



Technologie-Monitoring

Verwertungsprozesse für Biomasse: Vergasung,
Methanisierung und Pyrolyse

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The authors of this report are solely responsible for its content.

Biomass conversion: gasification, methanation, and pyrolysis

Technology monitoring

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1 Zusammenfassung und Synthese

Dieser Bericht gibt einen Überblick über eine Reihe von technologischen Optionen zur Umwandlung verschiedener Biomasse-Substrate in Energie (Wärme und Strom), erneuerbare Gase und Pflanzenkohle. Er erörtert den aktuellen Stand der technologischen Entwicklung und der praktischen Umsetzung mit Schwerpunkt auf der Schweiz und Europa, fasst Erkenntnisse und Erfahrungen aus vergangenen und laufenden Projekten zusammen und liefert Schätzungen für Kosten der genannten Technologien. Darüber hinaus werden die Vor- und Nachteile dieser Technologien und ihre potenzielle Rolle in einem zukünftigen Schweizer Energiesystem, das auf Netto-Null-Treibhausgasemissionen abzielt, qualitativ diskutiert. Tabelle 1.1 gibt einen Überblick über die in diesem Bericht behandelten Technologien, ihre Rohstoff-/Brennstoffnutzung sowie spezifische Vor- und Nachteile.

Holzvergaser für WKK-Anwendungen und Pflanzenkohleproduktionsanlagen

Holzvergaser sind von verschiedenen Herstellern in Europa mit Leistungen von ca. 35 kW_{el} bis 1 MW_{el} und darüber hinaus erhältlich. Die meisten Vergaser benötigen trockene Holzhackschnitzel von relativ homogener Grösse. Eine hohe Schüttdichte ist erforderlich, um einen reibungslosen Vergasungsprozess zu ermöglichen. Feuchtes Holz, das als Brennstoff verwendet werden soll, muss getrocknet und von feinen und grossen Partikeln getrennt werden. Holzvergaseranlagen zum Antrieb eines Verbrennungsmotors erreichen bei Nennlast Brutto-Stromwirkungsgrade von 25% bis 30%. Die Bruttoeffizienz für die zusätzliche Nutzwärmeerzeugung beträgt rund 50%. Wenn eine Brennstofftrocknung erforderlich ist, wird ein erheblicher Teil der Wärme prozessintern genutzt. Dieser Anteil ist abhängig vom Feuchtigkeitsgehalt des Holzes, der Effizienz des Trockners und den saisonalen Umgebungsbedingungen. Bei der Nutzung feuchter Waldhackschnitzel kann von einem durchschnittlichen Energieverbrauch in der Grössenordnung von 20% des Brennstoffeinsatzes für die Trocknung ausgegangen werden.

Moderne Technologien zur Wärme-Kraft-Kopplung (WKK) sind bei idealem Betrieb in der Lage, die Anforderungen hinsichtlich Luftschadstoffemissionen zu erfüllen und zum Teil deutlich zu unterschreiten. Die Erfahrung zeigt jedoch, dass der ordnungsgemässe Betrieb solcher Anlagen ein hohes Mass an Überwachung erfordert. Während viele der vor zehn bis 20 Jahren installierten Vergasungsanlagen nach einigen Jahren aufgrund ungelöster Betriebsprobleme oder unverhältnismässig hoher Wartungskosten ausser Betrieb genommen wurden, versprechen die meisten heute verfügbaren Technologien einen langfristigen Betrieb. Es ist daher zu erwarten, dass die Wartungskosten mit zunehmender Erfahrung sinken und sich dem Niveau von Holzfeuerungen¹ annähern werden.

Im Gegensatz zu automatischen Holzfeuerungen bieten Vergasungs- und Pflanzenkohleanlagen den Vorteil, dass sie Strom bzw. Pflanzenkohle als Hauptprodukte erzeugen, während Wärme als Nebenprodukt anfällt. Anlagen zur Wärme-Kraft-Kopplung mit Holzvergasung (Holzvergaser-BHKW) ermöglichen ähnliche Wirkungsgrade wie WKK-Anlagen mit Biomasseverbrennung und Dampfprozessen (Holzheizkraftwerke) mit einem Wasserdampfkreislauf und Einsatz einer Dampfturbine. Im Vergleich zu Dampfanlagen² bieten Holzvergaser-BHKW jedoch die Möglichkeit zur Wärme-Kraft-Kopplung bei deutlich kleineren Leistungen.

Die Hauptnachteile von Holzvergaser-WKK-Anlagen und Pflanzenkohleanlagen sind:

- Die höheren Kosten, das heisst Investitionskosten, Wartungskosten und folglich Energieproduktionskosten im Vergleich zu Wärme aus Holzkesseln, wenn alle Produkte nach ihrem Energiegehalt bewertet und alle Systeme mit identischen jährlichen Volllaststunden betrieben werden.

¹ Anlagen für Energieholz nach Schweizer Luftreinhalteverordnung (LRV).

² «Dampf» bezieht sich hier generell ausschliesslich auf Wasserdampf.

