested by DOE (DOE, 2010) and CRC (CRC, 2012; CRC, 2013). Design a test methodology that acknowledge results from previous international experiences and that might be reproduced and verified by the scientific community.
  b. Assess the effects of aging vehicles with mid-level ethanol blends and identify potential operability issues under real operating conditions in Colombia.
  c. Define a mitigation plan to avoid operability issues. A mitigation plan might include for instance the possibility to maintain E10 in fuel stations to allow consumers to choose their blend.
- Rigorous environmental studies subject to verification must be undertaken, including analyses of the impact of expanding cane cultivation on direct land use change (include ILUC only once scientific consensus on a sound methodology has been reached), water demand and wastewater produced, impact on biodiversity, impact of vinasse disposal on soil, groundwater and surface water, and finally life cycle emissions.

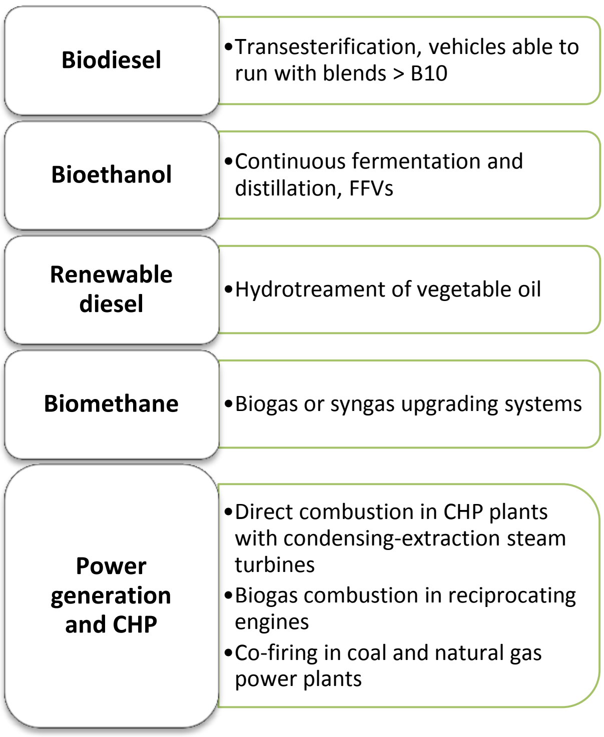


Figure 4. *Technologies to deploy by bioenergy technology area*

Table 6. *Action items on financing mechanisms and business development*

Vision	Bioenergy area	Action items on financing mechanisms and business development
Vision combining new and traditional technologies	**Biodiesel and bioethanol**	• Implement a program to reduce the cost of producing bioethanol and biodiesel by improving the efficiency in harvesting, collection and exploitation of residues (e.g. cane leaves and tops and palm oil rachis), wastewater treatment practices (e.g. methane capture) and conversion processes (e.g. boilers and CHP systems). This program might be accompanied by benefits for developing or importing appropriate machinery and equipment • Implement an incentive program primarily aimed at encouraging the local development or assembly of vehicles able to operate with high biofuel blends (e.g. flex-fuel vehicles for bioethanol) or secondly at reducing the import tariffs. Seek partnerships with OEMs willing to locally develop, assemble or import such vehicles • Implement an incentive program aimed at reducing import tariffs or the value added tax (VAT) for importing agricultural supplies used by local producers of biomass and biofuels
	Renewable diesel	• Implement a careful plan for managing palm oil production and distribution to biodiesel and renewable diesel processing plants in order to reduce the impacts of competition for feedstocks. Additionally, implement a mitigation plant to identify and manage alternative feedstocks
Vision focusing on new technologies	**Biomethane**	• Implement an incentive program aimed at encouraging the substitution of cheap fossil fuels (e.g. coal, diesel fuel, etc.) by biomethane (pure or blended with natural gas) either by penalizing the consumption of fossil fuels or by reducing taxes on biomethane
	Power generation and CHP	• Implement an incentive program aimed at encouraging the operation of small scale and distributed power plants and CHP through tax benefits and technical support. Additionally, encourage the local development or assembly of distributed and renewable energy technologies. It is crucial to seek partnerships with OEMs, utilities, SMEs and universities to build demonstration and pilot projects, etc. • New initiatives for providing services and energy solutions are required to support the incipient industry of distributed power generation and CHP. It would be advantageous to promote the creation of Energy Service Companies (ESCOs), able to provide energy savings projects, energy efficiency solutions, implementation of renewable energy sources, risk management, etc. However, a program for the promotion of ESCOs should be carefully designed in order to avoid the most common failures, e.g. lack of trust among investors, perceived high technical and business risk, lack of policy mechanisms to support ESCOs, high transaction costs, etc. (Bertoldi, 2007; Kostka, 2011)

- Various improvements to sugar cane cultivation and processing are recommended to enhance productivity and environmental performance, including:
  a. Transport of bioethanol from production sites to demand sites via pipeline.
  b. Avoid cane burning before harvesting. Deploy mechanical harvesting and recovery and exploitation of cane residues (e.g. leaves and tops) in CHP systems.
- Even though various topics are not part of this roadmap, it is recommended to start monitoring them and perform feasibility studies in the short term. These topics include biorefineries, lignocellulosic ethanol, bio-butane, drop-in biofuels and bioethanol direct cylinder injection in gasoline and diesel engines.

Biodiesel

- It is recommended to further deploy palm-based biodiesel via transesterification equipped with water treatment plants and subject to compliance with the sustainability scheme.
- A satisfactory operation of legacy vehicles operating with blends > B10 must be ensured. Similarly to the case of bioethanol, a well-coordinated test campaign involving all stakeholders and including the abovementioned guidance is highly recommended. A mitigation plan might include, for instance, the possibility of maintaining B10 in fuel stations to allow consumers to choose their blend.
- Rigorous environmental studies subject to verification must be undertaken (similarly to bioethanol).
- Various improvements to palm oil cultivation and processing are recommended to enhance productivity and environmental performance, including:
  a. Transport of biodiesel from production sites to demand sites via pipeline. Additionally, avoid construction of biodiesel processing plants far away from palm oil cultivation to minimize the transport of feedstock and potentially benefit from using palm oil residues and sub-products in energy processes.
  b. Avoid using coal and diesel fuel to supply heat. Deploy strategies to efficiently recover and exploit palm oil residues (e.g. rachis) in CHP systems.
  c. Deploy technologies to capture methane from wastewater plants.
- Further research is required to reduce the negative impacts associated with biodiesel blends. Topics include reduce tailpipe NO_x, particulate matter and ozone, reduce the negative impacts of antioxidant additives, reduce the impact of biodiesel crystallization on engine operability, etc.
- Even though various topics are not part of this roadmap, it is recommended to start monitoring them and perform feasibility studies in the short term. These topics include biorefineries, glycerol-free processes (e.g. Ecodiesel®, DMC-Biod®, Gliperol®), second and third generation biodiesel (using jatropha, brassica, algae, etc.).

Renewable diesel

- Long-term goals for renewable diesel can be reached using hydrocracking or hydrogenation of vegetable oil, which are in an early commercial phase and are expected to become available in Colombia by 2015. It would be advantageous to deploy these plants as stand-alone as well as integrated into a standard oil refinery.
- Rigorous environmental studies subject to verification must be undertaken (similarly to bioethanol).
- Further research is required to find ways to economically produce hydrogen from renewable sources and to carefully blend diesel fuel, biodiesel and renewable diesel.

Biomethane

- It is recommended that two technologies are deployed, depending on the feedstock: a) the purification of biogas from animal waste and b) syngas via gasification followed by methanation to convert biomass residues. While biogas purification is a mature technology, gasification and methanation are in an early commercial stage.
- Further research is required to increase the ability to process different types of feedstocks, to improve syngas cleaning (e.g. tar removal) and upgrade, and to reduce operability issues (particularly for biomass gasification). In addition, it is crucial to seek partnerships with OEMs, utilities, SMEs and universities to ensure that technology transfer encourages local innovation on this topic.

Power generation and CHP

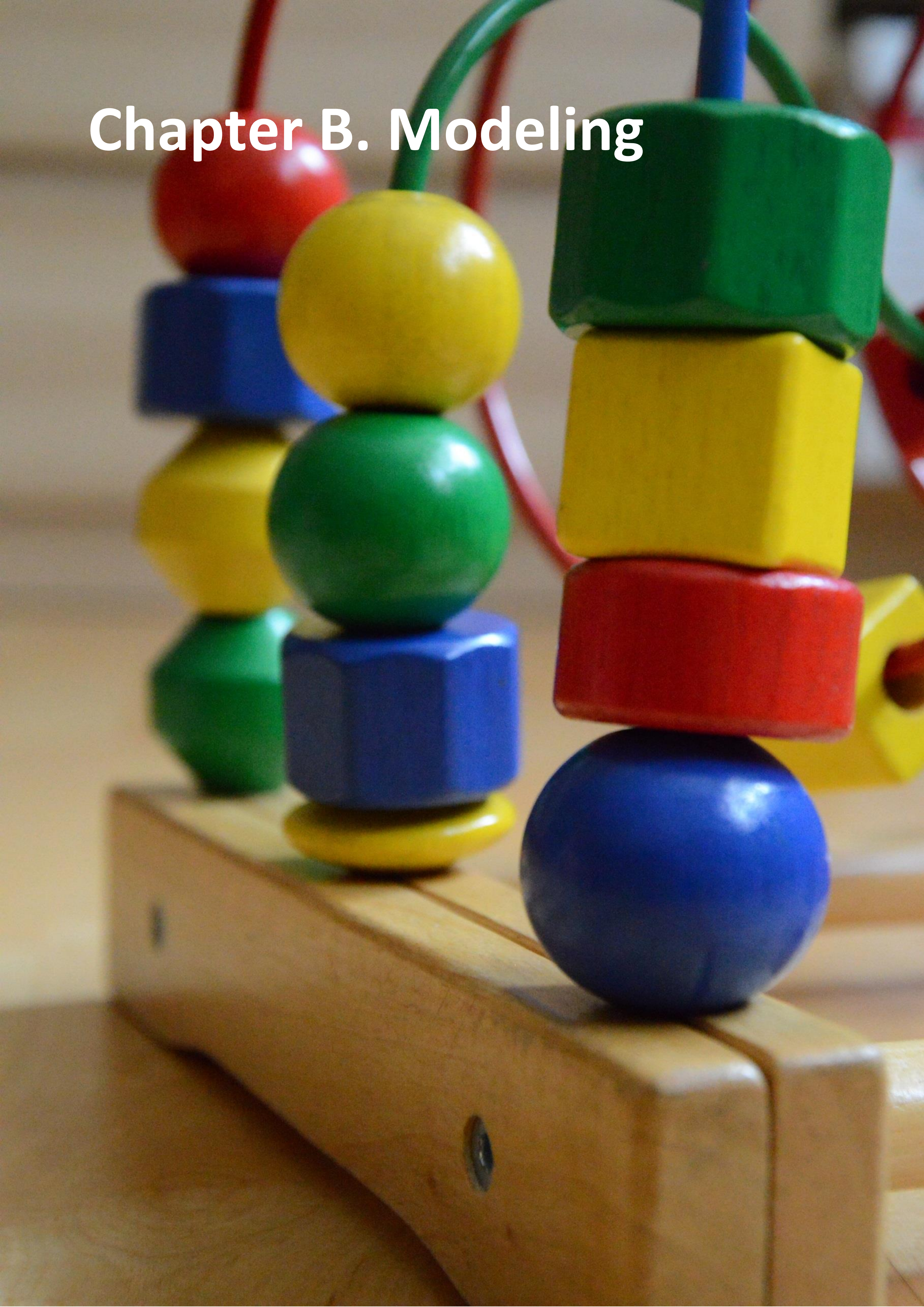
- To achieve the renewable target of 10% in 2025, it is recommended to deploy onshore wind, small-hydro and biomass power plants. Other renewable energy technologies (e.g. solar, geothermal, offshore wind, etc.) are not included in this roadmap, but it is recommendable to monitor their development and start feasibility analyses in the short-term.
- It is recommended that various biomass-based power generation technologies, are further deployed, including:
  a. Direct combustion in CHP power plants using condensing-extraction steam turbines. Feedstocks include wood residues, bagasse, cane tops and leaves, bagasse from jaggery cane, rice husk, and palm oil residues.

Additional burners for supplementary heat supply are also included.

b. Co-firing in coal power plants using biomass pellets from wood residues and agricultural residues. Co-firing in natural gas power plants using syngas from gasified wood residues and agricultural residues. Additional burners for supplementary heat supply are also included.
c. Combustion of landfill gas and biogas in reciprocating engines for power generation and CHP.

- To mitigate the technical and financial risks associated with renewable power, it is recommended to seek partnerships between OEMs, utilities, local companies and universities, to start demos and pilots in the short term that might lead to commercial projects in the medium term. An option might be to develop small-scale projects in non-interconnected zones that might lead to mid- and large-scale projects in areas connected to the grid. It is crucial to acknowledge past experiences and design strategies to ensure sustainable operation by involving local communities. It is also necessary to encourage technology transfer combined with local manufacturing to ensure the continuity of projects and know-how creation. It is critical to educate the industrial sector of the benefits of distributed generation, renewable power generation and cogeneration and exploitation of biomass residues, animal waste and by-products.
- It is recommended that clusters of hybrid power plants (a combination of different technologies, e.g. wind, small-hydro and biomass) are implemented, thereby increasing availability and reliability not by power plant but by cluster.
- The best practices of the sugar cane and paper industry engaged in cogeneration should be replicated to other crops producing large amounts of residues and consuming energy, such as palm oil, jaggery cane, rice, coffee, coconut, etc.
- Further research is required to evaluate the impact of replacing hydro power by biomass-based power. For instance, a complementing effect might be expected in dry seasons when the availability of bagasse-fired CHP tends to increase, while the availability of hydro power tends to reduce. Potential advantages include a higher availability and grid reliability and a reduced consumption of fossil fuels to replace hydro.
- Rigorous environmental studies, subject to verification, must be undertaken (similarly to bioethanol).
- Even though various topics are not part of this roadmap, it is recommended to start monitoring them and perform feasibility studies in the short term. These topics include: biomass pretreatment processes (torrefaction and pyrolysis), biomass combustion with organic Rankine cycles (ORC), gasification in gas turbines, etc.

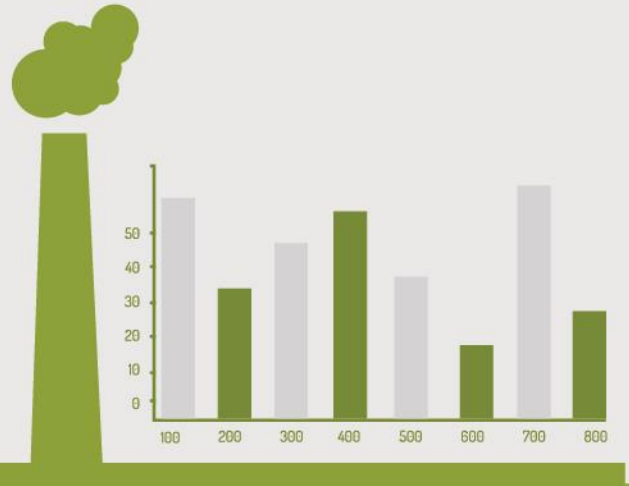
Chapter B. Modeling



Highlights Chapter B

1

A modeling methodology combining a scenario analysis with an energy system model (ESM) and a land use and trade model (LUTM) is proposed to evaluate the impacts of implementing the two long-term visions.



2

In a scenario analysis three main possible future storyline are defined:

- Baseline scenario: it assumes no change in policies or deployment of new technologies.

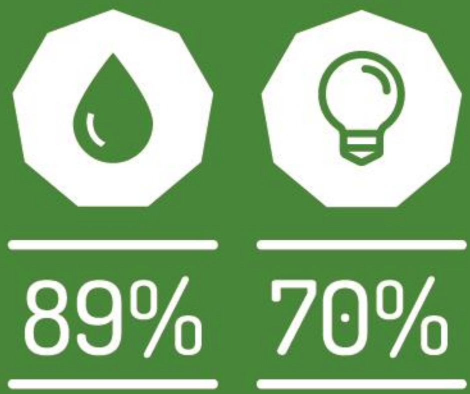
- Scenario I: it assumes new policy measures for biomethane and power generation & CHP.

- Scenario II: it assumes new policy measures for all bioenergy technology areas. A subset (Scenario II with expansion) is also defined to consider a significant expansion in cultivation land.

3

The energy system model (ESM) is a data-intensive, scenario-based model that combines various methodologies to comprehensively replicate the behavior of the country's energy system:

- End-use techniques: stock-turnover economic analysis, dynamic engineering analysis, etc.
- Techno-economic assessment: optimization of power generation technologies.
- Technical assessment: merit order analysis.
- Econometric techniques.



4

A land use and trade model (LUTM) was developed to estimate the land requirements necessary to accomplish the roadmap targets. This model estimates land allocation as well as production, imports and exports of 18 agricultural and forestry commodities.

B.1. Methodology

B.1.1. Overview

GBEP considers that a comprehensive analysis of the sustainability of bioenergy policies must be supported on three pillars: environmental, social and economic (GBEP, 2011a). The present study focuses only on the quantification and analysis of the impacts that implementing various bioenergy policies might cause on the energy supply and demand, energy-related GHG emissions and land use. Hence, a complete analysis of the social (i.e. job creation, improvement of the Human Development Index, etc.), environmental (i.e. life cycle GHG emissions, water footprint, impact on biodiversity, etc.) and economic impacts of implementing such policies is not covered and is considered beyond the scope of this study.

A modeling methodology combining a scenario analysis with an energy system model (ESM) and a land use and trade model (LUTM) is proposed to evaluate the impacts that implementing the two long-term visions might cause on the energy supply and demand, the energy-related GHG emissions and the land use. A scenario analysis is employed to define various possible future storylines characterized by different underlying assumptions on policy measures. The defined scenarios and their characteristics are then used as inputs in a very detailed energy system model (ESM), in order to evaluate the impacts on energy demand, supply and infrastructure as well as greenhouse gas emissions. In parallel, a land use and trade model (LUTM) linked to the energy system model (ESM) is used to estimate the effects that the implementation of the different scenarios might cause on land use and trade. A schematic representation of the modeling methodology is shown in Figure 5.

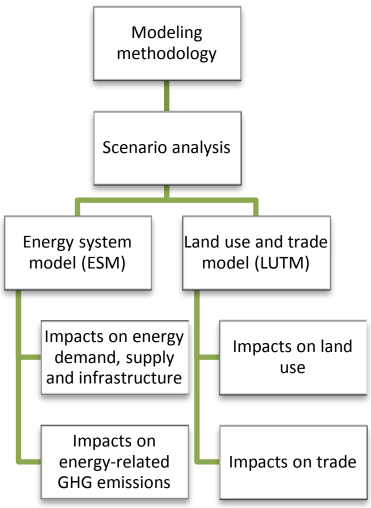


Figure 5. *Modeling methodology*

B.1.2. Scenario analysis

Opposing views of experts on the future of first generation biofuels led to two long-term visions: one vision focusing on new technologies (e.g. biomethane and power generation and CHP) and other one combining new and traditional technologies (e.g. first generation biofuels). A scenario analysis is proposed to evaluate the impacts of implementing these two visions, rather than selecting either. Scenario analysis is an effective method to address uncertainty associated with future events in which various possible alternative future storylines are considered. It is not intended to provide forecasts, but rather to represent possible future alternatives subject to particular conditions. It is a powerful tool to improve decision-making by allowing evaluation of how the different alternatives evolve over time, their effectiveness and impact.

In this roadmap, the scenarios represent possible long-term visions about the deployment of bioenergy technologies, which are primarily differentiated by their underlying assumptions on government policies. Three main scenarios are defined: a baseline scenario and two scenarios describing the two contrasting visions regarding the future of transport biofuels (i.e. bioethanol, biodiesel and renewable diesel):

- **Baseline scenario**: it assumes no change in policies or deployment of new technologies
- **Scenario I (focusing on new technologies):** it assumes new policy measures for biomethane and biomass-based power generation and CHP
- **Scenario II (combining new and traditional technologies):** it assumes new policy measures for all bioenergy technology areas

Firstly, a baseline scenario assuming no future change in policies or technologies was created and calibrated using the national energy balances (UPME, 2011a). It allows a description of how the energy system would unfold if policy measures, patterns of supply and demand and deployment of technologies remain unchanged. Scenario I (focusing on new technologies) considers new policy measures for biomethane and biomass-based power generation and CHP, but unchanged policies for transport biofuels through till 2030. This is a scenario with a vanguard vision regarding the deployment of efficient power generation technologies (i.e. biomass-based CHP and co-firing) and new technologies (i.e. biomethane), but with a prudent vision regarding the deployment of first generation transport biofuels. It is therefore a scenario that aims to deploy efficient technologies in terms of environmental performance and land use, while maintaining the current deployment of first generation transport biofuels.

Table 7. *Comparative overview of scenarios*

Scenario	Definition	Objective	Assumptions on policy measures	Assumptions on land
Baseline	Policies that have been adopted by 2013 continue unchanged	To provide a baseline that shows how the energy system would behave if trends in energy demand and supply continue unchanged	Unchanged policies	Land to cultivate sugar cane is limited to Valley of the Cauca River
Scenario I	It considers new policy measures for biomethane and biomass-based power generation and CHP, but unchanged policies for transport biofuels	To explore the results of deploying efficient power generation technologies and biomethane production	• New biomethane policy • New power generation and CHP policy	Land to cultivate sugar cane is limited to Valley of the Cauca River
Scenario II	It considers new policy measures for all bioenergy areas, i.e. bioethanol, biodiesel, renewable diesel, biomethane and biomass-based power generation	To explore the results of implementing an ambitious enlargement of current bioethanol and biodiesel programs and a pioneering renewable diesel program on top of the goals defined for Scenario I	• New bioethanol policy • New biodiesel policy • New renewable diesel policy • New biomethane policy • New power generation and CHP policy	Land to cultivate sugar cane is limited to Valley of the Cauca River
Scenario II with expansion	It considers the same goals than Scenario II and assumes a significant land expansion to cultivate cane at large-scale	To explore the implications of expanding the land to cultivate cane at large-scale beyond the Valley of the Cauca River, while aiming at the same goals defined for Scenario II	• New bioethanol policy • New biodiesel policy • New renewable diesel policy • New biomethane policy • New power generation and CHP policy	Land to cultivate sugar cane includes the Valley of the Cauca River and further expansion into Llanos and Costa regions

Scenario II (combining new and traditional technologies) considers new policy measures for all bioenergy areas, i.e. bioethanol, biodiesel, renewable diesel, biomethane and biomass-based power generation and CHP. This is a scenario that combines the vanguard vision of Scenario I with an ambitious vision to further deploy first generation transport biofuels. It is a scenario that aims at enlarging the current bioethanol and biodiesel programs, pioneering in the deployment of renewable diesel and biomethane as well as deploying state-of-the-art biomass-based power generation technologies.

A further important consideration for the different scenarios is the availability of land. In the baseline scenario as well as in Scenarios I and II it is assumed that land to cultivate sugar cane is available only in the Valley of the Cauca River, the only area in the country where it is produced at large-scale. However, experts agree that expansion in land to cultivate cane might be required to meet a growing demand for bioethanol. For this reason a subset of Scenario II is defined to take into consideration a significant expansion in cultivation land. This subset scenario is named Scenario II with expansion, which targets the same goals than Scenario II but assumes a significant land expansion to cultivate cane at a large-scale in other regions beyond the Valley of the Cauca River (e.g. Llanos and costa regions). A comparative overview of the definition, objective and assumptions on land for the different scenarios is shown in Table 7.

B.1.3. Energy System Model (ESM)

The two long-term visions were supported by modeling and scenario analysis to estimate baseline conditions and roadmap targets. For this purpose a very detailed model of the country's energy demand, conversion and supply, energy policy and environmental performance was created and validated using available statistics. Particularly, the national energy balances (UPME, 2011a; UPME, 2011b; UPME, 2011c) were used to calibrate and validate the model (see Section B.1.7 for more details on the model validation and calibration). An acknowledged source of uncertainty relates to the fact that the ESM model is calibrated using the latest available national energy balances, which correspond to year 2009 and predate five years the present study.

The energy system model (ESM) is a data-intensive, scenario-based model that combines various methodologies to comprehensively replicate the behavior of the country's energy system. Two main sides represent the energy system in the model, i.e. the demand side and the transformation side (see Figure 6). Energy requirements are calculated for each side separately. The model was built on the Long-range Energy Alternatives Planning System (LEAP) (Heaps, 2012), which is widely used to report energy policy analysis and greenhouse gas (GHG) mitigation assessments especially in developing countries (Connolly, 2010).

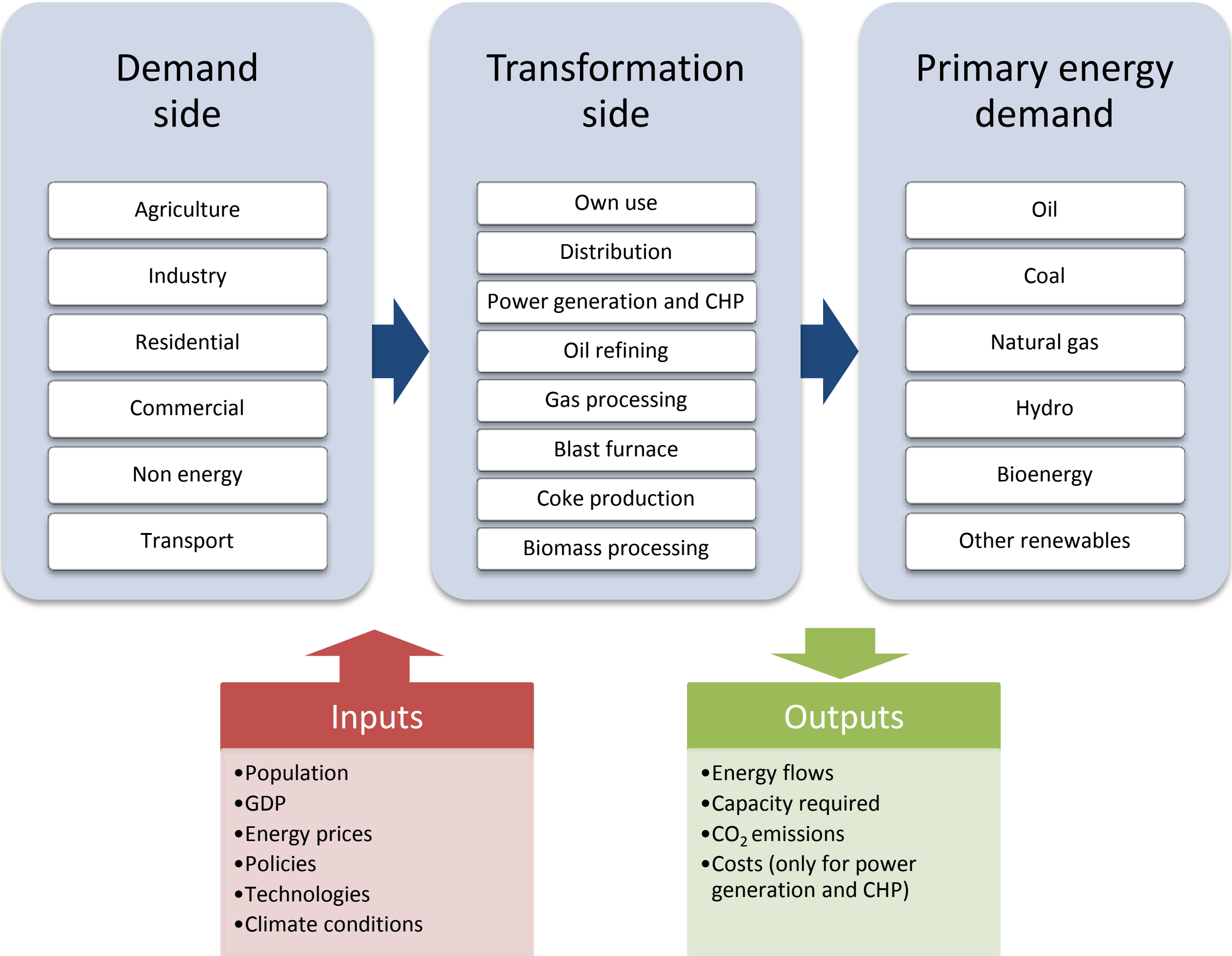


Figure 6. *Outlook of the energy system model (ESM)*

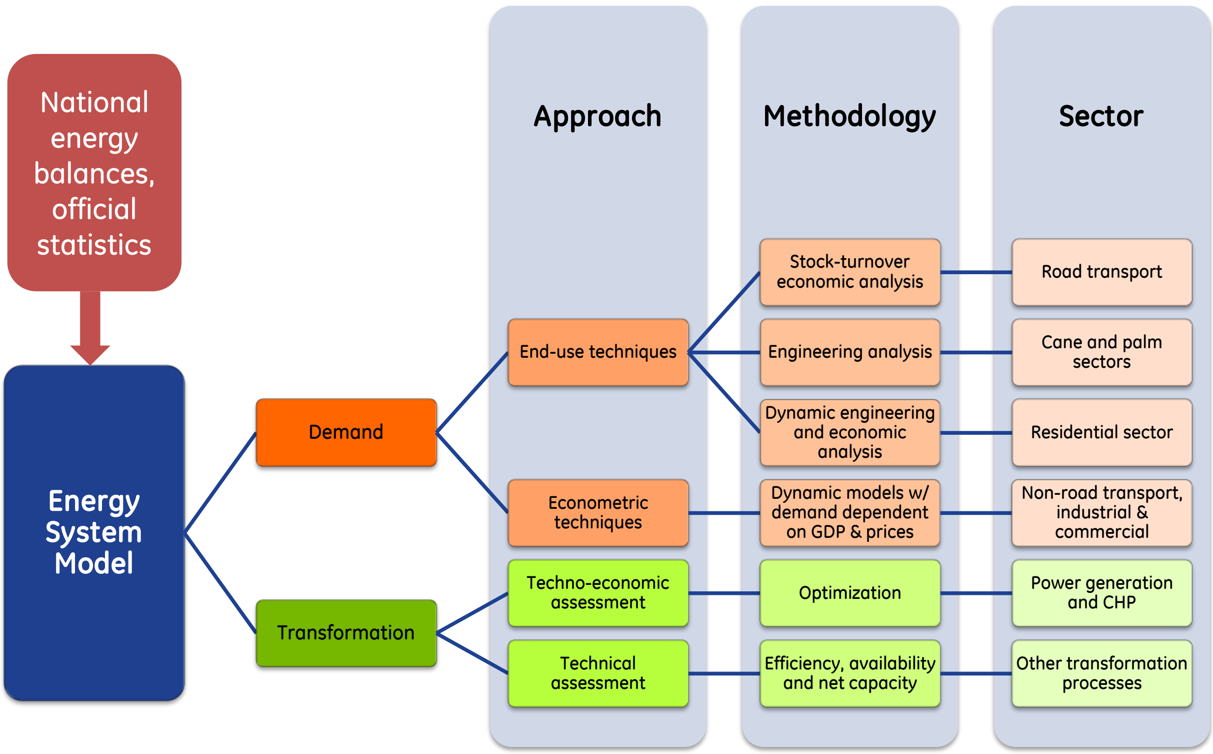


Figure 7. *Summary of the employed modeling techniques by branch*

While the abovementioned national energy balances provide information with a significant level of detail, often data and statistics for various branches of the energy system are not readily available. This is the case of the industrial, commercial and agricultural sectors, where time series describing specific energy demand and technology efficiency are not available. As a consequence, modeling methodologies were selected and developed for each branch according to the level of detail of available information. In general, more accurate and realistic methodologies (typically end-use or bottom-up approaches) were developed for branches with significant amounts of data. In contrast, top-down approaches were used in branches with lesser amount of disaggregated information. A summary of the employed modeling techniques by branch is presented in Figure 7.

For the demand side, a hybrid approach combining econometric methods with end-use techniques was used to estimate the final energy demand disaggregated by sector (residential, industrial, agriculture, transport, etc., see Figure 6). End-use or bottom-up techniques combine the use of activity variables (e.g. GDP, population, etc.) with economic variables (energy prices, income levels, etc.) and engineering variables (e.g. efficiencies, specific energy consumption, etc.) to estimate final energy demand. End-use techniques used in the model to estimate final energy demand include a stock-turnover-economic analysis of the road transport sector, an engineering module of the cane and palm sectors and a comprehensive dynamic engineering-economy module of the residential sector. Particular attention was paid to these three cases, as they concentrate most of the demand for bioenergy resources. Econometric methods were used to estimate the aggregate final demand by fuel and by sector as a function of key drivers (e.g. sectorial GDP, energy prices, etc.). Econometric methods were used in sectors where detailed statistics were not available or not substantially affected by changes in bioenergy technologies. These categories include the commercial sector, the non-road transport sector, the industrial sector and the agriculture sector excluding cane and palm.

For the transformation side, a techno-economic approach was used to calculate energy production, capacity requirements, losses and demand for resources. In this study, technology costs have been only considered for the power generation and CHP module. Hence, a full economic analysis of other bioenergy technologies remains to be investigated. Efficiencies and cost of conversion technologies were collected from several sources available in the literature and incorporated into the model. The competition between multiple technologies in the particular case of power generation and CHP was simulated with an optimization approach. In this approach an optimization algorithm orders electricity dispatch and capacity addition to minimize the net present value of the total costs of the system over the entire period (i.e. capital costs, operating costs, fuel costs, externalities, etc.).

B.1.4. Land Use and Trade Model (LUTM)

A land use and trade model (LUTM) was developed to estimate the land requirements necessary to accomplish the roadmap targets. This model estimates land allocation as well as production, imports and exports of 18 agricultural and forestry commodities during the period 2010-2030. The model is built under the assumption that the fundamental driver of land use and trade is the maximization of the profit perceived by local actors (i.e. local producers and importers). Main inputs of the model include the demand, local biofuel policies, yields, local and international prices and macroeconomic variables. An optimization algorithm is employed to maximize the profit perceived by local actor and to allocate land and trade. Competition is considered at three levels: food vs. biofuels, residues for energy vs. other uses and local production vs. imports. Figure 8 shows a representation of the methodology used in the land use and trade model (LUTM).

The energy system model (ESM) and the land use and trade model (LUTM) work in parallel and are interrelated (see Figure 9). Various outputs of the energy system model are used as inputs of the LUTM model. For instance, the local demand for biofuels (e.g. bioethanol and biodiesel) is estimated in the ESM model and then exported to the LUTM model. The LUTM model evaluates the required land and the optimal production, imports and exports of biofuels and their respective feedstock (i.e. sugar cane, palm oil). Then, the outputs of the LUTM model are used as a feedback loop in the ESM model to estimate the overall production of sugar cane and palm oil, as well as the power generation capacity and production of by-products and residues.

Land use calculations generated by the LUTM model are also used to estimate the land area required to produce a biomass fuel and also to achieve the long-term goals of the two visions. Generally speaking, the methodology to build the LUTM model is the same as described in detail in (Gonzalez-Salazar M, 2014b) with minor modifications. These modifications are described as follows:

- While a Monte Carlo optimization algorithm was used to estimate the land use and trade in (Gonzalez-Salazar M, 2014b), in the present LUTM model the optimization was performed using the

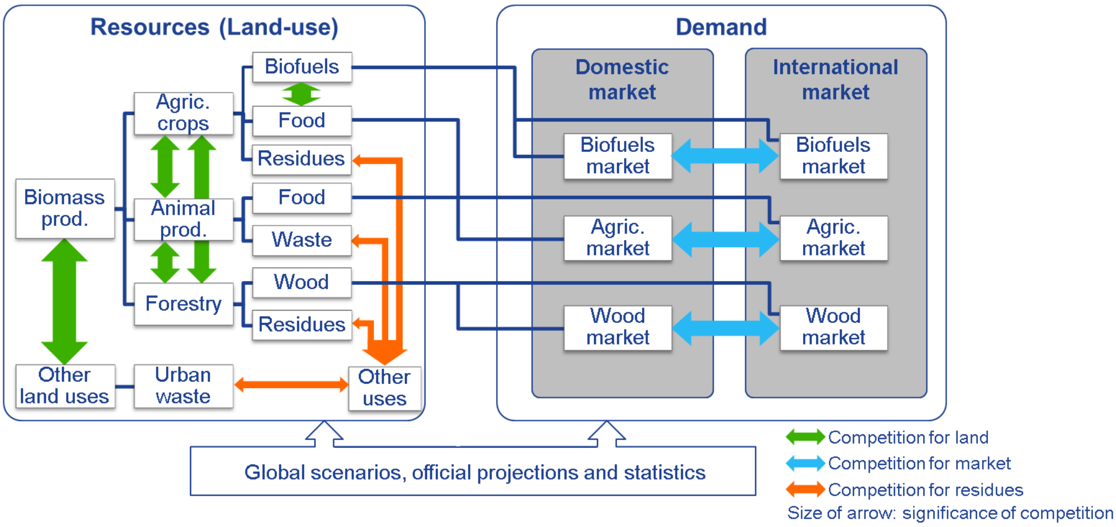


Figure 8. *Methodology of the land use and trade model (LUTM)*

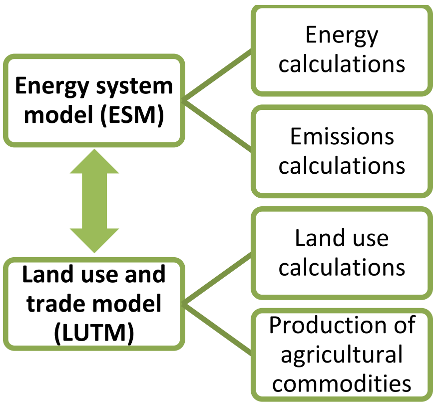


Figure 9. *Outputs of the ESM and LUTM models*

Generalized Reduced Gradient (GRG) Nonlinear algorithm incorporated in Microsoft Excel. This change improved the efficiency and calculation time of the optimization.

- In (Gonzalez-Salazar M, 2014b), there were two main routes to process sugar cane juice: one to co-produce bioethanol and sugar in a sugar factory and another to produce only bioethanol in an annexed distillery. In the present LUTM model there are three routes: one to produce only sugar, a second one to co-produce sugar and bioethanol and a third one to produce only ethanol. More details of these routes are explained in section B.2.2.2.
- In (Gonzalez-Salazar M, 2014b), production of sugar cane at large-scale was limited to the Valley of the Cauca River. In present LUTM model, expansion into the Llanos and Costa regions is possible.
- In (Gonzalez-Salazar M, 2014b) the influence of various global scenarios describing global biofuel use were analyzed. In the present LUTM model, only the conditions of the FAO-REF-01 scenario are considered. This is a scenario developed by IIASA-FAO and assumes that the global future use of biofuels follows the same trend as in the past (Fischer, 2011).
- Costs and yields of sugar cane, bioethanol, palm oil and biodiesel are updated using data published in (BID-MME, Consorcio CUE, 2012). This data and other assumptions for potential expansion in land to cultivate sugar cane in the Llanos and Costa regions are summarized in Table 30 to Table 32.

B.1.5. Boundary conditions

For the demand side of the ESM model, the country's economy is divided into seven main sectors, namely residential, commercial, industrial, transport, agriculture, non-energy and non-specified. The demand for primary and secondary energy resources is estimated in a disaggregated level for each of these sectors. Primary energy resources are raw energy forms that have not been transformed including coal, oil, natural gas, biomass and renewables (hydro, wind, etc.). On the other hand, secondary energy resources are derived from primary energy resources through conversion processes.

Secondary energy resources include electricity, heat, gasoline, diesel fuel, fuel oil, coke, kerosene, jet fuel, liquefied petroleum gas (LPG), charcoal, bioethanol, biodiesel, among others. Conversion technologies are modeled as much on the demand side as on the transformation side of the model. On the demand side of the model conversion technologies are modeled only for the road transport, the cane and palm and the residential sectors. For these sectors, the final energy demand is thus a function of the performance of the conversion technology. For example, the final demand of electricity for cooking in the residential sector is a function of the efficiency of electric stoves.

On the transformation side of the model conversion technologies are modeled for all conversion processes. Current conversion processes include power generation and CHP, heat production, oil refining, gas processing, charcoal and coke production, blast furnace, bioethanol and biodiesel production facilities and biomass processing. Conversion processes added for Scenarios I and II scenarios include biomethane production, co-firing in coal power plants and gas turbines, renewable diesel production, among others.

In addition to conversion processes, distribution losses and own use are also modeled on the transformation side of the model. Own use is the primary or secondary energy consumed by conversion technologies. In this study the own use is included on the transformation side of the model, in contrast to the national energy balances that include it on the demand side (UPME, 2011a). For calculating the greenhouse gas (GHG) emissions, the approach used in (UPME, 2011a) was followed. In this approach, the emissions associated to the combustion of fuels in each branch of the demand and the transformation sides of the model are accounted. N_2O, CH_4, CO_2 biogenic and non-biogenic emissions as well as Global Warming Potential (GWP) for 100 years were evaluated. The guidelines of the Intergovernmental Panel on Climate Change (IPCC) included in the technology and environmental database (TED) in LEAP are employed to calculate the emissions associated to combustion of fuels. One important difference is that this study includes the emissions associated to all conversion processes of the transformation side, while in (UPME, 2011a) only emissions related to power generation and coke production were estimated.

Following IPCC guidelines, biogenic CO_2 emissions (produced by burning biomass resources) are estimated but not accounted as emissions of the 'energy sector', because they are considered emissions of the 'land use, land-use change and forestry' (LULUCF) sector (UPME, 2011a). It is important to note that only direct impact from pollution emissions associated to combustion of fuels are accounted in LEAP. As a consequence, indirect emissions associated to processes including transport, exposure, dose/response effects, but also land-use change, cultivation, irrigation, etc. are not considered.

For the land use and trade model (LUTM), the boundary conditions include:

- Land use is estimated under the premise that the main driver is maximizing the profit of local producers and importers of agricultural commodities. It is assumed that both producers and importers are rational, which means that they always attempt to maximize their own profit
- It is assumed that the domestic market for agricultural commodities is unable to influence international markets
- For competition between local production vs. imports, commodities are assumed to be heterogeneous, which means that imports are imperfect substitutes of local products.
- For land competition, it is assumed that arable land is perfectly substitutable between different uses.
- Local production and imports of commodities are private activities.
- Further details of the used methodology to build the LUTM model are presented in (Gonzalez-Salazar M, 2014b)

B.1.6. General assumptions

B.1.6.1. Population

Current population is taken from (World Bank, 2013), while projected growth is taken from (DANE, 2005) for the period 2010-2020 and from (World Bank, 2013) for the period 2020-2030. Urban population was estimated using a linear regression function dependent on the total population. This function was calibrated with reported data over the last sixty years and a coefficient of determination R^2 of 99.99% was obtained.

Table 8. *Assumed population*

Million	2009	2010	2015	2020	2025	2030
Population	45.65	46.19	48.93	51.68	54.11	56.17
Urban pop.	34.12	34.63	37.16	39.71	41.96	43.87
Rural pop.	11.54	11.56	11.76	11.97	12.15	12.30

B.1.6.2. Growth in gross domestic product (GDP)

Current GDP in purchasing power parity (PPP) terms is taken from (World Bank, 2013), while projected real GDP growth through 2030 is taken from (UPME, 2012). GDP is disaggregated into three main economic sectors, e.g. agriculture, services and industry. Growth in GDP for the sector of services is assumed to be equal to the overall growth in GDP, while growth in agricultural GDP was taken from (Gonzalez-Salazar M, 2014b)[15]. Growth in GDP for the industrial sector was then assumed to be dependent on the growth of the other sectors. Table 9 shows the estimated growth in GDP and GDP in PPPs terms for all sectors.

[15] Growth in agricultural GDP is assumed to be equal to the growth in profits perceived by the agriculture sector as calculated by (Gonzalez-Salazar M, 2014b). Results for the scenario FAO-REF-01 are used.