- Die Betriebsbedingungen und Anforderungen an die Systemintegration zur Erreichung einer hohen Anzahl von jährlichen Volllaststunden schränken die Einsatzmöglichkeiten für einen wirtschaftlichen Betrieb von WKK-Anlagen ein, da die Wärmenachfrage, ausser bei industriellen Prozessen, vor allem im Winter anfällt.

Für eine Basis-Vergaser-WKK-Anlage unter den für typische Anwendungen in der Schweiz heute angenommenen Bedingungen werden die Energieproduktionskosten für Strom und Nutzwärme auf etwa 200 CHF/MWh geschätzt.³ Der Brennstoffpreis und die jährlichen Volllaststunden haben den grössten Einfluss auf die Energieerzeugungskosten. Im Basisfall machen die Brennstoffkosten mehr als 50% der Gesamtkosten aus, die Kapitalkosten etwa 30% und die Wartungskosten weniger als 20%. Daher wird die Anwendung durch Verwendung von Holzresten, die die Qualitätsanforderungen für Vergaser erfüllen, im Vergleich zu einem Betrieb mit kommerziellen Holzbrennstoffen wesentlich attraktiver. Höhere Energieholzpreise oder ein wärmegeführter Betrieb mit geringeren jährlichen Volllaststunden führen zu einem deutlichen Anstieg der Energieproduktionskosten.

Trotz der vergleichsweise hohen Kosten können Holzvergaser-BHKW wirtschaftlich eingesetzt werden – beispielsweise in holzverarbeitenden Betrieben, die unbehandeltes Restholz aus der Produktion nutzen und einen Teil der Nutzwärme betriebsintern zur Holz Trocknung brauchen. Denkbar ist auch eine Nutzung für Fernwärmenetze, bei denen das Holzvergaser-BHKW zur Deckung der Grundlast ausgelegt wird und damit eine hohe Vollbetriebsstundenanzahl erzielt.

Erzeugung erneuerbarer Gase: Vergasung trockener Biomasse und hydrothermale Vergasung sowie Methanisierung biogener Gase

Die Prozesskette zur Umwandlung von trockener, holzartiger Biomasse in erneuerbares Methan durch thermochemische Vergasung umfasst mehrere aufeinanderfolgende Schritte: Aufbereitung des Ausgangsmaterials (Trocknung), Vergasung, Gasreinigung und -aufbereitung, Methanisierung (allenfalls mit zusätzlichem Wasserstoff aus Power-to-Gas, PtG) und abschliessende Gasaufbereitung. Die zentrale Herausforderung besteht in der Auswahl optimaler Technologiekombinationen für Energie- und Kosteneffizienz.

Vergasungstechnologien werden in autotherme/direkte und allotherme/indirekte Systeme unterteilt. Direkte Vergaser benötigen reinen Sauerstoff anstelle von Luft, um eine Stickstoffverunreinigung zu vermeiden, was zu einer geringeren Effizienz und höheren Investitions- und Betriebskosten führt. Im Gegensatz dazu trennen indirekte Vergaser, wie z. B. der Dual-Fluidised-Bed-Vergaser (DFB), die endotherme Vergasungszone physikalisch von der Verbrennungszone und produzieren so ein stickstofffreies Gas. DFB-Vergaser, die sich in mehreren Pilotanlagen in Österreich, Schweden und Frankreich bewährt haben, arbeiten bei relativ niedrigen Temperaturen (~830°C) und produzieren ein methanreiches Gas (bis zu 10%). Dieses Gas enthält jedoch auch erhebliche Mengen an ungesättigten Kohlenwasserstoffen, die herkömmliche Katalysatoren zur Festbett-Methanisierung vergiften können, was eine komplexe und kostspielige Gasreinigungs- und -aufbereitungsstufe erforderlich macht. Alternativ dazu verwenden zweistufige Vergasungskonzepte die Pyrolyse, gefolgt von einer Hochtemperatur-Verkohlungsvergasung (>1000°C), um ein sehr sauberes, teerfreies Synthesegas⁴ zu erzeugen. Dies vereinfacht zwar die nachgeschaltete Reinigung, aber das resultierende Synthesegas⁴ hat einen sehr geringen Methangehalt (<1%), wodurch es für die SNG-Produktion weniger effizient und besser für die Synthese flüssiger Brennstoffe mittels Methanolsynthese oder Fischer-Tropsch-Verfahren geeignet ist, bei denen nur H₂ und CO bzw. CO₂ umgesetzt werden, aber kein Methan.

Die Wahl des Methanisierungsreaktors (Festbett vs. Wirbelschicht) ist entscheidend für die Wirtschaftlichkeit der Produktion von synthetischem Erdgas («synthetic Natural Gas», SNG). Eine grosstechnische Demonstrationsanlage für die Festbett-Methanisierung in Göteborg/Schweden

³ 6000 jährliche Volllaststunden; Energieholzpreis: 60 CHF/MWh; jährliche Wartungskosten: 5% der Investitionskosten; Amortisationsdauer: 20 Jahre; Zinssatz: 3% pro Jahr.