***Table 9.** Assumed growth in GDP and GDP [PPP]*

	2009	2015	2020	2025	2030
Agriculture	32.77	48.37	51.96	60.20	68.52
Services	206.76	273.11	348.57	434.37	528.47
Industry	137.92	177.09	235.80	298.39	367.76
Total	377.45	498.58	636.33	792.96	964.75
Agriculture	2.03%	1.69%	1.69%	3.59%	2.71%
Services	1.50%	4.75%	5.00%	4.00%	4.00%
Industry	1.79%	5.62%	5.76%	4.08%	4.24%
Overall	1.50%	4.75%	5.00%	4.00%	4.00%

B.1.6.3. Energy prices

Energy prices are exogenous inputs to the ESM models. Price forecasts of primary and secondary energy resources were taken from two main sources, namely (Rodríguez, 2013) for local prices, (EIA, 2011) for international prices and (DECC, 2011) for oil price projections.

Domestic price of bioethanol and biodiesel was calculated following the pricing structure for biofuels defined by various regulations (DNP, 2008; MME, 2009a; MME, 2009b). According to these regulations, the price of biofuels is a function of international price of oil, feedstock commodities (e.g. sugar in the case of ethanol and palm oil in the case of biodiesel), exchange rate and taxes. Domestic price of wood fuel was taken from (UPME, 2005) and updated; no statistics or price projections for wood fuel were found in literature and it was assumed that future prices would follow the growth in price of coal, which is a direct substitute for wood. Table 18 in the Appendix shows the assumed real price of energy expressed in U.S. dollars of 2005. Table 18 in the Appendix shows also the Manufactures Unit Value (MUV) Index published by the World Bank (World Bank, 2012), which was used to calculate the nominal prices of energy to account for the effect of price change over time. Ideally, it is advisable to forecast energy prices for each scenario in order to evaluate the impact of implementing different energy policies (IEA, 2012b; EIA, 2011). However, a dedicated forecast of energy prices is beyond the scope of this investigation. As a consequence, it is assumed that energy prices do not vary across policy scenarios.

B.1.6.4. Climate conditions

The following assumptions on climate conditions are taken:

- Climate conditions in Colombia are heavily influenced by El Niño and La Niña Southern Oscillation (ENSO). ENSO is characterized by two variation in the water temperature of the eastern Pacific Ocean (El Niño, warm and La Niña, cold) that causes extreme variations in temperatures, precipitation and wind patterns in the tropical western Pacific. ENSO cannot be predicted in the long-term, but the oscillation commonly lasts 4 to 5 years. In this study it is assumed that ENSO has three phases (warm, cold and a neutral intermediate) recurring every four years.
- Renewable power technologies and particularly hydro power are vulnerable to ENSO variations. Detailed information of the different power generation technologies during the last 15 years has been taken from XM S.A. (XM, 2013) and further analyzed. While it is found that the availability factor of hydro power and biomass-based power depends to certain extent on the solar radiance (see Figure 63 in the Appendix), this dependence is less clear for wind power. It is found that when the number of annual solar hours increases, the availability factor of biomass power grows while the availability factor of hydro power decreases. Interestingly, it is also found that the availability of biomass and hydro power are complementary. A possible explanation to this phenomenon is that when the solar radiance increases plants can absorb more solar energy and produce more biomass resources, which might cause an increase in the availability factor of biomass power. On the other hand, when solar radiance increases there is a reduction in rainfall, which might cause a reduction in the availability factor of hydro power. Figure 64 in the Appendix shows the availability of renewable energies for arranged days in various years. The highest availability of hydro power occurs at years with low solar radiance, when the availability of biomass-based power is lowest. It is therefore assumed that the availability for hydro and biomass-based power will remain complementary and will fluctuate between a warm-phase (using availability profiles for year 2003), an intermediate-phase (profiles for year 2004) and a cold-phase (profiles for year 2007) according to the variability caused by El Niño and La Niña Southern Oscillation (see averaged assumed profiles in Figure 65 in the Appendix). For wind power it is assumed that the availability is not dependent on ENSO variations and the availability profile corresponding to year 2008 is used.

B.1.6.5. Availability of land

Availability of land for the different uses is an exogenous input to the LUTM model and is based on statistical information. Main sources of statistics for Colombia include the Ministry of Agriculture and Rural Development (MinAgricultura, 2012) and FAOSTAT (FAO, 2012). Significant differences in statistics on land use are found between these two sources, though a dedicated comparison is beyond the scope of this report. Generally speaking, FAOSTAT offers a clear accounting methodology and a large amount of data, while MinAgricultura publishes only agricultural area based on information reported by producers.

FAOSTAT database is therefore selected to estimate the availability of land in this roadmap, as it provides a more consistent methodology and a larger amount of data. According to FAOSTAT, the forest area in 2009 accounts for 60.6 mio ha. Deforested area is estimated to be 100 kha per year in the last 20 years, resulting in a continuously increasing area for permanent meadow, pastures and crops. It is assumed that this deforestation rate and the consequent transformation of forest land into agricultural land will continue in the future. Area for other uses (e.g. urban use, etc.) is estimated by FAOSTAT to be about 7.8 mio ha. This area has remained relatively constant since 2000 (0.1% increase in a decade) and it is assumed to remain constant at 8 mio ha until 2030. FAOSTAT estimates the total agricultural area in 42.54 mio ha in 2009, which includes area for permanent meadows and pastures (39.18 mio ha) and area for crops (3.35 mio ha). The area required for the 18 commodities considered in this study accounts for 41.54 mio ha in 2009 (2.94 mio ha for agricultural products and 38.6 mio ha for cattle), while the remaining area correspond to other commodities not included in this study. The area required to produce these latter products has been reduced from 1.5 mio ha in 1990 to 0.4 mio ha in 2009. In this work it is assumed that this area remains constant at 1 mio ha until 2030. Assumed overall availability of land in the period 2010-2030 is illustrated in Table 19 in the Appendix. In the optimization model the area for agricultural crops and land-competing livestock commodities should not exceed the 'area for commodities not included in the model', whereas area for production of wood should not exceed the 'forest area' in Table 19 in the Appendix.

B.1.6.6. Other assumptions and limitations

- The selected base year is 2009, which is the year with the most recent statistics available. The last calculated year is 2030.
- Costs and prices are expressed in U.S. dollars of 2005 unless otherwise noted.
- For power generation & CHP technologies, capital costs are annualized using a 10% discount rate.
- Own use is defined as the primary or secondary energy consumed by conversion technologies. In this study it is included on the transformation side of the model, in contrast to the national energy balances that include it on the demand side (UPME, 2011a).
- Overall costs were estimated only for power generation and CHP technologies. Environmental externality costs were not included in the costing analysis.

B.1.7. Estimation of biomass potential and primary energy to meet the biomethane and biomass-based power generation targets

The methodology described in detail in (Gonzalez-Salazar M. M., 2014a; Gonzalez-Salazar M, 2014b) is used to estimate the biomass energy potential in Colombia. The biomass energy potential is here defined as the amount of energy contained in terrestrial biomass. It excludes the energy potential associated with biofuels to avoid potential confusion between primary energy resources (e.g. residues and wastes) and secondary energy resources/carriers (e.g. biofuels). Terrestrial biomass is classified into woody and non-woody biomass. Woody biomass comprises various sub-categories including natural forest and woodlands, forest plantations and energy plantations. On the other hand, non-woody biomass comprises sub-categories including agricultural crops, animal waste and urban waste. Under each of these sub-categories biomass is produced either for energy or non-energy purposes. Non-energy uses of biomass include supply for food and fiber as well as feedstock to the industrial sector. Current energy utilization is further divided into two categories: traditional use (wood fuel for cooking and heating) and modern use (use of bagasse and residues for heating, power generation and combined heat and power (CHP), biofuel production, etc.). Four main biomass categories are considered:

- Forestry and wood industry: wood fuel, forestry residues and industrial residual wood.
- Agricultural residues: residues from agro-industry (e.g. bagasse) and crop residues (e.g. rice husk, cotton husk, etc.).
- Animal waste: manure from cattle, poultry, pork, etc.
- Urban waste: municipal solid waste producing landfill gas, residues from the wholesale market, demolition residues, residual methane from water treatment plants, pruning residues, etc.

Two levels of biomass energy potential are evaluated, the theoretical potential (green area in Figure 10) and the technical potential including current uses (grey and blue areas in Figure 10, respectively). The theoretical potential is defined as the maximum amount of biomass that can be used for energy purposes, explicitly excluding biomass used for food, fiber (e.g. round wood) and feedstock for the industry (e.g. co-products). The technical potential is defined as the fraction of the theoretical potential that is available for energy production (including current uses) after considering various constraints.

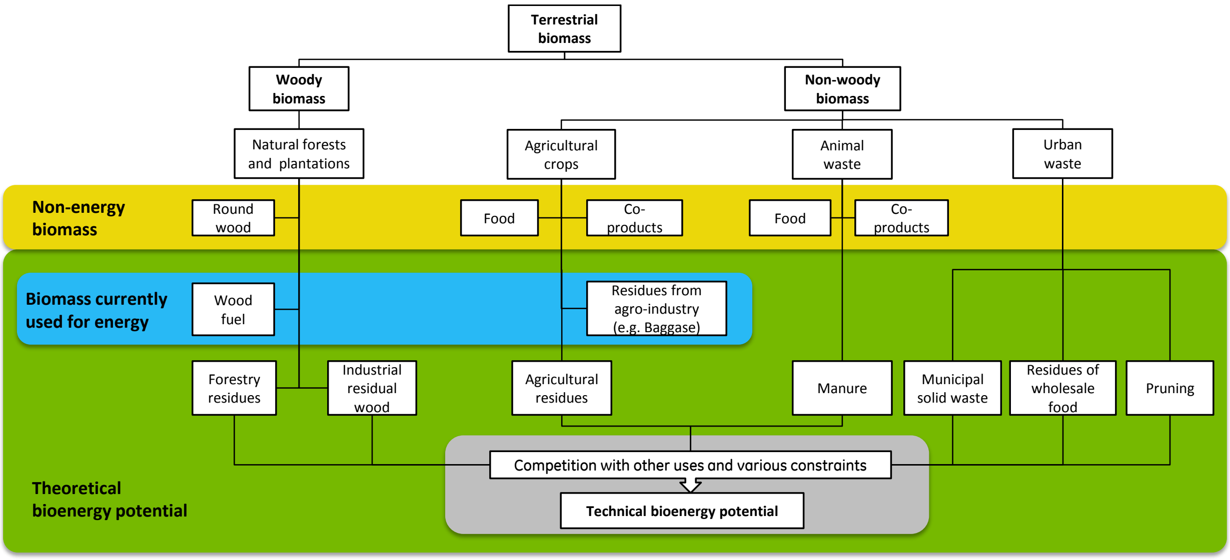


Figure 10. *Boundary conditions for estimating the biomass energy potential in Colombia*

The current biomass energy potential is then estimated following the methodology described in (Gonzalez-Salazar M. M., 2014a), while the future potential is estimated following the method explained in (Gonzalez-Salazar M, 2014b).

Volumes of biomass resources produced in the country between 2010 and 2030 are estimated with the LUTM model and are shown in Table 20 in the appendix. On the other hand, the specific energy and availability factors associated with these biomass resources are taken from various references and are shown in Table 21 and Table 22 in the appendix, respectively. Finally, the estimated theoretical potential is shown in Table 23 in the appendix, while the technical biomass potential including current uses is shown in Table 24 in the appendix. The theoretical biomass energy potential is then used to estimate the primary energy targeted in the long-term goals of biomethane and biomass-based power generation in Scenarios I and II (see Table 25).

B.1.8. Model validation

The ESM model is calibrated and validated using data published in the national energy balances (UPME, 2011a; UPME, 2011b; UPME, 2011c). The model is validated at different levels. At a first level, the primary and secondary energy demands are validated by fuel and branch. The validation of the primary energy demand in the ESM model against official statistics by fuel is shown in Table 26, Table 27 and Figure 66 in the Appendix. Results of the ESM model for the overall primary energy demand between 1975 and 2009 are in agreement with official statistics and an overall coefficient of determination R^2 of 99.2% is estimated. Results for most of the fuels agree with statistics and estimated R^2 range from 98.4% to 100%. However, model results for the biomass primary energy deviate between -8% and 26% from official statistics. This disagreement is believed to be caused by different methodologies used to account for biomass resources. While the ESM model uses the accounting methodology shown in (Gonzalez-Salazar M. M., 2014a), the methodology used in official statistics is unknown.

At a second level, the overall GHG emissions by branch are validated against official statistics and are shown in Table 28, Table 29 and Figure 67 in the Appendix. Most of the estimated GHG emissions by branch in the ESM model fully agree with official statistics. For instance, emissions associated with the demand side and power generation show R^2 of 99.8% and 97.4%. However, emissions associated with own use in the ESM model are 25% to 41% lower than those reported in official statistics. This difference is caused by additional emissions from combustion of refinery gas in the own use branch, which are reported in the national energy balances but whose origin is unknown.

In addition, the national energy balances only estimate GHG emissions associated with power generation and coke production on the transformation side. Thus, no emissions are estimated in the national energy balances for other transformation processes (e.g. oil refining, heat production, bioethanol and biodiesel production, blast furnace, charcoal factories, etc.). In contrast, the ESM model estimates the GHG for all these branches. Hence, the emissions estimated in the ESM model are 3% to 13% higher than those reported in the national energy balances and a R^2 of 88% is estimated. If the emissions of these other conversion processes are not included in the ESM model, the estimated coefficient of determination is 96%.

B.2. Modeling techniques

This section shows in more detail the modeling techniques to estimate the demand and supply of energy in Colombia and its validation using the national energy balances and other official statistics. While the national energy balances provide information with a significant level of detail, often data and statistics for various branches of the energy system are not readily available. This is the case of the industrial, commercial and agricultural sectors, where time series describing specific energy demand and technology efficiency are not available. As a consequence, modeling methodologies were selected and developed for each branch according to the level of detail of available information. In general, more accurate and realistic methodologies (typically end-use or bottom-up approaches) were developed for branches with significant amounts of data. In contrast, top-down approaches were used in branches with lesser amount of disaggregated information. The section is divided into two parts, a first part devoted to techniques used to model the demand side and a second part focused on techniques to model the transformation side.

B.2.1. Model of the demand side

The model of the demand side is divided into four main sub-models: 1) road transport, 2) cane and palm industry, 3) residential sector and 4) non-road transport, industrial and commercial sectors. A more detailed description of these sub-models is presented as follows.

B.2.1.1. Road transport

The energy demand of road transport and its associated emissions are estimated using a stock-turnover economic analysis consisting of four steps, as shown in Figure 11.

First step

In a first step the past vehicle ownership per type is taken from available statistics. Available data disaggregates the number of vehicles in four types, i.e. motorcycles, gasoline and diesel road vehicles (with at least 4 wheels) and CNG-fuelled vehicles (Ciudad Humana, 2012; MinTransporte-CEPAL, 2010; UPME, 2010; ACP, 2012). The number of vehicles is divided by the population (taken from (World Bank, 2013)) to obtain the vehicle ownership per type, which is shown in Table 10.

Table 10. *Number of vehicles by type*

Vehicles per 1000 people	1990	1995	2000	2005	2009
Gasoline vehicles	32.58	40.77	46.18	48.12	49.13
Diesel vehicles	6.08	8.33	10.38	12.03	17.37
CNG vehicles	0.00	0.11	0.15	2.23	6.51
Motorcycles	7.36	13.84	21.87	28.70	58.46
Total	46.02	63.06	78.59	91.09	131.47
Population (mi.)	33.20	36.45	39.76	43.04	45.65

References: (Ciudad Humana, 2012; MinTransporte-CEPAL, 2010; UPME, 2010; ACP, 2012)

Then, models representing the future vehicle ownership as a function of economic and social data are defined. For vehicles with at least four wheels, it is used the model proposed by (Dargay J, 2007), which relates the future vehicle ownership to historical data, GDP per capita, density and urbanization. This model is a long-term dynamic S-shaped curve (Gompertz function), in which vehicle ownership growth is slow at the lowest income, then it rapidly increases as income rises and then it reaches a saturation level. The model is defined by next equation:

Eq. 1
$$V_t = (\gamma_{MAX} + \lambda D_t + \varphi U_t)(\theta_R R_t + \theta_F F_t) e^{\alpha e^{\beta GDP_t}} + (1 - \theta_R R_t + \theta_F F_t) V_{t-1} + \varepsilon_t$$

Where V_t is the actual vehicle ownership (vehicles per 1000 people), GPD is the gross domestic product per capita (in purchasing power parity), γ_{MAX} is the saturation level, D_t is the population density, U_t is the urbanization rate, λ and φ are negative constants, R_t and F_t are dummy variables, $\theta_R$and θ_F are speeds of adjustment for periods of rising and falling income, α and β are parameters of the Gompertz function, subscript t represents the year and ε_t its random error term.

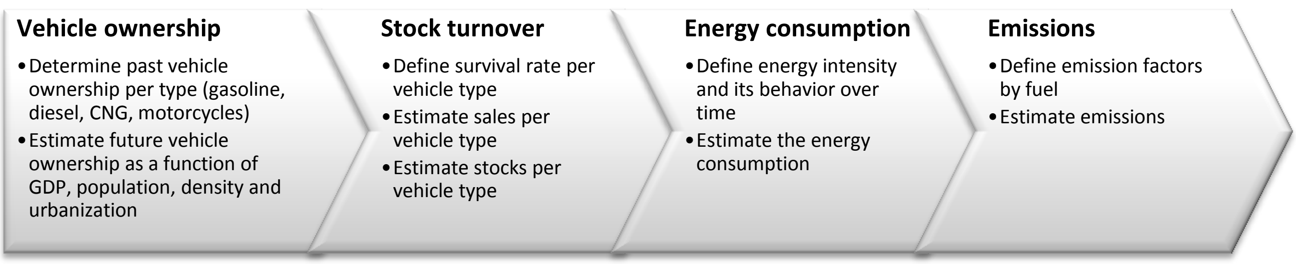


Figure 11. *Process to estimate energy demand of road transport*

In the original study by (Dargay J, 2007) the relationship between vehicle ownership and income growth was estimated for 45 countries for the period 1960-2002. Colombia was excluded from this study due to the lack of consistency in found data. In this roadmap, the model is re-evaluated using data shown in Table 11. In (Dargay J, 2007) only the maximum saturation level γ_{MAX} and the parameter β are country-specific, while all other parameters of the Gompertz function are the same for all countries. Using original parameters published by (Dargay J, 2007) a β value of -0.1169 and a coefficient of determination R^2 of 99.3% were estimated using a regression analysis. However, a modification in the parameters of the Gompertz function led to an improved fit of the model data compared to historical data. If α, β and γ_{MAX} are specifically estimated for Colombia with all the remaining parameters unmodified, a slightly higher coefficient of determination of R^2 of 99.6% can be obtained. A comparison of the model parameters of (Dargay J, 2007) and this study is shown in Table 11. The improved parameters are therefore used to estimate the future ownership of vehicles with at least four wheels through till 2030 in Colombia.

Table 11. *Comparison of model parameters for the vehicle ownership model*

Model parameters	Dargay et al.	This study
Parameter α	-5.8970	-4.8400
Parameter β	-0.1169	-0.0925
Maximum saturation γ_{MAX}	852	827
Constant λ	-0.000388	-0.000388
Constant φ	-0-007765	-0-007765
Speed of adjustment θ_R	0.095	0.095
Speed of adjustment θ_F	0.084	0.084
Coefficient of determination R^2	99.3%	99.6%

While this model describes ownership for four-wheeled vehicles, it does not further disaggregate data by vehicle. Therefore, a logit function is used to estimate the share of each vehicle type per year as shown in the following equation:

Eq. 2

$$Share_{c,t} = \frac{\left[{}^{1}/_{k_c F_{c,t}}\right]^{\gamma}}{\Sigma_c \left[{}^{1}/_{k_c F_{c,t}}\right]^{\gamma}} \cdot \theta + (1-\theta) \cdot Share_{c,t-1}$$

where, $F_{c,t}$ is the fuel cost required for each vehicle type to drive 100 km (US$2005/100 km), k_c is a cost exponent, γ is the cost sensitivity coefficient, θ is the speed of adjustment and subscripts c and t are respectively vehicle type and year. $F_{c,t}$ is estimated as the fuel cost per year (US$2005/MJ, see Table 18) for the different vehicle types multiplied by the fuel economy (MJ/100 km, see Table 15). The parameters of the logit function are obtained through a regression analysis to best fit the historical curve of shares. Table 12 shows the values of the fuel cost used and Table 13 summarizes the results of the regression analysis.

Table 12. *Historical fuel cost by vehicle*

Fuel cost US$2005/100 km	1990	1995	2000	2005	2009
CNG vehicles	0.1807	0.1502	0.2337	0.2547	0.3711
Gasoline vehicles	2.2382	2.9469	4.4550	7.6093	10.2489
Diesel vehicles	4.8226	6.3282	7.8072	11.4985	18.4029

Table 13. *Parameters of the logit function to estimate vehicle shares*

Model parameters	Gasoline vehicles	Diesel vehicles	CNG vehicles
Parameter k_c	0.2104	0.0999	50
Parameter γ	50	50	50
Speed of adjustment θ	0.015	0.0076	1
Coefficient of determination R^2	88.25%	85.35%	80.41%

For motorcycles, a simplified version of the model proposed by (Dargay J, 2007) is used. This model is a long-term dynamic S-shaped curve, in which future motorcycle ownership is a function of historical ownership and GDP per capita:

Eq. 3 $$V_t = \gamma_{MAX} \theta e^{\alpha e^{\beta GDP_t}} + (1-\theta) V_{t-1}$$

The parameters are estimated using a regression analysis to best fit the historical data and are shown in Table 14.

Table 14. *Model parameters of the motorcycle ownership model*

Model parameters	Value
Parameter α	-25
Parameter β	-0.3602
Maximum saturation γ_{MAX}	200
Speed of adjustment θ	0.4874
Coefficient of determination R^2	93.6%

Second step

In a second step, a detailed stock turnover analysis is performed. In this analysis the number of retired, legacy and new vehicles is estimated for the different types of vehicles (gasoline, diesel, CNG and motorcycles). Firstly, the age distribution of vehicles is defined. Detailed historical data by vehicle is collected from the literature. Historical data show irregular trends that reflect past vehicle context. However, it is uncertain whether these contexts will repeat exactly in the future. Therefore, modified curves with smoother trends are created by vehicles (see Figure 12).

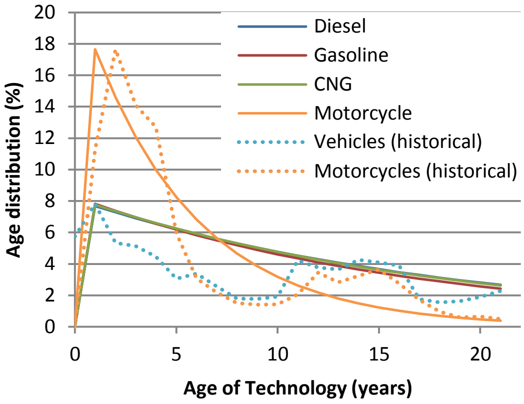


Figure 12. *Age distribution by vehicle*

Secondly, the survival rate per vehicle type is taken from the literature, see Figure 13. While survival rates for motorcycles and 4 wheeled vehicles are found in (UPME, 2010), further disaggregation is not available. It is therefore assumed that the survival for 4 wheeled vehicles is the same for diesel, gasoline and CNG vehicle. Further, the stock analysis from LEAP is employed to estimate the retired, legacy and new vehicles by vehicle type per year. The stock analysis is estimated using the following equations (Heaps, 2012):

Eq. 4 $Stock_{c,t,v} = Sales_{c,v} \cdot Survival_{c,t-v}$

Eq. 5 $Stock_{c,t} = \sum Stock_{c,t,v}$

In these equations stock is the number of vehicles existing in a particular year for a vehicle type, sales is the number of vehicles added in a particular year, and survival is the fraction of devices surviving after a number of years, subscripts c, t and v respectively represent vehicle type, year and vintage.

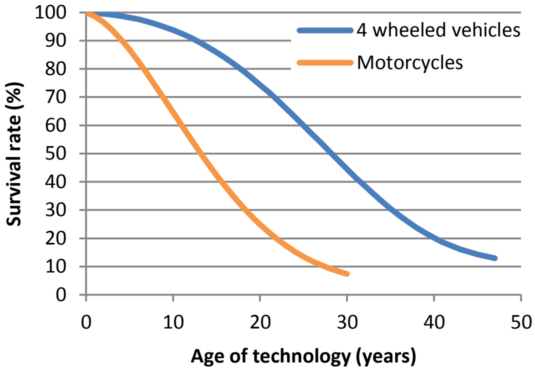


Figure 13. *Survival rate by vehicle type*

Third step

In a third step the fuel economy and overall energy consumption per vehicle type are estimated using the following equations:

Eq. 6 $FE_{c,t,v} = FE_{c,v} \cdot Degradation_{c,t-v}$

Eq. 7 $EC_{c,t} = Stock_{c,t,v} \cdot FE_{c,t,v} \cdot Mil_{c,t,v}$

Eq. 8 $EC_{c,t,f} = \mu_{c,t,f} \cdot EC_{c,t}$

Where $FE_{c,v}$ (MJ/100 km) is the fuel economy per vehicle type for a new vehicle, $FE_{c,t,v}$ (MJ/100 km) is the fuel economy per vehicle type per vintage and per year, $Degradation_{c,t-v}$ is a factor representing the change in fuel economy as a vehicle ages, $Mil_{c,t,v}$ is the mileage (km/vehicle); $EC_{c,t}$ (MJ) is the overall energy consumption per vehicle type per year, $EC_{c,t,f}$ (MJ) is the energy consumption per vehicle type per year disaggregated by type of fuel and $\mu_{c,t,f}$ is the share of the energy consumption by fuel type.

Table 15. *Energy intensity by vehicle type in year 2009*

	Motorcycles [A]	Gasoline vehicles [A]	Diesel vehicles [A]	CNG vehicles [B]
Vehicles (thousand)	2669[1]	2243[2]	793[2]	297[3]
Fuel type	Gasoline	Gasoline	Diesel fuel	CNG
Fuel LHV (MJ/l)	32.87[4]	32.87[4]	36.71[4]	0.04[5]
Fuel density (kg/liter)[6]	0.740	0.740	0.837	0.185
Average fuel economy $FE_{c,2009}$ (^{A} km/l, ^{B} km/m^3)[7]	40.89	8.17	3.80	28.10
Average fuel economy $FE_{c,2009}$ (MJ/100km)[8]	80.39	402.33	964.95	140.62
Average mileage (km/vehicle)[9]	12426	11773	18908	65349

[1] (Ciudad Humana, 2012)
[2] (MinTransporte-CEPAL, 2010; UPME, 2010)
[3] (ACP, 2012)
[4] (UPME, 2010)
[5] 't is taken the average of natural gas produced in the Cusiana field and the Guajira region according to data from (UPME, 2010)
[6] Data taken from (MIT, 2010). The density of CNG is at a pressure of 200 bar.
[7] (Econometria - UPME, 2010)
[8] Calculated using the fuel economy published by Econometria and the assumed fuel LHV
[9] Mileage is calculated as: energy consumed by fuel/ (Stocks · fuel economy). The energy consumed by fuel is taken from (UPME, 2011a)

Data on fuel economy per vehicle type is only available as an average and not disaggregated by vintage (Econometria - UPME, 2010). Reported data for base year (2009) is summarized in Table 15. The degradation factor is not available and it is therefore assumed that the average fuel economy remains constant for the different vintages (i.e. $FE_{c,t,v} = FE_{c,v}$). The future fuel economy is estimated using the fuel economy by vehicle for the base year and future projections for decline. An annual projected rate of decline of -0.7% in fuel economy for all vehicle types in Latin America until 2030 is taken from (OPEC, 2004; Dargay J, 2007).

Regarding the use of biofuels, it is assumed that they do not affect the fuel economy, which is assumed to be proportional to the fuel's lower heating value (MJ/l). While biofuels might offer certain advantages than counterparts (e.g. higher octane rating for bioethanol and higher lubricity and cetane number for biodiesel), significant modifications of the engine are required to exploit these advantages. For instance, to take advantage of the high octane number of bioethanol it is necessary to increase the compression ratio of the engine (Goettemoeller J, 2007). A similar approach is needed for biodiesel (Muralidharan, 2011). As technologies for modifying the engine are not considered in this roadmap, it is assumed that biofuels do not impact fuel economy. Finally, the share of the energy consumption by fuel type $\mu_{c,t,f}$ used to estimate the overall energy consumption by fuel is calculated as a function of the blend mandate and the lower heating value of the fuels. Another variable that is taken into account to estimate the demand for biofuels is the supply coverage at a national level, since there are regions where biofuels are not available (e.g. remote and border regions). The assumed supply coverage of the different biofuels is modeled through a Gompertz functions with a maximum value of 85%, which is shown in Figure 68 in the Appendix.

Next, the mileage is estimated. Mileage is the annual distance traveled per vehicle (km/vehicle). For the base year mileage is calculated using the overall energy consumed by vehicle taken from (UPME, 2011a) as well as the number of stocks and the fuel economy shown in Table 15. While it is desirable to include a mileage degradation factor that considers the reduction in travelled distance as a vehicle ages, this data is not readily available. Thus, it is assumed that the mileage by vintage is constant. Future mileage is estimated using available projections. A 0.4% annual growth for gasoline vehicles and motorcycles and a 0.5% annual growth for diesel vehicles and CNG vehicles are taken from (E4tech, 2013).

The competition of E85 with gasohol occurring by launching the E85 program in 2030 is modeled through the following equations:

Eq. 9 $$VE85_t = VEFF_t \cdot Coverage_{E85,t}$$

Eq. 10 $$Share_{E85,t} = \frac{\left[{}^{1}/_{F_{E85,t}}\right]^{\gamma}}{\left[{}^{1}/_{F_{E20,t}} + {}^{1}/_{F_{E85,t}}\right]^{\gamma}}$$

In Eq. 9 $VE85_t$ is the percentage of vehicles in year t that are able to run with E85 and have access to it, $VEFF_t$ is the percentage of vehicles that are flex fuel (assumed to enter into the market in 2015 and further calculated by LEAP considering the survival rate and new acquisitions), $Coverage_{E85}$ is the supply coverage of E85 by year (shown in Figure 68 in the Appendix). On the other hand, in Eq. 10 $Share_{E85,t}$ is the energy share of E85 used in flex fuel vehicles, which is modeled as a function of $F_{E20,t}$, i.e. the cost of E20 (fuel that compete with E85 in 2030 in US$2005/MMBtu), $F_{E85,t}$, i.e. the cost of E85 (US$2005/MMBtu) and γ, i.e. the cost sensitivity coefficient, which is assumed to be 2.

Fourth step

The fourth step is estimating the greenhouse gas emissions through the following equation:

Eq. 11 $$GHG_{c,t,v,p} = EC_{c,t,v} \cdot EF_{c,t,p} \cdot Degradation_{c,t-v,p}$$

Where $GHG_{c,t,v,p}$ (ton CO_2-eq.) are the emissions by pollutant for the different vehicle types, vintage and year, $EF_{c,t,p}$ is the emission factor by pollutant (kg/TJ) and $Degradation_{c,t-v,p}$ is a factor representing the change in emissions as a vehicle ages. Pollutants analyzed in this study include carbon dioxide (CO_2, both biogenic and non-biogenic), carbon monoxide (CO), methane (CH_4), non-methane volatile organic compounds (NMVOC), nitrogen oxides (NOx), Nitrous Oxide (N_2O) and sulfur dioxide (SO_2). The emission factors by pollutant are taken from the Technology and Environmental Database (TED) implemented in LEAP, which refers to the default Tier 1 emissions factors suggested by IPCC (Heaps, 2012). For combustion of biofuels, it is used the methodology suggested in (TNO, 2009). This study suggests that emission factors for biofuels can be estimated using the following equation:

Eq. 12 $$EF_{biofuel,p} = EF_{fossil,p} \cdot MEF_{biofuel,p}$$

Where $EF_{biofuel,p}$ is the emission factor for biofuels by pollutant, $EF_{fossil,p}$ is the emission factor for counterpart fossil fuel and $MEF_{biofuel,p}$ is a multiplying emission factor for biofuels. $MEF_{biofuel,p}$ for gasoline vehicles and motorcycles using 100% bioethanol and diesel vehicles using 100% biodiesel is shown in Table 16. Then, for biofuel blends the emissions are proportional to the biofuel energy content in the blend. Further, it is assumed that the CO_2 emissions produced during combustion of bioethanol, biodiesel, renewable diesel and biomethane (present in CNG) are biogenic. The $Degradation_{c,t-v,p}$ factors for NOx, NMVOC, N_2O, CO and CH_4 by vehicle are taken from (Toro Gómez, 2012). For the sake of brevity these degradation profiles are not included in this report.

Table 16. *Multiplying emission factors for biofuels*

Multiplying emission factor by pollutant, taken from (TNO, 2009)	**Gasoline vehicles and motorcycles using 100% bioethanol**	**Diesel vehicles using 100% biodiesel**
NOx	1.28	1.3
PM	1.35	0.43
HC	1	0.46
CO	1	0.81

Acknowledged limitations of the approach suggested above include a restricted number of vehicle categories with limited statistical information about performance, vehicle use, emissions, etc. This is a natural consequence of lack of available data in a more disaggregated form. Recommendations for further studies include creating databases that include detailed information for past and existing fleet, fuel economy, mileage, emissions, costs, etc.

B.2.1.2. Residential sector

The energy demand of the residential sector and its associated emissions are estimated using a bottom-up dynamic model consisting of four steps (see Figure 14). This approach is partly based on the methodology proposed in (Daioglou, 2010), which uses five exogenous primary drivers to determine five energy demand uses (see Figure 15). The primary drivers include population, household expenditure, population density, household size and ambient temperature. The energy demand uses include cooking, appliances, water heating, space heating/cooling and lighting.

<u>**First step**</u>

In a first step, the five primary drivers are defined for Colombia. Future urban and rural populations are taken from Table 8. Historical household final consumption expenditure in PPP (US\$2005) is taken from (World Bank, 2013). It is found that the historical household final consumption expenditure is linearly correlated with the GDP in the following form (coefficient of determination R^2 = 99.53%):

Eq. 13 $HH = 0.5327 \cdot GDP + 2.3E10$

Then, the future household expenditure is estimated by using this correlation and the assumed future GDP shown in Table 9. The household expenditure widely varies across the different segments of the income distribution.

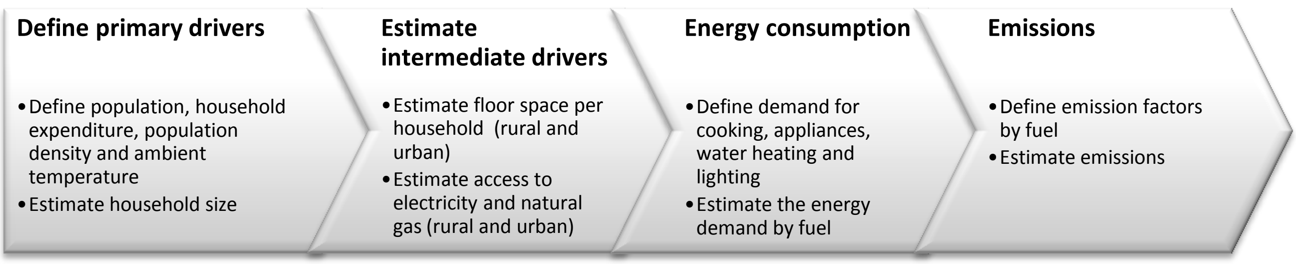


Figure 14. *Methodology process to estimate energy demand of residential sector*

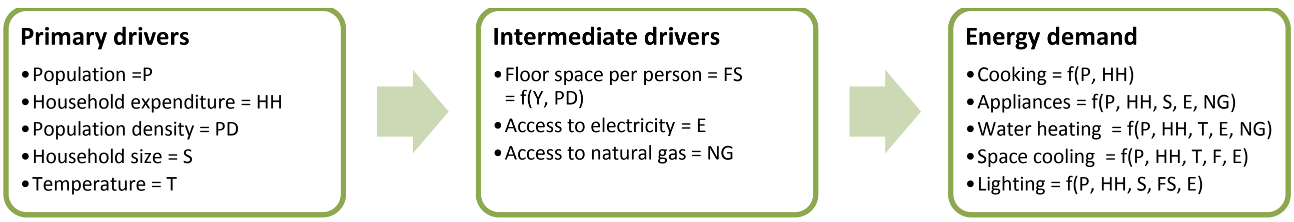


Figure 15. *Relationship between energy demand and drivers, adapted from (Daioglou, 2010)*

Therefore, the future household expenditure is further disaggregated into income quintiles and expressed as household expenditure per person (expenditure by quintile divided by the quintile population, i.e. 20% of the total population), following the methodology suggested by Daioglou.

The historical income shares by quintiles are taken from (World Bank, 2013), but this data is not available by region (i.e. urban vs. rural). Income shares by quintile and region are available for Colombia at the Global Income Distribution Dynamics Dataset (World Bank, 2009), although only for year 1999 (see Table 35). Due to lack of more data, it is therefore assumed that the income share by quintile remains constant across the period analyzed.

The future income shares are estimated using time-series analysis (i.e. autoregressive integrated moving average model –ARIMA–) to mathematically fit historical data whose trend is assumed to continue into the future. For this purpose the Predictor tool of Oracle® Crystal Ball 11.1.2.1 is used (see Table 33 in the Appendix). Finally, the future household expenditure per person-quintile is estimated using the following equation:

Eq. 14 $HHp_{r,Q} = IS_r \cdot IS_Q \cdot Y/(P_r/5)$

Where $HHp_{r,Q}$ is the household expenditure per person by region and quintile (US\$2005/person), HH is the household expenditure (mi. US\$2005), P_r is the population by region, IS_Q is the income share by quintile (see Table 33 in the Appendix) and IS_r is the income share by region (see Table 35 in the Appendix). The obtained household expenditure per person by quintile and region is shown in Table 34 in the Appendix.

The population density (PD, inhabitant/km^2), the urban and rural densities are calculated using the population projections shown in Table 8 and the land area. Ambient temperature is expressed in heating degree days (HDD), which in average for Colombia are 677 (ChartsBin, 2014). Household size represents the number of inhabitants per household and significant differences exist by region (rural vs. urban) and by household income. Therefore, household size is estimated by region and by income quintile following the methodology suggested by Daioglou. The historical average household size is taken from available statistics for years 1973, 1985, 1993 and 2005 (DANE, 2006), which have decreased over the years. The exponential correlation is obtained with a coefficient of determination R^2 of 99.15%.:

Eq. 15 $\mathrm{S} = 6.2324\mathrm{E}10 \cdot e^{-0.01173 \cdot Year}$

Where S is the household size in inhabitants per household. This correlation is then used to estimate the average household size in the future. The allocation of household size by region is not available and is therefore estimated using the correlation proposed by Daioglou:

Eq. 16 $S_{Urban}/S = 0.174078 \cdot Urb + 0.82592$

Eq. 17 $Urb = Pop_{Urban}/Pop_{Total}$

Where Urb is the urban fraction of the total population. Next, the allocation of household sizes across quintiles is defined using the approach defined in (Daioglou, 2010). The obtained household size by region and quintile are then presented in Figure 69 in the Appendix.

__Second step__

In a second step, intermediate drivers are estimated. Intermediate drivers include floor space per person, access to electricity and natural gas. The floor space per person is determined using a Gompertz curve defined by the following equations (Daioglou, 2010):

Eq. 18 $FS_{Total} = \varphi_1 \cdot e^{-1.341 \cdot e^{\left(\frac{-0.125}{1000}\right) \cdot HHp}}$

Eq. 19 $FS_{Urban,Q} = (0.28925 \cdot Urb + 0.71705) \cdot FS_{Total} \cdot FSQ_{r,Q}$

Eq. 20 $FS_{Rural,Q} = \left[\frac{FS_{Total} - (Urb \cdot FS_{Urban})}{1 - Urb}\right] \cdot FSQ_{r,Q}$

Eq. 21 $\varphi_1 = (-2.964 \cdot Ln(PD) + 60.577) \cdot \left(1 + \frac{0.125 * HHp}{35000}\right)$

Eq. 22 $FSQ_{r,Q} = 1 + \big(0.131 \cdot (Q - 3)\big)$

Where FS_{Total} is the average floor space (m^2/person), $FS_{Urban,Q}$ and $FS_{Rural,Q}$ are the urban and rural floor spaces by quintile, PD is the population density, $FSQ_{r,Q}$ is the floor space quintile factor, Q is the quintile number and φ_1 is a parameter of the Gompertz curve. Obtained floor spaces by region and quintile are shown in Table 36 in the Appendix. Historical data on access to electricity and natural gas disaggregated by region for various years is collected from several sources (see Table 37 in the Appendix). The access to electricity and natural gas follows an evolutionary trend over the years that might be described by a Gompertz curve. Then, Gompertz curves are created using regression analysis to best fit historical data and subsequently used to estimate future values. A general Gompertz curve defined by the following equation is used:

Eq. 23 $AES_{type} = \kappa_1 \cdot e^{-\kappa_2 \cdot e^{-\kappa_3 \cdot (Year - 1973)}}$

Where AES_{type} is the access to energy services (i.e. electricity or natural gas) in percentage, Year is the year of evaluation and $\kappa_1, \kappa_2, \kappa_3$ are parameters of the Gompertz function. The parameters of the Gompertz function are positive numbers estimated through a regression analysis for electricity and natural gas by region (i.e. rural and urban). These parameters are shown in Table 38 in the Appendix, along with their coefficients of determination. Obtained results from the Gompertz models and historical data are plotted in Figure 16. Disaggregation of the urban and rural access to electricity and natural by quintile is estimated using the following equations, as suggested by Daioglou (see obtained results in Figure 70 and Figure 71 in the Appendix):

Eq. 24 $E_{r,Q} = E_r \cdot \left[1 + 0.3070 \cdot \left(\frac{E_r}{100} - 1\right) \cdot (3 - Q)\right]$

Eq. 25 $NG_{r,Q} = E_r \cdot \left[1 + 0.3070 \cdot \left(\frac{E_r}{100} - 1\right) \cdot (3 - Q)\right]$

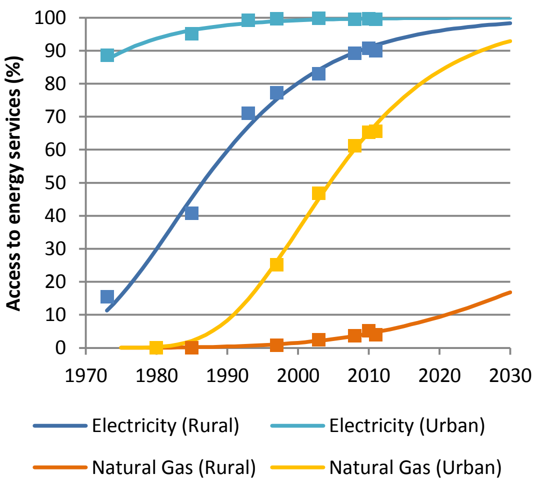


***Figure 16.** Estimated access to energy services*

Third step

In a third step, the demand for cooking, appliances, water heating, space cooling and lighting as well as the energy demand by fuel are estimated.

Water heating

Demand for water heating is modeled as a Gompertz curve dependent on income, following the methodology developed by Daioglou. For the particular case of water heating, the demand is not disaggregated by region and quintile and is rather estimated for the entire country.