⁴ Eine Mischung aus CO und H₂, sowie je nach Produktionsverfahren noch CO₂, Wasserdampf, Methan, Ethen/Ethan/Ethin, Aromaten, Teeren, Schwefelkomponenten etc.

kombinierte erfolgreich einen DFB-Vergaser mit einem Festbett-Methanisierungssystem. Das Vorhandensein ungesättigter Kohlenwasserstoffe im DFB-Produkt erforderte jedoch eine kostspielige Vorbehandlung, bevor das Gas in die adiabatischen Festbettreaktoren gelangen konnte. Der Betrieb der Anlage wurde aufgrund ungünstiger wirtschaftlicher Bedingungen (hohe Holzkosten und geringe Erlöse aus dem SNG-Verkauf) eingestellt. Die Wirbelschichtmethanisierung stellt eine robustere Lösung für das Produktgas des DFB-Vergasers dar, wie in einer 1-MW-Pilotanlage in Güssing/Österreich demonstriert wurde. Ihr Hauptvorteil ist die Fähigkeit, ungesättigte Kohlenwasserstoffe direkt in Methan umzuwandeln, ohne den Katalysator zu verkoken. Dies vereinfacht die Gasreinigung erheblich und führt zu einer höheren chemischen Effizienz und geringeren Investitionskosten. Das Wirbelschichtkonzept wird im Hinblick auf die Lastflexibilität weiterentwickelt, um die flexible Zugabe von Wasserstoff aus Elektrolyseuren innerhalb von PtG-Systemen zu ermöglichen, bei denen das inhärent anfallende CO₂ mit verfügbarem Wasserstoff zu zusätzlichem Methan umgewandelt werden kann.

Die direkte Methanisierung von rohem Biogas (mit CO₂) ist eine fortschrittliche Power-to-Gas-Anwendung, bei der Wasserstoff aus Elektrolyse mit Biogas gemischt wird, um das darin enthaltene CO₂ in zusätzliches Methan umzuwandeln. Bei der biologischen Methanisierung werden gerührte Blasensäulen mit Mikroorganismen verwendet, die oft bei einem Druck von 10 bar betrieben werden, jedoch deutlich grössere Reaktoren erfordern als die katalytische Methanisierung. Diese arbeitet mit Reaktoren, die mehr als zehnmals kleiner sind, was einen erheblichen Investitionsvorteil darstellt. Darüber hinaus können katalytische Reaktoren eine hohe Gesamtsystemeffizienz erzielen, indem sie Prozesswärme nutzen, um Hochtemperatur-Festoxid-Elektrolyseure (SOEC) Dampf zuzuführen.

Die verfügbaren Schätzungen für die Produktionskosten von erneuerbarem Methan (SNG) aus Holzvergasung mit oder ohne Wasserstoffzugabe sind derzeit mit hohen Unsicherheiten behaftet – vor allem aufgrund der Tatsache, dass nur sehr wenige Studien die Produktion von erneuerbarem Methan aus Holz untersucht und noch weniger Studien die Zugabe von Wasserstoff aus wirtschaftlicher Sicht betrachtet haben. Die wichtigsten Kostenfaktoren sind die Investitionskosten für die Vergasungsinfrastruktur und die Betriebskosten für den Holzbezug. Die Schätzungen der SNG-Produktionskosten weisen eine grosse Variabilität auf und reichen von 5 bis 28 Rp/kWh_{SNG}. Die höchsten und niedrigsten Schätzungen können nicht als repräsentativ für die aktuellen Bedingungen in der Schweiz angesehen werden, da das untere Ende dieses Bereichs sehr optimistischen Technologieeigenschaften und sehr niedrigen Holzpreisen entspricht, während das obere Ende des Bereichs eine ungünstige Wahl der Technologien repräsentiert. Typische Biomethan-Kosten aus Aufbereitung von Biogas liegen bei etwa 12 Rp/kWh_{SNG}.

Auch zur direkten Umwandlung von Biogas mit Wasserstoff zu Biomethan, um höhere Methanausbeuten aus dem CO₂ zu erzielen, gibt es nur wenige techno-ökonomische Analysen – daher sind die Unsicherheiten hoch und die geschätzten Kostenbereiche breit. Drei Kostenblöcke sind entscheidend: die Kapitalkosten, die Kosten für Rohbiogas und die Kosten für Wasserstoff (welche durch die Kosten für Elektrolyseure und die Kosten für die Stromversorgung bestimmt werden). Die repräsentativen SNG-Produktionskosten für die Schweiz können im Bereich von 10-20 Rp/kWh_{SNG} angenommen werden.

Die hydrothermale Vergasung (HTG), bei der Biomasse und andere kohlenstoffhaltige Materialien unter superkritischen Wasserbedingungen umgewandelt werden, eignet sich gut für die Verarbeitung von feuchten Biomasseabfällen wie Klärschlamm. Der Vorteil des Betriebs unter überkritischen Bedingungen besteht darin, dass keine Phasentrennung zwischen Dampf und Flüssigkeit stattfindet und eine einzige Fluidphase mit etwa der Hälfte der Dichte von flüssigem Wasser vorliegt. Infolgedessen ist keine Verdampfung notwendig, und der damit verbundene Energieeinsatz entfällt. Es wurden zwei verschiedene Konzepte entwickelt: Hochtemperatur- und katalytische HTG. Die Schätzung der HTG-Kosten ist mit hohen Unsicherheiten verbunden, da bisher nur wenige Anlagen gebaut und diese noch nicht über einen längeren Zeitraum unter realistischen Bedingungen betrieben