Eq. 26 $WUE = WUE_{Max} \cdot e^{-\kappa_4 \cdot e^{-\kappa_5 \cdot HHp}}$

Eq. 27 $WUE_{Max} = (0.003 \cdot \mathrm{HDD} + 2.756) \cdot \mathrm{OD}$

Where $WUE_{r,Q}$ is the useful energy demand for water heating by region and quintile ($\mathrm{MJ_{UE}}$/person/year), $WUE_{Max}$is the maximum useful energy demand for water heating ($\mathrm{MJ_{UE}}$/person/year), HDD is the heating degree days equal to 677 for Colombia according to (ChartsBin, 2014), $HHp_{r,Q}$ is the household expenditure per person by region and quintile (US$2005/person), OD are the annual number of days demanding hot water and κ_4, κ_5 are parameters of the Gompertz function. Then, a Gompertz function is created to best fit the historical data published in (UPME, 2011a; UPME, 2011b; UPME, 2011c). Obtained Gompertz function and historical data for water heating are compared in Figure 72 in the Appendix, along with parameters of the Gompertz function. Next, the fuel shares are calculated by dividing the demand into two groups, group #1 with access to electricity, natural gas and other fuels and group #2 with access only to electricity. Then, for both groups the fuel shares are estimated using a logit function described by the following equation:

Eq. 28

$$Share_{f,t} = \frac{\left[{}^{1}/_{k_f F_{f,t}}\right]^{\gamma}}{\sum_f \left[{}^{1}/_{k_f F_{f,t}}\right]^{\gamma}} \cdot \theta + (1 - \theta) \cdot Share_{f,t-1}$$

Where, $F_{f,t}$ is the fuel cost (US$2005/MMBtu), k_c is a cost exponent, γ is the cost sensitivity coefficient, θ is the speed of adjustment and subscripts f and t are respectively fuel and year. The parameters of the logit function are obtained through a regression analysis to best fit the historical curve of shares. Historical and estimated fuel shares along with parameters of the Gompertz curves are shown in Figure 73 in the Appendix.

Appliances

Demand for energy associated with appliances is modeled for three categories: refrigeration, air conditioning and other appliances. Models are based on ownership and energy use per appliance. The appliance ownership is defined by the general equation:

Eq. 29 $OW_{a,r,Q} = Sat_a \cdot e^{-\kappa_6 \cdot e^{-(\kappa_7/1000) \cdot HHp_r}}$

Where $OW_{a,r,Q}$ is the ownership by appliance (units/household), region and quintile, Sat_a is the saturation level by appliance (units/household), HHp_r is the household expenditure per capita by region (US$2005/person), κ_6, κ_7 are parameters of the Gompertz function and the subscript a represents the type of appliance. The unit energy consumption of appliances is defined by the general equation:

Eq. 30 $UEC_a = \alpha_a \cdot \beta_a^{(t-1971)} + UECm_a$

Where UEC_a is the unit energy consumption by type of appliance (kWh/year), $UECm_a$ is an assumed limit to UEC_a and α_a, β_a are coefficients that vary the unit energy consumption over the years. Finally, the energy demand per capita for appliances is estimated by the general equation:

Eq. 31 $EDA_a = \frac{\sum_{r,Q} OW_{a,r,Q} \cdot UEC_a \cdot Households_{r,Q}}{P}$

Where $Households_{r,Q}$ is the number of households by region and quintile and *P* is the total population.

The category of refrigerators is now analyzed in detail. The saturation for refrigerators by region and quintile is defined as:

Eq. 32 $Sat_{Ref} = \left(m_{Ref} \cdot (t-1970) + b_{Ref}\right) \cdot \left(0.206 \cdot ln\left(HHp_{r,Q}/HHp_r\right) + 1\right) \cdot E_{r,Q}$

Where t is the year, m_{Ref} and b_{Ref} are coefficients, $HHp_{r,Q}$ is the household expenditure per capita by region and quintile, HHp_r is the average household expenditure per capita by region and subscript *Ref* denotes refrigerator. Then, the parameter κ_7 of the Gompertz curve for refrigerators is defined as:

Eq. 33 $\kappa_7 = \left(d_{Ref} \cdot ln(t) + e_{Ref}\right)$

Where t is the year and d_{Ref} and e_{Ref} are constants. By substituting Eq. 32 and Eq. 33 into Eq. 29 it is possible to estimate the ownership of refrigerators. Then, the energy demand for refrigeration per capita is estimated using Eq. 31. There is neither available data for ownership of refrigerators in Colombia nor for unit energy consumption, therefore the models described above are validated with the overall energy demand for refrigeration per capita taken from (UPME, 2011a; UPME, 2011b; UPME, 2011c). Model parameters and obtained results through regression analysis are shown in Figure 74 and Figure 75 in the Appendix.

The category of air conditioners is now analyzed in detail. The saturation for air conditioners by region and quintile is defined as:

Eq. 34 $Sat_{AC} = \left(\frac{m_{AC}}{m_{AC} + e^{-(b_{AC}/1000)\cdot(HHp_r - 250)}}\right) \cdot \left(0.206 \cdot ln\left(HHp_{r,Q}/HHp_r\right) + 1\right) \cdot E_{r,Q}$

Where m_{AC} and b_{AC} are coefficients, $HHp_{r,Q}$ is the household expenditure per capita by region and quintile, HHp_r is the average household expenditure per capita by region and subscript *AC* denotes air conditioner. For air conditioners parameters κ_6, κ_7 of the Gompertz function are zero and ownership is entirely defined by Eq. 34. For the particular case of air conditioners the unit energy consumption is not defined by Eq. 30, but rather by the following equation:

Eq. 35 $UEC_{AC,r,Q} = \frac{\text{CDD} \cdot \left(0.6053 \cdot \ln\left(HHp_{r,Q}\right) - 3.1897\right)}{COP_t/COP_{Reference}}$

Where $UEC_{AC,r,Q}$ is the unit energy consumption of air conditioners by region and quintile ($kWh_{cooling}$/household), CDD is the average cooling degree days (2119 for Colombia according to (ChartsBin, 2014)), $HHp_{r,Q}$ is the household expenditure per capita (US$2005/person), COP_t is the coefficient of performance for air conditioners in year t and $COP_{Reference}$ is the coefficient of performance for base year (2009). It is assumed that $COP_{Reference}$ at base year is 2.8 and increase linearly to 3.5 in 2050 (3.19 in 2030) as described in (Rong, 2007).

By substituting Eq. 34 and Eq. 35 in Eq. 31 it is possible to estimate the energy demand for air conditioning per capita. Similarly to refrigerators, there is neither available data for ownership of air conditioners nor for unit energy consumption, therefore the models described above are validated with the overall energy demand for air conditioning per capita available in (UPME, 2011a; UPME, 2011b; UPME, 2011c). Model parameters and obtained results through regression analysis are shown in Figure 76 and Figure 77 in the Appendix.

Given lack of more disaggregated data all other appliances are lumped into a single group and it is analyzed now in detail. The saturation for other appliances by region and quintile is defined as:

Eq. 36 $Sat_{OA} = (m_{OA} \cdot (t-1970) + b_{OA}) \cdot \left(0.144 \cdot ln\left(HHp_{r,Q}/HHp_r\right) + 1\right) \cdot E_{r,Q}$

Where m_{OA} and b_{OA} are coefficients, t is the year, and subscript *OA* refers to other appliances. The unit energy consumption of other appliances is modeled through the following equation:

Eq. 37 $UEC_{OA,r,Q} = C_{OA1} \cdot \ln\left(HHp_{r,Q}\right) - C_{OA2}$

Where, $UEC_{OA,r,Q}$ is the unit energy consumption of lumped appliances (kWh/unit), C_{OA1}, C_{OA2} are coefficients and $HHp_{r,Q}$ is the household expenditure per capita (US$2005/person). The overall energy demand per capita for other appliances is then estimated by substituting Eq. 36 and Eq. 37 in Eq. 31. Models are calibrated with published data in (UPME, 2011a; UPME, 2011b; UPME, 2011c). Model parameters and obtained results through regression analysis are shown in Figure 78 and Figure 79 in the Appendix.

Lighting

Energy demand for lighting is modeled through the following equation proposed by Daioglou:

Eq. 38 $LE_{r,Q} = 0.68 \cdot FS_{r,Q} \cdot Wattage \cdot LHF_r$

Where $LE_{r,Q}$ is the annual energy demand for lighting per household by region and quintile (kWh/person), $FS_{r,Q}$ is the floor space per person, $Wattage$ is the unit energy consumption per light bulb (assumed to be 60 W/unit) and LHF_r is a lighting hours factor coefficient. In addition, the energy demand for lighting per capita is estimated through the following equation:

Eq. 39 $LEp = \frac{\sum_{r,Q} LE_{r,Q} \cdot Households_{r,Q} \cdot E_{r,Q}}{P}$

Where LEp is the lighting energy demand per capita, $E_{r,Q}$ is the access to electricity by region and quintile and $\sum_{r,Q} LE_{r,Q} \cdot Households_{r,Q} \cdot E_{r,Q}$ is the overall lighting energy demand. LHF_r is estimated through regression analysis to best fit historical data available in (UPME, 2011a; UPME, 2011b; UPME, 2011c). Obtained results and parameters are shown in Figure 80 in the Appendix.

Cooking

The energy demand for cooking is estimated separately for rural and urban regions. For urban regions, the energy demand for cooking per capita is assumed to be a constant and is estimated as the average for the period 1975-2009 using historical data available in (UPME, 2011a; UPME, 2011b; UPME, 2011c). The obtained value is 1.8225 MJ_{UE}/person/day (standard deviation = 0.1722), see Figure 81 in the Appendix. For rural regions, the energy demand for cooking is estimated through the following equations:

Eq. 40 $CKE_Q = C_{CK1} \cdot C_{CK2}^{t-1970} + C_{CK3}$

Eq. 41 $CKEp = \frac{\sum_Q CKE_Q \cdot Households_Q}{P}$

Where CKE_Q is the annual energy demand for cooking per household by quintile (MJ_{UE}/household/day), $CKEp$ is the annual energy demand for cooking per person (MJ_{UE}/person/day). Obtained parameters and results for the model are presented in Figure 82 in the Appendix.

Fuel shares for cooking both in rural and urban regions are estimated using Eq. 28. Similarly to the water heating, the fuel shares by region are calculated by dividing the demand into two groups, group #1 with access to electricity, natural gas and other fuels and group #2 with access only to electricity. Models are calibrated using historical data and obtained results are shown in Figure 83, Table 39, Figure 84 and Table 40 in the Appendix.

Fourth step

The fourth step relates to the definition of emission factor and the estimation of total emissions. Generally, the methodology to estimate emissions is the same as that used for road transport. The emission factors by pollutant are taken from the Technology and Environmental Database (TED) implemented in LEAP. Further, it is assumed that the CO_2 emissions produced during combustion of biomass resources are biogenic.

B.2.1.3. Cane and palm industries

Demand for energy in cane and palm industries is estimated as the product of the activity level by sector and the annual energy intensity by sector:

Eq. 42 $\text{Demand} = \text{activity level} \cdot \text{energy intensity}$

The activity level by sector is the total amount of locally produced commodities, such as sugar, palm oil and jaggery. The local production of these commodities is estimated through a land use and trade model that is explained in more detail in section B.1.4. On the other hand, the energy intensity is the demand of energy per unit of activity. For the cases of sugar, palm oil and jaggery the demand of electricity and heat per unit of activity is summarized in Table 17.

Table 17. *Energy intensity for palm and can industries*

Commodity	Electricity (MJ/ ton)	Heat (MJ/ ton)	Reference
Sugar	450[1]	9625[1]	(Macedo I. L., 2004)
Palm oil	533	11,481	(Panapanaan, 2009)
Jaggery	-	12051[2]	(Velásquez, 2004) (UPME, 2011a)

[1] It is assumed that the yield of sugar is 12 ton per ton of sugar cane without leaves. In general, the demand of electricity is 54 MJ/ton-cane and the demand of heat is 1155 MJ/ton-cane, taken from (Macedo I. L., 2004)

[2] Evaluated using efficiency published in (Velásquez, 2004) and energy demand published in (UPME, 2011a)

B.2.1.4. Non-road transport, agriculture, industrial and commercial sectors

Econometric methods were used to estimate the aggregate final energy demand by fuel as a function of key drivers (e.g. sectorial GDP, energy prices, etc.) in non-road transport, agriculture, industrial and commercial sectors. Econometric methods were used mainly because data was not readily available and not substantially affected by changes in bioenergy technologies.

The final energy demand by fuel is estimated using the following equation and calibrated using the national energy balances:

Eq. 43 $$Demand_{f,t,s} = e^{\left[\theta\cdot\left(\xi_1\cdot Ln(\pi_{f,t})+\xi_2\cdot Ln(GDP_{t,s})\right)+\left((1-\theta)\cdot Demand_{f,t-1,s}\right)\right]}$$

Where $Demand_{f,t,s}$ is the energy demand by sector (s), fuel (f) and year (t), ξ_1 and ξ_2 are coefficients of the equation, $\pi_{f,t}$ is the price of fuel by year (US$2005/MMBtu), $GDP_{t,s}$ is the gross domestic product by sector and year (Billion US$2005) and θ is the speed of adjustment.

Coefficients ξ_1 and ξ_2 and speed of adjustment θ are calibrated through regression analysis to best fit historical data available in (UPME, 2011a; UPME, 2011b; UPME, 2011c). The price of fuel by year is taken from Table 18 in the Appendix, while the GDP by sector is taken from Table 9. Results of the regression analysis of the energy demand by sector and fuel are presented in Table 41 in the Appendix. In a few cases the results of the regression analysis were not satisfactory, i.e. if the coefficient of determination was lower than 60%. The energy demand was not substantial in these cases and thus assumed that the average demand of last ten years would continue until 2030. These assumptions are shown in Table 42 in the Appendix.

B.2.2. Model of the transformation side

The model of energy transformation processes is divided into two main sub-models: 1) power generation and 2) other energy transformation processes. A more detailed description of these sub-models is presented as follows.

B.2.2.1. Power generation

Power generation is modeled through an optimization algorithm which orders dispatch and capacity addition to minimize the net present value of the lifetime total costs of the system (i.e. capital costs, operating costs, fuel costs, decommissioning, etc.). For Scenarios I and II, the optimization algorithm is additionally configured to meet a renewable power target. The methodology to analyze power generation consists of four steps (see Figure 17).

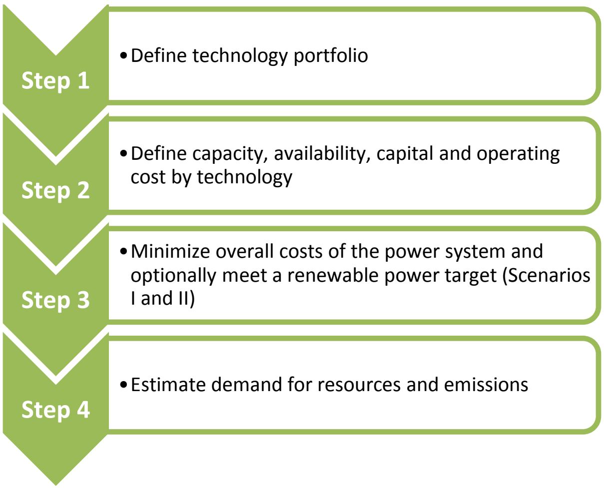


Figure 17. *Methodology to analyze power generation*

<u>First step</u>

In a first step, a technology portfolio is defined. The technology portfolio consists of two main groups: traditional technologies and new technologies.

Traditional technologies include large and small hydro power plants (<10 MWe), simple and combined cycle gas turbines, coal power plants, diesel and gas reciprocating engines, wind turbines, bagasse-fuelled steam CHP power plants, palm residues-fuelled steam CHP power plants and small power generation units burning a wide range of fuels (UPME, 2011a). From these technologies only bagasse- and palm residues-fuelled steam CHP power plants are able to co-produce combined heat and power (CHP).

New technologies include: biomass co-firing in coal power plants, syngas co-firing in gas turbine simple and combined cycles, biomass-fuelled CHP power plants at small scale (up to 10 MWe), biogas- and landfill gas-fuelled reciprocating engines. New technologies able to co-produce heat and power include biomass-fuelled CHP power plants at small scale, biogas- and landfill gas-fuelled reciprocating engines.

<u>Second step</u>

In a second step the capacity, availability, efficiency, capital and operating cost and other characteristics of the different technologies are collected from several sources and defined (see Table 43 in the Appendix).

<u>Third step</u>

In a third step, an optimization algorithm calculates the least cost capacity expansion and dispatch required to meet a minimum planning reserve margin and optionally a renewable power target (only for Scenarios I and II). The optimization algorithm minimizes the net present value of the lifetime total costs of the system. For this purpose the Open Source Energy Modeling System (OSeMOSYS) algorithm incorporated into LEAP is used. The total costs of the system include capital, operation & maintenance, fuel and decommissioning costs. The objective function, taken from (Howells, 2009), is defined as:

Eq. 44 $$Minimize\ Total\ Discounted\ Costs = \sum_t (Investment_t + O\&M_t + Fuel_t + Decommissioning_t) \cdot (1+r)^{-t}$$

Where $Investment_t$ is the investment cost in year t (US$2009/kW taken from Table 43 in the Appendix), $O\&M_t$ is the operation and maintenance costs (US$2009/kW taken from Table 43), $Fuel_t$ is the fuel cost (US$2009/MMBtu, converted from US$2005/MMBtu originally shown in Table 18), $Decommissioning_t$ is the cost for decommissioning a power plant and *r* is the discount rate. Other general assumptions include:

- A discount rate of 10% is assumed (IEA-NEA, 2010).
- A decommissioning cost of 5% of capital cost is assumed (IEA-NEA, 2010).
- Investment cost includes owner's costs but exclude interest during construction (IEA, 2012).

The optimization algorithm needs to meet two main requirements:

- Meet the planning reserve margin (all scenarios)
- Meet the renewable power target (only Scenarios I and II)

The planning reserve margin is defined as:

Eq. 45 $$Reserve\ margin = \frac{(\sum Capacity \cdot Capacity\ credit) - Peak\ Load}{Peak\ Load}$$

Where *capacity* is the installed capacity by technology (MW), *capacity credit* is the amount of firm conventional generation capacity that can be replaced by renewable power and *peak load* is the peak demand throughout the year (IEA, 2012). Capacity credit by technology is shown in Table 43 in the Appendix. The assumed minimum planning reserve margin is 40%, which has been the average value between 1998 and 2010 in Colombia (UPME, 2011). This value is significantly higher than in other countries, where typically ranges between 15 and 25% (IEA, 2007; NERC, 2012; EIA, 2014). The annual electricity loads are divided into daily slices, for which a load shape is assigned. The load shape is taken from the state-owned transmission firm Interconexión Eléctrica S.A. for year 2009 (XM, 2013) and is shown in Figure 85 in the Appendix. When compared to data of 1996 the load shape of 1999 has virtually no differences and therefore it has been decided to keep the load shape constant until 2030.

For Scenarios I and II the renewable power target linearly increases from 0% in 2015 to 10% in 2025 and remains at this level afterwards. Technologies that qualify as renewable energy to meet the renewable power target include: wind power, small hydro (< 10 MWe), biomass fuelled CHP plants, biomass co-firing in coal power plants, syngas co-firing in gas turbine simple and combined cycles, biomass-fuelled CHP power plants at small scale (up to 10 MWe), biogas-fuelled reciprocating engines and landfill gas fuelled reciprocating engines.

Additional variables required to perform the optimization include a) exogenous capacity additions and b) maximum annual capacity and capacity addition by technology.

Exogenous capacity additions reflect planned capacity additions and retirements and are exogenously entered into LEAP for all scenarios (see Table 44 in the Appendix with detailed capacity additions by technology, taking data from the Mining and Energy Planning Unit (UPME) and other sources). Technologies exogenously added up to 2019 include large and small hydro, coal, natural gas simple cycle gas turbines and diesel engines. In addition to that, further capacity is exogenously added for Scenarios I and II to comply with the long-term targets:

- Reciprocating engine fuelled with biogas from animal waste and municipal water treatment plants to comply with the 5% target to exploit it by 2030
- Reciprocating engine fuelled with biogas from biodiesel production plants to comply with the 100% target to exploit it by 2030
- Reciprocating engine fuelled with landfill gas to comply with the 10% target to exploit it by 2030

Further capacity exogenously added in Scenarios I and II to comply with the long-term targets for exploiting biogas and landfill gas is shown in Table 45 in the Appendix.

The maximum annual capacity addition is estimated on a technology by technology basis. The maximum annual capacity addition for those technologies that are already planned to be added (e.g. large and small hydro, coal, natural gas simple cycle gas turbines and diesel reciprocating engines) is assumed to be the maximum observed planned addition during the period 2009-2019 (see Table 46 in the Appendix).

Based on discussion with experts a maximum annual capacity addition of 100 MWe is assumed for gas turbines at small-scale, coal power plants at small-scale and natural gas reciprocating engines, while 50 MWe is assumed for wind power given its slow-paced deployment. For biomass-based power generation technologies, the maximum annual capacity addition is related to the future technical biomass energy potential described in detail in (Gonzalez-Salazar, et al., 2014b). It is estimated through the following equations:

Eq. 46 $CADD_{Max,c} = \left(TEP_{Max,b}/20\right) \cdot FA$

Eq. 47 $FA = \frac{\eta \cdot FEF \cdot 1e6}{CAPF \cdot 8760 \frac{h}{year} \cdot 3600 \frac{s}{h}}$

Where $CADD_{Max,c}$ is the maximum annual capacity addition by technology (MW), $TEP_{Max,\mathrm{b}}$ is the maximum technical energy potential by biomass resource (TJ) (taken from Table 24 in the Appendix), subscripts c and b respectively represent power technology and type of biomass resource. FA is a coefficient, η is a generalized efficiency for biomass-based power generation technologies (assumed to be that of biomass CHP at small scale, i.e. 30%), $CAPF$ is a generalized capacity factor (assumed to be the average of 2004-2011 for bagasse-based CHP, i.e. 59.19%) and FEF is a factor that attempts at considering that most likely not all technical biomass energy potential can be exploited (assumed to be 40%).

Note that the maximal annual increment of biomass-based power technologies is assumed to be lineal, which is described in Eq. 46 by dividing the maximum technical energy potential ($TEP_{Max,\mathrm{b}}$) by the 20 years span from 2010 to 2030. Obtained maximum annual capacity additions for biomass-based power generation technologies are shown and compared to other technologies in Table 46 in the Appendix. The maximum annual capacity is also limited for some technologies. This is the case of biomass co-firing in coal power plants in which the capacity is limited to 10% of the overall coal power capacity and for syngas co-firing in gas turbines the capacity is limited to 5% of the overall gas power capacity. Moreover, for biomass-based power generation technologies the maximum annual capacity is also limited by the technical biomass energy potential by resource ($TEP_{Max,\mathrm{b}}$) and the factor FEF.

<u>Fourth step</u>

In a fourth step, the demand for resources and the generated emissions by technology are estimated. The demand for resources is estimated through the following equation:

Eq. 48 $Resources_{c,t} = \sum \frac{\mathrm{Power}_{c,d}}{\eta}$

Where $Resources_{c,t}$ is the demand for resources by technology *c in* year *t*, $\mathrm{Power}_{c,d}$ is the daily power generation by technology and η is the efficiency.

Finally, the greenhouse gas emissions are calculated through the following equation:

Eq. 49 $GHG_{c,t,p} = Power_{c,t} \cdot EF_{c,t,p}$

Where $GHG_{c,t,p}$ (Tons of CO_2 equivalent) are the emissions by pollutant by technology and year, $EF_{c,t,p}$ is the emission factor by pollutant (kg/TJ), $Power_{c,t}$ is the annual power generation by technology, and subscripts *c, t* and *p* respectively are technology, year and pollutant.

Pollutants analyzed in power generation include carbon dioxide (CO_2, both biogenic and non-biogenic), carbon monoxide (CO), methane (CH_4) and nitrogen oxides (NOx). The emission factors by pollutant are taken from the TED database implemented in LEAP, which refers to the Tier 1 emissions factors for power generation suggested by IPCC (Heaps, 2012). Detailed characteristics of all fuels used in the power generation module are shown in Table 47 in the Appendix. Further, it is assumed that the CO_2 emissions produced during combustion of biomass resources in power generation are biogenic. It is also assumed that no GHG emissions are generated by wind and hydro power technologies.

For Scenarios I and II, an additional assumption for new technologies is considered. It is assumed that there are two effects by burning landfill gas and biogas from biodiesel processing plants, wastewater plants and animal waste. One effect relates to the emission of biogenic CO_2 in direct proportion to the carbon content in landfill gas and biogas. The second effect is the reduction in methane emissions that otherwise would be released into the atmosphere by not using these resources. This reduction is proportional to the methane content in the landfill gas/biogas and the volumes combusted: 0.2671 kg-CH_4/kg-landfill gas and 0.3906 kg-CH_4/kg-biogas. The avoidance of methane emission is therefore treated here as a credit, i.e. a 'negative' emission following the methodology suggested in (den Boer, 2005).

B.2.2.2. Cane mill, sugar and bioethanol production

In the sugar cane mill, the cane is crushed and cane juice, bagasse, tops and leaves are extracted. The juice is used to produce sugar and ethanol and the bagasse is partly used to produce steam in boilers and CHP plants and partly used as raw material in paper mills. Tops and leaves are actually left on the field for soil replenishment, but for simplicity here are considered a sub-product of the cane mill. The mill is mechanically driven by steam turbines fed with steam produced in bagasse-fuelled boilers.

Three independent routes are considered for the co-production of sugar and bioethanol from cane juice (see Figure 18). In the first route only sugar is produced in a sugar factory. Cane juice is purified, filtrated and evaporated to produce molasses. This is followed by a crystallization and centrifugation process, in which sugar crystals are formed and separated from molasses. Finally, crystals are dried and refined and sugar is then produced, while molasses are sold as animal feed. For this route it is assumed a constant yield of 0.12 tons of sugar per ton of sugar cane (without leaves), taken from (BID-MME, Consorcio CUE, 2012).

In the second route, sugar and bioethanol are co-produced in a sugar factory with an annexed distillery. In this route, sugar is produced in a similar fashion as in Route 1, but molasses are converted into bioethanol via microbial fermentation, distillation and dehydration. For this route constant yields of 0.093 tons of sugar and 0.019 tons of bioethanol per ton of sugar cane (without leaves) are assumed, taken from (BID-MME, Consorcio CUE, 2012). In the third route, only bioethanol is produced by directly converting cane juice into bioethanol via fermentation, distillation and dehydration, but without co-producing sugar. This route is also known as autonomous distillery. It is assumed a constant yield of 80 liters of ethanol per ton of cane (without leaves), taken from (Ferreira-Leitao, 2010). Additional assumptions considered for the sugar cane mill and the sugar and bioethanol co-production routes are presented in Table 48.

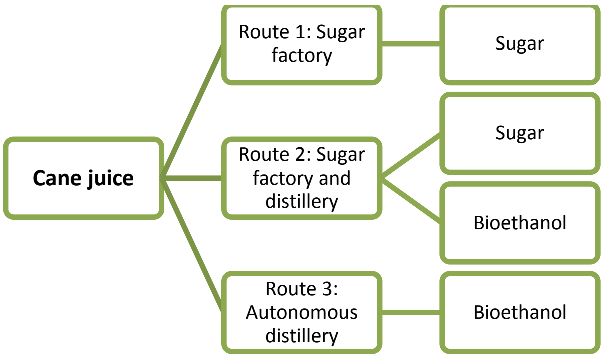


Figure 18. *Sugar and bioethanol co-production routes*

The fraction of cane juice allocated to each of the three routes is estimated through the LUTM model explained in section B.1.4.

B.2.2.3. Other conversion processes

Other conversion processes are modeled on a case-by-case basis. Some conversion processes are not modeled in depth and are rather calculated and calibrated using general official data, whereas some other processes are analyzed in more detail using data from technical reports and various sources.

Conversion processes that are not modeled in detail include: natural gas works, reinjection and flaring, oil refining, coke factories, blast furnace, charcoal production, own use and energy distribution. For these processes, the installed capacities, efficiencies, inputs and outputs are calculated and calibrated using official data published in (UPME, 2011a; UPME, 2011b; UPME, 2011c). For the sake of brevity this data is not included in this report.

Conversion processes that are modeled in more detail include:

- Palm oil mill and biodiesel production plant
- Gasification of wood and biomass residues
- Wood pelletization (as pretreatment in co-firing with coal)
- Renewable diesel production
- Biomethane production
- Heat production in biomass-based boilers

<u>Palm oil mill and biodiesel production plant</u>

In the palm oil extraction mill, the fresh fruit bunches of the palm are crushed producing palm oil and residues. Part of the residues (e.g. fiber, stone) is commonly used as fuel in steam boilers to provide heating, while other part of the residues (e.g. rachis) is commonly returned to the field for soil replenishment. The process to convert palm oil into biodiesel consists of oil refining, transesterification and biodiesel purification steps. Similarly to the case of bioethanol, the production, imports and exports of biodiesel are estimated through the LUTM model. Regarding emissions, methane produced in wastewater as by-product of the biodiesel conversion processes is assumed to be 1.03 Ton-CH_4/Ton-FFB as published in (BID-MME, Consorcio CUE, 2012), which according to the source is released to the atmosphere. Other assumptions considered for the palm oil mill and the biodiesel production process are also shown in Table 48 in the Appendix.

<u>Gasification of wood and biomass residues</u>

Biomass gasification is a thermochemical process to convert biomass resources into a gas mixture called syngas and containing carbon monoxide, hydrogen and carbon dioxide. Syngas is used in other conversion processes, including syngas co-firing in gas turbine simple and combined cycles, heat production in boilers and biomethane production. Two gasification processes are considered, one using wood and other using other biomass residues (e.g. rice husk, cane leaves and tops, bagasse, palm residues, etc.) as feedstocks. For wood gasification it is considered a MILENA gasifier, a twin-bed gasifier with a circulating fluidized bed as gasifier and bubbling fluidized bed as combustor (Risø DTU, 2010). For gasification of biomass residues it is considered a SilvaGas gasifier, a commercially available technology proven on large scale (up to 40 MW) consisting of two circulating fluidized beds with sand as heat carrier (Risø DTU, 2010). This gasifier can also be fed with a wide variety of feedstocks, which makes it appropriate for gasification of biomass residues. Technical characteristics of both gasifiers are shown in Table 49 in the Appendix.

Wood pelletization

Wood pelletization is a process to convert wood into pellets via milling and mechanical compression. It is a process that demands electricity and that is required for other processes such as biomass co-firing in a coal power plant. Wood pellets have higher energy content than wood and are easier to handle, which facilitates its use in coal power plants. Technical characteristics of the wood pelletization process are shown in Table 49 in the Appendix.

Renewable diesel production

Renewable diesel is produced by hydrotreating of vegetable oils using palm oil as feedstock. In this process, hydrogen is used to remove oxygen from the triglyceride vegetable oil molecules and to split them into three separate chains, which are similar to diesel fuel components (NESTE OIL, 2014). The process consumes palm oil, electricity, heat and natural gas and produces renewable diesel, renewable gasoline and renewable propane. Emissions associated with the renewable diesel conversion process include biogenic CO_2 (1.0884 Ton/TJ-renewable diesel), non-biogenic CO_2, CO, CH_4, NMVOC and NOx for burning natural gas as well as avoided non-biogenic emissions (emission credits) by substituting renewable fuel products (i.e. renewable diesel, renewable gasoline and renewable LPG) for fossil fuels. Characteristics of the process are summarized in Table 49.

Biomethane production

Biomethane is produced through two different conversion processes: methanation and biogas upgrading. Methanation is a catalyst-based exothermic process in which syngas is converted into a gas stream containing mainly methane. It is chemically described by the balance $CO + 3H_2 \rightarrow CH_4 + H_2O$. If syngas from wood is used (using a MILENA gasifier), it is then converted into biomethane in a HaldorTopsøe's TREMP® methanation process. The TREMP® methanation process is a custom-made commercially available technology using three step reactors with heat recovery from exothermic reactions. If syngas from biomass residues is used (using a SilvaGas gasifier), it is then converted into biomethane in a PSI/CTU methanation system. This is an isothermal fluidized bed methanation technology with internal regeneration of the catalyst, which is on the demonstration phase. On the other hand, biomethane production through biogas upgrading is a process to increase the methane content of the biogas in order to achieve quality characteristics to natural gas. In this process various components are removed from the biogas (mainly CO_2, H_2O and H_2S) through a pressure swing adsorption (PSA) process, pre-purification and dehydration systems. This is a commercial and mature technology. Emissions associated with the biomethane conversion process include (see also Table 49 in the Appendix):

- Avoided non-biogenic CO_2 emissions by substituting biomethane for natural gas (-55.8 tons of non-biogenic CO_2 /ton-biomethane) for all conversion processes
- Avoided methane release for biomethane production through upgrading biogas from animal waste (-0.3906 kg of methane per kg of biogas), following the methodology suggested in (den Boer, 2005).

Main technical characteristics and assumptions for the different biomethane production processes are shown in Table 49 in the Appendix.

Heat production in biomass-based boilers

Heat production in biomass-based boilers is mostly used in the jaggery cane industry, but can also be used to provide supplementary heat to other industries (i.e. sugar cane and palm oil industries). Two commercially available technologies are considered, viz. bagasse-fuelled boiler at small-scale and wood boiler at small scale able to burn coal if necessary. The assumed efficiency for these technologies is 30% for bagasse boilers (Velásquez, 2004), and 60% for wood boilers (Thermoflow, 2011). The availability of a bagasse boiler is assumed to be that shown in Figure 65 in the Appendix, whereas the availability of a wood boiler is assumed to be 55%. For the operation of the system, a merit order based on the fuel price is set. Thus, first bagasse is burned, followed by wood and then coal. Regarding emissions, it is assumed that the CO_2 emissions produced during combustion of biomass resources in power generation are biogenic.

Chapter C.Impacts

Highlights Chapter C

1

Characteristics of baseline by 2030:

- The share of bioenergy in the primary energy demand and various sectors reduce.
- Land for producing liquid biofuels and woodfuel amount to 0.6 mio ha.
- GHG emissions reach 223 mio tons CO2-eq. by 2030.

2

Characteristic of Scenario I by 2030:

- The share of bioenergy in power generation and natural gas supply increases, but the share in primary energy demand reduces. Share in road transport remains unchanged compared to baseline.
- Emissions reduction reach 11 mio tons of CO2-eq. and savings of fossil fuels reach 2 mio TOE.
- Land for producing liquid biofuels and woodfuel increases to 0.67 mio ha by 2030.
- It can accomplish long-term emission targets with available lands and turns out to be the most effective scenario in terms of emission reduction per additional hectare of land.

3

Characteristics of Scenario II by 2030:

- The share of bioenergy in power generation, natural gas supply and road transport increases, but the share in primary energy demand reduces.
- Emissions reduction reach 20 mio tons of CO2-eq. and savings of fossil fuels reach 4.5 mio TOE (Scenario II with expansion: 22 mio tons of CO2-eq. and 5.4 mio TOE).
- Land for producing liquid biofuels and woodfuel grows to 1.1 mio ha by 2030 (Scenario II with expansion: 1.3 mio ha).
- However, emissions reductions per additional hectare of land are about 4 to 5 times less compared to Scenario I.
- End-use techniques: stock-turnover economic analysis, dynamic engineering analysis, etc.

4

The most effective policy measure to reduce emissions is power generation & CHP. It accounts for more than 50% in reductions, which come from avoiding methane release via landfill gas and biogas from animal waste through combustion in reciprocating engines.

C.1. Impacts on the energy system

C.1.1. Primary energy demand

C.1.1.1. Trend and influence of GDP

The primary energy demand is found to be somewhat proportional to the Gross Domestic Product (GDP) and describes a trend that is consistent with historical data (see Figure 19 and Figure 20). In the past, the primary energy demand grew moderately as a result of a modest increase in GDP. In contrast, a substantial increase in primary energy demand is expected when the future GDP growth predicted by the government is used. In fact, an increase of 139% in the primary energy demand is expected between 2009 and 2030 for the baseline scenario, as a consequence of the assumed growth in GDP of 156%. This represents an increase from 39.39[16] to 94.16 mio TOE by 2030.

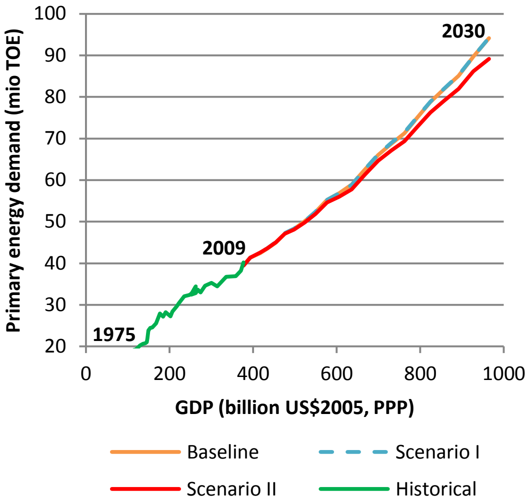


Figure 19. *Primary energy demand vs. GDP*

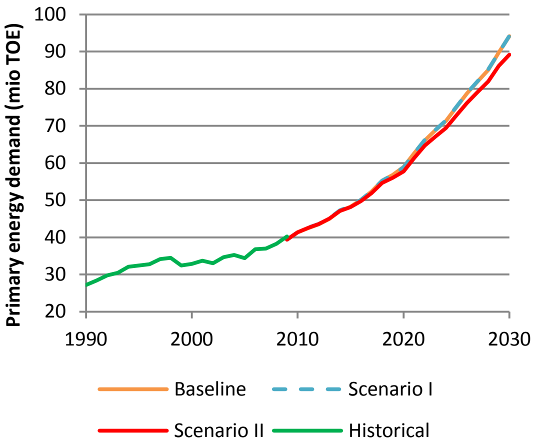


Figure 20. *Primary energy demand by scenario*

[16] Note that this value is slightly higher than the value shown in Table 26in the Appendix, because the energy associated to bagasse from jaggery is included.

On the other hand, the primary energy demand for Scenarios I and II follows a similar path to that of the baseline and reaches 94.18 and 89.18 mio TOE in 2030 respectively. The differences in primary energy between Scenarios I and II compared to the baseline will be highlighted in the next section.

The energy intensity, defined as the energy demand per dollar of GDP, is expected to slowly reduce until 2030 for all scenarios after a continuous decrease over several decades (see Figure 21). This trend is consistent with values estimated for other developing and emerging countries (IEA, 2012b).

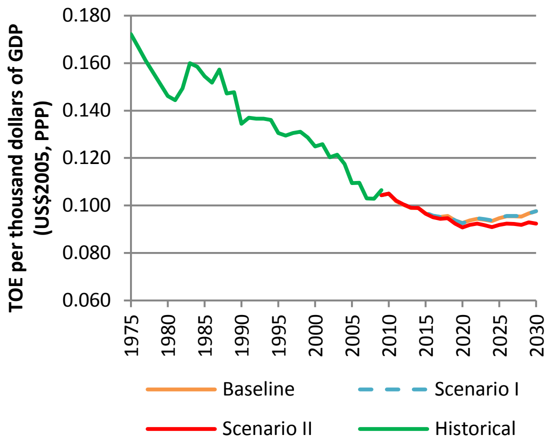


Figure 21. *Estimated energy intensity*

C.1.1.2. Primary energy demand by fuel

The primary energy demand for the baseline scenario disaggregated by fuel is shown in Figure 22. Fossil fuels, i.e. natural gas, coal and oil, continue dominating the primary fuel mix through till 2030. The demand for fossil fuels is expected to grow from 29 to 80 mio TOE, which represents an increase in their share from 74% in 2009 to 85% in 2030. The demand for hydro and bioenergy increases, although their share in the primary energy mix reduces. Demand for hydro grows from 4.2 to 6.3 mio TOE between 2009 and 2030, but its share reduces from 10.6% to 6.7%. The demand for bioenergy[17] increases from 5.9 to 7.7 mio TOE, although its share reduces from 14.9% to 8.2%. The demand for other renewables is marginal (0.005 mio TOE) and remains unchanged through to 2030.

[17] In these calculations, the demand for bioenergy covers bagasse from sugar cane and jaggery cane, palm oil residues and wood. In contrast, UPME does not account for the energy content of bagasse from jaggery cane. As a consequence, results in 2009 are slightly different from those presented in (UPME, 2011a) and also those shown in Figure 2.

The dominance of fossil fuels and the decreased importance of bioenergy and hydro in the baseline scenario agree with historical trends (see Figure 2) and are consequences of maintaining current energy policies in the future.

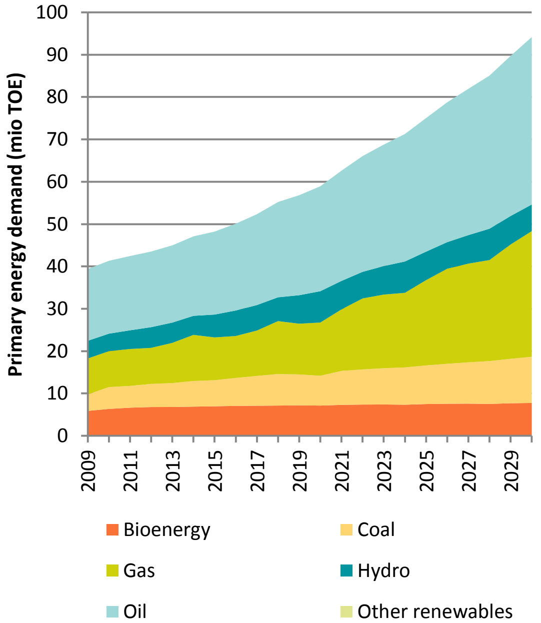


Figure 22. *Primary energy demand by fuel for baseline scenario*

The differences in primary energy demand by fuel between Scenario I and the baseline are shown in Figure 23. Demand for fossil fuels also dominates the primary energy mix in Scenario I. However, this dominance is slightly more moderate than in the baseline, causing a slower reduction in the share of renewables. In fact, while the share of renewables reduces from 25.6% to 14.9% in the baseline, it reduces from 25.6% to 17.2% in Scenario I.

Demand for fossil fuels (mostly natural gas) is expected to reduce in Scenario I compared to the baseline, amounting to 2.2 mio TOE in 2030. Consequently, the share of fossil fuels grows less rapidly than in the baseline, from 74.4% in 2009 to 82.7% in 2030. This reduction in demand for fossil fuels is explained by the implementation of policy measures supporting the substitution of biomethane for natural gas and the replacement of natural gas-based power by biomass-based power and wind power.

On the other hand, demand for bioenergy, hydro and other renewables (i.e. wind) is expected to grow in Scenario I compared to the baseline. The increment in demand for bioenergy reaches 2 mio TOE by 2030. Consequently, the share of bioenergy slightly increases compared to the baseline and accounts for 10% of the primary energy demand by 2030. Demand for wind grows 0.2 mio TOE by 2030 relative to the baseline, and its share of the primary energy demand slightly increases from 0.04% to 0.2%. The increment in demand for hydro is marginal (only small hydro) and amounts to 0.03 mio TOE by 2030, while its contribution reduces to 6.7%.

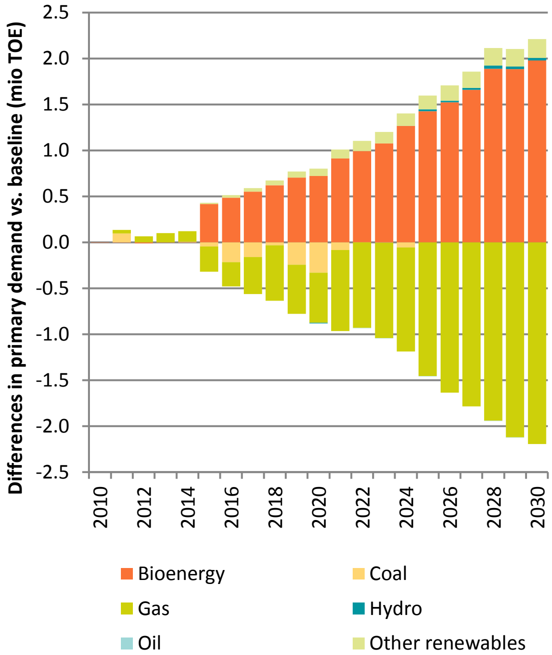


Figure 23. *Differences in primary energy demand by fuel between Scenario I and baseline*

Differences in primary energy demand by fuel between Scenario II and the baseline are shown in Figure 24. Demand for fossil fuels in Scenario II is expected to reduce even further than in Scenario I, amounting to 7.4 mio TOE. Apart from the 2 mio TOE reduction in demand for natural gas, similarly to Scenario I, there is a further reduction of 5.4 mio TOE in demand for oil.