wurden. Für die Klärschlammbehandlung scheint Full-Stream-HTG (ohne vorgelagerte anaerobe Vergärung) im Vergleich zum herkömmlichen Referenzfall der anaeroben Vergärung mit anschliessender Schlammverbrennung niedrigere Kapital- und Betriebskosten aufzuweisen, wobei aber noch hohe Unsicherheiten bestehen. Dies deutet darauf hin, dass die hydrothermale Vergasung, welche mehr Methan und weniger CO₂ als die Kombination Biogas plus Klärschlammverbrennung liefert, eine gut geeignete Technologie für dezentrale Abfallbehandlungsanlagen mit kleinen bis mittleren Kapazitäten ist.

Rolle der Biomasse-Vergasung/Pyrolyse und deren Produkten (erneuerbarer Gase und Pflanzenkohle) im Schweizer Energiesystem

Holzvergaser-BHKW und Pflanzenkohleanlagen weisen deutlich höhere Energieproduktionskosten auf als reine Wärmeerzeugungsanlagen. Daher müssen Holzvergaser-BHKW und Pflanzenkohleanlagen längere Betriebszeiten als reine Heizkessel erzielen und werden deshalb meistens nur zur Deckung des Grundlastwärmebedarfs ausgelegt. Folglich können Holzvergaser-BHKW und die Pflanzenkohleproduktion andere Wärmeerzeugungssysteme ergänzen, während eine 1:1-Substitution in der Regel nicht möglich ist.

Bei der Betrachtung des Potenzials von Energieholz als Ersatz für fossile Brennstoffe für eine CO₂-neutrale Energieversorgung sollte die Verwendung von Holz und anderen Biomassebrennstoffen für Hochtemperatur-Prozesswärme Vorrang haben, da andere erneuerbare Lösungen für diese Anwendung derzeit fehlen oder oft zu geringen Wirkungsgraden und hohen Kosten führen. Die Erzeugung von Niedertemperaturwärme aus Holz sollte auf ein Minimum reduziert werden, da diese durch Umgebungswärme und Wärmepumpen, die mit erneuerbarem Strom betrieben werden, bereitgestellt werden kann. Reine Wärmeerzeuger mit Energieholz sollte nur zur Deckung des Spitzenlastbedarfs verwendet werden, während Holzvergaser-BHKW und Pflanzenkohleanlagen für den kontinuierlichen Grundlastbetrieb ausgelegt werden müssen.

Die Pflanzenkohleproduktion ermöglicht die Verwendung von minderwertigen Biomasse-Reststoffen, die aufgrund ihrer geringen Schüttdichte oder ihres hohen Aschegehalts nicht für die Verbrennung und Vergasung geeignet sind. Die Verwendung solcher Biomasse-Reststoffe für die Pflanzenkohleproduktion kann somit das Spektrum der nutzbaren Biomasse erweitern und dank der Nebenprodukte der Pflanzenkohleproduktion einen zusätzlichen Beitrag zur Schweizer Energieversorgung leisten und potenziell auch CO₂ aus der Atmosphäre entfernen. Allerdings hat die Produktion von Pflanzenkohle ein geringeres Potenzial zum Ersatz fossiler Brennstoffe als der Einsatz von Energieholz für Hochtemperatur-Prozesswärme. Holzvergaser-BHKW sowie Dampfanlagen mit WKK mit grösseren Leistungen können im Winter erneuerbaren Strom für den Betrieb von Wärmepumpen liefern. Der Hauptunterschied zwischen Holzvergaser-BHKW und Holzheizkraftwerken mit Dampfanlagen besteht darin, dass Holzvergaser-BHKW die Nutzung von Energieholz in kleineren, dezentralen Anlagen ermöglichen, jedoch hohe Anforderungen an die Brennstoffqualität stellen, während Dampfanlagen auf grössere Kapazitäten beschränkt sind, aber zusätzlich Holz aus dem Abfallstrom nutzen können. Folglich ergänzen sich die beiden Technologien und der Einsatz von Holzvergasern mit WKK wird nicht zu einer wesentlichen Veränderung des Beitrags von Energieholz zur Energieversorgung der Schweiz führen. Insgesamt wird der Einsatz von Holzvergaser-BHKW und Pflanzenkohleanlagen hauptsächlich eine ergänzende Anwendung zu Holzheizkesseln und Dampfanlagen mit WKK bleiben.

Auch der potenzielle Beitrag von erneuerbarem Methan aus anaerober Vergärung, hydrothermalen Vergasung, Holzvergaser und Power-to-Gas zur Energieversorgung sollte auf die optimale Nutzung der begrenzten Ressource Holz abzielen. Synthetisches Erdgas sollte idealerweise zur Bereitstellung von Hochtemperaturwärme in industriellen Prozessen verwendet werden, die nicht ohne Weiteres elektrifiziert werden können, sowie allenfalls für die Abdeckung der Nachfragespitzen in Wärmenetzen und für Gebäudeheizung in engen Innenstädten ohne Wärmenetz. Die Umwandlung von biogenen Abfällen, insbesondere den stark wasserhaltigen, in solches SNG ist der einfachste Weg,

um Umweltbelastungen zu vermeiden und die Energie transportierbar und speicherbar zu machen, wenn ein Gasnetz vorhanden ist. Dies würde die Nutzung der heimischen biogenen Nassabfälle (Klärschlamm, Grünabfälle, Gülle, Rückstände aus der Lebensmittelproduktion usw.) in Form von SNG ermöglichen, die Speicherung von ansonsten nicht nutzbarer Elektrizität über Power-to-Gas erlauben und die Industrie mit Hochtemperaturwärme sowie Fernwärmesystemen während der Spitzenlastzeiten versorgen.

Tabelle 1.1: Technologieübersicht inkl. spezifischer Vor- und Nachteile.

Technologie	Input Substrat	Output	TRL	Vorteile (Gestehungskosten Hauptprodukt, Wert der Nebenprodukte)	Nachteile (Gestehungskosten Hauptprodukt, Wert der Nebenprodukte)
Kleine Holzvergaser mit Wärme-Kraft-Kopplung (WKK)	Holz mit hohen Anforderungen an Brennstoff (Mindest-Schüttdichte, geringer Staubanteil, begrenzter Wassergehalt oder Trocknung)	Wärme und Strom	8-9	Flexibilisierung der Stromversorgung durch dezentrale Stromerzeugung mit kleiner Leistung und für Bandlast oder on-demand Elektrizität	Alle: Wegen hoher spezifischer Kapitalkosten ist aus wirtschaftlichen Gründen ein Betrieb mit mehr als 6000 jährlichen Vollbetriebsstunden notwendig, was den Einsatz für Gebäude- und Fernwärme einschränkt. Einfache Vergaser: Anfall von separat zu entsorgenden Nebenprodukten (z.B. mit Kohlenwasserstoffen belastetes Kondensatwasser).
Pflanzkohleanlagen (auch "Pyrolyseanlagen" genannt)	Holz und andere Biomasse mit geringen Anforderungen an Brennstoff (auch für geringe Schüttdichte und hohe Aschegehalte, z.B. für Abgang von Vergärungsanlagen)	Holzkohle oder Pflanzkohle und Wärme	8-9	Potenzial dezentraler Biomasse-Nutzung für Sortimente, die für Feuerungen und Vergaser ungeeignet sind. Anwendungen: - Ersatz ökologisch fragwürdiger Import-Holzkohle - Kohlenstoffspeicherung in der Landwirtschaft oder in Produkten wie Beton	Wie Holzvergaser: Hohe jährliche Vollbetriebsstundenzahl.
Grosse Pyrolyse-Anlagen (nicht Teil dieser Studie)	Holz	Pyrolyseöl	8-9	Produkt kann als Heizölersatz eingesetzt werden, ist transportierbar und für Tage bis Monate lagerbar, mit Hydrierung auch länger. Kein Gasnetz nötig.	Uneinheitliche Zusammensetzung, ohne Hydrierung mit vielen Säure-, Keton, Aldehyd- und Ether-/Alkohol- Gruppen; schwierig aufzuarbeiten. Begrenzte Möglichkeiten H ₂ einzubinden und H ₂ so zu speichern.
Grosse Vergaser (DFB)	Holz, trockene Biomasse; technisch gesehen auch black pellets, refuse derived fuel (aus Siedlungs-, Gewerbe- und Industrieabfällen), nur mit Luftreinhaltung	Syngas (H ₂ /CO/CO ₂ /CH ₄ /C ₂ H ₄), Umwandlung in Methan für Erdgasnetz	7-8	Erprobt, hoher Wirkungsgrad Holz zu Methan (>61%); flexible H ₂ -Zugabe: PtG bei tiefen Strompreisen (Netzstabilisierung, Sektorkopplung); CO ₂ -Abtrennung prozessinhärent, dieses steht dann für CCU/S zur Verfügung; Methan-Kosten: 15-20 Rp/kWh	Erst ab mehreren MW Leistung; 20-40 MW in der Schweiz machbar, darüber Transportaufwand im Binnenland zu hoch; braucht ein Gasnetz in der Nähe
Grosse Vergaser (two step, pyrolysis and gasification)		Umwandlung in SAF Methanol	7 (MeOH) 8-9 (SAF)	Produkt wertvoller als Methan; braucht kein Erdgasnetz in der Nähe. CO ₂ -Abtrennung prozessinhärent, dieses steht	Wenig erprobt, tieferer Wirkungsgrad wegen höherer Temperatur; flexible H ₂ -Zugabe nicht getestet