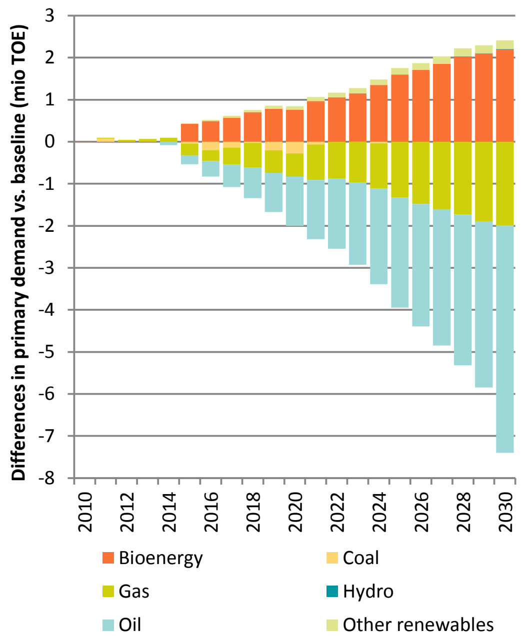


Figure 24. *Differences in primary energy demand by fuel between Scenario II and baseline*

This reduction in demand for oil is explained by the implementation of policy measures supporting the substitution of bioethanol for gasoline and biodiesel and renewable diesel for diesel fuel. It is important to note that, while there is an increase in demand for liquid transport biofuels, this increase is not reflected in a higher demand for primary bioenergy. The reason for this is that in order to be consistent with the accounting methodology of UPME, only bagasse and solid biomass are accounted as primary energy. Consequently, primary energy required to produce liquid transport biofuels (i.e. cane juice to produce bioethanol and palm oil to produce biodiesel and renewable diesel) is not accounted for.

C.1.2. Impacts on the demand side

C.1.2.1. Sectorial demand

The final energy demand (i.e. secondary energy and non-transformed primary energy used on the demand side) by sector for the baseline scenario is shown in Figure 25. It is expected that the final energy demand will grow from 24 to 68 mio TOE, which would represent an annual average growth rate of 5.1%. Sectors experiencing the highest growths in final energy demand between 2009 and 2030 include road transport with 20 mio TOE and industry with 18 mio TOE. These two sectors alone would contribute 75% of the overall final energy demand by 2030. Sectors experiencing moderate growth in this period include residential (2.4 mio TOE), non-road transport (2 mio TOE) and commercial (1.5 mio TOE). The final energy demand for the baseline disaggregated by fuel is shown in Figure 26. The highest growth in final demand between 2009 and 2030 corresponds to oil and derivatives (23 mio TOE), followed by natural gas (10.2 mio TOE), and to a lesser extent by electricity (4.7 mio TOE) and coal and derivatives (4 mio TOE). Demand for bioenergy and derivatives is expected to slightly increase by 1.9 mio TOE during this period.

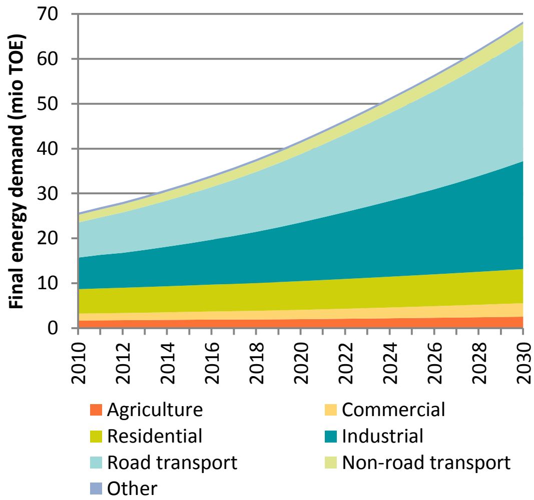


Figure 25. *Final energy demand by sector for baseline*

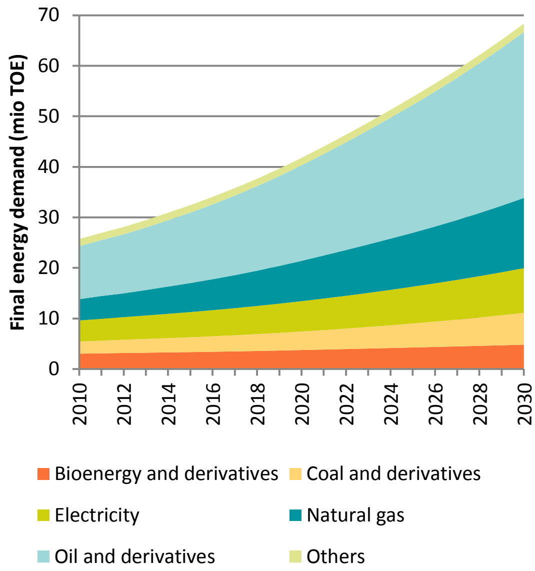


Figure 26. *Final energy demand by fuel for baseline*

Various differences in the final energy demand by fuel arise for Scenarios I and II relative to the baseline:

- For Scenario I: there is a substitution of biomethane for natural gas, causing a reduction in the overall demand for natural gas
- For Scenario II: there is a substitution of biomethane for natural gas. In addition, there is a substitution of bioethanol for gasoline and of biodiesel and renewable diesel for diesel fuel.

Details of these differences in final energy demand are described as follows.

C.1.2.2. Road transport

The estimated number of road vehicles for all scenarios is shown in Figure 27. Since it is assumed that vehicle ownership is a function of GDP per capita (which does not change across scenarios), the estimated number of vehicles is the same for all scenarios. The number of vehicles is expected to grow from 6 to 27 mio between 2009 and 2030 according to the assumptions made. The largest growth by 2030 is expected for gasoline motorcycles (11.6 mio), followed by gasoline four-wheeled vehicles (7.4 mio), diesel vehicles (2 mio) and CNG-fuelled vehicles (0.2 mio). Only one study estimating ownership of gasoline vehicles and motorcycles in Colombia was found in the literature (Echeverry, 2008). It did not estimate ownership for diesel- and CNG-fuelled vehicles and generally reported lower growth rates than the present study (see Figure 86 in the Appendix). The estimated secondary energy demand (i.e. energy forms which have been transformed from primary energy sources) by vehicle type is shown in Figure 28.

The secondary energy demand is expected to grow in road transport from 7.3 to 27 mio TOE. The vehicles that most contribute to this increase are gasoline- and diesel-fuelled vehicles, whose demands by 2030 amount to 10.5 and 12.2 mio TOE respectively. These two types of vehicles account on average for 80% of the overall energy demand in road transport. The energy demand from motorcycles is expected to increase from 0.6 to 3.2 mio TOE between 2009 and 2030 as a consequence of their growth in number. The demand for energy from CNG-fuelled vehicles also grows, but less rapidly than for the other vehicles. It increases from 0.65 to 1 mio TOE in this period.

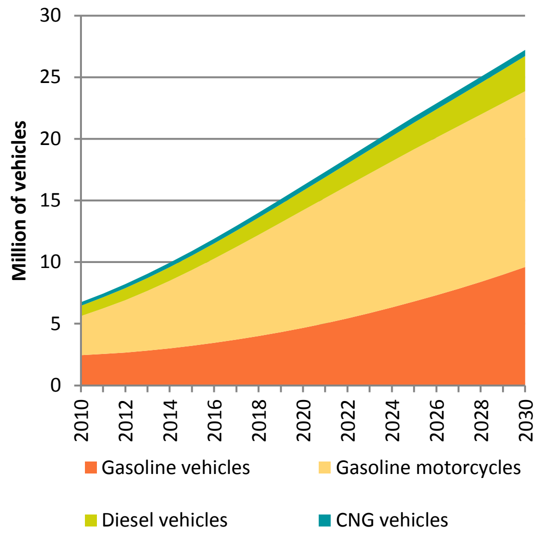


Figure 27. *Estimated number of vehicles*

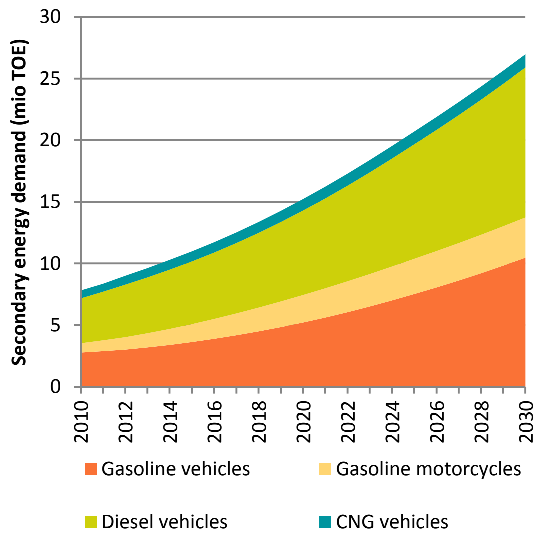


Figure 28. *Secondary energy demand in road transport by vehicle type*

The secondary energy demand by fuel for the baseline scenario is shown in Figure 29. The demand for all the fuel types continuously increases between 2009 and 2030, but gasoline and diesel fuel strongly dominate. Demand for gasoline grows almost four-fold from 3 to 13 mio TOE by 2030, while the demand for diesel fuel significantly grows from 3.3 to 11.2 mio TOE. The share of these two fuels in the demand account for more than 85% of the overall demand for secondary energy. Demand for CNG is expected to grow from 0.65 to 1 mio TOE, but its share reduces from 9% to 4%. A considerable increase in demand for bioethanol and biodiesel is also expected. It grows from 0.34 to 1.7 mio TOE, while its share also grows from 4.7% to 6.3%.

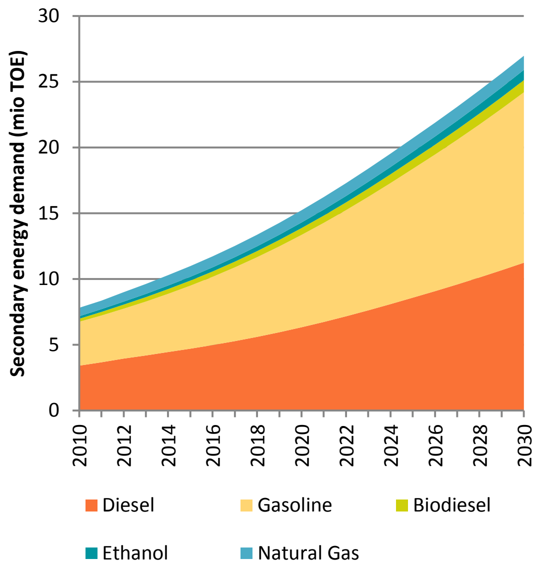


Figure 29. *Secondary energy demand in road transport by fuel for baseline scenario*

No policies to further deploy liquid transport biofuels are implemented in Scenario I. For this reason, its secondary energy demand by fuel remains unchanged compared to the baseline scenario. On the other hand, Scenario II does implement various policies to further deploy bioethanol, biodiesel and renewable diesel. The differences in secondary energy demand by fuel between Scenario II and the baseline are shown in Figure 30. Demand for gasoline and diesel fuel is expected to decrease by 1.85 and 2.85 mio TOE by 2030 compared to the baseline, as these fuels are being substituted by liquid transport biofuels. As a result, their share in the overall demand reduces from 86% in 2009 to 72% in 2030. On the contrary, the demand for biofuels in Scenario II significantly increases compared to the baseline. Bioethanol grows by 1.85 mio TOE, biodiesel by 1.9 mio TOE and renewable diesel by 0.9 mio TOE relative to the baseline. The share of biofuels in the road transport energy demand also grows from 4.6% in 2009 to 24% in 2030. The demand for CNG remains unchanged compared to the baseline.

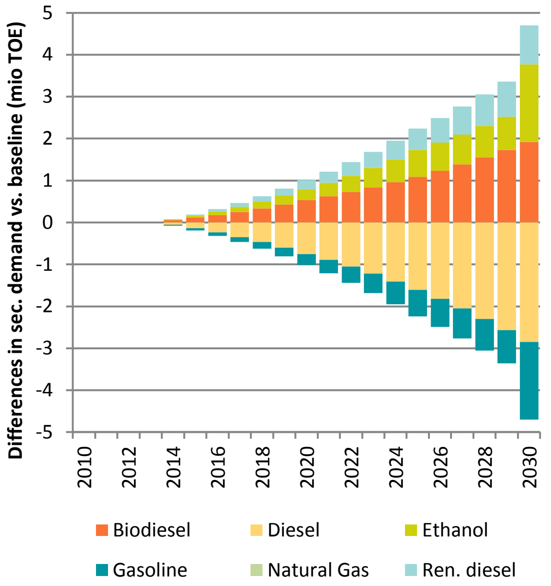


Figure 30. *Differences in secondary energy demand in road transport between Scenario II and baseline*

C.1.2.3. Residential sector

One of the sectors traditionally demanding substantial bioenergy resources for traditional cooking and water heating is the residential sector. The final energy demand in the residential sector disaggregated by fuel for the baseline scenario is shown in Figure 31. Final energy demand grows moderately in the residential sector, i.e. from 5 to 7.6 mio TOE between 2009 and 2030. For some fuels, demand is expected to nearly double by 2030: electricity amounts to 3.2 mio TOE and natural gas to 1.5 mio TOE.

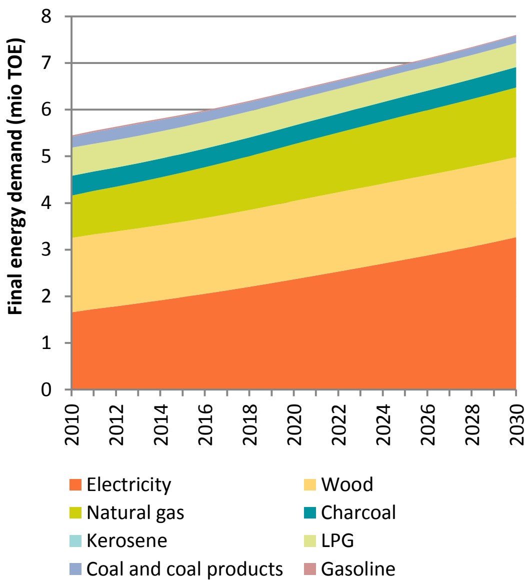


Figure 31. *Final energy demand in the residential sector for baseline scenario*

Demand for wood is expected to grow by 12% and achieve 1.7 mio TOE by 2030. For some other fuels the demand is expected to maintain relatively constant, e.g. coal and derivatives and LPG. The demand for final energy disaggregated by type, i.e. cooking, air conditioning, hot water, refrigeration, etc., is shown for the residential sector in Figure 87 in the Appendix.

The impacts of implementing Scenarios I and II on the energy demand in the residential sector are limited to the substitution of biomethane for natural gas. The overall effects of substituting biomethane for natural gas are analyzed in more detail in the next section.

C.1.2.4. Substitution of biomethane for natural gas

As shown in Figure 26, the final demand for natural gas in the baseline scenario is expected to grow from 3.6 to 13.9 mio TOE between 2009 and 2030. This is a result of the modernization of the energy infrastructure in the country combined with the low prices of natural gas relative to other fuels. Scenarios I and II introduce biomethane into the energy matrix, which is a direct substitute for natural gas. The supply of biomethane for Scenarios I and II is estimated to grow from 0 to 0.9 mio TOE between 2015 and 2030 (see Figure 32). Consequently, the demand for natural gas for these scenarios is reduced in the same proportion. Moreover, the contribution of biomethane to the overall energy content in natural gas grows from 0% to 6.7% within this period.

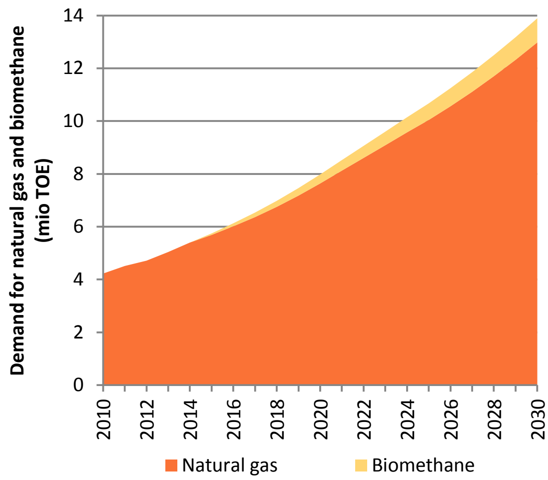


Figure 32. *Demand for natural gas and biomethane for Scenarios I and II*

C.1.3. Impacts on power generation and combined heat and power (CHP)

C.1.3.1. Electricity demand

The electricity supply[18] and demand by sector for the baseline scenario is shown in Figure 33. Electricity demand in final uses doubles between 2009 and 2030, growing from 4.1 to 8.9 mio TOE. The bulk of this demand arises in the residential and industrial sectors, whose aggregated contribution amounts to nearly 80% of the overall demand. The remaining portion of the end-use demand corresponds to commercial and other sectors (agriculture, transport, etc.). Distribution losses and own use by power generation units amount to 15% and 3% of the electricity supply throughout the entire period.

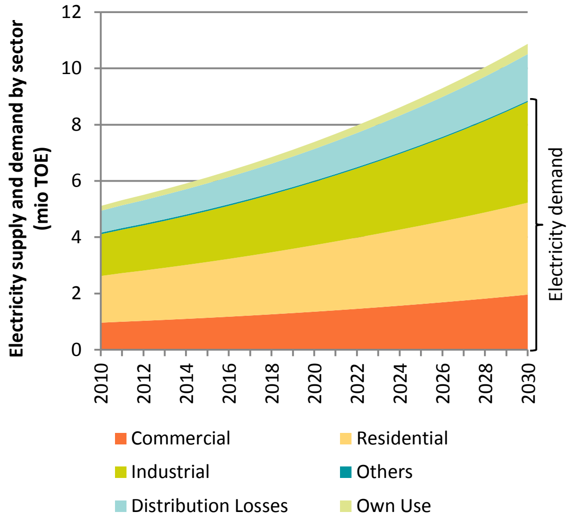


Figure 33. *Electricity supply and demand by sector for baseline scenario*

C.1.3.2. Electricity supply

Electricity supply or gross electricity generation is expected to double between 2009 and 2030, growing from 5.1 to 10.9 mio TOE (see Figure 34). Among sources, hydro dominates power generation with an average contribution of 68%. Gross generation from hydro power increases from 3.5 to 5.3 mio of TOE between 2009 and 2030. While hydro's share starts growing in 2010 and reaches 85% in 2020, it decreases to 50% by 2030. The behavior of the system between 2010 and 2020 is explained by a significant increase in the planned expansion capacity of hydro power plants (5.7 GW). However, between 2020 and 2030 natural gas-fired power plants replace hydro to a certain extent, given that their overall production cost is lower than that of hydro (see Table 50 in the Appendix for details). The observed fluctuations in power generation from year to year are explained by the varying availability of hydro resources caused by El Niño oscillation.

Hydro power generation is followed by natural gas, coal and to a smaller extent by bioenergy, oil and other renewables. Natural gas-based power generation grows from 0.9 to 4.4 mio TOE, and its contribution increases from 18% to 40% within this period. Coal power generation grows from 0.5 to 1 mio TOE and its contribution slightly reduces from 10 to 9.5% by 2030. Power generation from biomass grows from 130 to 170 kTOE, although its contribution reduces from 2.5% to 1.6%. Power generation from oil and other renewables is marginal and accounts for less than 1% of the gross generation between 2009 and 2030. The energy balance (defined as the energy inputs and outputs of the power generation module) for the baseline scenario is shown in Figure 35.

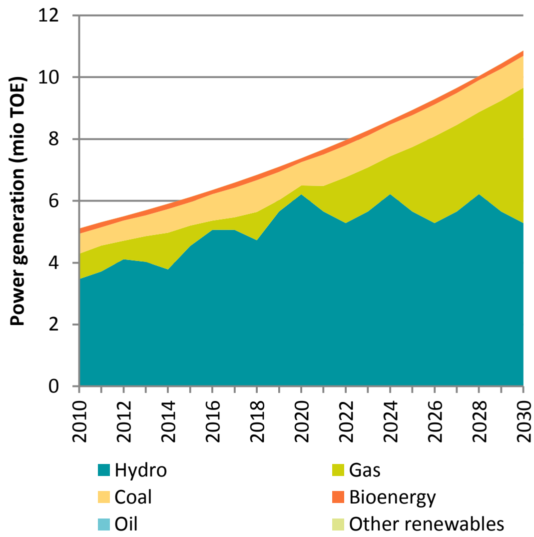


Figure 34. *Power generation by source for the baseline scenario*

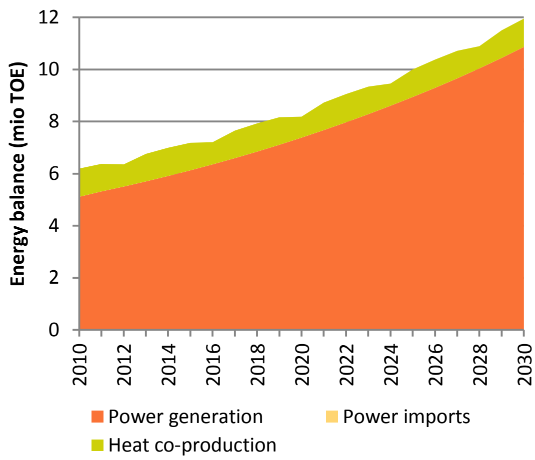


Figure 35. *Energy balance in power generation for the baseline scenario*

[18] The electricity supply is defined as gross power generation including own use to cover the demand in final uses (commercial, industrial, residential, etc.) and distribution losses (IEA, 2012b).

Energy outputs include electricity and heat, while energy inputs are power imports. Heat co-produced in CHP power plants is expected to slightly increase from 0.83 to 1.08 mio TOE between 2009 and 2030, which represents a growth of nearly 30%. No electricity imports are expected throughout the entire period, which means that the system is self-sufficient in power generation.

Power generation by source is shown for Scenario I in Figure 36. In Scenario I Power generation continues being mostly dominated by hydro, with an average share similar to that of the baseline (68.3%). Scenario I is also characterized by an increased participation of other renewables that replace gas-based power generation. An increment of 0.44 mio TOE is expected for bioenergy by 2030 relative to the baseline, which causes an increase in its share from 2.5% to 5.6% in this period. Wind grows from 15 to 210 kTOE and its share increases from 0.3% to 2%.

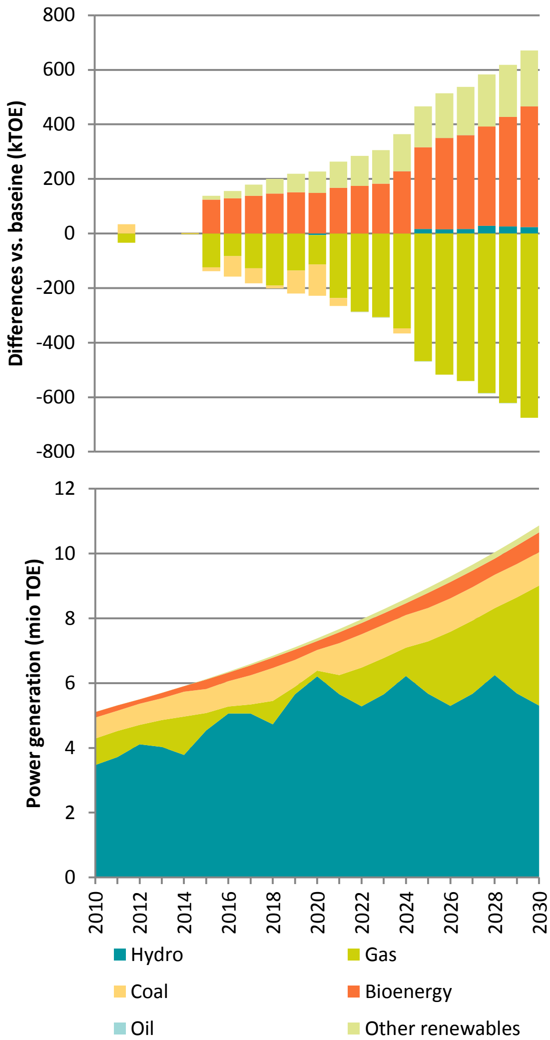


Figure 36. *Power generation by source for Scenario I*

The growth of bioenergy and wind is a result of implementing the power generation & CHP targets between 2015 and 2030. Thus, the aggregated contribution of renewables (excluding large hydro) grows from 2.9% in 2009 to 7.8% in 2030. Simultaneously, gas-based power generation reduces 0.67 mio TOE by 2030 compared to the baseline. Then, the share of gas in power generation in 2030 reduces from 40% in the baseline to 34% in Scenario I. Power generation in Scenario II presents nearly the same behavior as that in Scenario I with almost negligible modifications. For the sake of brevity, it is not shown here but included in the Appendix (see Figure 88).

C.1.3.3. Capacity

The installation of additional power generation capacity is required to meet the continuously growing demand and replace retired capacity through till 2030. The installed power generation capacity by source for the baseline scenario is presented in Figure 37. It is expected that the overall power generation capacity will grow from 13.5 to 26.4 GW between 2009 and 2030. The bulk of the capacity additions estimated by 2030 comes from natural gas, hydro, coal and oil. Of the 13.2 GW of capacity additions, 6.8 GW correspond to gas-fired power plants (49% simple cycles, 51% combined cycles), 5.75 GW correspond to hydro power plants, 0.57 GW to coal-fired power plants and 0.12 GW to oil-fired power plants. About 46% of the expected capacity additions between 2009 and 2030 are already in construction or planned (6 GW), while the remaining 54% are expected after 2019. It is interesting to note that after the planned expansion of 5.75 GW of hydro between 2009 and 2019, no further capacity is added between 2020 and 2030. This is most likely a consequence of the higher production cost of hydro relative to other technologies (particularly gas), according to the accepted assumptions. Nonetheless, these results must be interpreted with caution. Results are obtained through a cost minimization approach, which does not necessarily take into consideration other drivers, such as the influence of politics, future energy and environmental regulations, sudden depletion of energy reserves, etc. Regarding capacity retirements, official plans estimate that 434 MW of hydro power will be withdrawn by 2015 and no other retirements are expected through till 2030.

Differences in installed power generation capacity between Scenario I and the baseline scenario are shown in Figure 38. Two important trends are observed. Firstly, additional capacity is required for renewables to comply with the power generation & CHP targets as of 2015.

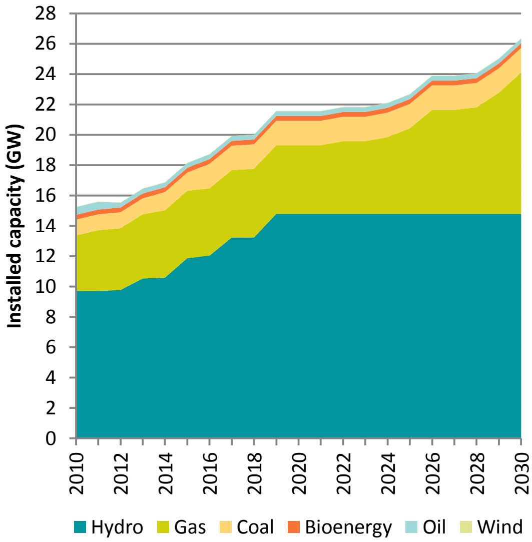


Figure 37. Installed power generation capacity by source for baseline scenario

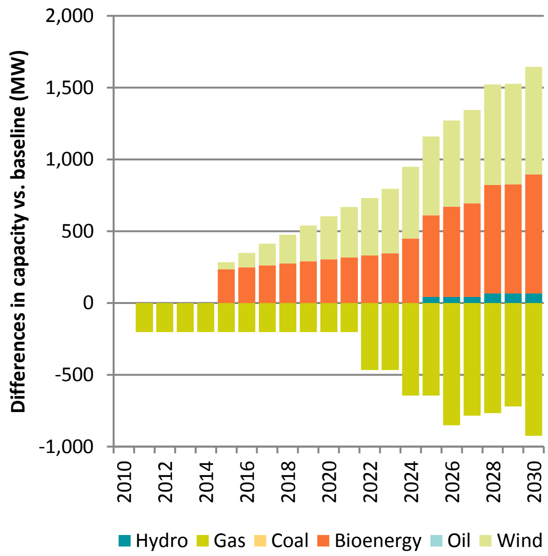


Figure 38. Differences in installed power generation capacity between Scenario I and baseline

In fact, 0.75 GW of additional capacity is required for wind by 2030, while 0.83 GW is required for biomass-based power generation and 0.07 GW for small-hydro. Secondly, an increase in installed capacity of renewables causes a less rapid growth of gas-fired power plants through till 2030. In fact, while in the baseline the capacity of gas-fired power plants grows 6.8 GW between 2009 and 2030, it grows 5.9 GW in Scenario I (i.e. 0.92 GW less). Installed power generation capacity in Scenario II presents nearly the same structure as that in Scenario I with almost negligible modifications. For the sake of brevity, the differences relative to the baseline are not shown here but included in the Appendix (see Figure 89).

C.1.3.4. Complementarity of hydro and bioenergy

In the last 15 years a complementarity in the availability of hydro and biomass-based power generation has been documented (XM, 2013) but has not been fully exploited. This complementarity relates to the fact that the highest availability of hydro power occurs in years with low solar radiance, when the availability of biomass-based power is lowest (see Figure 64 in the Appendix). Scenarios I and II attempt to exploit to a certain extent this complementarity, assuming that it will continue in the future. A reduction in fossil-fuel based power generation is expected for Scenarios I and II relative to the baseline. This reduction is maximal in wet years when hydro can deliver more power, but it is actually critical in dry years when hydro becomes less available. Figure 39 shows the aggregated contribution of hydro and bioenergy to the overall power generation for the baseline and Scenario I.

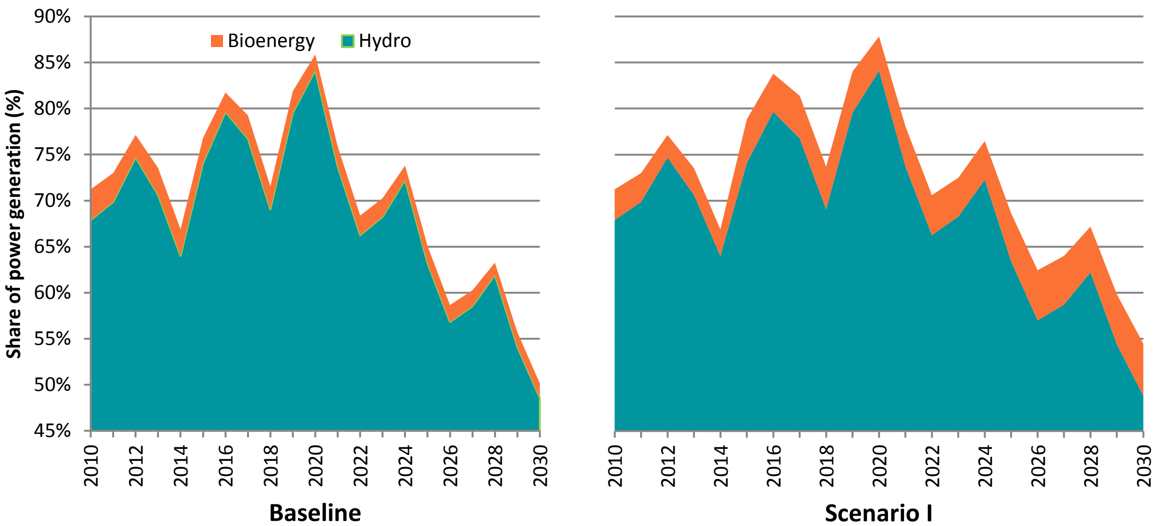


Figure 39. Contribution of hydro and bioenergy to power generation in Scenario I and baseline scenario

C.1.3.5. Costs

The cost of producing electricity is expected to increase until 2030 in order to meet a continuously growing demand (see Figure 40). The overall cost almost doubles, growing from 1094 to 2056 mio US$2005 between 2009 and 2030. The total cost of producing electricity is expected to be higher for Scenarios I and II relative to the baseline. This is a consequence of deploying renewables (i.e. wind and bioenergy), which are more expensive than gas-fired power plants and hydro. The cost of producing electricity grows to 2194 mio US$2005 in Scenario I and to 2225 mio US$2005 in Scenario II. The cost of electricity is then obtained by dividing the total cost of producing electricity by the power generation for the different scenarios. The obtained cost of electricity (US$2005/MWh) for the different scenarios is presented in Figure 41. For all scenarios, the cost of electricity fluctuates over the entire period, which to a certain extent is a consequence of El Niño oscillation. Between 2010 and 2020 there is an upward trend for all scenarios, while after 2020 the trend is downward. By 2030 the cost of electricity decreases to 16.3 US$2005/MWh for the baseline and to 17.3 US$2005/MWh for Scenarios I and II.

The causes for these trends are better explained by disaggregating the cost of electricity by technology for the different scenarios. Figure 42 shows the cost of electricity disaggregated by technology for the baseline scenario. It can be seen that the upward trend between 2010 and 2020 is motivated by a large expansion of hydro power generation, which contributes 74% of the cost of electricity by 2020. On the other hand, the downward trend after 2020 is explained by the displacement of hydro power generation for less expensive gas-fired power generation.

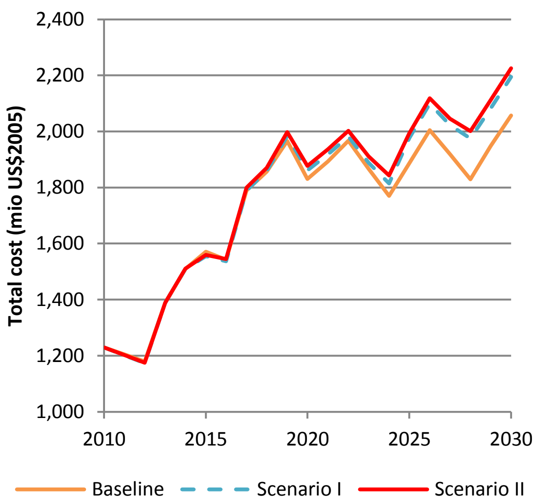


Figure 40. *Cost of producing electricity by scenario*

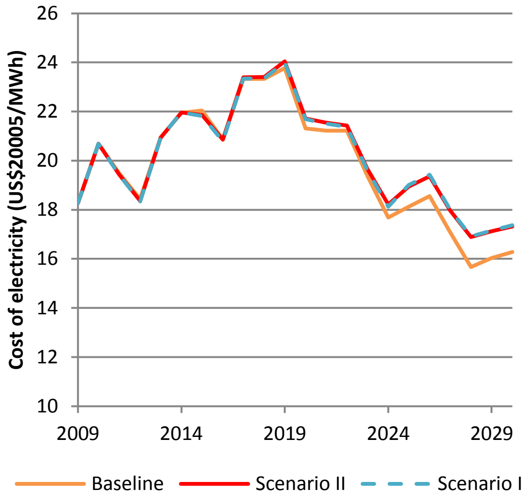


Figure 41. *Cost of electricity by scenario*

The differences in the cost of electricity by technology between Scenario I and the baseline are shown in Figure 43. This figure shows that there is a positive difference in the cost of electricity between Scenario I and the baseline, caused by deploying and operating renewables (wind, bioenergy and small-hydro). Simultaneously, there is a negative difference caused by savings in operating and fuel costs for reducing the use of gas-fired power plants.

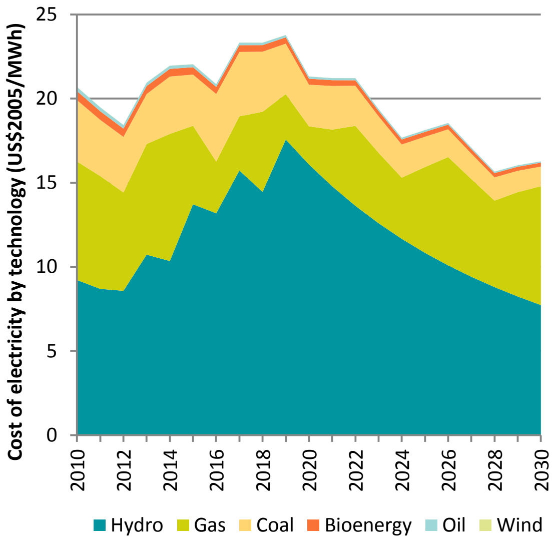


Figure 42. *Cost of electricity by technology for baseline*

However, the positive difference in the cost of electricity for operating renewables is twice as much as the negative difference for not operating gas-fired power plants. This event results in a higher cost of electricity for Scenario I compared to the baseline. The differences in cost of electricity by technology between Scenario II and the baseline are very similar to those for Scenario I and, for the sake of brevity, are shown in the Appendix (see Figure 90).

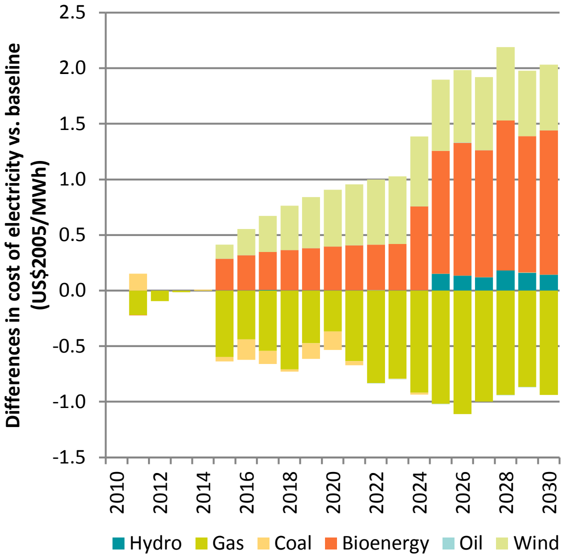


Figure 43. *Differences in cost of electricity by technology between Scenario I and baseline*

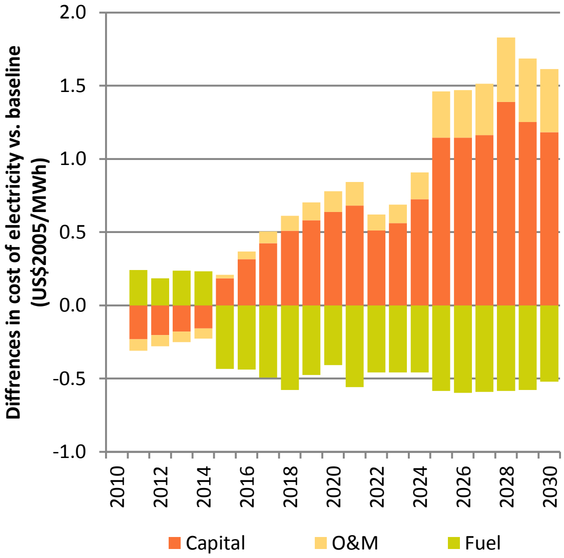


Figure 45. *Differences in cost of electricity by cost type between Scenario I and baseline*

Disaggregation of the cost of electricity by type of cost (i.e. capital cost, O&M and fuel cost) is shown in Figure 44 for the baseline scenario. This graph shows that the contribution of capital costs significantly grows from 15% in 2010 to 45% in 2020 and then decreases to 25% in 2030. The upward trend is again caused by the expansion of hydro power generation between 2010 and 2020, while the downward trend is caused by a replacement of hydro power by less expensive gas power generation. On the other hand, the strongest contributor is the cost of operation and maintenance (O&M), which on average accounts for 47% of the cost of electricity. This share is quite high but not uncommon for energy systems based on large hydro power plants. The share for fuel costs decreases from 37% to 8% between 2010 and 2020 due to the hydro expansion and then increases to 26% by 2030 as a consequence of increased gas-fired power generation.

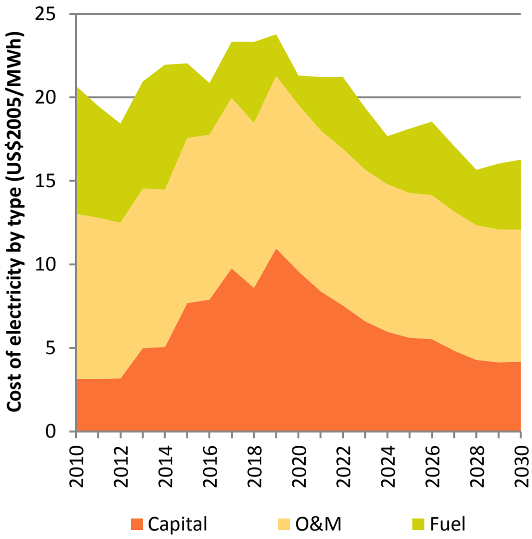


Figure 44. *Cost of electricity by cost type for the baseline*

Finally, the differences in cost of electricity by cost type between Scenario I and the baseline are shown in Figure 45. This graph shows that after 2015 there is mostly an increase in capital costs relative to the baseline, while at the same time there is a reduction in fuel costs. By 2030 the increase in capital and O&M costs amounts to 1.6 US$2005/MWh, while the reduction in fuel cost reaches 0.5 US$2005/MWh. This results in an aggregated higher cost of electricity for Scenario I compared to the baseline. The differences in cost of electricity by type between Scenario II and the baseline are very similar to those for Scenario I and, for the sake of brevity, are not shown here but included in the Appendix (see Figure 91).

C.1.4. Bioenergy outlook by scenario

C.1.4.1. Share of bioenergy by category

Scenarios I and II describe long-term visions in which the role of bioenergy in the future energy mix of the country becomes more relevant. Scenario I represents a long-term vision that: a) focuses on new technologies for the production of biomethane and biomass-based power generation & CHP and b) fixes the current blend mandate of first generation liquid biofuels. Its long-term goals by area include:

- Biomethane: use 5% of biomass residues and 1% animal waste resources nationwide to produce biomethane to be injected into the natural gas network by 2030.
- Power generation and CHP: a) achieve a renewable power target of 10% by 2025, b) use 5% of the biogas from animal waste and municipal water treatment plants nationwide by 2030, c) use 100% of the biogas produced in the water treatment process of biodiesel production plants by 2030, d)

use 10% of the municipal landfill gas produced nationwide by 2030.

On the other hand, Scenario II represents a long-term vision that combines new technologies for the production of biomethane and biomass-based power generation and CHP (the same as in Scenario I) with further growth of first generation transport biofuels:

- Biodiesel: increase the quota mandate to B20 in 2020 and B30 in 2030.
- Bioethanol: a) increase the quota mandate to E20 in 2025 and b) implement an E85 fuel program in 2030.
- Renewable diesel: achieve a 10% contribution (on an energy basis) of renewable diesel to the total diesel fuel production in 2030.

Consequently, the future role of bioenergy differs for these two storylines. An overview of the share of bioenergy by category and scenario is presented in Figure 46. In the baseline scenario, the share of bioenergy is expected to reduce from 15.2% (note that this share is higher than the 10% shown in Figure 2, given that bagasse from jaggery cane has been included in the calculation) to 8.1% in the primary energy demand and from 3.3% to 1.6% in power generation between 2010 and 2030. These events are consequences of a combination of factors including increasing urbanization, higher access to electricity and natural gas services nationwide, rapid growth of road vehicle ownership and the associated demand for oil-based fuels, as well as an increased deployment of gas- and coal-fired power plants.

The share of bioenergy in road transport marginally increases from 5.4% to 6.3% over this period, as a consequence of higher supply coverage of biofuels (i.e. bioethanol and biodiesel) at a national level. Finally, the share of bioenergy in the natural gas supply is nil.

The implementation of policies supporting the deployment of new technologies for producing biomethane and power generation in Scenario I motivate an increase in the share of bioenergy (in the form of biomethane) from 0% to 6.6% in the natural gas supply and from 3.3% to 5.6% in power generation between 2010 and 2030. For Scenario I the shares in road transport remain unchanged relative to the baseline, given that the biofuel policies are not modified. As a result, the share of bioenergy in the primary energy demand for Scenario I decreases less rapidly than in the baseline, from 15.2% in 2010 to 10.2% in 2030.