Technologie	Input Substrat	Output	TRL	Vorteile (Gestehungskosten Hauptprodukt, Wert der Nebenprodukte)	Nachteile (Gestehungskosten Hauptprodukt, Wert der Nebenprodukte)
				dann für CCU/S bereit	
Hydro-thermale Vergasung hohe Temperatur <u>ohne</u> Katalyse	Klärschlamm, Grünabfall, Gülle, Reste aus Lebensmittelverarbeitung etc.	Salze, Metall, Syngas für Upgrade zur Einspeisung ins Erdgasnetz	8	Kann Stoffströme verwerten, die nicht brennbar sind, aber auch nicht (100%) vergärbar sind. Höhere Kohlenstoff-Ausbeute als Vergärung; Nährstoffabtrennung inhärent.	Wenig Details bekannt, wenig Erfahrung; hohe Kapitalkosten. Produktgas ist eine Mischung mit höherem Aufwand bei der Aufbereitung.
Hydro-thermale Vergasung mittlere Temperatur <u>mit</u> Katalyse	Alle pumpbaren Biomassen inkl. Suspensionen in H ₂ O und org. Fraktionen	Salze (Phosphor) und Methan/CO ₂ /(H ₂) für Upgrade zur Einspeisung ins Erdgasnetz	7	Methan als Hauptprodukt, wenig Upgrade nötig; kann Stoffströme verwerten, die nicht brennbar sind, aber auch nicht (100%) vergärbar sind. Höhere Kohlenstoff-Ausbeute als Vergärung. Nährstoffabtrennung inhärent.	Wenig Details bisher bekannt, wenig Erfahrung; hohe Kapitalkosten
Aufbereitung von CO ₂ oder Rohbiogas mit Wasserstoff zu Methan für Einspeisung ins Gasnetz	Biogas aus Klärschlamm	Erneuerbares Methan für Erdgasnetz	8-9	Verschiedene Technologien erfolgreich demonstriert inkl. solchen ohne Upstream-CO ₂ -Abtrennung (höherer Wirkungsgrad); Biogaspreise 9-20 Rp/kWh, je nach Grösse und Strompreisen	Braucht Gasnetz; muss flexibel sein und sollte mit Standard-Aufbereitung kombiniert sein, um teure Stromstunden vermeiden zu können.

2 Summary and synthesis

This report provides an overview of a range of technological options for converting various biomass substrates into energy (heat and electricity), renewable gases and biochar. It discusses the current state of technological development and practical implementation with a focus on Switzerland and Europe, summarizes findings and experiences from past and ongoing projects, and provides estimates for the costs of these technologies. In addition, the advantages and disadvantages of these technologies and their potential role in a future Swiss energy system aiming for net-zero greenhouse gas emissions are discussed in qualitative terms. Table 2.1 provides an overview of the technologies covered in this report, their raw material/fuel use and specific advantages and disadvantages.

Wood gasifiers for CHP applications and biochar production plants

Wood gasifiers are available from various manufacturers in Europe with outputs ranging from approximately 35 kW_{el} to 1 MW_{el} and above. Most gasifiers require dry wood chips of relatively uniform size. A high bulk density is necessary to enable a smooth gasification process. Moist wood to be used as fuel must be dried and separated from fine and large particles. Wood gasifiers for driving a combustion engine achieve gross electrical efficiencies of 25% to 30% at rated load. The gross efficiency for additional useful heat generation is around 50%. If fuel drying is necessary, a significant portion of the heat is used internally in the process. This proportion depends on the moisture content of the wood, the efficiency of the dryer and the seasonal environmental conditions. When using moist wood chips, average energy consumption for drying can be assumed to be in the order of 20% of the fuel input.

When operating under ideal conditions, modern combined heat and power (CHP) technologies are capable of meeting air pollutant emission requirements and, in some cases, significantly exceeding them. However, experience shows that the proper operation of such plants requires a high degree of monitoring. While many of the gasification plants installed ten to 20 years ago were decommissioned after a few years due to unresolved operational problems or disproportionately high maintenance costs, most of the technologies available today promise long-term operation. It is therefore to be expected that maintenance costs will fall with increasing experience and approach the level of wood-fired heating systems⁵.

In contrast to automatic wood-fired heating systems, gasification and biochar plants offer the advantage of generating electricity or biochar as their main products, with heat as a by-product. Combined heat and power plants with wood gasification (wood gasifier CHP plants) enable similar efficiencies to CHP plants with biomass combustion with a steam cycle and the use of a steam turbine. Compared to steam plants⁶, however, wood gasification CHP plants offer the possibility of combined heat and power generation at significantly lower outputs.

The main disadvantages of wood gasification CHP plants and biochar plants are:

- Higher costs, i.e. investment costs, maintenance costs and, consequently, energy production costs compared to heat from wood boilers, if all products are evaluated according to their energy content and all systems are operated with identical annual full-load hours.
- The operating conditions and system integration requirements for achieving a high number of annual full-load hours limit the possibilities for the economic operation of CHP plants, as heat demand, except in industrial processes, occurs mainly in winter.

For a basic gasification CHP plant under the conditions assumed for currently typical applications in Switzerland, the energy production costs for electricity and useful heat are estimated at around CHF

⁵ Plants for energy wood in accordance with the Swiss Air Pollution Control Ordinance.

⁶ "Steam" here generally refers exclusively to water vapour.

200/MWh.⁷ The fuel price and the annual full-load hours have the greatest influence on energy production costs. In the base case, fuel costs account for more than 50% of total costs, capital costs for around 30% and maintenance costs for less than 20%. Therefore, the use of wood residues that meet the quality requirements for gasifiers makes the application much more attractive compared to operation with commercial wood fuels. Higher energy wood prices or heat-led operation with fewer annual full-load hours lead to a significant increase in energy production costs.