In Scenario II the share of bioenergy in power generation and in natural gas supply is almost the same as in Scenario I. However, the further implementation of policies supporting additional deployment of first generation biofuels results in a boost of the share of bioenergy in road transport from 5.4% in 2010 to 24% in 2030. However, this only translates into a slightly higher share of bioenergy in the primary energy demand compared to the baseline and Scenario I.

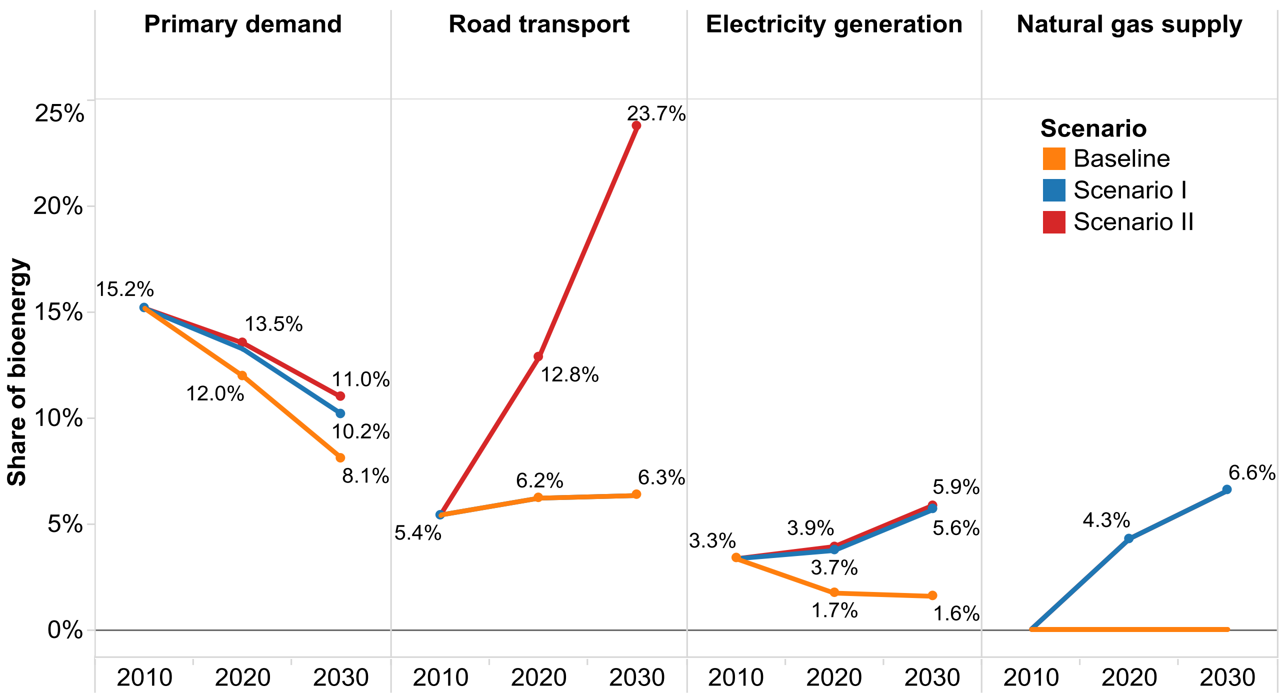


Figure 46. *Share of bioenergy by category and scenario*

In summary, the contribution of bioenergy in road transport, power generation and natural gas supply grows in Scenarios I and II relative to the baseline. However, despite the ambitious goals envisioned in this roadmap, a decreased share of bioenergy and an increased share of fossil fuels in the primary energy demand of the country occur in all scenarios. This suggests that, irrespective of the chosen scenario, the demand for fossil fuels would continue to grow motivated by a more urban and wealthier population and a more modern and oil- and gas-dependent energy system.

C.1.4.2. Reduction in demand for fossil fuels

The overall reduction in the use of fossil fuels by 2030 relative to the baseline amounts to 2.2 mio TOE by implementing Scenario I (see Figure 47) and 7.4 mio TOE by implementing Scenario II (see Figure 48).

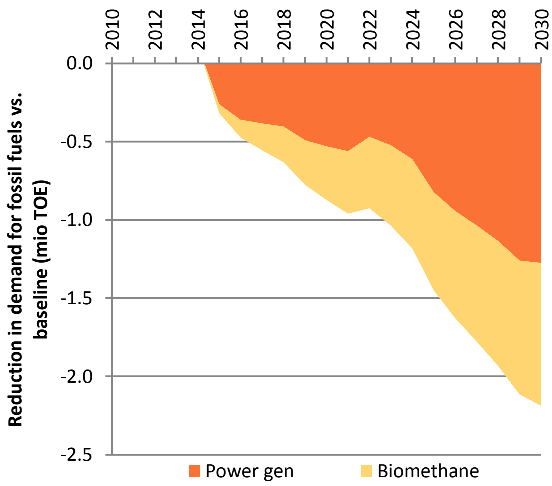


Figure 47. *Reduction in demand for fossil fuels in Scenario I vs. baseline*

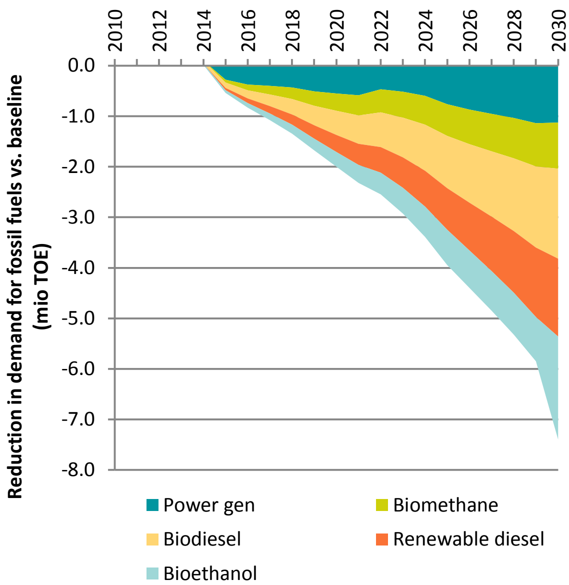


Figure 48. *Reduction in demand for fossil fuels in Scenario II vs. baseline*

The reduction in demand for fossil fuels is dependent on the policy measures implemented in each scenario. In Scenario I the policy on power generation and CHP contributes 59% of the overall reduction in the demand for fossil fuels between 2009 and 2030, while the policy on biomethane contributes the remaining 41%. In Scenario II the contribution of the different policy measures to the overall reduction in demand for fossil fuels is quite even: biodiesel (25.6%), power generation and CHP (20.9%), renewable diesel (20.4%), bioethanol (17.5%) and biomethane (15.4%).

C.2. Impacts on land use

C.2.1. Land uses

Estimated uses of land for the different scenarios are shown in Figure 49. The land for producing biofuels[19] is expected to grow from 0.1 mio ha in 2010 to a value ranging from 0.6 to 1.2 mio ha, depending on the scenario. The largest growth is expected for Scenario II with expansion with 1.2 mio ha, followed by Scenario II with 0.7 mio ha and lastly by the baseline and Scenario I with 0.6 mio ha. It is important to note that the land for producing biofuels covers the production of biofuels for local consumption and for exports. A disaggregation into land for producing biofuels for local consumption and for export is presented in the next section.

The land for producing wood in forestry plantations is expected to increase from 0.31 mio ha in 2010 to about 0.5 mio ha in 2030 for all scenarios. This accounts for a small portion of the total forest land (58.5 mio ha in 2030), which, as described in Table 19, is expected to decrease by 2 mio ha between 2010 and 2030 as a consequence of deforestation.

The land for cattle is expected to increase for all considered scenarios. In the baseline and in Scenario I it increases from 38.16 mio ha in 2009 to 40.51 mio ha in 2030. In Scenario II and Scenario II with expansion it respectively increases to 40.47 and 40.18 mio ha in 2030. This increase in land for cattle is explained by a change in land use. Two types of changes in land use are foreseen: a) agricultural land transformed into land for cattle and b) forest land transformed into land for cattle. Transformation of agricultural land into land for cattle occurs for all scenarios, accounting for 0.7 to 1 mio ha. Transformation of forest land into land for cattle via deforestation occurs, therefore, in all scenarios to cover the remaining gap, accounting for 1 to 1.7 mio ha.

[19] Including bioethanol, biodiesel and renewable diesel for local production and exports but excluding woodfuel.

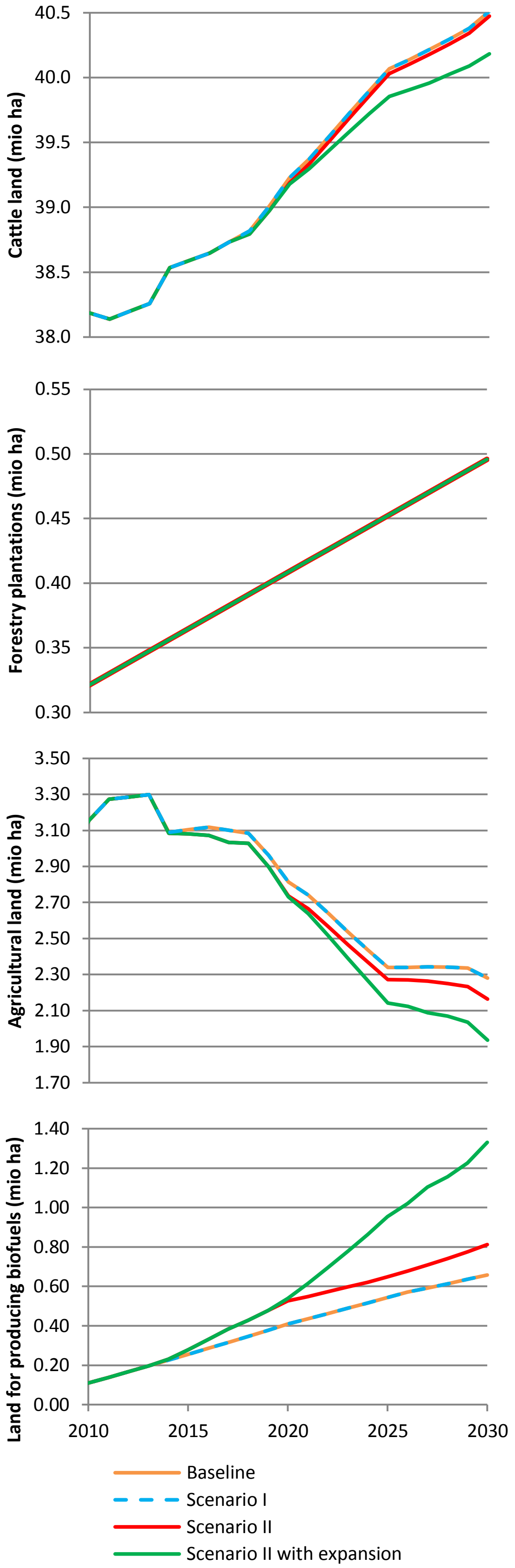


Figure 49. *Land uses by scenario*

Agricultural land (excluding biofuels) is expected to be reduced for all scenarios as a consequence of three factors. Firstly and most important, agricultural land is transformed into cattle land as a consequence of the higher cost competitiveness of cattle products (i.e. meat and milk) compared to other agricultural products. Secondly, the assumed international prices for key export commodities (e.g. coffee) decrease in the long term and cause a significant reduction in harvested area. Thirdly, more cost-competitive duty-free imports from the U.S., available as of 2012, cause a further reduction in harvested area for some crops (e.g. rice and corn).

C.2.2. Land for biofuels and woodfuel for local consumption

The land for producing biofuels and woodfuel for local consumption is shown in Figure 50. The land for producing biofuels and woodfuel for local consumption between 2015 and 2030 is characterized by marked changes caused by: a) the implementation of scenario policies or b) reaching the maximum land available for cultivating a particular biomass resource (e.g. palm, cane, wood, etc.). The land for producing locally consumed biodiesel is expected to increase until 2030 at varying degrees, depending on the scenario. For the baseline and Scenario I, it grows from 67 kha in 2010 to about 245 kha in 2030. For Scenario II and Scenario II with expansion, it rapidly grows to 0.3 mio ha by 2020 and then remains somewhat constant until 2030.

This value appears to be the limit in land for local production of biodiesel, as after 2020 it would be required to import it for Scenario II and Scenario II with expansion (see next section). For these two scenarios, the amount of land for producing locally consumed renewable diesel starts growing in 2015 and progressively reaches 0.37 mio ha in 2030. The baseline and Scenario I do not consider deployment of renewable diesel and consequently no land is required.

The amount of land for producing locally consumed bioethanol grows for all scenarios through till 2030. For the baseline and Scenario I, it grows from 42 kha in 2010 to around 130 kha in 2025 and then remains constant. For Scenario II it grows slightly faster than for Scenario I, reaches about 140 kha in 2020 and then stabilizes at 130 kha by 2030. It appears that 130 kha is the limit in land for local production of bioethanol using the two routes described in Section B.2.2.2. Once this limit is reached, it is necessary to import bioethanol (see next section). Finally, for Scenario II with expansion, the amount of land for producing bioethanol for local consumption continuously grows from 42 kha in 2010 to 364 kha in 2030. This substantial growth proves insufficient, however, to avoid imports in 2030, when the E85 program is launched (see next section).

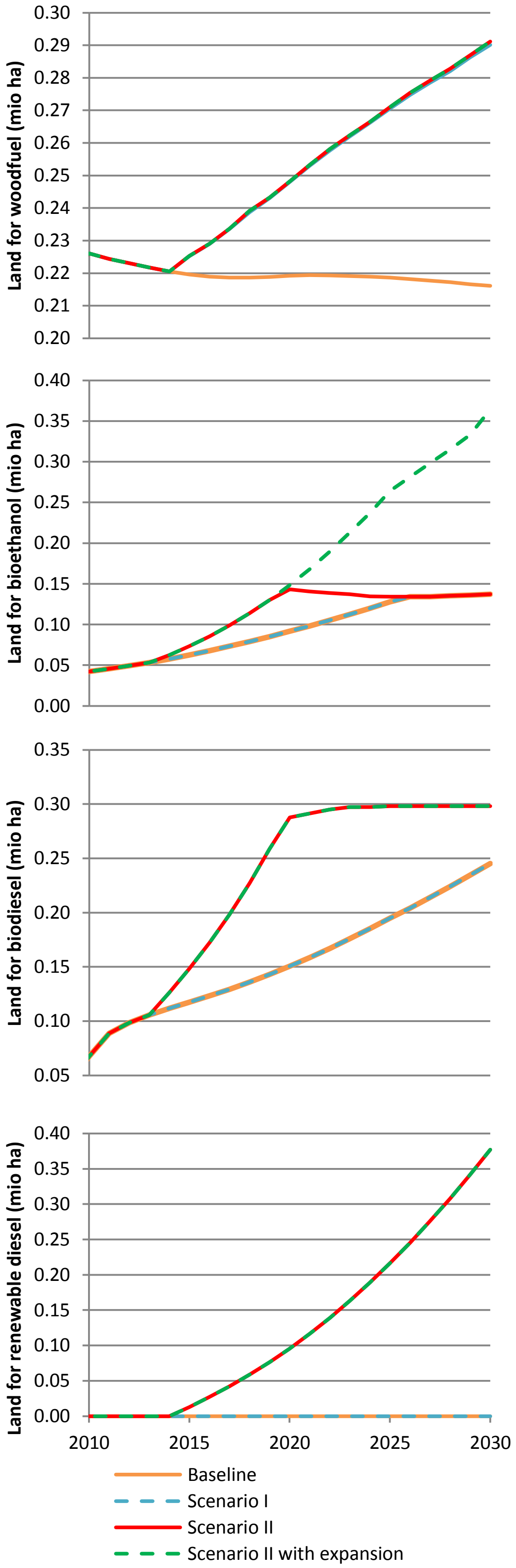


Figure 50. *Land for producing biofuels and woodfuel for local consumption*

The amount of land for producing locally consumed woodfuel grows at varying degrees through till 2030, depending on the scenario. For the baseline scenario it is expected to slightly reduce from 226 kha in 2010 to 216 kha in 2030. This trend appears to agree with forecasts from UPME, which foresee a reduction in woodfuel demand as it continues being substituted by LPG in rural areas. On the other hand, for Scenario I, Scenario II and Scenario II with expansion, it slightly decreases to 216 kha in 2015 and subsequently grows to 291 kha in 2030. This is a consequence of the implementation in 2015 of a new policy to exploit woodfuel and residues for power generation & CHP and biomethane production. The aggregated land to produce locally consumed biofuels and woodfuel is shown in Figure 51.

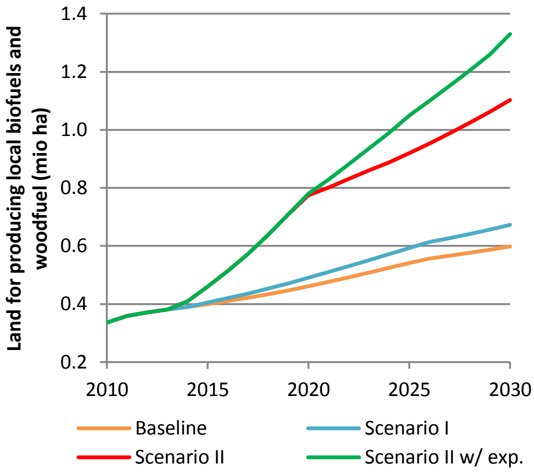


Figure 51. *Aggregated land for producing biofuels and woodfuel for local consumption*

C.2.3. Trade balance of biofuels

The trade balance of bioethanol and biodiesel is shown in Figure 52. The trade balance is defined here as exports minus imports, since they do not occur simultaneously for these commodities. Therefore, positive curves represent exports and negative curves represent imports. The trade balance of bioethanol for all scenarios is negative, meaning that imports are expected in the future. For scenarios not supporting further deployment of biofuels (i.e. the baseline and Scenario I), imports of bioethanol are expected after 2025 and might amount to 230 ktons by 2030. Scenario II envisages an ambitious increase in demand for bioethanol, but it requires significant imports since no expansion in land is considered. Imports start in 2020 with 37 ktons and reach 3.1 mio tons in 2030. When expansion in land is considered, imports of biofuels in Scenario II are not avoided but delayed to 2030. In this case imports are required to meet the bioethanol demand when the E85 program is launched and amount to 1.5 mio tons.

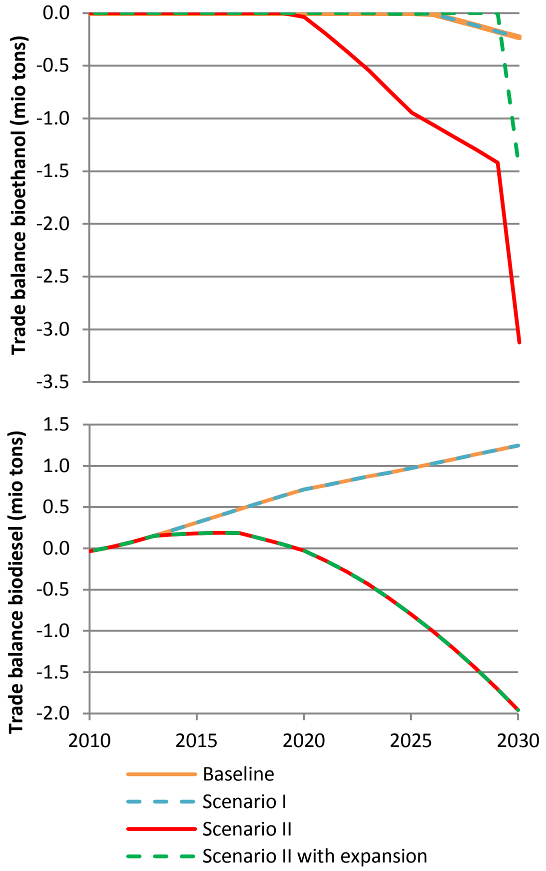


Figure 52. *Trade balance of liquid biofuels by scenario*

The trade balance of biodiesel varies depending on the scenario. For the baseline and Scenario I, the trade balance is positive through till 2030, meaning that biodiesel is exported. Biodiesel exports might start in 2011 and grow to 1.25 mio tons in 2030. For Scenario II and Scenario II with expansion, the trade balance is positive until 2019 and then becomes negative through till 2030. There are various reasons for this behavior. Between 2010 and 2019, Scenario II starts producing renewable diesel and consuming more biodiesel, which reduces biodiesel exports compared to the baseline. By 2020 the growth in the production of biodiesel and renewable diesel reaches the limit in land for cultivating palm oil and thus imports are required through till 2030.

Finally, the relation of imports to total demand for bioethanol and biodiesel is shown in Figure 53. This graph shows that, in Scenario II, imports of bioethanol might account for more than 70% of the demand by 2030, while imports of biodiesel might reach 60% of the demand. This shows that the available land is insufficient to accomplish the proposed long-term goals. Imports can even account for 35% of the demand in Scenario II with expansion, which suggests that expanding the cultivation land beyond the Valley of the Cauca River might also be insufficient to accomplish the targets.

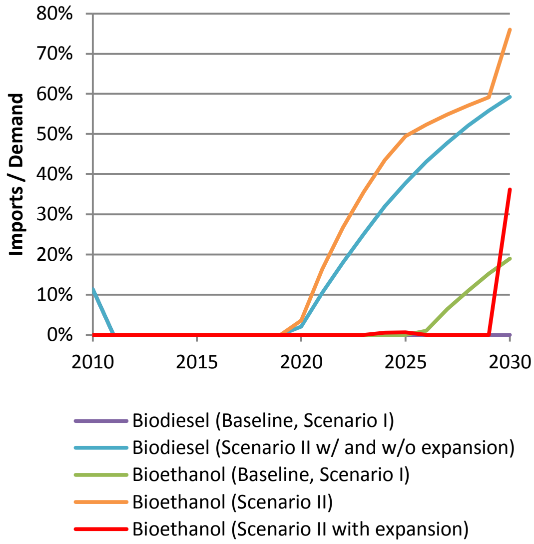


Figure 53. *Imports vs. demand for biofuels by scenario*

C.3. Impacts on emissions

C.3.1. Overall emissions by scenario

One of the main potential advantages associated with the deployment of bioenergy technologies is the reduction in greenhouse gas emissions. The Global Warming Potential (GWP) for the different scenarios, as well as the reductions for Scenarios I and II relative to the baseline, are plotted in Figure 54.

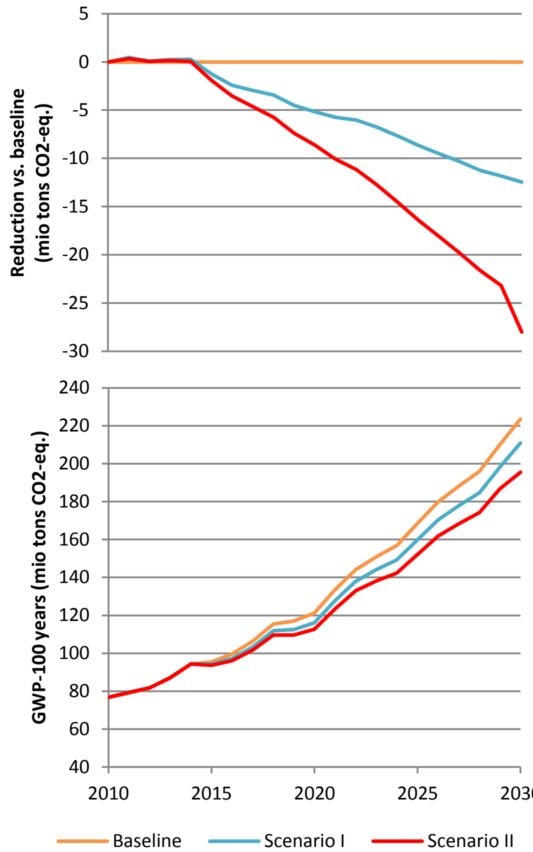


Figure 54. *Global warming potential by scenario*

For the baseline, a significant growth in the GWP is expected. It increases from 72 to 223 mio ton CO_2-eq. between 2009 and 2030. Disaggregation of the GWP by fuel and branch respectively for the baseline scenario is shown in Figure 92 and Figure 93 in the Appendix. The bulk of the emissions is caused by combustion of oil and gas (76%) and is associated with the energy use in road transport, industry final demand and power generation.

Greenhouse gas emissions reduce in Scenario I relative to the baseline. Reduction in emissions starts in 2015 and reaches 12.5 mio tons of CO_2-eq. by 2030. In order to visualize the impact of implementing the different individual policy measures in Scenario I, this reduction is further disaggregated by policy in Figure 55. The bulk of the reduction in GWP for Scenario I comes from implementing new policy measures on power generation and CHP (76%), followed by new policy measures on biomethane (24%).

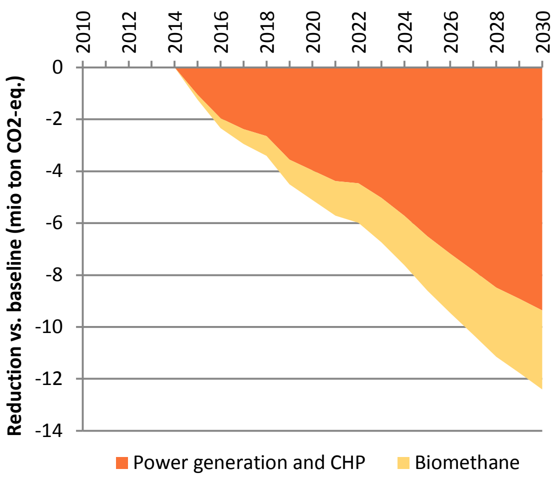


Figure 55. *Reduction in GWP by policy measure for Scenario I*

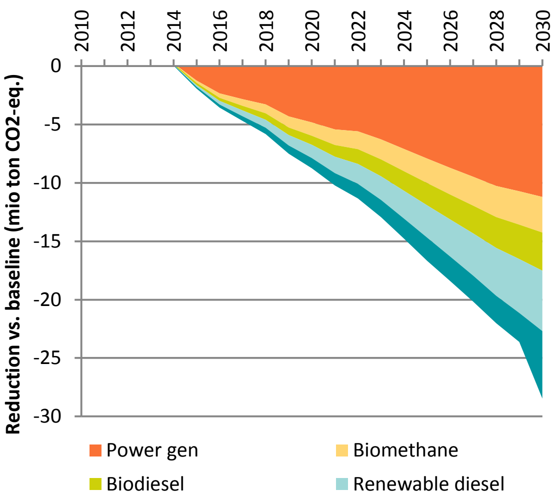


Figure 56. *Reduction in GWP by policy measure for Scenario II*

For Scenario II the reduction in GWP relative to the baseline is shown in Figure 56. In this scenario the reduction starts in 2015 and amounts to 28.5 mio tons of CO_2-eq. by 2030. Similarly to Scenario I, the bulk of the reduction comes from implementing new policy measures on power generation and CHP (48%). The remaining 52% of the reduction relates to the implementation of new policies on renewable diesel (16.5%), biomethane (12.3%), bioethanol (12.1%) and biodiesel (11.2%).

It can be deduced that the most effective policy measure to reduce greenhouse gas emissions is the one on power generation and CHP, which accounts for more than 50% in emissions reduction for Scenarios I and II relative to the baseline. Its impact is followed by the aggregated effect of implementing policies on first generation biofuels (i.e. bioethanol, biodiesel and renewable diesel), which contribute 39% of the reduction in Scenario II. It is remarkable that, while the impact of power generation and CHP is the strongest, its set of long-term goals is less ambitious than that of first generation biofuels.

By disaggregating the emissions reduction by technology, it is possible to better observe how emissions are avoided in the power generation and CHP sector. Figure 57 shows the emissions reduction by technology in the power generation and CHP sector for Scenario I.

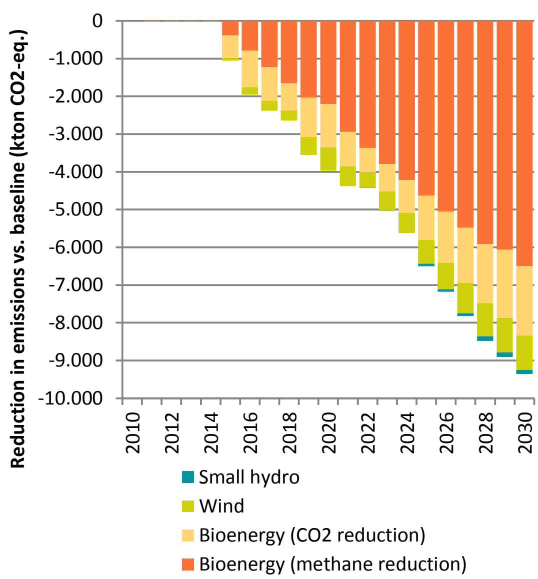


Figure 57. *Reduction in GWP in the power generation and CHP sector for Scenario I*

Three events can be observed. Firstly, 67.5% of the reduction comes from avoiding methane release in landfill gas and animal waste/wastewater through combustion in reciprocating engines. Secondly, the reduction in CO_2-eq. emissions through the replacement of gas- by biomass-based power is less impactful than the methane reduction and accounts for 21.2% of the reduction. Thirdly, wind and small-hydro also replace gas-fired power, and their aggregated impact accounts for 11% of the reduction. The emissions reduction by technology in the power generation and CHP sector for Scenario II is shown in Figure 58. Similarly to Scenario I, the bulk of the reduction (77.2%) comes from avoiding methane release in landfill gas and animal waste/wastewater through combustion in reciprocating engines. It is followed by a reduction in CO_2-eq. emissions in biomass-based power generation (15.7%) as well as in wind and small-hydro (7%).

In summary, the most effective policy measure to reduce greenhouse gas emissions is the one on power generation and CHP. Its impact is twofold: it avoids methane release in landfill gas and animal waste/wastewater through combustion in reciprocating engines, and, at the same time, it reduces CO_2 emissions by replacing gas-fired electricity. It is followed in order of impact by the policies on renewable diesel, bioethanol, biomethane and biodiesel.

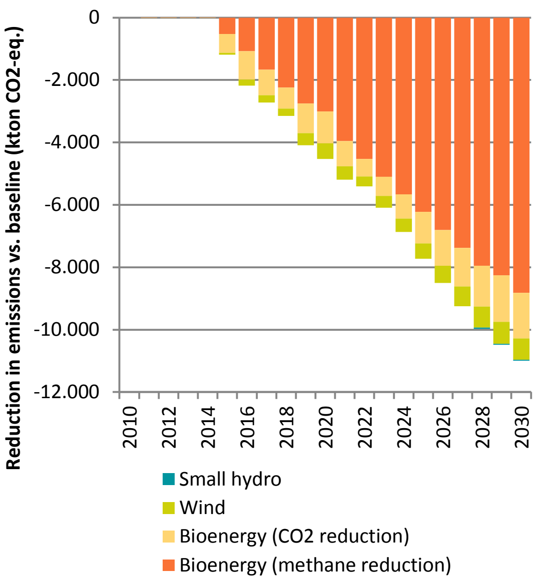


Figure 58. *Reduction in GWP in the power generation and CHP sector for Scenario II*

C.3.2. Domestic bioenergy-induced emissions reductions

Overall emissions for Scenarios I and II, shown in Figure 54, are rearranged in order to highlight the emissions reduction resulting only from bioenergy deployed within the country. To rearrange the domestic bioenergy-induced emissions reductions, the following procedure was followed:

- Emissions reductions caused by wind and small-hydro are subtracted from the overall reduction for Scenarios I and II shown in Figure 54.
- Emissions reductions caused by imported bioethanol and biodiesel are subtracted from the overall reduction for Scenarios I and II shown in Figure 54.

The obtained domestic bioenergy-induced emissions reductions are respectively shown in Figure 59 for Scenarios I, II and II with expansion relative to the baseline. The domestic bioenergy-induced emissions reductions amount to 11.4 mio ton CO_2-eq. in Scenario I, 20.3 mio ton CO_2 in Scenario II, and 22.6 mio ton CO_2 in Scenario II with expansion. In a similar fashion, the savings in fossil fuel demand shown in Section C.1.4.2 are rearranged to highlight the savings resulting only from bioenergy deployed within the country. Figure 60 shows the obtained results, which amount to 1.9 mio TOE in Scenario I, 4.6 in Scenario II and 5.4 in Scenario II with expansion.

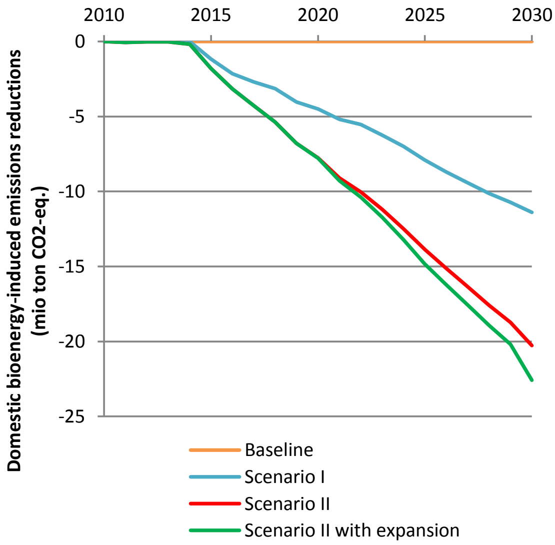


Figure 59. *Domestic bioenergy-induced emissions reductions by scenario*

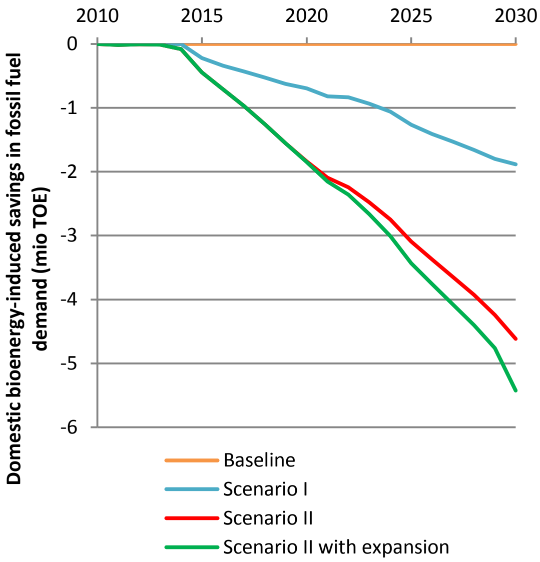


Figure 60. *Domestic bioenergy-induced savings in fossil fuel demand by scenario*

Finally, to visualize the effectiveness of the different scenarios in reducing emissions as a function of the required land, the emissions reductions per required incremental land[20] are plotted for the different scenarios. Figure 61 shows the results by scenario over the period of study.

Among the scenarios, Scenario I offers the highest emissions reduction per additional hectare of land used to cultivate biomass resources, i.e. nearly 150 tons of CO_2-eq. per additional ha. This high value is a consequence of the ability of some biomass-based power technologies, such as landfill gas and biogas-fuelled reciprocating engines, not only to reduce CO_2 emissions relative to fossil-fired power plants but also to capture methane otherwise released via landfill and manure. An additional advantage of exploiting landfill gas and biogas for energy purposes is that, in contrast to first generation biofuels, these routes do not require additional land to produce biomass.

Note that a sharp increase occurs in 2015, which is the year when the policies supporting the deployment of biomethane and power generation & CHP technologies are implemented. In contrast, Scenario II and Scenario II with expansion respectively achieve 40 and 30 tons of CO_2-eq. per additional ha. These results suggest that despite the fact that Scenario II and Scenario II with expansion achieve higher reduction in emissions and fossil fuels than Scenario I, they are less effective to reduce GHG emissions per additional hectare of land use.

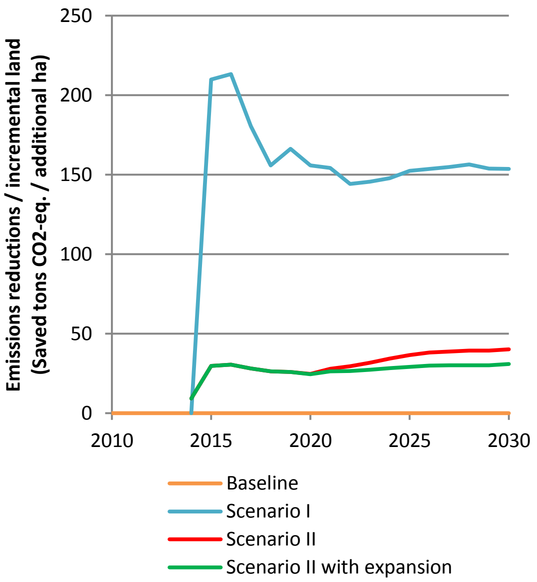


Figure 61. *Emissions reductions per incremental land*

C.3.3. Cost of CO_2-eq. avoided in power generation

The estimated cost of CO_2-eq. avoided in power generation[21] for Scenarios I and II is shown in Figure 62. It reflects the cost to be paid for each additional ton of CO_2-eq. avoided by implementing Scenarios I and II between 2015 until 2030. The cost of CO_2-eq. avoided varies between -15 and 17 US$2005/ton CO_2-eq. in Scenario I and between -10 and 14 US$2005/ton CO_2-eq. in Scenario II. The cost of CO_2-eq. is lower in Scenario II as it reduces more GHG emissions in power generation than Scenario I. For both scenarios the cost of CO_2-eq. avoided between 2015 and 2016 is negative and then increase through till 2030. A negative cost (i.e. a cost saving) occurs in 2015 and 2016 as a result of a cost of electricity slightly lower in Scenarios I and II compared to the baseline. A higher cost of electricity of Scenarios I and II compared to the baseline after 2016 causes an increase in the cost of CO_2 avoided, which reaches 12 to 15 US$2005/ton CO_2-eq. in 2030.

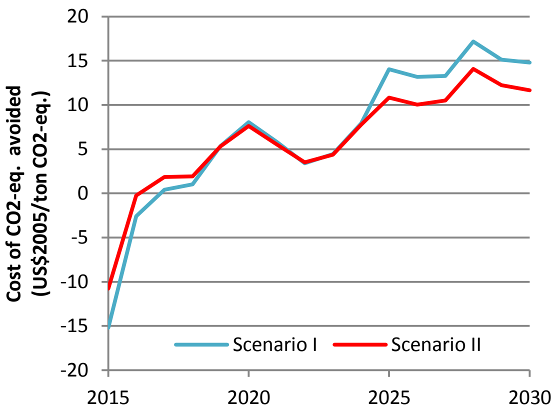


Figure 62. *Cost of CO_2-eq. avoided by scenario*

[20] Defined as $\frac{(Emissions_{Scenarios,t} - Emissions_{Baseline,t})}{(Land_{Scenarios,t} - Land_{Baseline,t})}$ in year t

[21] Calculated as: $\frac{(COE)_{Scenarios,t} - (COE)_{Baseline,t}}{(CO2\ Eq./MWh)_{Baseline,t} - (CO2\ Eq./MWh)_{Scenarios,t}}$

Conclusions

This roadmap addresses the challenge of defining a strategic vision and plan to deploy sustainable biofuel and biomass technologies in Colombia for the period 2015-2030. It was elaborated combining an energy modeling framework with experienced advice from over 30 bioenergy experts from the government, academia, industry and non-governmental organizations (NGOs). The roadmap identifies barriers to bioenergy deployment and recommends: a) strategies, plans and policies to deploy biofuel and biomass technologies in Colombia for the period 2015-2030 and b) actions that should be taken by stakeholders to accomplish the proposed goals. In addition, through detailed modeling, the impacts of achieving roadmap goals are quantified (e.g. substitution of fossil fuels, emissions reduction, land requirements, etc.).

Roadmap vision

In order of importance, the experts agreed on the following reasons to support the deployment of bioenergy technologies in Colombia: 1) to promote rural development, 2) to enhance energy security and 3) to reduce greenhouse gas emissions. Five bioenergy technology areas are considered fundamental: a) bioethanol, b) biodiesel, c) renewable diesel, d) biomethane and e) biomass-based power generation and combined heat & power (CHP). Unanimous agreement was achieved on the long-term vision for biomethane and biomass-based power generation. However, there were opposing views on the long-term vision of liquid transport biofuels (i.e. bioethanol, biodiesel and renewable diesel) produced from feedstocks that are used for human consumption. Consequently, this roadmap considers two different visions.

The first vision focuses on new technologies and targets the deployment of new technologies for the production of biomethane, electricity and CHP, while fixing the current blend mandate of first generation liquid biofuels. Advantages of this vision include: a) it is a vanguard vision that conceives the deployment of novel and efficient technologies (e.g. CHP) that might not only reduce emissions but also decrease the demand for primary energy, b) envisioned technologies can be deployed in distributed energy systems, which might potentially support rural development, c) envisioned technologies can exploit residual biomass and waste that do not require additional land, and d) replacement of natural gas by biomethane can profit from the existing pipeline infrastructure. The main disadvantage is that, while most envisioned technologies are commercially available (e.g. direct combustion in CHP, biogas combustion and purification, etc.), some are currently in the demonstration phase (e.g. methanation, co-firing in gas turbines, etc.).

The second vision targets a combination of new technologies for the production of biomethane, electricity & CHP, while further growing first generation biofuels. The advantages of this vision in addition to those of the first vision include: a) it might be able to reduce emissions in the road transport sector in addition to the reductions in power generation and natural gas supply, and b) it further deploys technologies already proven in the country. Disadvantages of this vision include: a) it requires additional land to produce first generation biofuels, which might worsen the conflicts of land use and food vs. biofuels, and b) it requires a substantial effort to ensure that new and legacy vehicles can safely operate with biofuels blends higher than current levels.

A detailed set of long-term goals, milestones, technologies, policies and barriers were defined for each of the two visions. Identified long-term goals by bioenergy area include:

- Biodiesel: increase the quota mandate to B20 in 2020 and B30 in 2030.
- Bioethanol: a) increase the quota mandate to E20 in 2025 and b) implement an E85 fuel program in 2030.
- Renewable diesel: achieve a 10% contribution (on an energy basis) of renewable diesel to total diesel fuel production in 2030.
- Biomethane: use 5% of biomass residues and 1% animal waste resources nationwide to produce biomethane to be injected into the natural gas network by 2030.
- Power generation and CHP: a) achieve a renewable power target of 10% by 2025, b) use 5% of the biogas from animal waste and municipal water treatment plants nationwide by 2030, c) use 100% of the biogas produced in the water treatment process of biodiesel production plants by 2030, d) use 10% of the municipal landfill gas produced nationwide by 2030.

Various actions are required to deploy the technologies defined in the first vision. Firstly, new regulations and policies are required to enable the implementation of the targets on renewable power, biomethane, biogas and landfill gas. These regulations must actively promote the deployment of cogeneration, distributed generation and renewables through attractive pricing schemes and solid frameworks. While new regulations on power generation have been recently created (e.g. Law 1715 of 2014), their effectiveness needs to be proven.

Secondly, incentive programs and financial mechanisms need to be implemented to encourage technology transfer combined with local development. This ensures not only the deployment of novel technologies but also the generation of local employment and know-how. It is therefore crucial to seek partnerships among OEMs, utilities, SMEs and universities to build pilot projects and demos in the short term that might lead to commercial projects in the mid-term. Thirdly, technical risks (e.g. technology malfunctioning, integration into the country's energy system, feedstock shortage, etc.) must be mitigated by engaging all stakeholders and local communities, acknowledging past international experiences, following best practices and training personnel.

On top of these actions, additional tasks are needed to implement the long-term goals of liquid biofuels defined in the second vision. Firstly, it is necessary to unify and centralize the biofuel policy-making. This might ease the definition of long-term goals, strategies and milestones. Secondly, new regulations are required to ensure a gradual increase in the quota mandates of bioethanol, biodiesel and renewable diesel, as well as to ensure the introduction of vehicles able to operate with high biofuel blends. Thirdly, the operation of legacy vehicles with high biofuel blends must be ensured through a well-coordinated test campaign and a plan to mitigate potential operability issues. Fourthly, the environmental and social benefits of biofuels in the Colombian context must be further analyzed, verified and acknowledged by all stakeholders.

One action of critical importance for both visions is the need for defining and implementing a bioenergy sustainability scheme. Although a dedicated sustainability scheme is beyond the scope of this roadmap, an exploratory scheme is suggested. It proposes forcing the use of biofuels and the conversion of biomass to electricity and heating to reach a minimum requirement in GHG reductions, which should be calculated using a methodology recognized by the scientific community. It is also suggested to exclude certain land categories for bioenergy production (e.g. tropical forests, wooded land, etc.), to use a sustainable wood certification scheme and to limit access to subsidies to a verifiable increase in rural jobs, increase in rural development, reduction in life cycle GHG emissions, protection of water sources and biodiversity and non-use of land categories excluded from bioenergy production.

Modeling

Expert advice was supported by modeling to evaluate the impact of implementing the two long-term visions. Scenario analysis was employed to define various possible future storylines, which are used as inputs to a very detailed energy system model (ESM). Then, the impacts on energy demand, supply and GHG emissions are evaluated. In parallel, a land use and trade model (LUTM) linked to the energy system model (ESM) is used to estimate the land requirements necessary to accomplish the roadmap targets. Three main scenarios are defined:

- Baseline scenario: it assumes no change in policies or deployment of new technologies
- Scenario I (focusing on new technologies): it assumes new policy measures for biomethane and biomass-based power generation and CHP
- Scenario II (combining new and traditional technologies): it assumes new policy measures for all bioenergy technology areas

A subset of Scenario II (Scenario II with expansion) is also defined to consider a significant expansion in cultivation land beyond the Valley of the Cauca River, which is not examined in the three main scenarios.

It is important to note that the proposed modeling framework involves various uncertainties, e.g. the unavoidable unpredictability of future events, limited information of model parameters, limited knowledge about the model structure as well as known and unknown limitations of the mathematical model because of gaps in knowledge, computational limitations or methodological disagreements. One important source of uncertainty relates to the fact that models are calibrated using the latest available statistics, which correspond to year 2009 and predate the present study by five years.

In addition, the modeling framework presents various limitations. The energy system model (ESM) estimates only direct GHG associated with combustion of fuels (i.e. energy-related emissions) and therefore indirect emissions associated to fuels transport, exposure, dose/response effects, but also land-use change, cultivation, irrigation, etc. are not considered. This means the emissions estimated in the ESM model cannot be considered GHG life cycle emissions, which need to be separately evaluated. Although the influence of fuel prices was considered throughout the ESM model, a complete economic analysis was only performed for power generation and CHP technologies. Therefore, a full economic analysis of other bioenergy technologies (e.g. biofuels, biomethane, etc.) remains to be investigated. Regarding modeling techniques, various accurate and realistic methods were used for sectors of key importance to bioenergy (i.e. road transport, residential, etc.) or with large amounts of data (i.e. power generation). However, less sophisticated top-down techniques were used in sectors with limited data (e.g. industrial, commercial, etc.). One of the main limitations of the land use and trade model

(LUTM) is that due to the lack of data it does not include at this stage detailed cost supply curves for all relevant commodities in the country.

In addition, some other important aspects of bioenergy have been considered out of the scope of the proposed modeling framework and are acknowledged limitations. These include: the impact that bioenergy might cause on rural development, living standards of rural communities, generation of employment, water demand and supply, among others. As a consequence of the mentioned uncertainties and limitations, results should be interpreted with caution. Results should not be regarded as forecasts but rather as outcomes of scenario analyses. Hence, they are potential representations of future storylines subject to particular conditions, assumptions and limitations.

Impacts

Scenarios I and II describe long-term visions, in which the role of bioenergy in the future energy mix of the country becomes more relevant than in the baseline. The baseline is characterized by a reduction in the share of bioenergy in the primary demand (from 15% in 2009 to 8% in 2030) and in power generation (from 3.3% to 1.6%) and by a slight increase in the share in road transport (from 5.4% to 6.3%). In contrast, Scenarios I and II are characterized by an increased share of bioenergy in various sectors. In both Scenarios I and II, the share of bioenergy grows to 5.6-5.9% in power generation and to 6.6% in natural gas supply by 2030. The share of bioenergy in road transport remains unchanged for Scenario I relative to the baseline but grows to 24% in Scenario II. This progress is, however, not sufficient to avoid a reduction in the share of bioenergy in the primary demand by 2030 for these scenarios (10% and 11%, respectively).

Regarding impacts on land use, an increase is expected in land for producing liquid biofuels and woodfuel at varying degrees, depending on the scenario. While a portion of this land is used to produce liquid biofuels for export, the bulk of it is used to produce biofuels and woodfuel for local consumption. In the baseline, the amount of land for producing non-export biofuels and woodfuel grows to 0.6 mio ha by 2030, while it grows to 0.67 mio ha in Scenario I, to 1.1 mio ha in Scenario II and to 1.3 mio ha in Scenario II with expansion. In Scenario II and Scenario II with expansion, this increase comes at the expense of a reduction in agricultural and cattle land relative to the baseline. This significant growth in land for producing non-export liquid biofuels and woodfuel is, however, insufficient to accomplish the proposed long-term goals. As a consequence, imports are needed in all scenarios. In the baseline and Scenario I, bioethanol imports might achieve 20% of the domestic demand by 2030. In Scenario II, imports of bioethanol might account for more than 70% of the demand by 2030, while imports of biodiesel might reach 60% of the demand. Imports can even account for 35% of the demand in Scenario II with expansion by 2030, which suggests that expanding the cultivation land beyond the Valley of the Cauca River might also be insufficient to accomplish the targets.

Regarding impacts on emissions, reductions are expected in Scenarios I and II relative to the baseline. Reductions amount to 12.5 mio ton CO_2-eq. in Scenario I (-5.6% in 2030 compared to baseline) and 28.5 mio ton CO_2-eq. in Scenarios II and II with expansion (-12.7% in 2030 compared to baseline). However, these reductions include decrements caused by non-bioenergy resources (e.g. wind and small-hydro) as well as by imported biofuels. When rearranged, emissions reductions caused by local bioenergy reach 11.4 mio ton CO_2-eq. in Scenario I (-5% in 2030 vs. baseline), 20.3 mio ton CO_2-eq. in Scenario II (-9% in 2030 vs. baseline) and 22.6 mio ton CO_2-eq. in Scenario II with expansion (-10% in 2030 vs. baseline). In a similar fashion, the savings in fossil fuel demand caused by local bioenergy amount to 1.9 mio tons of oil equivalent (TOE) in Scenario I, 4.6 in Scenario II and 5.4 in Scenario II with expansion.

Among the different policy measures, the most effective to reduce greenhouse gas emissions is the one on power generation and CHP (in particular technologies using biogas and landfill gas), which accounts for more than 50% in reduction for Scenarios I and II relative to the baseline. Its impact is twofold: it avoids methane release in landfill gas and animal waste/wastewater through combustion in reciprocating engines, and, at the same time, it reduces CO_2 emissions by replacing gas-fired electricity. Another advantage of biogas and landfill gas power plants relates to their ability to significantly reduce GHG emissions without using additional land. Power generation and CHP are followed in order of impact by the policies on renewable diesel, bioethanol, biomethane and biodiesel.

Among the different scenarios, it is found that Scenario I offers the highest emissions reduction per additional hectare of land used to cultivate biomass resources, i.e. nearly 150 tons of CO_2-eq. per additional ha. In contrast, Scenarios II and II with expansion respectively achieve 40 and 30 tons of CO_2-eq. per additional ha. These results suggest that, despite Scenarios II and II with expansion achieving higher reductions in emissions and fossil fuels than Scenario I, they are less effective per additional hectare of land use.

Summary

In Scenario I, bioenergy plays a more relevant role in the supply of power generation and natural gas relative to the baseline. It can accomplish long-term targets with available land and is actually the most effective scenario for reducing emissions per additional hectare of land. Its emissions reduction amounts to 11.4 mio tons of CO_2-eq., while its saving of fossil fuels amounts to 1.9 mio TOE.

In Scenario II, bioenergy plays a more relevant role, not only in the supply of power generation and natural gas, but also in road transport relative to the baseline. While it reduces emissions and fossil fuels more than Scenario I, it achieves this in a less effective manner. In addition, long-term goals for bioethanol and biodiesel cannot be achieved with the available land and imports are required. The expansion in cultivation land beyond the Valley of the Cauca River proposed in Scenario II with expansion also proves insufficient to accomplish the targets. Imports of biofuels occurring in Scenario II and Scenario II with expansion are not considered appropriate because they transfer the positive and negative impacts of producing biofuels to other countries. While importing biofuels might contribute to reducing GHG emissions, it does not enhance domestic rural development, it does not generate local employment, R&D and know-how, it requires additional energy to be transported from abroad and it transfers potential social and environmental negative impacts to other countries.

An important finding is that deploying power generation, CHP and biomethane technologies is more effective in reducing GHG emissions than deploying road transport biofuels. This result is not obvious for two reasons: a) the power generation system in Colombia is largely based on hydro power, and b) road transport is mostly based on fossil fuels. This result, however, agrees with findings of other studies (Cherubini, 2011; IEA, 2011; IEA, 2012a).

Another conclusion is that bioenergy alone cannot significantly reduce emissions by 2030. Obtained results show that the maximum emissions reduction caused by achieving all the long-term goals proposed in this roadmap is 10% relative to the baseline. This suggests that a portfolio of measures including bioenergy is needed to achieve a substantial emissions reduction.

Recommendations

Policy recommendations are listed as follows:

- It is firstly recommended to initiate a technology roadmapping process for bioenergy led by governmental agencies, aimed at defining long-term goals and strategies and involving all stakeholders, i.e. government, industry, academia, NGOs, SMEs, rural communities, external observers, etc.
- It is recommended to consider policy measures proposed in Scenario I (i.e. biomethane, power generation and CHP) in a long-term portfolio of technologies aimed at reducing national GHG emissions. Policy measures proposed in Scenario I proved to be attainable and are the most effective to reduce GHG emissions per additional hectare of land among the studied options. A particularly advantageous route is the use of biogas from animal waste/wastewater and landfill gas in reciprocating gas engines for combined heat and power. This option avoids methane release, substitutes fossil fuels in power generation, reduces CO_2 emissions and does not require additional land.
- It is recommended to pursue policy measures for renewable diesel, which also proved to be attainable and effective in reducing emissions. Renewable diesel presents various advantages compared to biodiesel, e.g. higher energy content, higher cetane number, no detrimental effect on engines and ability to use current refining infrastructure. However, it is critical to identify feedstocks other than palm oil to address concerns about food vs. biofuels and single crop farming.
- It is recommended to re-evaluate the policy measures proposed in this roadmap for bioethanol and biodiesel. The proposed long-term goals could not be attained under current land conditions, and they appeared less effective for reducing emissions than other options. In addition, the proposed timeline to ensure the operability of new and legacy vehicles with high biofuel blends should be reconsidered and adjusted to a 5- to 10-year horizon.

Recommendations for further studies include:

- It is recommended to further investigate the life cycle GHG emissions associated with the different routes proposed in this roadmap under the specific conditions of Colombia.
- It is also recommended to perform a detailed, rigorous and objective economic analysis of deploying novel bioenergy technologies (e.g. biogas, biomethane, renewable diesel, etc.) in Colombia to improve the accuracy of the proposed modeling framework.
- It is strongly recommended to identify modeling frameworks, tools and methodologies to evaluate the impacts of implementing different bioenergy technologies on rural development, water supply, biodiversity, etc.

Nomenclature

Acronyms

ARIMA	autoregressive integrated moving average model
Asocaña	Asociación de Cultivadores de Caña de Azúcar de Colombia (Association of Sugar Cane Growers of Colombia)
BID	Inter-American Development Bank
BOD	biochemical oxygen demand
CHP	combined heat and power
CNG	compressed natural gas
COE	cost of electricity
COP	coefficient of performance
CREG	Comisión de Regulación de Energía y Gas (Energy and Gas Regulatory Comission)
DANE	Departamento Administrativo Nacional de Estadística (National Administrative Department of Statiscs)
DNP	Dirección Nacional de Planeación (National Planning Division)
DOE	U.S. Department of Energy
Ecopetrol	Empresa Colombiana de Petróleos (Colombian Petroleum Co.)
EIA	U.S. Energy Information Administration
ENSO	El Niño and La Niña southern oscillation
ESCO	energy service company
ESM	energy system model
FAO	Food and Agriculture Organization of the United Nations
FFB	fresh fruit bunches (palm oil)
FFV	flex-fuel vehicles
GBEP	Global Bioenergy Partnership
GDP	gross domestic product
GHG	greenhouse gas
GT	gas turbine
GWP	Global Warming Potential
HHD	Human Development Index
IDEAM	Instituto de Hidrología, Meteorología y Estudios Ambientales de Colombia (Colombian Institute of Hydrology, Meteorology and Environmental Studies)
IEA	International Energy Agency
ILUC	indirect land-use change
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelized cost of electricity
LEAP	Long-range Energy Alternatives Planning System
LHV	lower heating value
LPG	liquefied petroleum gas
LULUCF	land use, land-use change and forestry
LUTM	land use and trade model
MME	Ministry of Mines and Energy
MUV	Manufactures Unit Value
NGO	non-governmental organization
NGCC	natural gas combined cycle
NIZ	non-interconnected zones
NMVOC	non-methane volatile organic compounds
NOx	nitrogen oxides
NREL	U.S. National Renewable Energy Laboratory
OEM	original equipment manufacturer
PPP	purchasing power parity
R&D	research and development
SME	small and medium-sized enterprises
SOx	sulfur oxides
TED	technology and environmental database
TOE	ton of oil equivalent
UEC	unit energy consumption
UPME	Unidad de Planeación Minero Energética (Mining and Energy Planning Unit)

Glossary

Biodiesel: mixture of fatty acid alkyl esters (FAAE) (mainly methyl esters) produced from lipids via transesterification of the acylglycerides or esterification of fatty acids for use in compression diesel engines (Verhé, 2011).

Bioenergy: secondary energy resource or carriers such as electricity and biofuels derived from biomass (Slade, 2011).

Bioenergy potential: amount of energy associated to secondary energy resources/carriers such as electricity and biofuels after conversion (Slade, 2011).

Bioethanol (ethyl alcohol): is a liquid oxygenated biofuel produced by fermentation of sugars and employed either as a fuel or as an additive in gasoline-fuelled vehicles (Pinzi, 2011).

Biofuel: liquid and gaseous fuels produced from biomass, e.g. organic matter (IEA, 2011).

Biogas: gaseous mixture consisting mainly of methane and carbon dioxide and produced by the degradation of organic matter in the absence of oxygen (Stamatelatou, 2011).

Biogenic: produced or originating from a living organisms or biological processes

Biomass: biodegradable fraction of products, waste and residues from agriculture (including vegetal and animal substances), forestry and related industries, as well as the biodegradable fraction of industrial and municipal waste (EC, 2008).

Biomass energy potential: amount of energy contained in biomass before any type of conversion (Slade, 2011).

Biomethane: methane sourced from renewable biomass such as organic waste, sewage, agricultural residues or energy crops or from woody biomass through production of syngas (Strauch, 2013).

Combined heat and power: simultaneous generation of both electricity and heat from the same fuel for useful purposes (IEA, 2011).

First generation biofuels: biofuels produced from feedstocks that are used for human consumption, e.g. cane-based bioethanol, palm-based biodiesel, etc.

Primary energy: energy resource found in nature, which has not been transformed or converted.

Renewable diesel (hydrotreated vegetable oil –HVO–): mixture of straight chain and branched paraffinic hydrocarbons free of sulfur and aromatics, produced from vegetable oil via hydrocracking or hydrogenation (NESTE OIL, 2014).

Renewable energy: energy from natural resources (e.g. sunlight and wind) that are replenished at a faster rate than they are consumed. Solar, wind, geothermal, hydro and some forms of biomass are common sources of renewable energy (IEA, 2014b).

Renewable resource: natural resource that is replenished at a faster rate than it is consumed. Examples include biomass harvested sustainably, i.e. certified wood. Tropical forests, native rain forests, protected forests and highly diverse ecosystems (wetlands, swamps, páramos, biodiverse savannah, etc.) are not considered renewable resources in this report, as they do not renew themselves at a sufficient rate for sustainable economic extraction.

Secondary energy: energy forms which have been transformed from primary energy, e.g. electricity, gasoline, diesel fuel, etc.

Second generation biofuels: biofuels produced from feedstocks (biomass/organic matter) that are not used for human consumption.

Sustainability: it means meeting the needs of the current generation without compromising the ability of future generations to meet their own needs (UN, 1987). This definition, however, is not complete. In addition, it must include equity and justice and the whole instead of the specific (Center for Sustainable Communities, 2014; Leonard, 2010).

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Appendix for Chapter B

Table 18. *Assumed energy prices (US$2005)*

US$2005	Unit	1975	1980	1985	1990	1995	2000	2005	2009	2010	2015	2020	2025	2030
International prices														
Aviation gasoline	MMBtu	10.27	18.87	16.21	12.90	10.24	12.25	18.56	18.52	22.69	27.98	32.41	34.66	36.33
Coke	MMBtu	10.33	6.67	4.85	5.26	4.20	3.00	8.92	9.86	12.04	10.86	11.44	11.67	11.77
Coal	MMBtu	3.07	3.05	2.74	2.06	1.68	1.40	1.62	2.12	2.18	2.40	2.52	2.69	2.87
Jet fuel	MMBtu	6.10	13.31	9.59	7.86	4.90	7.48	12.86	11.49	14.67	17.36	20.11	21.51	22.54
Kerosene	MMBtu	8.13	14.58	12.56	10.13	6.79	10.07	14.44	19.30	21.16	23.99	26.43	28.15	29.23
LPG	MMBtu	8.81	11.80	10.76	9.45	7.98	10.76	14.58	14.93	17.67	18.56	20.44	21.77	22.61
Oil	Barrel	21.36	48.37	38.98	23.66	15.95	31.60	53.39	56.50	69.99	100.48	105.07	109.75	114.69
Domestic prices														
Fuel oil	MMBtu	3.48	4.60	4.10	2.13	1.78	3.26	5.22	6.91	9.93	9.37	10.21	10.66	11.07
Natural gas	MMBtu	0.54	2.25	3.09	1.19	1.02	1.64	1.86	2.78	3.49	4.54	5.82	6.65	7.29
Electricity	MMBtu	1.70	3.04	4.56	3.28	4.38	7.07	9.42	17.46	17.82	11.29	12.43	13.71	15.16
Gasoline	MMBtu	4.21	9.18	7.61	5.13	7.00	10.96	19.39	26.86	29.63	33.46	34.44	34.35	34.65
Diesel	MMBtu	4.63	8.22	6.81	4.61	6.27	8.01	12.22	20.11	21.77	31.07	32.83	33.52	34.21
Wood fuel[1]	MMBtu	3.15	3.14	2.82	2.12	1.73	1.44	1.67	2.18	2.24	2.46	2.59	2.77	2.95
Anhydrous ethanol[2]	Gallon								2.79	3.21	3.22	2.74	2.64	2.74
Biodiesel[2]	Gallon								3.26	3.80	3.59	3.76	3.78	3.98
MUV index (2005 = 1)									1.09	1.13	1.20	1.19	1.23	1.27

[1] Prices for wood fuel are not available. It is assumed to be proportional to the international price of coal.
[2] Future prices for anhydrous ethanol and biodiesel are taken from (Gonzalez-Salazar M, 2014b), scenario FAO-REF-01

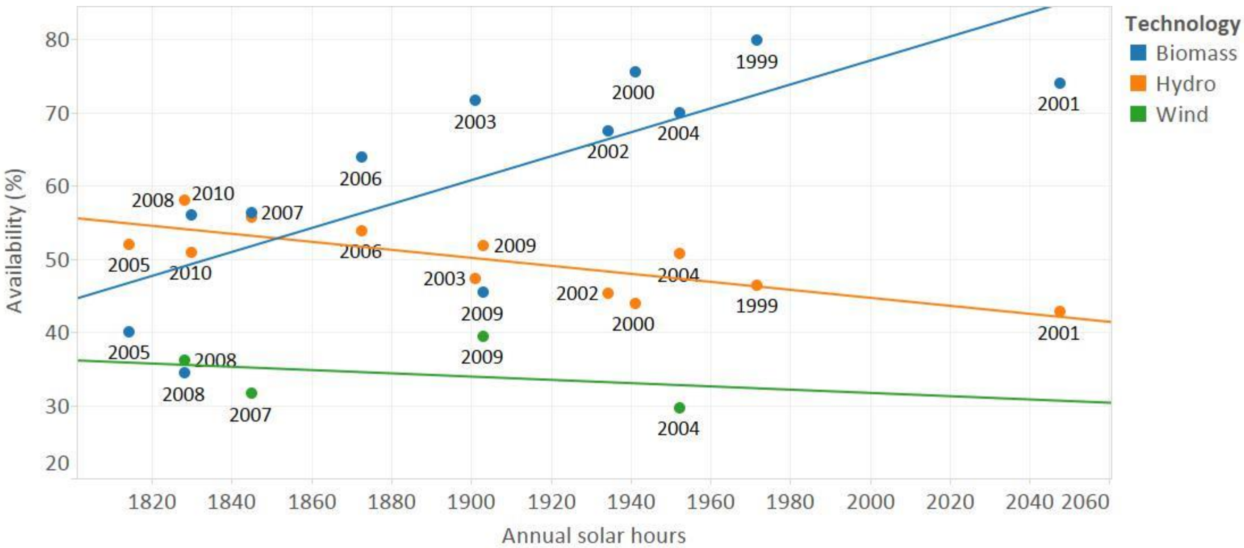


Figure 63. *Availability of renewable energies as a function of solar radiance (XM, 2013)*

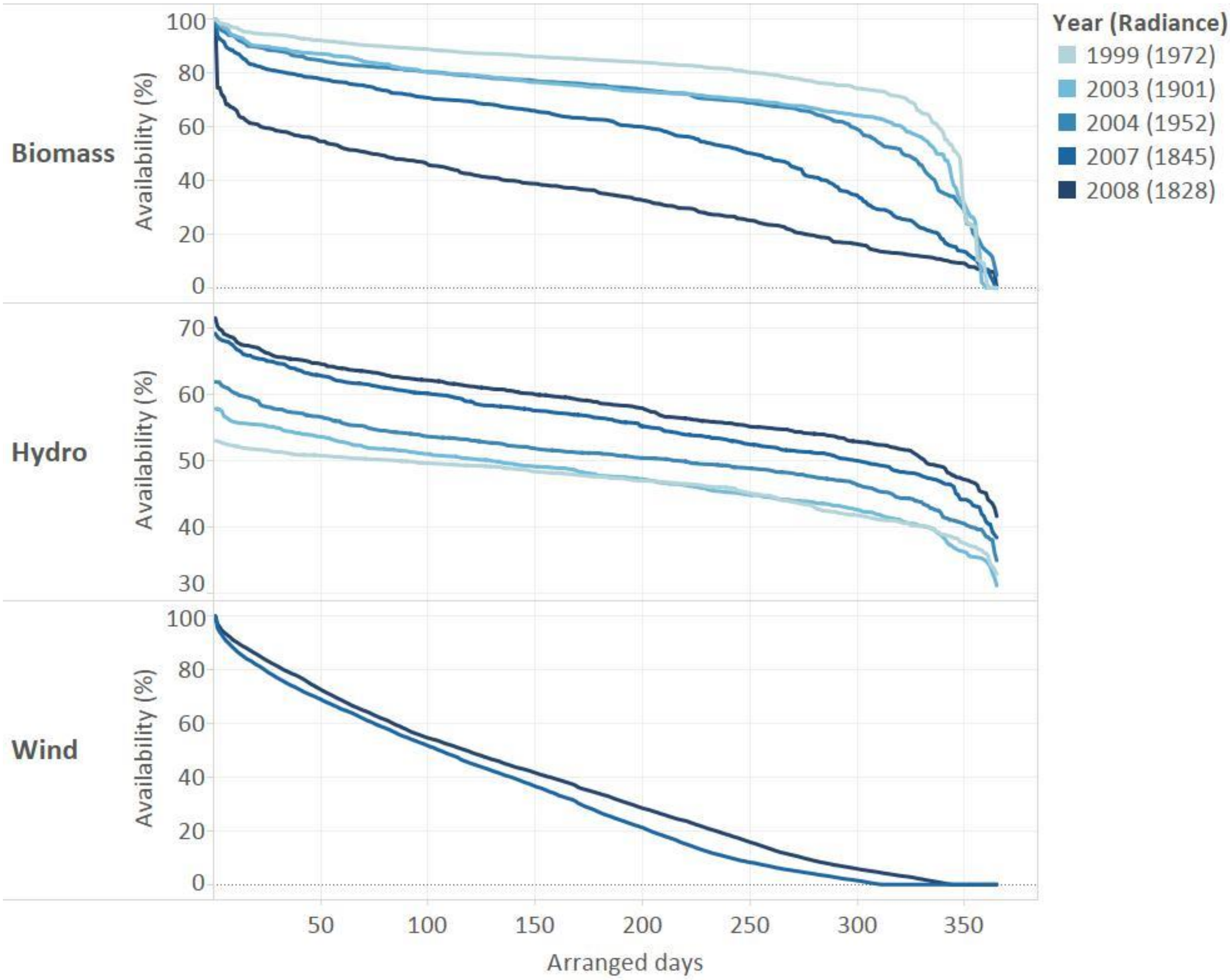


Figure 64. *Availability of renewable energies for arranged days in different years (XM, 2013)*

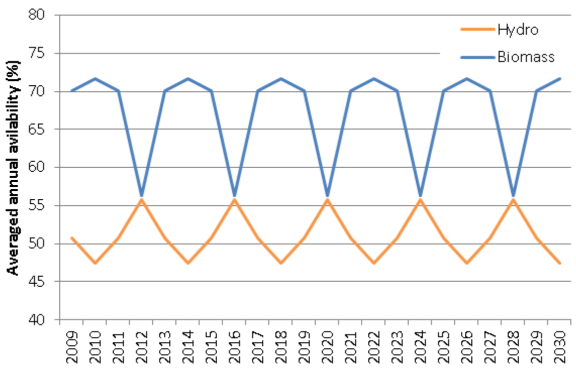


Figure 65. *Averaged assumed profiles for hydro and biomass-based power*

Table 19. *Assumed availability of land*

Availability of land (mio ha)	2010	2015	2020	2025	2030
Forest area	60.50	60.00	59.50	59.00	58.50
Other land	8.00	8.00	8.00	8.00	8.00
Area for commodities not included in model	1.00	1.00	1.00	1.00	1.00
Area for commodities included in model (including area for cattle)	41.45	41.95	42.45	42.95	43.45

Table 20. *Produced volumes of biomass resources*

Biomass categories	2010	2015	2020	2025	2030
Agricultural crops [1] (million tons)					
Cotton	0.04	0.06	0.06	0.08	0.06
Palm oil (FFB)	5.50	8.19	9.73	12.68	15.78
Sugar cane without leaves (large-scale)	25.67	28.50	28.17	28.50	28.50
Sugar cane without leaves (small-scale)	17.11	19.81	22.82	26.06	29.51
Coffee (green)	0.77	0.83	0.63	0.08	0.08
Corn	1.48	1.69	1.81	2.09	2.29
Rice (paddy)	3.42	2.39	2.39	2.18	1.49
Banana	2.09	2.35	2.68	3.06	3.45
Plantain	2.72	2.97	3.24	3.50	3.75
Animals (million stocks)					
Cattle [1]	29.74	31.05	32.61	34.41	35.94
Pork [1]	3.87	2.91	1.88	1.27	1.29
Poultry [1]	624.45	643.88	680.07	651.38	406.17
Equine [1]	2.14	2.27	2.40	2.51	2.61
Buffalos [2]	0.23	0.23	0.23	0.23	0.23
Sheep [3]	3.58	3.58	3.58	3.58	3.58
Goats [3]	2.69	2.69	2.69	2.69	2.69
Mules and asses [3]	0.71	0.71	0.71	0.71	0.71
Forest resources from forest plantations [1] (million m^3)					
Roundwood	11.59	13.49	15.48	17.56	19.74
Woodfuel	9.12	10.61	12.18	13.82	15.53
Industrial roundwood	2.47	2.87	3.30	3.74	4.21
Forest resources from deforestation [7] (million m^3)					
Field residues	13.44	13.44	13.44	13.44	13.44
Urban waste					
Landfill gas [4] (kton)	739.64	1021.80	1194.72	1333.10	1457.66
Wastewater [5] (kton BOD)	666.55	712.27	756.43	798.85	839.59
Wastewater from biodiesel plants [6] (kton BOD), Baseline and Scenario I	77.54	123.15	162.46	216.11	279.49
Wastewater from biodiesel plants [6] (kton BOD), Scenarios II and II with expansion	77.54	155.51	316.91	531.99	834.42

Notes:

[1] Produced volumes of agricultural crops, forestry resources and animal stocks are taken from the results of the LUTM model for the baseline scenario. These values are almost unchanged across scenarios and it is assumed that they are the same for all scenarios.

[2] Account of these animals is not included in LUTM. Values for 2014 are taken from (ICA, 2014) and assumed to maintain constant until 2030 given their low contribution.

[3] Account of these animals is not included in LUTM. Values for 2014 are taken from (FAO, 2012) and assumed to maintain constant until 2030 given their low contribution.

[4] Volumes of landfill gas are estimated using the Colombia Landfill Gas Model Version 1.0 (SCS Engineers, 2010). The model calculates landfill gas generation by using a first order decay equation, specific data of climate, waste composition and disposal practices in each of the 33 departments in Colombia. It is assumed that the type of landfill is engineered or sanitary, that the start year of the landfill is 2005 and that the projected closure year is 2030. Current production of municipal solid waste (MSW) for the different departments is taken from various reports published by the Colombian Administration of Public Services (Superservicios, 2009; Superservicios, 2011; Superservicios, 2012). Future production of MSW is estimated by multiplying the current MSW per capita for the different departments by the population forecast taken from Table 8.

[5] Estimated using the Tier 1 methodology to estimate wastewater treatment and discharge in the IPCC guidelines for national greenhouse gas inventories (IPCC, 2006). Specifically, a theoretical BOD generation per capita of 40 g BOD/person/day and population forecast from Table 8 are used.

[6] The volume of wastewater produced in biodiesel processing plants is estimated by multiplying a BOD emission factor by the production of biodiesel for the different scenarios. A BOD emission factor of 0.0523 kg-BOD/kg-FFB taken from (BID-MME, Consorcio CUE, 2012) is used. The biodiesel production for the different scenarios is taken from the results of the ESM model (see Figure 29 and Figure 30).

[7] It is assumed that forest residues left in the field are available from deforested areas, which amount to 100 kha annually until 2030. The amount of residues is estimated using an above-ground biomass yield of 259.7 ton-dry/ha taken from (Phillips, et al., 2011), a ratio of residues to total biomass of 0.31 ton-residues/ton-biomass taken from (Gonzalez-Salazar M. M., 2014a) and a density of 0.6 dry-ton/m^3 taken from (Gonzalez-Salazar M. M., 2014a).

***Table 21.** Specific energy of biomass resources*

Agriculture	**Residues**	**Residue to product ratio (RTP)**	**Moisture**	**LHV (kJ/kg, d)**	**References**
Cotton	Husk	2.17	0.09	15815	For all residues from agricultural crops the average values from (Gonzalez-Salazar M. M., 2014a) are taken.
Palm oil	Stone	0.17	0.09	17948	
	Fiber	0.22	0.35	18220	
	Rachis	0.35	0.54	17993	
Sugar cane (large-scale)	Leaves and top	0.36	0.23	17394	
	Bagasse	0.31	0.48	17342	
Sugar cane (small-scale)	Bagasse	0.30	0.48	17342	
	Leaves and top	0.33	0.23	17394	
Coffee	Pulp	2.12	0.68	18518	
	Husk	0.21	0.11	16151	
	Stem	3.02	0.29	19062	
Corn	Stem and leaves	0.93	0.15	16108	
	Cob	0.27	0.29	16340	
	Skin	0.20	0.08	16590	
Rice	Stem	1.94	0.82	14599	
	Husk	0.25	0.10	15551	
Banana	Rachis	1.00	0.95	7863	
	Stem	5.00	0.94	8836	
	Rejected fruit	0.15	0.84	10820	
Plantain	Rachis	1.00	0.94	7570	
	Stem	5.00	0.93	8508	
	Rejected fruit	0.15	0.83	10417	

Animal waste	**kg-CH4/head**	**Reference**
Cattle	93.29	(Gonzalez-Salazar M. M., 2014a)
Swine	19.17	(Gonzalez-Salazar M. M., 2014a)
Poultry	0.84	(Gonzalez-Salazar M. M., 2014a)
Equine	149.48	(Gonzalez-Salazar M. M., 2014a)
Buffalos	56.92	(IPCC, 2006)
Sheep	5.18	(IPCC, 2006)
Goats	5.21	(IPCC, 2006)
Mules and asses	11.08	(IPCC, 2006)

Forestry residues	**RTP**	**Specific weight (ton-d/m^3)**	**LHV (kJ/kg, d)**	**Reference**
Field residues	0.45		18548	All values taken from averages in (Gonzalez-Salazar M. M., 2014a)
Industrial residues	0.24		18548	
Woodfuel		0.725	18098	

Urban waste	**Value**	**Reference**
Landfill LHV (MJ/m^3)	16.99	(Gonzalez-Salazar M. M., 2014a)
Wastewater (kg-CH_4/kg-BOD)	0.198	Tier 1 method in (IPCC, 2006) and using population from Table 8
Wastewater in biodiesel plants (kg-CH_4/kg-BOD)	0.197	(BID-MME, Consorcio CUE, 2012)

Table 22. *Availability of biomass resources*

Categories	Residues	Availability factor
Residues from agricultural crops [1]		
Cotton	Husk	0.00
Palm oil	Stone	1.00 [3]
	Fiber	1.00 [3]
	Rachis	1.00 [3]
Sugarcane (large-scale)	Leaves and top	0.43
	Bagasse	0.94 [3]
Sugarcane (medium, small-scale)	Bagasse	1.00 [3]
	Leaves and top	0.00
Coffee	Pulp	0.00
	Husk	0.00
	Stem	0.00
Corn	Stem and leaves	0.00
	Cob	0.00
	Skin	0.00
Rice	Stem	0.00
	Husk	0.75
Banana	Rachis	0.00
	Stem	0.00
	Rejected fruit	0.00
Plantain	Rachis	0.00
	Stem	0.00
	Rejected fruit	0.00
Animal waste [1]		
Cattle	Manure	0.16
Pork	Manure	0.11
Poultry	Manure	0.00
Equine	Manure	0.00
Other	Manure	0.00
Forest resources from forest plantations [1]		
Woodfuel		1.00 [3]
Field residues		0.30
Industrial residues		0.00
Forest resources from deforestation [1]		
Field residues		0.30
Urban waste [1]		
Landfill gas		0.57
Methane from wastewater		0.03
Methane from wastewater in biodiesel processing plants [2]		
Scenario I		1.00
Scenario II		1.00

Notes:
[1] For these categories the average values from (Gonzalez-Salazar M. M., 2014a) are taken.
[2] For methane from wastewater in biodiesel processing plants it is assumed a technical availability of 100% in 2030 based on recommendations of experts.
[3] For these sub-categories the availability factor considers two parts: a) the part of the resource already used for energy production and b) the part of the resource potentially available for energy production after considering competition and other constraints as described in (Gonzalez-Salazar M. M., 2014a).

Table 23. *Theoretical biomass energy potential*

Categories	**2010**	**2015**	**2020**	**2025**	**2030**
Residues from agricultural crops (thousand TJ)					
Cotton	3.23	2.02	1.95	2.41	1.89
Palm oil	44.92	68.54	81.45	106.12	132.04
Sugar cane (large-scale)	152.15	216.17	213.64	216.17	216.17
Sugar cane (small-scale)	119.69	141.19	162.64	185.73	210.28
Coffee	43.90	47.03	35.42	4.27	4.41
Corn	20.92	32.22	34.39	39.69	43.48
Rice	21.25	20.72	20.77	18.89	12.96
Banana	7.08	8.25	9.41	10.74	12.10
Plantain	10.43	10.43	11.37	12.29	13.17
Sub-total	423.58	546.57	571.04	596.31	646.50
Animal waste (thousand TJ)					
Cattle	138.74	144.85	152.11	160.50	167.63
Pork	3.71	2.79	1.80	1.22	1.23
Poultry	26.16	26.97	28.49	27.29	17.01
Equine	16.03	16.98	17.93	18.78	19.49
Other	2.69	2.69	2.69	2.69	2.69
Sub-total	187.32	194.27	203.02	210.46	208.06
Forest resources from forest plantations (thousand TJ)					
Woodfuel	119.63	139.27	159.83	181.33	203.82
Field residues	96.75	112.64	129.26	146.66	164.84
Industrial residues	11.00	12.80	14.69	16.67	18.74
Sub-total	227.38	264.71	303.78	344.66	387.41
Forest resources from deforestation (thousand TJ)					
Field residues	149.54	149.54	149.54	149.54	149.54
Urban waste (thousand TJ)					
Landfill gas	9.89	13.66	15.97	17.82	19.49
Methane from wastewater	6.69	7.14	7.57	7.99	8.39
Sub-total	16.58	22.01	25.15	27.94	30.63
Methane from wastewater in biodiesel processing plants (thousand TJ)					
Scenario I	0.76	1.21	1.60	2.13	2.75
Scenarios II and II with expansion	0.76	1.53	3.12	5.24	8.22
Total (thousand TJ)					
Baseline and Scenario I	1005.16	1178.33	1254.12	1331.04	1424.90
Scenarios II and II with expansion	1005.16	1178.64	1255.65	1334.15	1430.36

***Table 24.** Technical biomass energy potential including current uses*

	2010	2015	2020	2025	2030
Residues from agricultural crops (thousand TJ)					
Cotton	0.00	0.00	0.00	0.00	0.00
Palm oil	44.92	68.54	81.45	106.12	132.04
Sugar cane (large-scale)	94.58	134.37	132.80	134.37	134.37
Sugar cane (small-scale)	45.04	53.12	61.19	69.88	79.12
Coffee	0.00	0.00	0.00	0.00	0.00
Corn	0.00	0.00	0.00	0.00	0.00
Rice	6.35	6.19	6.21	5.64	3.87
Banana	0.00	0.00	0.00	0.00	0.00
Plantain	0.00	0.00	0.00	0.00	0.00
Sub-total	190.88	262.22	281.65	316.02	349.40
Animal waste (thousand TJ)					
Cattle	22.34	23.33	24.50	25.85	27.00
Pork	0.41	0.31	0.20	0.13	0.14
Poultry	0.00	0.00	0.00	0.00	0.00
Equine	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00
Sub-total	22.75	23.63	24.69	25.98	27.13
Forest resources from forest plantations (thousand TJ)					
Woodfuel	119.63	139.27	159.83	181.33	203.82
Field residues	29.26	34.06	39.09	44.35	49.85
Industrial residues	0.00	0.00	0.00	0.00	0.00
Sub-total	148.89	173.33	198.92	225.68	253.67
Forest resources from deforestation (thousand TJ)					
Field residues	45.22	45.22	45.22	45.22	45.22
Urban waste (thousand TJ)					
Landfill gas	5.59	7.72	9.03	10.07	11.02
Methane from wastewater	0.18	0.19	0.20	0.21	0.22
Sub-total	5.77	9.12	10.83	12.41	13.99
Methane from wastewater in biodiesel processing plants (thousand TJ)					
Scenario I	0.76	1.21	1.60	2.13	2.75
Scenario II	0.76	1.53	3.12	5.24	8.22
Total (thousand TJ)					
Baseline and Scenario I	414.27	514.75	562.91	627.45	692.17
Scenario II	414.27	515.06	564.43	630.56	697.63

***Table 25.** Primary energy targeted in long-term goals of biomethane and biomass-based power generation in Scenarios I and II*

Primary energy targeted	**Scenario I**				**Scenario II**			
	2015	**2020**	**2025**	**2030**	**2015**	**2020**	**2025**	**2030**
Biomethane								
5% biomass residues (TJ)	2020	12122	22224	32325	2020	12122	22224	32325
1% animal waste (TJ)	130	780	1430	2081	130	780	1430	2081
Power generation								
5% animal waste (TJ)	650	3901	7152	10403	650	3901	7152	10403
5% methane in wastewater (TJ)	26	157	288	420	26	157	288	420
100% methane in wastewater from biodiesel plants (TJ)	172	1032	1892	2752	514	3081	5649	8217
10% landfill gas (TJ)	85	512	938	1364	85	512	938	1364

Table 26. *Validation of the primary energy demand by fuel in the ESM model against official statistics*

Primary energy (mio TOE), taken from the national energy balances	**1975**	**1980**	**1985**	**1990**	**1995**	**2000**	**2005**	**2009**
Bioenergy	4.45	4.39	4.47	4.35	4.31	3.74	3.78	3.77
Coal	2.27	2.43	3.05	1.60	3.61	2.70	1.34	3.86
Gas	1.66	2.77	3.57	3.76	4.12	6.25	6.92	8.42
Hydro	1.00	1.48	1.89	2.81	3.27	3.15	4.01	4.20
Oil	8.07	8.49	10.56	13.66	15.21	15.00	15.99	16.95
Other renewables	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.91
Total	17.44	19.56	23.53	26.18	30.52	30.85	32.09	38.10
Primary energy (mio TOE), modeled values								
Bioenergy	4.50	4.25	4.12	4.17	4.91	4.50	4.73	4.60
Coal	2.35	2.52	3.14	1.69	3.70	2.75	1.38	3.89
Gas	1.67	2.86	3.66	3.87	4.20	6.25	6.94	8.48
Hydro	1.00	1.48	1.89	2.81	3.27	3.15	4.00	4.19
Oil	8.07	8.49	10.56	13.66	15.21	15.00	15.99	16.95
Other renewables	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02
Total	17.57	19.60	23.38	26.21	31.29	31.65	33.06	38.13

Notes:

1. Bioenergy in national energy balances includes bagasse from sugar cane at large scale, wood and residues of palm oil, but excludes bagasse from jaggery cane. Bioenergy in the ESM model includes all these sub-categories. For the sake of comparison bagasse from jaggery cane is not accounted in the validation of the ESM model.
2. Imports of oil-based secondary fuels are converted into primary energy.
3. Accounting adjustments published in the national energy balances for all fuels are considered for validating the ESM model.