Despite the comparatively high costs, wood gasification CHP plants can be used economically – for example, in wood processing companies that use untreated wood residues from production and need part of the useful heat internally for wood drying. It is also conceivable to use them for district heating networks, where the wood gasification CHP plant is designed to cover the base load and thus achieves a high number of full operating hours.

Production of renewable gases: gasification of dry biomass and hydrothermal gasification as well as methanisation of biogenic gases

The process chain for converting dry, woody biomass into renewable methane through thermochemical gasification comprises several consecutive steps: preparation of the raw material (drying), gasification, gas purification and treatment, methanation (possibly with additional hydrogen from power-to-gas, PtG) and final gas treatment. The key challenge is to select the optimal combination of technologies for energy and cost efficiency.

Gasification technologies are divided into autothermal/direct and allothermal/indirect systems. Direct gasifiers require pure oxygen instead of air to avoid nitrogen contamination, which results in lower efficiency and higher investment and operating costs. In contrast, indirect gasifiers, such as the dual fluidized bed (DFB) gasifier, physically separate the endothermic gasification zone from the combustion zone, thus producing a nitrogen-free gas. DFB gasifiers, which have proven themselves in several pilot plants in Austria, Sweden and France, operate at relatively low temperatures (~830°C) and produce a methane-rich gas (up to 10%). However, this gas also contains significant amounts of unsaturated hydrocarbons, which can poison conventional catalysts for fixed-bed methanation, requiring a complex and costly gas cleaning and treatment stage. Alternatively, two-stage gasification concepts use pyrolysis followed by high-temperature carbonization gasification (>1000°C) to produce a very clean, tar-free synthesis gas. Although this simplifies downstream purification, the resulting synthesis gas⁸ has a very low methane content (<1%), making it less efficient for SNG production and more suitable for the synthesis of liquid fuels via methanol synthesis or Fischer-Tropsch processes, in which only H₂ and CO or CO₂ are converted, but not methane.

The choice of methanation reactor (fixed bed vs. fluidized bed) is crucial for the economic viability of synthetic natural gas (SNG) production. A large-scale demonstration plant for fixed-bed methanation in Gothenburg, Sweden, successfully combined a DFB gasifier with a fixed-bed methanation system. However, the presence of unsaturated hydrocarbons in the DFB product required costly pre-treatment before the gas could enter the adiabatic fixed bed reactors. The plant was shut down due to unfavorable economic conditions (high wood costs and low revenues from SNG sales). Fluidized bed methanation is a more robust solution for the product gas from the DFB gasifier, as demonstrated in a 1 MW pilot plant in Güssing, Austria. Its main advantage is its ability to convert unsaturated hydrocarbons directly into methane without coking the catalyst. This greatly simplifies gas purification and results in higher chemical efficiency and lower investment costs. The fluidized bed concept is being further developed in terms of load flexibility to enable the flexible addition of hydrogen from electrolyzers within PtG systems, where the inherently produced CO₂ can be converted into additional methane using available hydrogen.

⁷ 6'000 full-load hours per year; energy wood price: 60 CHF/MWh; annual maintenance costs: 5% of investment costs; amortization period: 20 years; interest rate: 3% per year.

⁸ A mixture of CO and H₂ as well as CO₂, water vapor, methane, ethene/ethane/ethyne, aromatics, tars, sulfur components, etc., depending on the production process.

Direct methanation of raw biogas (with CO₂) is an advanced power-to-gas application in which hydrogen from electrolysis is mixed with biogas to convert the CO₂ it contains into additional methane. Biological methanation uses stirred bubble columns with microorganisms, which are often operated at a pressure of 10 bar but require significantly larger reactors than catalytic mechanization. The latter uses reactors that are more than ten times smaller, which represents a considerable investment advantage. In addition, catalytic reactors can achieve high overall system efficiency by using process heat to supply steam to high-temperature solid oxide electrolyzers (SOEC).

The available estimates for the production costs of renewable methane (SNG) from wood gasification with or without hydrogen addition are currently subject to high uncertainty – mainly due to the fact that very few studies have investigated the production of renewable methane from wood and even fewer studies have considered the addition of hydrogen from an economic perspective. The most important cost factors are the investment costs for the gasification infrastructure and the operating costs for wood procurement. Estimates of SNG production costs vary widely, ranging from 5 to 28 Rp/kWh_{SNG}. The highest and lowest estimates cannot be considered representative of current conditions in Switzerland, as the lower end of this range corresponds to very optimistic technology characteristics and very low wood prices, while the upper end of the range represents an unfavorable choice of technologies. Typical biomethane costs from biogas upgrading are around 12 Rp/kWh_{SNG}.

There are also a few techno-economic analyses of the direct conversion of biogas with hydrogen to biomethane in order to achieve higher methane yields from CO₂, so the uncertainties are high, and the estimated cost ranges are wide. Three cost components are decisive: capital costs, raw biogas costs, and hydrogen costs (which are determined by the costs of electrolyzers and the costs of electricity supply). Representative SNG production costs for Switzerland can be assumed to be in the range of 10-20 Rp/kWh_{SNG}.