Table 27. *Goodness of fit between primary energy modeled values and official statistics*

Goodness of fit	**R^2**
Bioenergy	-
Coal	98.4%
Gas	99.9%
Hydro	100%
Oil	100%
Other renewables	-
Total	99.2%

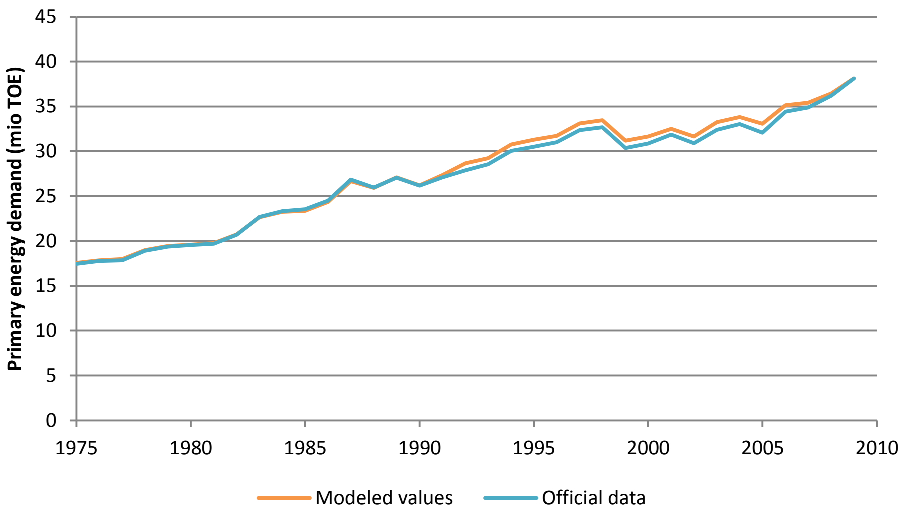


Figure 66. *Modeled primary energy demand vs. official data*

Table 28. *Validation of the GHG emissions by branch in the ESM model against official statistics*

Energy related GHG emissions (mio ton CO_2-eq.), taken from the national energy balances	**1975**	**1980**	**1985**	**1990**	**1995**	**2000**	**2005**	**2009**
Demand	23.30	26.20	27.65	34.16	41.38	41.06	44.97	48.03
Own use	3.20	3.14	3.20	3.94	4.44	6.61	6.91	7.59
Power generation	4.70	6.53	7.91	7.05	9.28	8.71	8.49	12.40
Other transformation processes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	31.20	35.87	38.76	45.16	55.11	56.38	60.36	68.01
Total excluding other processes	31.20	35.87	38.76	45.16	55.11	56.38	60.36	68.01
Energy related GHG emissions (mio ton CO_2-eq.), calculated values								
Demand	22.86	25.86	27.04	33.66	41.09	40.87	44.70	47.54
Own use	2.09	2.09	1.93	2.36	2.68	4.72	4.97	5.62
Power generation	4.47	6.17	7.73	7.02	9.07	8.54	8.23	11.96
Other transformation processes	4.70	5.99	6.60	6.88	5.83	5.29	4.56	6.17
Total	34.12	40.12	43.30	49.92	58.66	59.42	62.47	71.28
Total excluding other processes	29.42	34.13	36.70	43.04	52.83	54.13	57.91	65.11

Table 29. *Goodness of fit between GHG emissions modeled values and official statistics*

Goodness of fit	**R^2**
Demand	99.8%
Own use	-
Power generation	97.4%
Other transformation processes	-
Total	87.9%
Total excluding other processes	95.7%

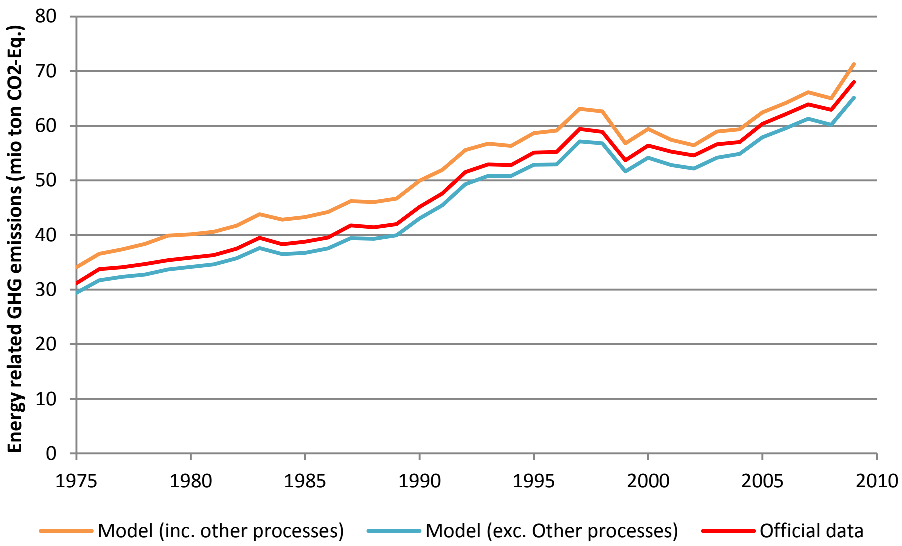


Figure 67. *Modeled GHG emissions vs. official data*

***Table 30.** Updated production costs of sugar, palm oil and biofuels in LUTM model*

Production cost (US$2005)	2010	2015	2020	2025	2030
Palm oil (US$2005/ton)	623.3	673.0	642.4	646.1	684.1
Biodiesel (US$2005/liter)	0.7	0.8	0.8	0.8	0.8
Sugar (US$2005/ton), Route 1 in Valley of the Cauca River	519.6	631.8	656.8	687.0	759.9
Sugar (US$2005/ton), Route 2 in Valley of the Cauca River	519.6	631.8	656.8	687.0	759.9
Bioethanol (US$2005/liter), Route 2 in Valley of the Cauca River	0.40	0.48	0.50	0.52	0.58
Bioethanol (US$2005/liter), Route 3 in Valley of the Cauca River	0.52	0.63	0.66	0.69	0.76
Sugar (US$2005/ton), Route 1 in Llanos and Costa regions	896.9	1026.3	1004.7	990.6	1033.0
Sugar (US$2005/ton), Route 2 in Llanos and Costa regions	896.9	1026.3	1004.7	990.6	1033.0
Bioethanol (US$2005/liter), Route 2 in Llanos and Costa regions	0.67	0.76	0.75	0.74	0.77
Bioethanol (US$2005/liter), Route 3 in Llanos and Costa regions	0.88	1.01	0.98	0.97	1.01

***Table 31.** Updated yields of sugar, palm oil and biofuels in LUTM model*

Yields	2010	2015	2020	2025	2030
Palm oil and derivatives					
Fresh fruit bunches -FFB- (Ton/Ha) -	19.61	20.20	20.80	21.39	21.98
Palm oil (Ton/Ha)	3.58	3.73	3.89	4.05	4.20
Biodiesel (liters/ton fresh fruit)	233.61	233.61	233.61	233.61	233.61
Biodiesel (liters/ha)	4581.72	4719.94	4858.16	4996.38	5134.60
Biodiesel yield (ton-oil/liter)	0.00078	0.00079	0.00080	0.00081	0.00082
Sugar and derivatives in Valley of the Cauca River					
Cane without leaves (Ton/Ha)	114.00	114.00	114.00	114.00	114.00
Sugar (ton/ha), Route 1	13.68	13.68	13.68	13.68	13.68
Sugar (ton/ha), Route 2	10.60	10.60	10.60	10.60	10.60
Bioethanol (ton bioethanol/ton sugar), Route 2	0.21	0.21	0.21	0.21	0.21
Bioethanol (liters/ton cane), Route 3	80.00	80.00	80.00	80.00	80.00
Bioethanol (liters/ha), Route 3	9120.00	9120.00	9120.00	9120.00	9120.00
Sugar and derivatives in expansion (i.e. Llanos and Costa regions)					
Cane without leaves (Ton/Ha)	70.83	75.13	79.69	84.53	89.67
Sugar (ton/ha), Route 1	8.50	9.02	9.56	10.14	10.76
Sugar (ton/ha), Route 2	5.42	5.94	6.49	7.07	7.68
Bioethanol (ton bioethanol/ton sugar), Route 2	0.21	0.21	0.21	0.21	0.21
Bioethanol (liters/ton cane), Route 3	80.00	80.00	80.00	80.00	80.00
Bioethanol (liters/ha), Route 3	5666.42	6010.50	6375.48	6762.62	7173.27

References: (BID-MME, Consorcio CUE, 2012; Ferreira-Leitao, 2010)

***Table 32.** Other assumptions for expansion of sugar cane in the Llanos and Costa regions*

Assumptions in Llanos and Costa regions	Value	References
Maximum historical yearly growth (ha)	35249	Assumed to be the same as for sugar cane in Valley of the Cauca River taken from (Gonzalez-Salazar M, 2014b)
Available land area (ha)	1518000	Taken from (BID-MME, Consorcio CUE, 2012)

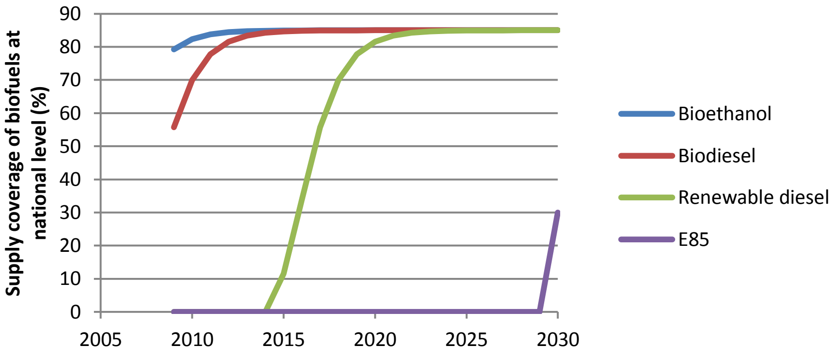


***Figure 68.** Supply coverage of biofuels at a national level*

Table 33. *Income shares by quintile*

	1980	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Income shares by quintile											
Income share by lowest 20% (Q1)	2.60%	3.06%	3.57%	2.75%	1.90%	2.79%	2.79%	3.31%	3.18%	2.75%	2.62%
Income share by second 20% (Q2)	5.97%	6.75%	7.38%	7.38%	6.76%	7.11%	6.70%	6.70%	6.70%	6.70%	6.70%
Income share by third 20% (Q3)	10.52%	11.52%	12.21%	11.43%	10.97%	11.24%	11.12%	11.21%	11.24%	11.26%	11.27%
Income share by fourth 20% (Q4)	18.20%	19.33%	19.95%	18.70%	18.13%	18.54%	18.84%	18.78%	18.68%	18.70%	18.78%
Income share by highest 20% (Q5)	62.71%	59.35%	56.90%	59.74%	62.24%	60.32%	60.54%	60.01%	60.20%	60.59%	60.64%

Table 34. *Household expenditure per person by quintile and region*

	1980	1985	1990	1995	2000	2005	2010	2015	2020	2025	2030
Rural household expenditure per person-quintile (US$2005/person)											
Lowest 20% (Q1)	839	1069	1439	1343	919	1519	1854	2678	3176	3326	3769
Second 20% (Q2)	1430	1751	2210	2678	2428	2873	3303	4028	4966	6020	7166
Third 20% (Q3)	1895	2249	2752	3119	2963	3417	4125	5066	6268	7611	9068
Fourth 20% (Q4)	2303	2650	3158	3585	3440	3958	4908	5965	7314	8878	10610
Highest 20% (Q5)	4971	5099	5643	7174	7398	8068	9879	11938	14766	18015	21465
Average	2288	2564	3040	3580	3430	3967	4814	5935	7298	8770	10416
Urban household expenditure per person-quintile (US$2005/person)											
Lowest 20% (Q1)	263	289	344	289	183	281	319	436	493	496	544
Second 20% (Q2)	907	957	1069	1166	979	1074	1148	1327	1558	1814	2091
Third 20% (Q3)	1980	2023	2190	2234	1967	2102	2359	2747	3236	3774	4355
Fourth 20% (Q4)	4020	3983	4201	4291	3815	4069	4690	5405	6310	7357	8516
Highest 20% (Q5)	15659	13829	13545	15496	14807	14965	17036	19521	22988	26941	31089
Average	4566	4216	4270	4695	4350	4498	5110	5887	6917	8076	9319

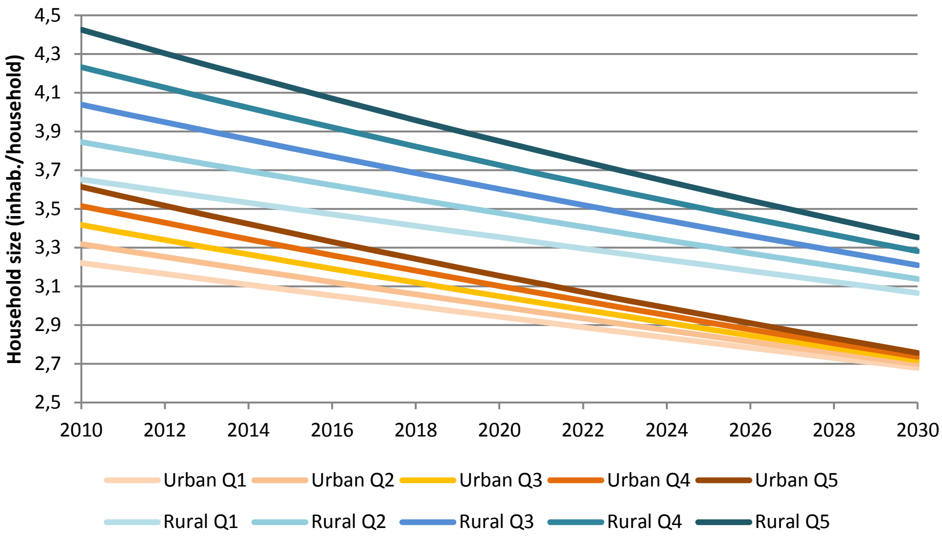


Figure 69. *Household size by region and quintile*

Table 35. *Income shares by quintile and region*

Quintile	Urban (%)	Rural (%)
Income share by lowest 20% (Q1)	33.98%	66.02%
Income share by second 20% (Q2)	51.00%	49.00%
Income share by third 20% (Q3)	63.14%	36.86%
Income share by fourth 20% (Q4)	74.11%	25.89%
Income share by highest 20% (Q5)	83.78%	16.22%

Table 36. *Floor space by region and quintile*

Floorspace	2010	2015	2020	2025	2030
Rural (m^2/person)					
Q1	21.85	23.53	25.61	27.80	30.01
Q2	25.73	27.71	30.16	32.74	35.33
Q3	29.61	31.89	34.71	37.67	40.66
Q4	33.49	36.07	39.25	42.61	45.99
Q5	37.37	40.24	43.80	47.54	51.31
Urban (m^2/person)					
Q1	17.03	18.37	20.03	21.76	23.51
Q2	20.06	21.64	23.58	25.63	27.68
Q3	23.08	24.90	27.14	29.49	31.86
Q4	26.11	28.16	30.69	33.35	36.03
Q5	29.13	31.42	34.25	37.22	40.21

Table 37. *Historical access to electricity and natural gas by region*

	1973	1985	1993	1997	2003	2008	2010	2011
Access to electricity								
Rural	15.4	40.8	71	77.2	83.1	89.2	90.7	89.9
Urban	88.6	95.1	99.2	99.6	99.8	99.4	99.6	99.5
Total	61.9	78.2	91.2	93.8	95.6	97.2	97.7	97.4
References	(Fresneda, 2009)	(Fresneda, 2009)	(Fresneda, 2009)	(Parra Torrado, 2011)	(Parra Torrado, 2011)	(Parra Torrado, 2011)	(DANE, 2010)	(DANE, 2011)
Access to natural gas								
Rural	0	0	N.A.	0.8	2.4	3.6	5.1	4
Urban	0	0	N.A.	25.1	46.8	61.2	65.3	65.6
Total	0	0	N.A.	18.9	35.9	47.4	52.4	52.1
References		(Coronado Arango, 2005)		(Parra Torrado, 2011)	(Parra Torrado, 2011)	(Parra Torrado, 2011)	(DANE, 2010)	(DANE, 2011)

Table 38. *Gompertz parameters to model the access to electricity and natural gas*

	Electricity		Natural gas	
	Rural	**Urban**	**Rural**	**Urban**
Parameter κ_1	100	100	100	100
Parameter κ_2	2.18446	0.13653	6.37273	5.99393
Parameter κ_3	0.08488	0.10477	0.02833	0.08802
Coefficient of determination R^2	99.05%	97.49%	93.31%	99.75%

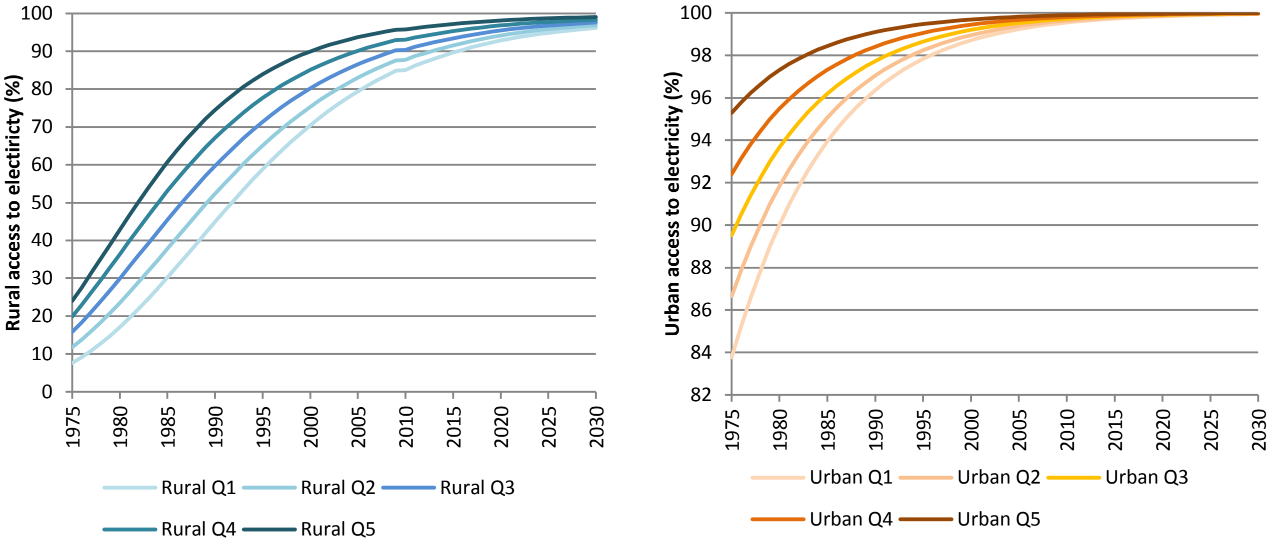


Figure 70. *Estimated access to electricity by region and quintile*

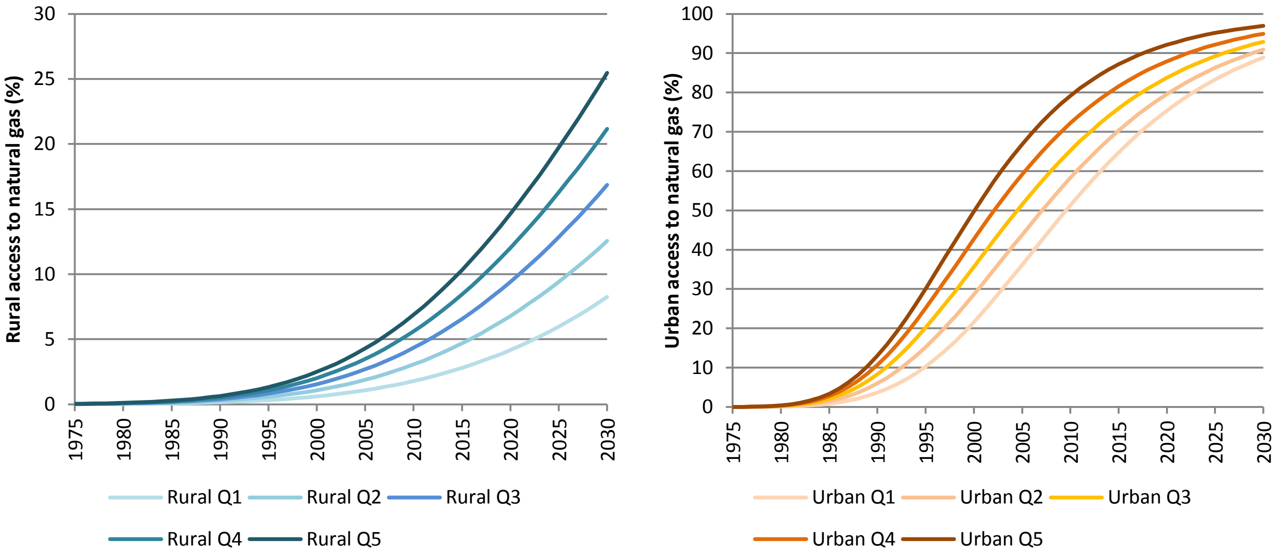


Figure 71. *Estimated access to natural gas by region and quintile*

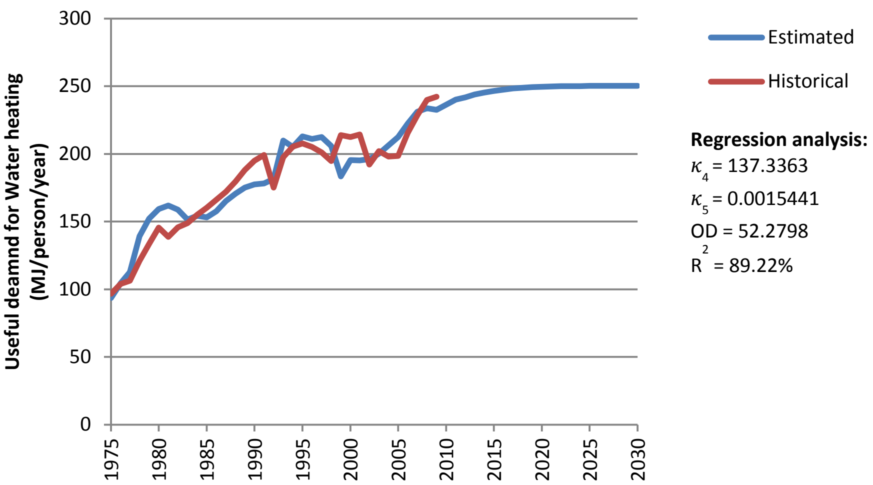
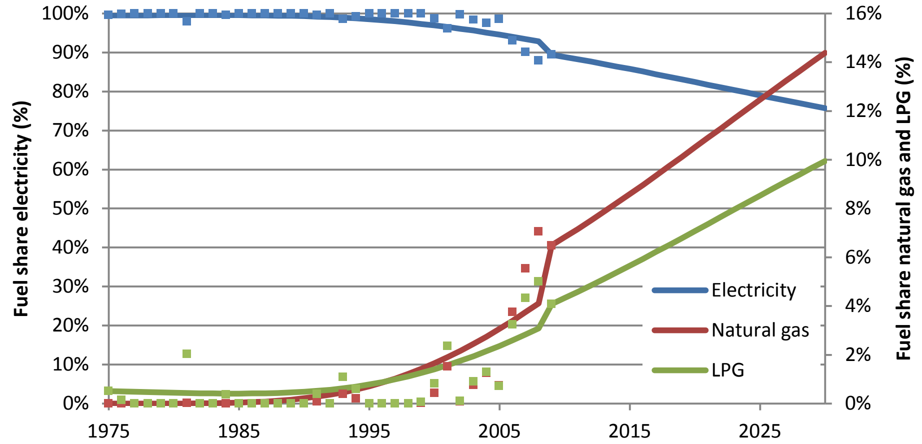


Figure 72. *Historical and estimated useful demand for water heating*



Regression analysis

k_f Electricity	4.84E-07
k_f Natural gas	9.24E-06
k_f LPG	3.44E+00
γ	2.41E-02
θ	2.80E-02
R^2 Electricity	68.25%
R^2 Natural gas	70.90%
R^2 LPG	60.44%

Figure 73. *Historical and estimated fuel shares for water heating*

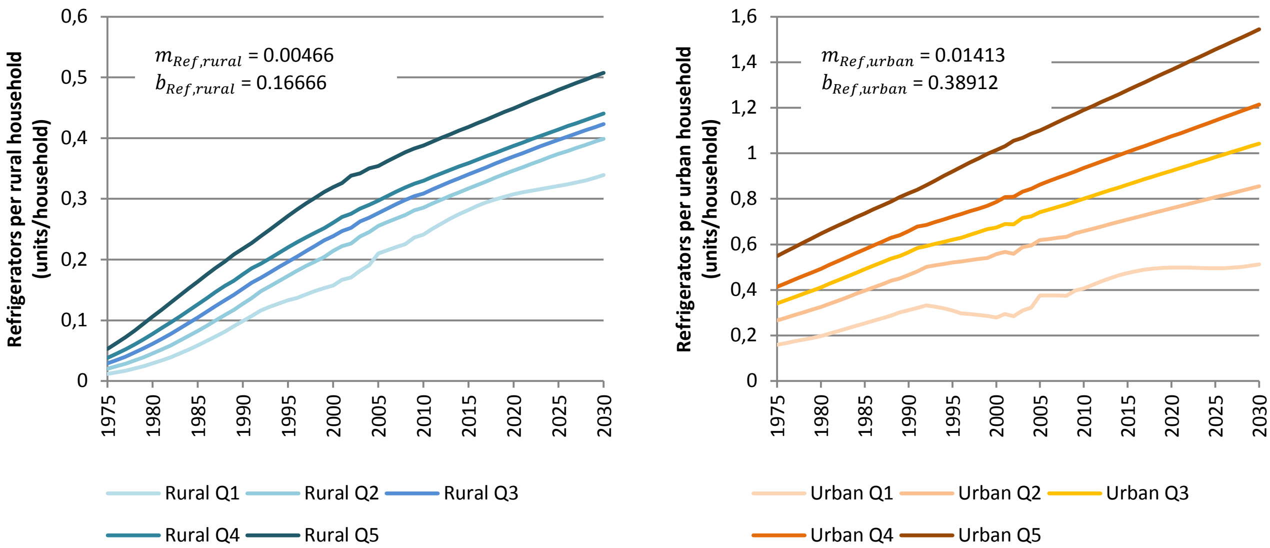
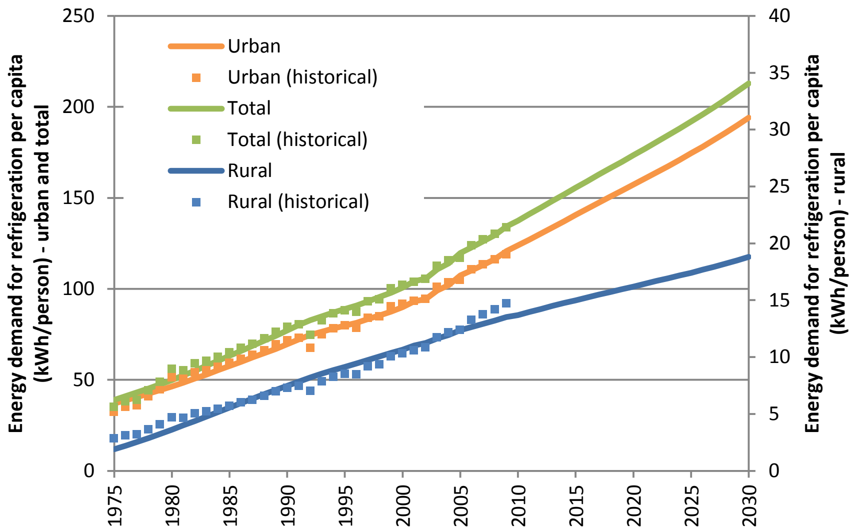


Figure 74. *Ownership of refrigerators by region and quintile*



Regression analysis

α_{Ref}	501.4419
β_{Ref}	0.9639
$UECm_{Ref}$	600

Gompertz	Rural	Urban
κ_6	5	5
m_{Ref}	0.0046	0.0141
b_{Ref}	0.1666	0.3891
d_{Ref}	27.9541	27.9560
e_{Ref}	104.2357	104.2357
R^2	96.38%	98.92%

Figure 75. *Energy demand for refrigeration per capita (historical vs. estimations)*

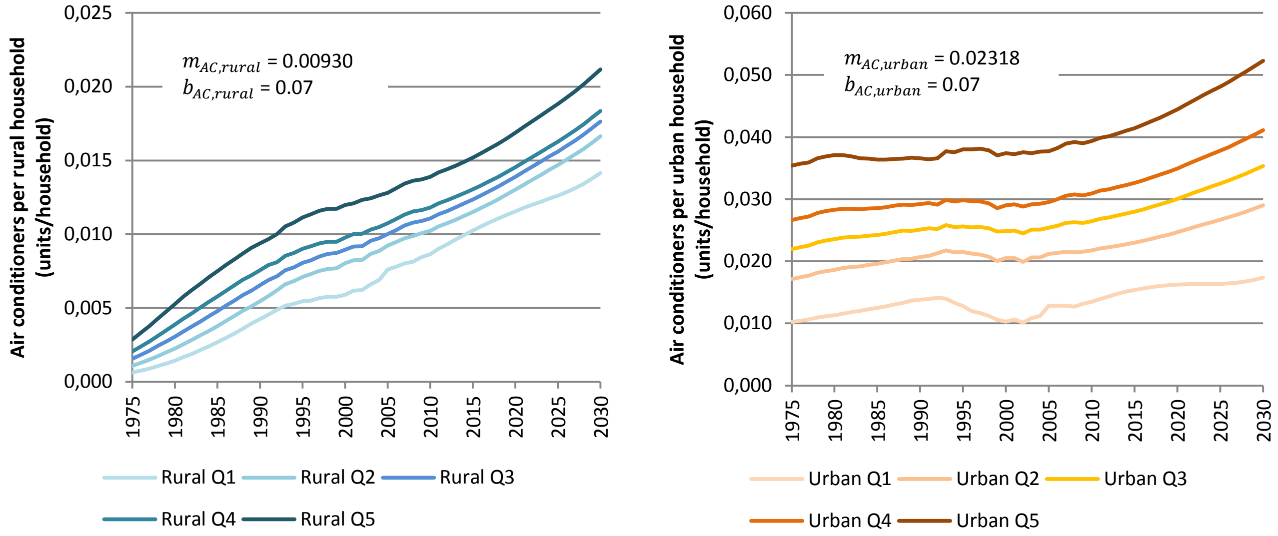
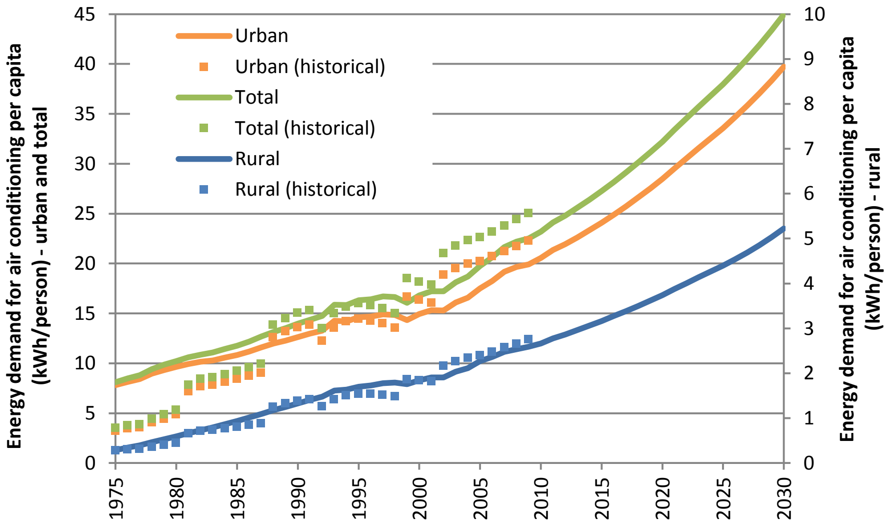


Figure 76. *Ownership of air conditioners by region and quintile*



Regression analysis

COP	3.5 (in 2050)	
$COP_{Reference}$	2.8 (in 2009)	
Parameters	**Rural**	**Urban**
κ_6, κ_7	0	0
m_{AC}	0.0093	0.02318
b_{AC}	0.07	0.07
R^2	96.06%	77.80%

Figure 77. *Energy demand for air conditioning per capita (historical vs. estimations)*

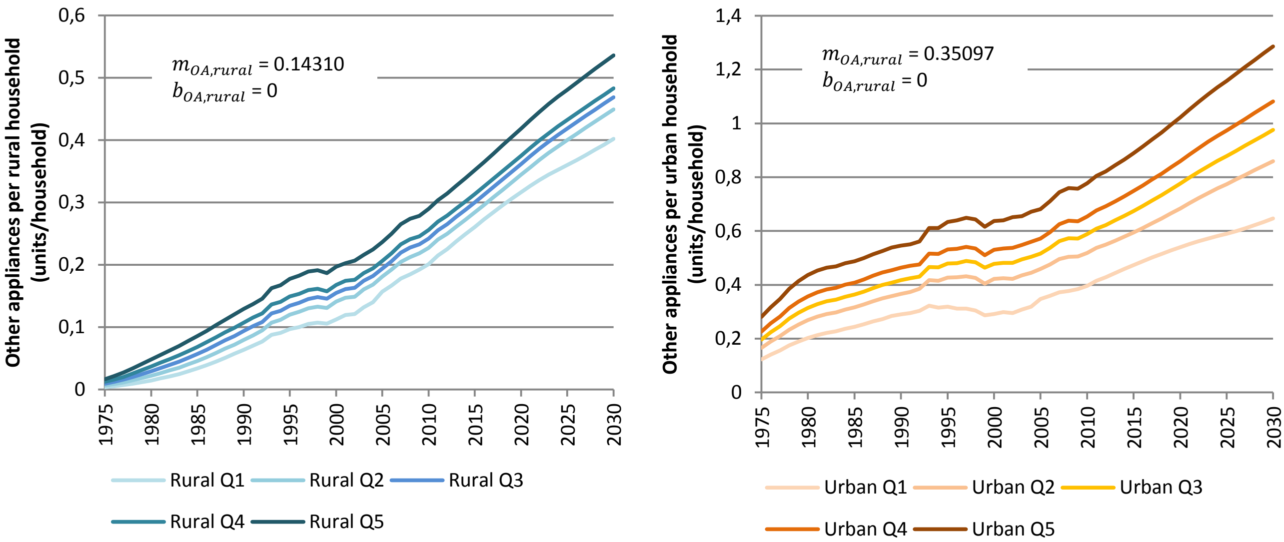
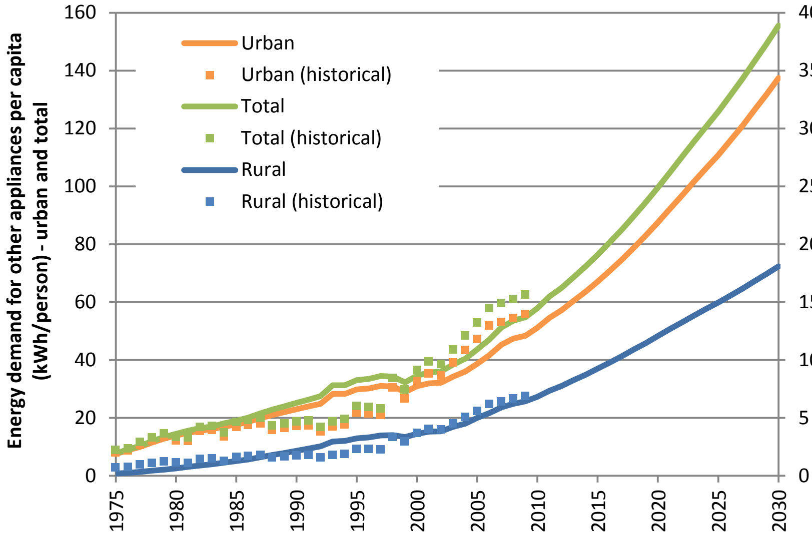


Figure 78. *Ownership of other appliances by region and quintile*

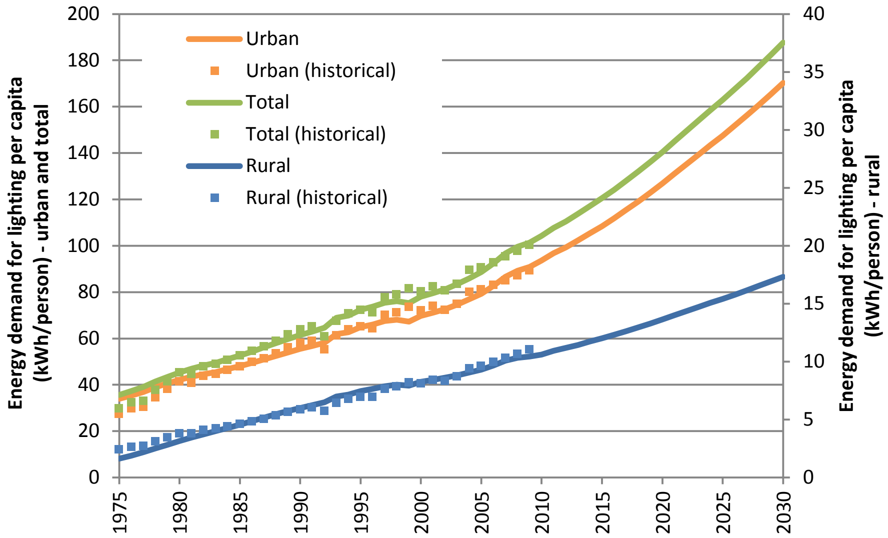


Regression analysis

C_{OA1}	148.39815
C_{OA2}	786.51005

Gompertz	Rural	Urban
κ_6	2	2
κ_7	0.23185	0.21444
m_{OA}	0.14310	0.35097
b_{OA}	0	0
R^2	89.13%	83.09%

Figure 79. *Energy demand for other appliances per capita (historical vs. estimations)*



Regression analysis

	Rural	Urban
LHF_r	0.431292	1.251358
R^2	97.25%	97.4%

Figure 80. *Energy demand for lighting per capita (historical vs. estimations)*

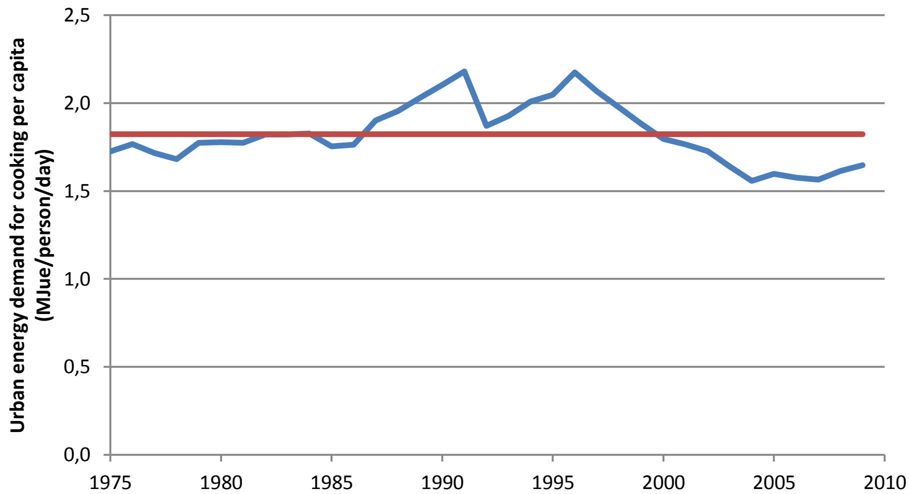


Figure 81. *Historical urban energy demand for cooking per capita*

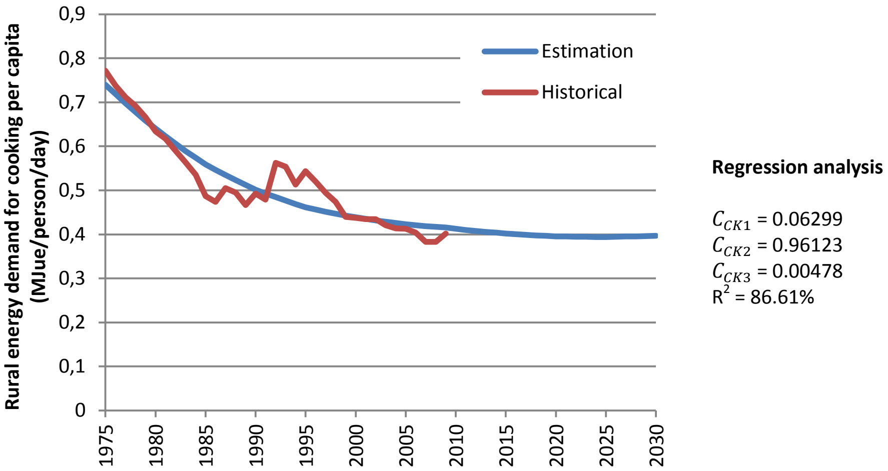


Figure 82. *Historical and estimated rural energy demand for cooking per capita*

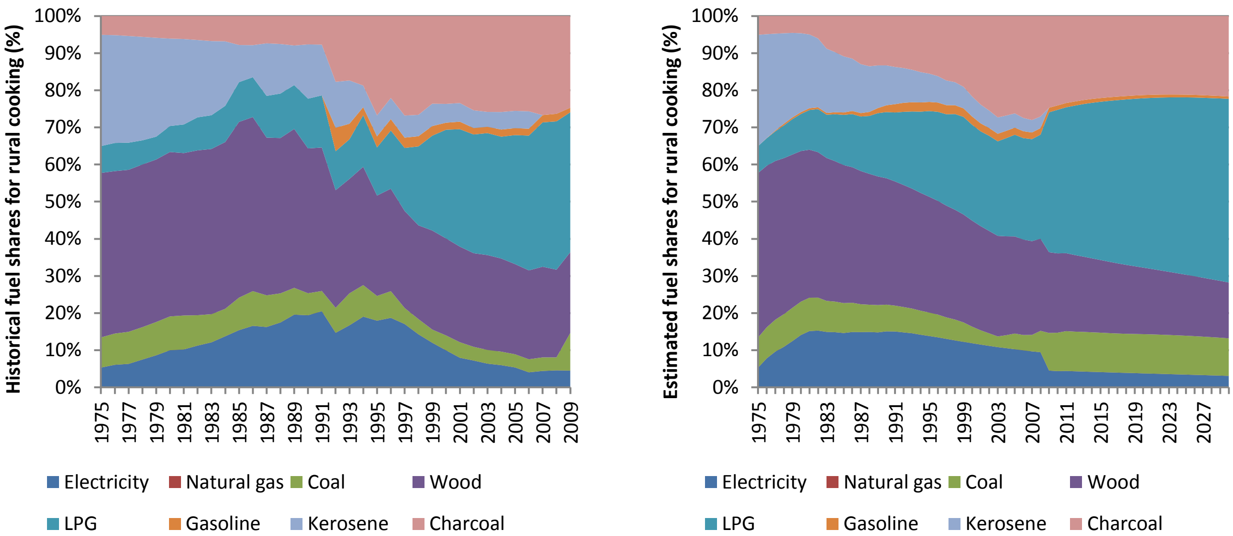


Figure 83. *Historical and estimated fuel shares for rural cooking*

Table 39. *Model parameters to estimate fuel shares for rural cooking*

Fuel	γ	k_f	θ	R^2
Electricity	5.28591	0.47499	0.03130	53.10%
Natural gas	5.28591	2.22007	0.00000	100.00%
Coal	5.28591	1.54585	0.50000	80.40%
Wood	5.28591	1.61729	0.01740	76.23%
LPG	5.28591	0.14489	0.02608	71.43%
Gasoline	5.28591	0.32915	0.03300	55.65%
Kerosene	5.28591	1.12338	0.06618	92.86%
Charcoal	5.28591	0.32906	0.03610	78.65%

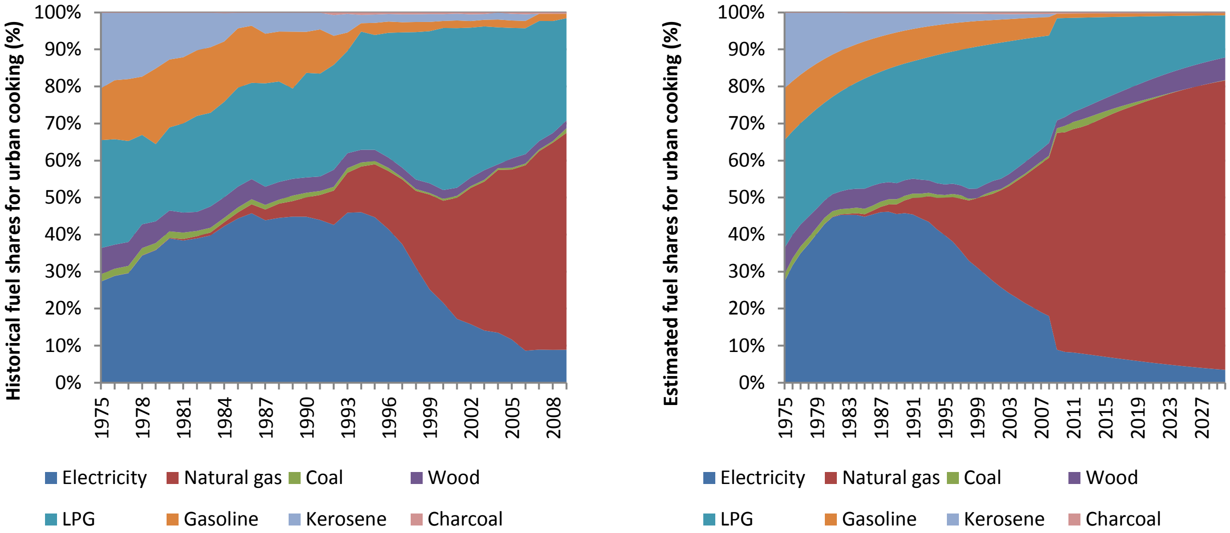


Figure 84. *Historical and estimated fuel shares for urban cooking*

Table 40. *Model parameters to estimate fuel shares for urban cooking*

Fuel	γ	k_f	θ	R^2
Electricity	2.84822	0.28248	0.07738	80.47%
Natural gas	2.84822	0.11892	0.14616	89.44%
Coal	2.84822	0.96167	0.51704	89.53%
Wood	2.84822	0.13601	0.12188	86.21%
LPG	2.84822	0.11630	0.07437	67.93%
Gasoline	2.84822	0.42613	0.03736	53.86%
Kerosene	2.84822	1.14088	0.09420	96.24%
Charcoal	2.84822	1.09590	0.03696	30.53%

Table 41. *Results of the regression analysis of the energy demand by fuel for various sectors*

	Agriculture				Commercial				Industrial				Transport by air				Transport by rail				Transport by river			
	θ	ξ_1	ξ_2	R^2	θ	ξ_1	ξ_2	R^2	θ	ξ_1	ξ_2	R^2	θ	ξ_1	ξ_2	R^2	θ	ξ_1	ξ_2	R^2	θ	ξ_1	ξ_2	R^2
Bagasse									0.01	0.00	0.11	0.77												
Biodiesel				a																				
Bioethanol				a																				
Charcoal												b												
Coal									0.02	0.00	1.99	0.88					0.00	0.00	-6.03	0.86				
Coke									0.14	0.00	0.72	0.57												
Diesel	0.02	0.00	2.15	0.88	0.15	-3.17	1.06	0.78	0.18	-0.21	1.34	0.86								b				b
Electricity	0.00	-148.21	88.88	0.75	0.00	-15.85	10.24	0.98	0.00	-11.77	11.26	0.99									0.15	0.00	0.31	0.80
Fuel Oil				b				b	0.00	0.00	-47.74	0.90								b	0.05	-2.15	0.94	0.79
Gasoline	0.09	-0.88	0.52	0.67					0.09	-1.68	0.93	0.82	0.00	-5.99	-5.08	0.90				b	0.90	-0.70	0.88	0.73
Industrial gas									0.69	-0.10	0.93	0.64												
Kerosene	0.01	-38.93	22.14	0.95				b				b	0.00	0.00	65822.39	0.70								
LPG					0.73	-0.42	1.00	0.92	0.43	-0.54	1.26	0.94												
NG					0.09	-0.70	1.36	0.98	1.00	-0.06	1.59	0.87												
Non energy												b												
Oil	0.24	-1.22	1.48	0.91	0.00	-0.24	5.19	0.98	0.77	-1.83	2.63	0.63									0.38	-1.32	1.85	0.99
Refinery gas												b												
Waste									0.15	0.00	1.11	0.77												
Wood				b								b												

a. Not sufficient years to evaluate the regression analysis. It is assumed that the demand for bioethanol and biodiesel in the agricultural sector remains constant with the value of year 2009.
b. Coefficient of determination lower than 60%. Future demand is assumed to be the average of the last ten years if available. If not available, it is used the average of available data

Table 42. *Assumed energy demand by sector in fuel in cases where regression was not satisfactory*

Th. TOE	Agriculture	Commercial	Industrial	Transport by air	Transport by rail	Transport by river
Biodiesel	29.11					
Bioethanol	0.24					
Charcoal			9.74			
Diesel					29.12	661.01 in 2010, 1464.31 in 2030
Fuel oil	0.48	1.51			2.14	
Gasoline					0.00	
Kerosene		0.00	96.49			
Non energy			325.41			
Refinery gas			0.00			
Wood	332.01		10.43			

Table 43. *Assumptions for power generation technologies*

Power technologies	Available in current portfolio	Available in future portfolio	Installed capacity in 2009 (MW)[6]	Lifetime (years)	Construction time (years)	Capacity factor (%)	Capacity credit (%)	Capital cost[9] (US$2009/kW)			O&M cost (US$2009/kW)			Electrical efficiency[10] (%) Heat co-product efficiency in brackets: Currently installed units[6]	New units		
								2009	2020	2030	2009	2020	2030	2009	2009	2020	2030
Natural gas combined cycle	✓	✓	0	30[1]	2[1]	0.85[1]	100	700[2]	700[2]	700[2]	25[2]	25[2]	25[2]	-	57[2]	59[2]	61[2]
Natural gas simple cycle GT[15]– Large	✓	✓	2478	30[1]	2[1]	0.85[1]	100	400[2]	400[2]	400[2]	20[2]	20[2]	20[2]	38.1	36[2]	38[2]	40[2]
Simple cycle gas turbine GT[15]– Small	✓	✓	628.84	30[1]	2[1]	0.85[1]	100	400[2]	400[2]	400[2]	20[2]	20[2]	20[2]	30.9	31[6]	31[6]	31[6]
Natural gas reciprocating engine	✓	✓	15.25	30[1]	2[1]	0.85[1]	100	443[4]	443[4]	443[4]	20[4]	20[4]	20[4]	30.9	31[6]	31[6]	31[6]
Hydro power plant – Large	✓	✓	8525	50[2]	4[2]	Variable[3a]	85[11]	1860[2]	1900[2]	2050[2]	45[2]	46[2]	49[2]	84	84[6]	84[6]	84[6]
Hydro power plant – Small	✓	✓	518.8	50[2]	4[2]	Variable[3b]	85[11]	3130[2]	3150[2]	3160[2]	59[2]	60[2]	60[2]	84	84[6]	84[6]	84[6]
Coal power plant – Large	✓	✓	990	40[1]	4[1]	0.85[1]	100	1400[2]	1400[2]	1400[2]	44[2]	44[2]	44[2]	38.1	35[2]	35[2]	35[2]
Coal power plant – Small	✓	✓	53.24	40[1]	4[1]	0.85[1]	100	2032[5]	2032[5]	2032[5]	44[2]	44[2]	44[2]	30.9	31[6]	31[6]	31[6]
Diesel reciprocating engine	✓	✓	7.06	30[1]	2[1]	0.85[1]	100	443[4]	443[4]	443[4]	20[4]	20[4]	20[4]	30.9	31[6]	31[6]	31[6]
Wind turbine	✓	✓	18.4	20[2]	1.5[2]	Variable[3c]	20[12]	1470[2]	1390[2]	1370[2]	22[2]	21[2]	21[2]	100	100[2]	100[2]	100[2]
Biomass CHP – Medium	✓	✓	315.34	25[2]	2[2]	Variable[3d]	90[13]	2830[2]	2790[2]	2590[2]	106[2]	102[2]	97[2]	4.9 (37.8)[7]	35 (35)[2]	35 (35)[2]	35 (35)[2]
Biomass CHP – Small	×	✓	0	25[2]	2[2]	Variable[3e]	90[13]	4710[2]	4540[2]	4310[2]	177[2]	170[2]	162[2]	-	30 (35)[2]	30 (35)[2]	30 (35)[2]
Biomass co-firing	×	✓	0	40[2]	2[2]	0.7[2]	100[14]	550[2]	530[2]	510[2]	21[2]	20[2]	19[2]	-	37[2]	37[2]	37[2]
Syngas co-firing in simple cycle GT[15]	×	✓	0	30[2]	2[2]	0.7[2]	100[14]	550[2]	530[2]	510[2]	21[2]	20[2]	19[2]	-	36[8]	38[8]	40[8]
Syngas co-firing in combined cycle GT[15]	×	✓	0	30[2]	2[2]	0.7[2]	100[14]	550[2]	530[2]	510[2]	21[2]	20[2]	19[2]	-	57[8]	59[8]	61[8]
Biogas reciprocating engine	×	✓	0	25[2]	2[2]	0.7[2]	90[13]	2340[2]	2230[2]	2110[2]	89[2]	85[2]	80[2]	-	30 (35)[2]	30 (35)[2]	30 (35)[2]

[1] (IEA-NEA, 2010)
[2] (IEA, 2012), using values corresponding to Africa
[3a] Assumed profile availability as described in Section B.1.6.4. For LCOE calculations it is used the average of 1998-2011, i.e. 50.01% (XM, 2013)
[3b] Assumed profile availability as described in Section B.1.6.4. For LCOE calculations it is used the average of 1998-2011, i.e. 50.01% (XM, 2013)
[3c] Assumed profile availability as described in Section B.1.6.4. For LCOE calculations it is used the average of 2004-2011, i.e. 34.30% (XM, 2013)
[3d] Assumed profile availability as described in Section B.1.6.4. For LCOE calculations it is used the average of 2004-2011, i.e. 59.19% (XM, 2013)
[3e] Assumed profile availability as described in Section B.1.6.4.
[4] (Thermoflow, 2011), cost database
[5] Down-scaled using the equation $Cost_{Small} = Cost_{Large}\left(600MW_{Large}/50MW_{Large}\right)^{0.15}$
[6] (UPME, 2011a)
[7] Numbers corresponding to bagasse-fuelled CHP steam power plants in sugar industry
[8] Assumed to respectively match the efficiencies of simple and combined cycles without co-firing
[9] It includes owner's costs but exclude interest during construction
[10] Electrical efficiency based on the lower heating value (LHV)
[11] Capacity credit for hydro power is close to 100% according to (Sims, 2011). It is assumed a value of 85%, in line with (Mora Alvarez, 2012)
[12] Capacity credit for wind power ranges between 5-40% depending on market and location and decreases with increasing penetration level (Sims, 2011). It is assumed a value of 20%, in line with (Mora Alvarez, 2012)
[13] Capacity credit for bioenergy is close to 100% according to (Sims, 2011). It is assumed a value of 90%, in line with (DLR, 2005).
[14] Capacity credit for bioenergy is close to 100% according to (Sims, 2011). It is assumed that since co-firing occurs in a thermal power plant, it has the same capacity credit of a thermal power plant, i.e. 100%
[15] GT stands for gas turbine

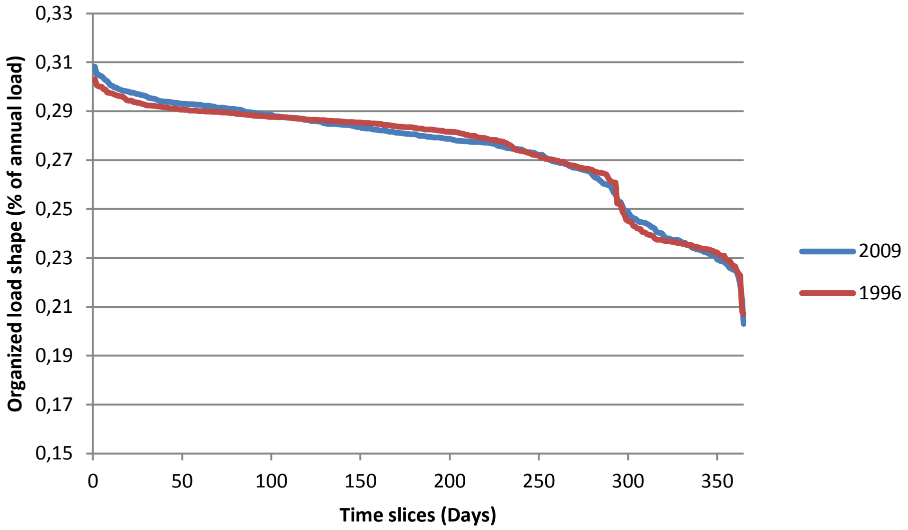


Figure 85. *Organized energy load shape (% of annual load), taken from (XM, 2013)*

Table 44. *Exogenous capacity added by technology until 2019*

Addition	Capacity added (MWe)	Technology	Year	Reference
Porce III	660	Hydro power plant - Large	2012	(Portafolio, 2011; UPME, 2009)
Amoya	78	Hydro power plant - Large	2012	(El Colombiano, 2013; UPME, 2009)
Termo Flores	163	Natural gas simple cycle - Large	2012	(IFC, 2008; UPME, 2009)
Amaime	19.9	Hydro power plant - Small	2012	(Portafolio, 2011a; UPME, 2009)
Termocol	202	Natural gas simple cycle - Large	2014	(BNamericas, 2012; UPME, 2009)
Gecelca III	150	Coal power plant - Large	2014	(UPME, 2009)
Popal	20	Hydro power plant - Small	2014	(UPME, 2009)
Bajo Tulua	20	Hydro power plant - Small	2014	(UPME, 2009)
Tunjita	20	Hydro power plant - Small	2014	(UPME, 2009)
Cucuana	60	Hydro power plant - Large	2015	(UPME, 2009)
El Quimbo	420	Hydro power plant - Large	2015	(Portafolio, 2012; UPME, 2009)
Sogamoso	800	Hydro power plant - Large	2015	(UPME, 2009)
Gecelca 3.2	250	Coal power plant - Large	2016	(UPME, 2009)
San Miguel	42	Hydro power plant - Large	2016	(Sector Electricidad, 2012; UPME, 2009)
Rio Ambeima	45	Hydro power plant - Large	2016	(Sector Electricidad, 2012; UPME, 2009)
Carlos Lleras Restrepo	78	Hydro power plant - Large	2016	(Sector Electricidad, 2012; UPME, 2009)
Termotasajero II	160	Coal power plant - Large	2016	(BNamericas, 2013; UPME, 2009)
Ituango Fase I	1200	Hydro power plant - Large	2017	(UPME, 2009)
Termonorte	88	Natural gas simple cycle - Large	2018	(Portafolio, 2013; UPME, 2009)
Ituango Fase II	1200	Hydro power plant - Large	2019	(UPME, 2009)
Porvenir II	352	Hydro power plant - Large	2019	(UPME, 2009)

Table 45. *Capacity exogenously added to comply with the biogas and landfill gas targets in Scenarios I and II*

Capacity exogenously added to comply with targets (MWe)	Scenario II				Scenario II			
	2015	2020	2025	2030	2015	2020	2025	2030
Reciprocating engines fuelled with biogas from animal waste	8,70	58,82	109,63	152,30	8,70	58,82	109,63	152,30
Reciprocating engines fuelled with landfill gas and biogas from animal waste/wastewater	8,45	50,76	92,90	135,21	3,75	22,60	41,27	60,12

Table 46. *Maximum annual capacity addition by technology*

Technology	Biomass resource	Maximal annual capacity addition (MWe)
Natural gas combined cycle	-	575
Natural gas simple cycle – Large	-	575
Natural gas simple cycle – Small	-	100
Natural gas reciprocating engine	-	100
Hydro power plant – Large	-	1552
Hydro power plant – Small	-	60
Coal power plant – Large	-	410
Coal power plant – Small	-	100
Diesel reciprocating engine	-	100
Wind turbine	-	50
Biomass CHP – Small	Bagasse from jaggery cane	25.4
Biomass co-firing	Wood and forestry residues	99
Syngas co-firing in simple cycle GT	Wood and biomass residues	123.9
Biomass CHP – Medium	Rice husk	3.0
	Bagasse and leaves at large-scale	43.2
	Palm residues	43.1
	Wood and forestry residues	96.1
Biogas reciprocating engine	Biogas from biodiesel plants	6.6[1]
	Biogas from wastewater plants	0.07
	Biogas from animal waste	8.7
	Landfill gas	3.6

Notes:
[1] Assuming a FEF factor of 100% given that 100% of this resource is targeted to be used by 2030.

Table 47. *Fuel assumptions*

Fuel Name	Fuel Grouping	Net Energy Content (MJ)	per Physical Unit	LHV/HHV Ratio	Density (kg/liter)	% Carbon Content[a]	% Sulfur Content[a]	% Nitrogen Content[a]	% Ash Content[a]	% Moisture Content[a]	% Methane Content[a]	% Oxidized[a]	% Sulfur Retention	References
Bagasse	Bioenergy	9.316	kg	0.90	0.6000	58.73	0.04	0.38	3.47	46.59	0.00	100	0	Averaged values of data in (Gonzalez-Salazar M. M., 2014a)
Bagasse small scale	Bioenergy	9.316	kg	0.90	0.6000	58.73	0.04	0.38	3.47	46.59	0.00	100	0	Averaged values of data in (Gonzalez-Salazar M. M., 2014a)
Biodiesel	Bioenergy	36950	Ton	0.95	0.8800	76.41	0.00	0.00	0.00	0.00	0.00	99	0	LHV and density taken from (MIT, 2010), carbon content taken from (Agudelo, 2011)
Biogas from animal waste	Bioenergy	21.649	m^3	0.90	0.0011	45.83	0.50	0.00	0.00	0.00	39.06	100	0	(Gonzalez-Salazar M. M., 2014a)
Cane	Bioenergy	7200	Ton	-	-	-	-	-	-	-	-	-	-	(Patzek, 2005; BNDES - CGEE, 2008; Nogueira, 2008)
Cane leaves and top	Bioenergy	10.082	kg	0.90	1.0000	50.06	0.09	0.92	9.57	41.00	0.00	100	0	Averaged values of data in (Gonzalez-Salazar M. M., 2014a)
Cane leaves small scale	Bioenergy	10.082	kg	0.90	1.0000	50.06	0.09	0.92	9.57	41.00	0.00	100	0	Averaged values of data in (Gonzalez-Salazar M. M., 2014a)
Cane small scale	Bioenergy	7200	Ton	-	-	-	-	-	-	-	-	-	-	(Patzek, 2005; BNDES - CGEE, 2008; Nogueira, 2008)
Charcoal	Bioenergy	28880	Ton	0.90	0.2500	88.00	0.00	1.40	1.00	5.00	0.00	100	0	(Heaps, 2012)
Coal and Coal Products	Coal	29310	Ton	0.95	1.3300	74.60	2.00	1.50	8.00	5.00	0.00	98	30	(Heaps, 2012)
Crude NGL and Feedstocks	Oil	41870	Ton	0.95	0.8740	83.50	1.00	1.00	0.05	0.00	0.00	99	0	(Heaps, 2012)
Diesel	Oil	43856	Ton	0.95	0.8370	85.96	0.05	0.00	0.01	0.00	0.00	99	0	LHV taken from (UPME, 2010), carbon content from (Agudelo, 2011), sulfur and lead content from (Ecopetrol, 2013), everything else from (Heaps, 2012)
Ethanol	Bioenergy	26700	Ton	0.90	0.7920	52.17	0.00	0.00	0.00	0.00	0.00	100	0	LHV taken from (MIT, 2010), carbon content calculated from formula C_2H_6O, everything else from (Heaps, 2012)
Forestry and wood residues	Bioenergy	15080	Ton	0.90	0.8918	43.80	0.00	0.09	0.00	18.70	0.00	100	0	LHV and density from (Gonzalez-Salazar M. M., 2014a), everything else from (Heaps, 2012)
Gas landfill and water treat.	Bioenergy	16.993	m^3	0.90	0.0013	39.96	0.50	0.00	0.00	0.00	26.71	100	0	(Gonzalez-Salazar M. M., 2014a)
Gasoline	Oil	44422	Ton	0.95	0.7400	84.60	0.03	0.00	0.00	0.00	0.00	99	0	LHV taken from (UPME, 2010), sulfur and lead content from (Ecopetrol, 2013), everything else from (Heaps, 2012)
Heat	Other fuels	1	MJ	1.00	-	-	-	-	-	-	-	-		(Heaps, 2012)
Industrial gas	Gas	39.513	m^3	0.90	0.0008	73.40	0.00	0.03	0.00	0.00	100	100	0	Assumed to be the same as natural gas
Kerosene	Oil	44750	Ton	0.95	0.8100	85.00	0.04	0.98	0.00	0.00	0.00	99	0	(Heaps, 2012)
LPG	Oil	47310	Ton	0.95	0.5400	82.00	0.00	0.00	0.00	0.00	0.00	100	0	(Heaps, 2012)
Metallurgical Coke	Coal	26380	Ton	0.95	1.3500	85.00	0.75	1.00	2.75	5.00	0.00	98	0	(Heaps, 2012)
Natural Gas	Gas	39.513	m^3	0.90	0.0008	73.40	0.00	0.03	0.00	0.00	100	100	0	(UPME, 2010), assumed to be 100% methane
Other Energy	Other fuels	1	MJ	1.00	-	-	-	-	-	-	-	-	-	(Heaps, 2012)
Palm Fresh Fruit Bunches	Bioenergy	16.608	kg	0.90	1.0000	0.00	0.00	0.00	0.00	0.00	0.00	0	0	Averaged values of data in (Gonzalez-Salazar M. M., 2014a)
Palm oil	Bioenergy	36.500	kg	-	-	-	-	-	-	-	-	-	-	(Fehrenbach, 2007)
Palm residues	Bioenergy	11.239	kg	0.90	1.0000	49.80	0.06	0.88	8.40	37.73	0.00	100	0	Averaged values of data in (Gonzalez-Salazar M. M., 2014a)
Petroleum Products	Oil	44800	Ton	0.95	0.7400	84.60	0.04	0.60	0.00	0.00	0.00	99	0	(Heaps, 2012)
Refinery Feedstocks	Oil	44800	Ton	0.95	0.8740	83.50	1.00	1.00	0.00	0.00	0.00	99	0	(Heaps, 2012)
Refinery gas	Gas	39.513	m^3	0.90	0.0008	73.40	0.00	0.03	0.00	0.00	100	100	0	Assumed to be the same as natural gas
Renewable Diesel	Bioenergy	44100	Ton	0.95	0.7800	85.04	0.00	0.00	0.00	0.02	0.00	0	0	(NESTE OIL, 2014; Sotelo-Boyás, 2012)
Residual Fuel Oil	Oil	40190	Ton	0.95	0.9500	84.40	2.00	1.00	0.08	0.00	0.00	99	0	(Heaps, 2012)
Rice Husk	Bioenergy	14.007	kg	0.90	1.0000	51.35	0.08	0.29	19.59	9.93	0.00	100	0	(Escalante, 2011)
Syngas	Bioenergy	11658	Ton	0.95	0.0002	44.40	0.00	4.33	0.00	20.62	6.89	0	0	Composition taken from (SGC, 2011; Risø DTU, 2010) for Milena gasifier, LHV calculated in Aspen Hysys®
Wood	Bioenergy	15500	Ton	0.90	0.7100	43.80	0.00	0.09	0.00	15.00	0.00	100	0	(Heaps, 2012)
Wood pellets	Bioenergy	16900	Ton	0.90	0.7100	43.80	0.08	0.00	1.50	10.00	0.00	100	0	(IEA Bioenergy, 2011)

[a] % by weight

Table 48. *Characteristics of conversion processes (Part I)*

Conversion process	Inputs		Outputs		Energy efficiency	Emissions	References
Sugar cane mill	Cane w/ leaves	1 ton	Bagasse Cane juice Tops and leaves	0.2588 ton [a] 0.5182 ton [a] 0.2229 ton [a]	100%		[a] (Gonzalez-Salazar M. M., 2014a)
	Cane w/ leaves	1 MJ	Bagasse Cane juice Tops and leaves	0.3348 MJ [a] 0.3528 MJ [a] 0.3122 MJ [a]			
Sugar factory	Cane w/o leaves	1 Ton	Sugar	0.12 Ton [a]	32.76% [b]		[a] (BID-MME, Consorcio CUE, 2012) [b] Calculated as the energy content in sugar as output divided by the energy content in cane as input
Sugar factory with annexed distillery	Cane w/o leaves	1 Ton	Sugar Bioethanol	0.093 Ton [a] 0.019 Ton [a]	33.37% [b]		[a] (BID-MME, Consorcio CUE, 2012) [b] Calculated as the energy content in sugar and bioethanol as outputs divided by the energy content in cane as input
Bioethanol distillery (autonomous)	Cane juice	1 ton	Bioethanol	0.095 ton [a]	51.62%	• Biogenic CO_2 (Ton/TJ-Ethanol): 36.2593 [c] • Methane (kg/ TJ-Ethanol): 5.3436 [c]	[a] Conditions and characteristics corresponding to a process with microbial fermentation, distillation and dehydration producing 80 liters-ethanol/ton-cane w/o leaves (assumed constant), data taken from (Ferreira-Leitao, 2010) [b] Electricity in this case is treated as an auxiliary fuel in LEAP, i.e. energy consumed per unit of energy produced in a process. It is energy consumed but not converted and therefore not included in the calculation of the overall energy efficiency of the process. It is assumed 47 MJ/l-ethanol, taken from (Macedo I. L., 2004) [c] (BID-MME, Consorcio CUE, 2012), methane is assumed to be released to the atmosphere
	Cane juice Electricity	1 MJ [a] 0.027 MJ [b]	Bioethanol	0.5162 MJ			
Palm oil mill	Fresh fruit bunches	1 ton	Palm oil Kernel oil Palm residues Non-usable by-products	0.2138 ton [a] 0.020 [a] 0.4240 ton [a] 0.3422 ton [a]	69.48% [b]		[a] Conditions of the palm mill described in (BID-MME, Consorcio CUE, 2012) [b] Estimated as the energy fraction of the fresh fruit bunches transformed into palm oil and palm residues
	Fresh fruit bunches (FFB)	1 MJ	Palm oil Kernel oil Palm residues Non-usable by-products	0.4314 MJ [a] 0.0040 MJ [a] 0.2634 MJ [a] 0.2648 MJ [a]			
Biodiesel production	Palm oil	1.04 ton	Biodiesel	1 ton [a]	97.33%	Methane (kg/TJ-Biodiesel): 1355.96 [c]	[a] Conditions and characteristics corresponding to a process with oil refining, transesterification and biodiesel purification producing 233.61 liters-biodiesel/ton-FFB (assumed constant), data taken from (BID-MME, Consorcio CUE, 2012) [b] Electricity and heat are treated as auxiliary fuels, data is taken from (Panapanaan, 2009) [c] 1.03 Ton-methane per 100 Ton-FFB (BID-MME, Consorcio CUE, 2012)
	Palm oil Heat Electricity	1.0273 MJ [a] 0.0563 MJ [b] 0.0879 MJ [b]	Biodiesel	1 MJ			

Table 49. *Characteristics of conversion processes (Part II)*

Conversion process	Inputs		Outputs		Energy efficiency	Emissions	References
Gasification of wood	Wood	1 MJ	Syngas	0.8200 MJ	82% [a]		[a] Assumed to be a Milena gasifier as described in (SGC, 2011; Risø DTU, 2010)
Gasification of biomass residues	Biomass residues (including rice husk, cane leaves & tops, bagasse, palm residues, etc.)	1 MJ	Syngas	0.8300 MJ	83% [a]		[a] Assumed to a SilvaGas gasifier as described in (SGC, 2011; Risø DTU, 2010)
Wood pelletization	Wood Electricity	1.2500 MJ [a] 0.0400 MJ [b]	Wood pellets	1 MJ	80% [a]		[a] (IEA Bioenergy, 2011) [b] Electricity in this case is treated as an auxiliary fuel in LEAP. Data is taken from (IEA Bioenergy, 2011)
Renewable diesel production	Palm oil Electricity Natural gas Heat	0.9114 MJ [a] 0.0070 MJ [a] 0.1160 MJ [a] 0.0097 MJ [a]	Renewable diesel Renewable gasoline Renewable LPG	0.9070 MJ [a] 0.0228 MJ [a] 0.0700 MJ [a]	95.77% [a]	• Biogenic CO_2 (Ton/TJ-Ren. diesel): 1.0884 [a] • Natural gas is burned to produce hydrogen. Emissions include: 55.8 ton-CO_2 no biogenic per TJ-natural gas, 20 kg-CO per TJ-natural gas, 1 kg-CH_4 per TJ-natural gas, 5 kg-NMVOC per TJ-natural gas, 150 kg-NOx per TJ-natural gas and 0.1 kg-N_2O per TJ-natural gas [b] • Avoided non-biogenic CO_2 emissions by substituting renewable fuel products for fossil fuels include: i. -73.3 tons non-biogenic CO_2 per TJ of renewable diesel [c] ii. -68.6 tons non-biogenic CO_2 per TJ of renewable gasoline [d] iii. -72.9 tons non-biogenic CO_2 per TJ of renewable LPG [e]	[a] Conditions and characteristics of the NExBTL™ hydrotreated vegetable oil conversion process by the company Neste Oil using palm oil as feedstock are used. Data is taken from (Nikander, 2008; NESTE OIL, 2014; Sotelo-Boyás, 2012) [b] IPCC Tier 1 default emissions for combustion of natural gas in power generation, data taken from (Heaps, 2012) [c] IPCC Tier 1 default emission for combustion of diesel fuel in road vehicles, data taken from (Heaps, 2012) [d] IPCC Tier 1 default emission for combustion of gasoline in road vehicles, data taken from (Heaps, 2012) [e] IPCC Tier 1 default emission for combustion of LPG in households (Heaps, 2012)
Biomethane production from wood	Syngas from wood	1 MJ	Biomethane	0.8048 MJ [a]	80.48% [a]	Avoided non-biogenic CO_2 emissions by substituting biomethane for natural gas:-55.8 tons non-biogenic CO_2 per TJ of biomethane [b]	[a] Characteristics of syngas from a MILENA gasifier, OLGA tar removal and TREMP methanation as described in (Risø DTU, 2010) [b] IPCC Tier 1 default emission for combustion of natural gas in households and services (Heaps, 2012)
Biomethane production from biomass residues	Syngas from biomass residues	1 MJ	Biomethane	0.6867 MJ [a]	68.67% [a]	Avoided non-biogenic CO_2 emissions by substituting biomethane for natural gas:-55.8 tons non-biogenic CO_2 per TJ of biomethane [b]	[a] Characteristics of syngas from the SilvaGas gasifier and the PSI/CTU methanation system as described in (Risø DTU, 2010) [b] IPCC Tier 1 default emission for combustion of natural gas in households and services (Heaps, 2012)
Biomethane production from biogas	Biogas from animal waste	1 MJ	Biomethane	0.93 MJ [a]	93.00% [a]	Avoided methane release: -0.3906 kg-CH_4/kg-biogas [b] Avoided non-biogenic CO_2 emissions by substituting biomethane for natural:-55.8 tons non-biogenic CO_2 per TJ of biomethane [c]	[a] Characteristics of a Pressure Swing Adsorption (PSA) upgrading system as described in (DBFZ, 2012) [b] Assuming a CH_4 content of 63.75% by volume, taken from (Gonzalez-Salazar M. M., 2014a) [c] IPCC Tier 1 default emission for combustion of natural gas in households and services (Heaps, 2012)

Appendix for Chapter C

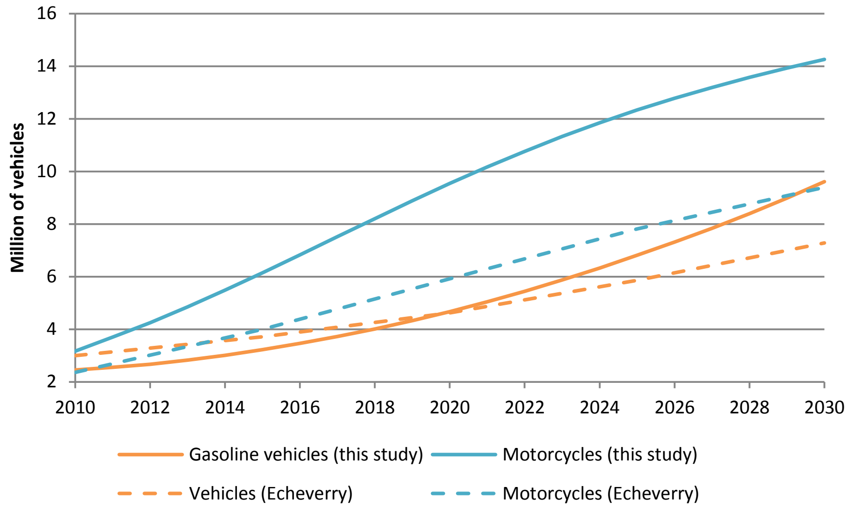


Figure 86. *Results of vehicle ownership and comparison to other studies*

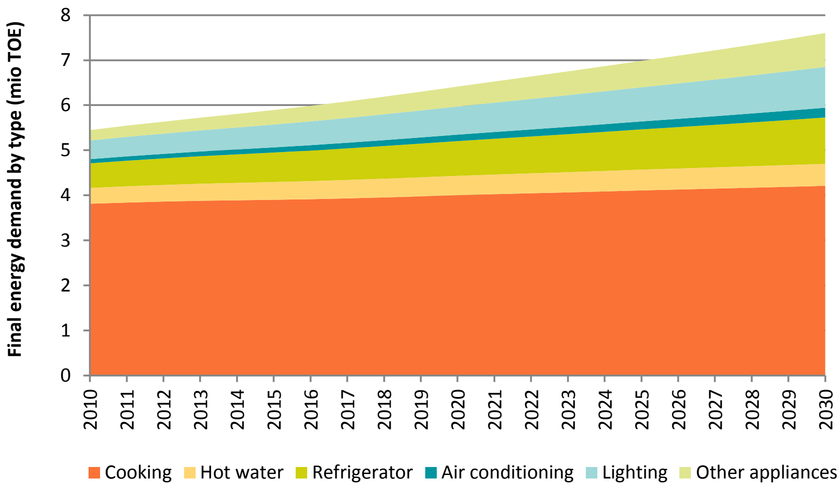


Figure 87. *Final energy demand by type in the residential sector for baseline scenario*

Table 50. *Levelized cost of electricity (LCOE) by technology*[22]

US$2009/MWh	Levelized cost of electricity (LCOE)		
	2009	**2020**	**2030**
Natural gas combined cycle	67.5	66.9	66.9
Natural gas reciprocating engine	73.0	72.6	72.6
Wind power turbine	85.3	77.8	77.0
Natural gas simple cycle - Large	86.0	85.7	85.7
Natural gas simple cycle - Small	86.0	85.7	85.7
Coal power plant - Large	92.6	92.9	92.9
Coal power plant - Small	104.7	104.5	104.5
Hydro power plant - Large	128.8	128.7	137.9
Biomass CHP (medium)	131.4	123.2	117.2
Fuel oil fuelled gas turbine - Small	151.2	150.9	150.9
Hydro power plant - Small	191.1	188.4	188.7
Diesel reciprocating engine	196.9	196.6	196.6
Diesel fuelled gas turbine - Small	244.9	244.6	244.6

[22] Estimated as $LCOE = \frac{\sum_t (Investment_t + O\&M_t + Fuel_t + Decommissioning_t)\cdot(1+r)^{-t}}{\sum_t (Electricity_t)\cdot(1+r)^{-t}}$, according to the equation proposed by (IEA-NEA, 2010)

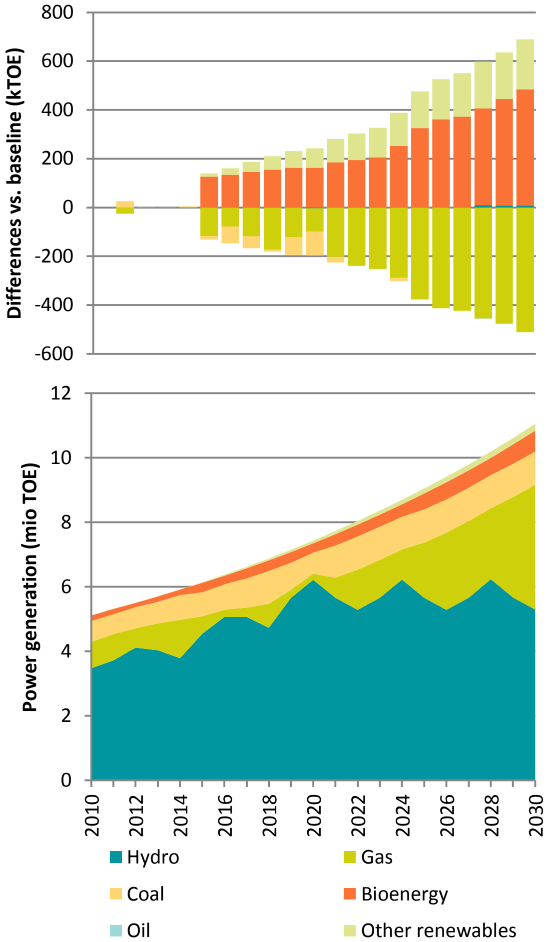


Figure 88. *Power generation by source for Scenario II*

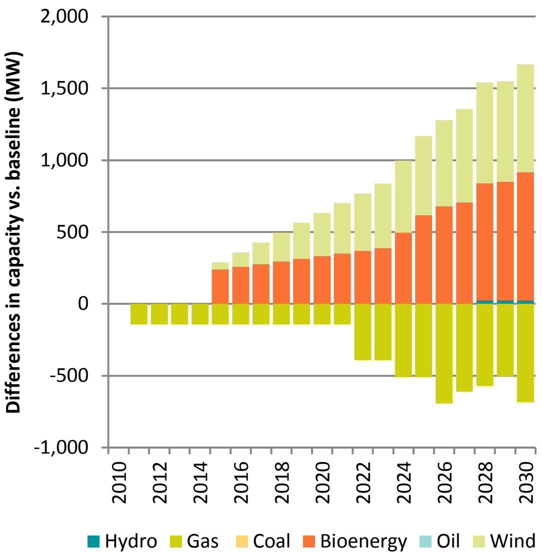


Figure 89. *Differences in installed power generation capacity between Scenario II and baseline scenario*

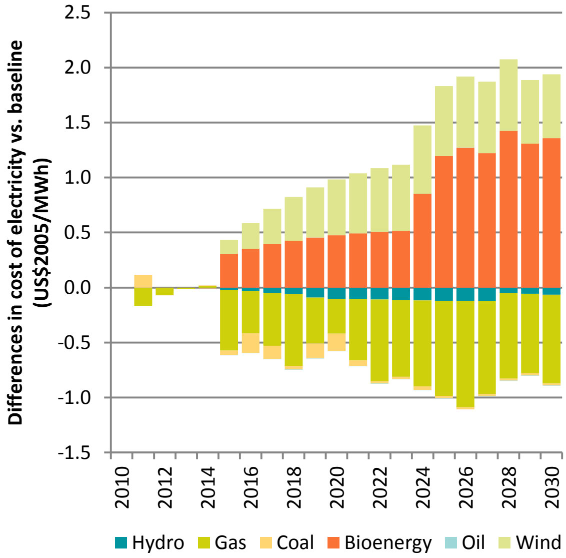


Figure 90. *Differences in cost of electricity by technology between Scenario II and baseline*

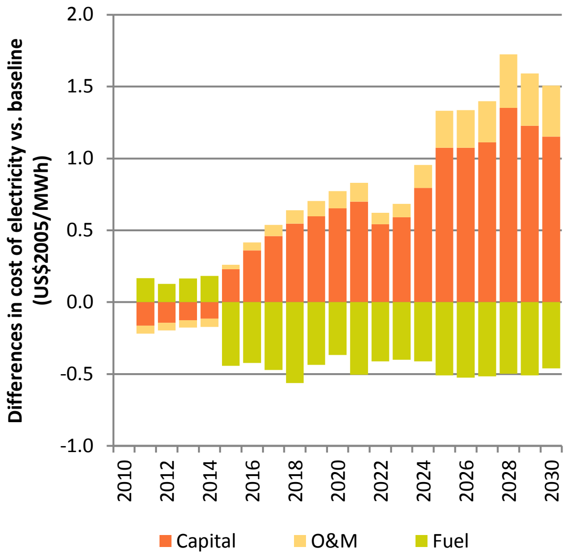


Figure 91. *Differences in cost of electricity by cost type between Scenario II and baseline*

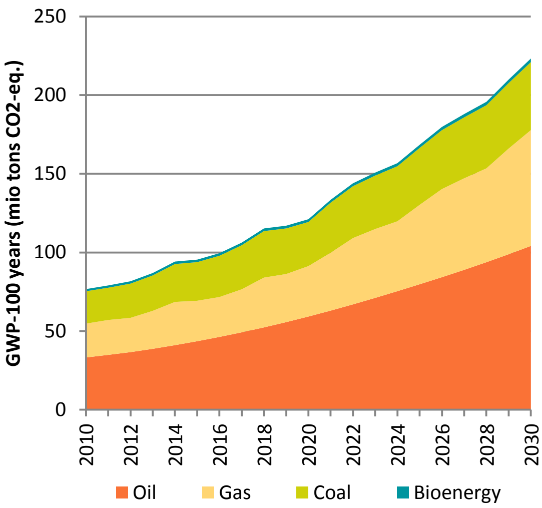


Figure 92. *GWP-100 years disaggregated by fuel for the baseline scenario*

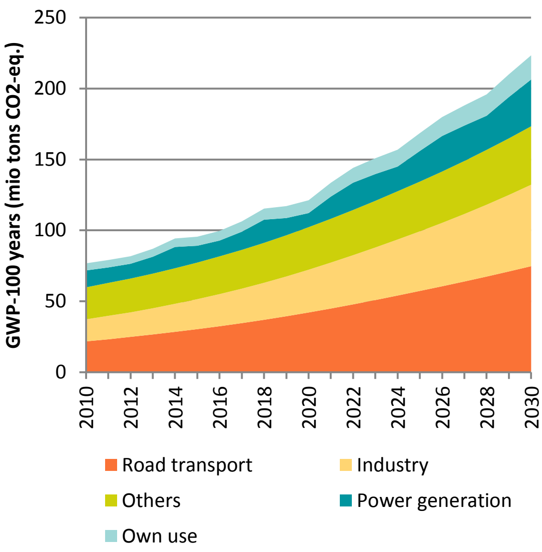


Figure 93. *GWP-100 years disaggregated by category for the baseline scenario*

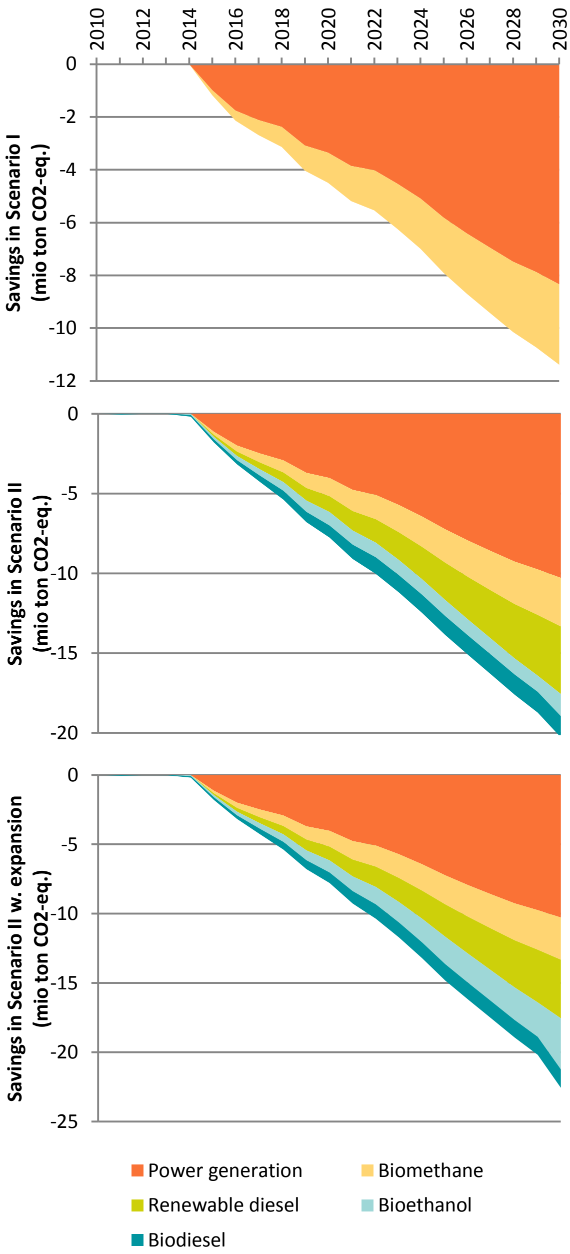


Figure 94. *Domestic bioenergy-induced emissions reductions by category and scenario*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