Hydrothermal gasification (HTG), in which biomass and other carbonaceous materials are converted under supercritical water conditions, is well-suited for processing wet biomass waste such as sewage sludge. The advantage of operating under supercritical conditions is that there is no phase separation between steam and liquid, and a single fluid phase with approximately half the density of liquid water is present. As a result, no evaporation is necessary, and the associated energy input is eliminated. Two different concepts have been developed: high-temperature and catalytic HTG. Estimating the costs of HTG is associated with a high degree of uncertainty, as only a few plants have been built to date, and these have not yet been operated under realistic conditions over a longer period of time. For sewage sludge treatment, full-stream HTG (without upstream anaerobic digestion) appears to have lower capital and operating costs compared to the conventional reference case of anaerobic digestion followed by sludge incineration, although there is still a high degree of uncertainty. This suggests that hydrothermal gasification, which produces more methane and less CO₂ than the combination of biogas and sewage sludge incineration, is a well-suited technology for decentralized waste treatment plants with small to medium capacities.

Role of biomass gasification/pyrolysis and its products (renewable gases and biochar) in the Swiss energy system

Wood gasification CHP plants and biochar plants have significantly higher energy production costs than pure heat generation plants. Therefore, wood gasification CHP plants and biochar plants must achieve longer operating times than pure boilers and are therefore usually only designed to cover the base load heat demand. Consequently, wood gasification CHP plants and biochar production can supplement other heat generation systems, while a 1:1 substitution is generally not possible.

When considering the potential of energy wood as a substitute for fossil fuels for a CO₂-neutral energy supply, the use of wood and other biomass fuels for high-temperature process heat should be given priority, as other renewable solutions for this application are currently lacking or often result in low efficiency and high costs. The production of low-temperature heat from wood should be kept to a minimum, as this can be provided by ambient heat and heat pumps powered by renewable electricity.

Pure heat generators using energy wood should only be used to cover peak load demand, while wood gasification CHP plants and biochar plants must be designed for continuous base load operation.

Biochar production enables the use of low-grade biomass residues that are not suitable for combustion and gasification due to their low bulk density or high ash content. The use of such biomass residues for biochar production can thus expand the range of usable biomass and, thanks to the by-products of biochar production, make an additional contribution to Switzerland's energy supply and potentially also remove CO₂ from the atmosphere. However, the production of biochar has less potential for replacing fossil fuels than the use of energy wood for high-temperature process heat. Wood gasification CHP plants and steam plants with CHP with higher outputs can supply renewable electricity for the operation of heat pumps in winter. The main difference between wood gasification CHP plants and wood-fired power stations with steam plants is that wood gasification CHP plants enable the use of energy wood in smaller, decentralized plants, but place high demands on fuel quality, while steam plants are limited to larger capacities but can also use wood from the waste stream. Consequently, the two technologies complement each other, and the use of wood gasifiers with CHP will not lead to a significant change in the contribution of energy wood to Switzerland's energy supply. Overall, the use of wood gasification CHP plants and biochar plants will mainly remain a complementary application to wood-fired boilers and steam plants with CHP.

The potential contribution of renewable methane from anaerobic digestion, hydrothermal gasification, wood gasification, and power-to-gas to energy supply should also aim at the optimal use of the limited resource of wood. Synthetic natural gas should ideally be used to provide high-temperature heat in industrial processes that cannot easily be electrified, as well as to cover peak demand in heating networks and for heating buildings in densely populated city centers without heating networks. The conversion of biogenic waste, especially waste with a high water content, into such SNG is the easiest way to avoid environmental burdens and to make energy transportable and storable if a gas network is available. This would enable the use of domestic biogenic wet waste (sewage sludge, green waste, manure, residues from food production, etc.) in the form of SNG, allow the storage of otherwise unusable electricity via power-to-gas, and supply industry with high-temperature heat and district heating systems during peak load times.

Table 2.1: Technology overview with specific advantages and disadvantages.

Technology	Input substrate	Output	TRL	Advantages (production costs of main product, value of by-products)	Disadvantages (production costs of main product, value of by-products)
Small wood gasifiers with combined heat and power (CHP)	Wood with high fuel requirements (minimum bulk density, low dust content, limited water content, or drying)	Heat and electricity	8-9	Flexibility of electricity supply through decentralized electricity generation with low output, for base load or on-demand electricity	All: Due to high specific capital costs, operation with more than 6,000 full operating hours per year is necessary for economic reasons, which limits its use for building and district heating. Simple gasifiers: Generation of by-products that must be disposed of separately (e.g., condensate water contaminated with hydrocarbons).
Biochar plants (also known as "pyrolysis plants")	Wood and other biomass with low fuel requirements (also for low bulk density and high ash content, e.g., for effluent from fermentation plants)	Charcoal or biochar and heat	8-9	Potential of decentralized biomass use for assortments that are unsuitable for combustion and gasifiers. Applications: Replacement of ecologically questionable imported charcoal; Carbon storage in agriculture or in products such as concrete	Like wood gasifiers: a high annual number of full operating hours.

Technology	Input substrate	Output	TRL	Advantages (production costs of main product, value of by-products)	Disadvantages (production costs of main product, value of by-products)
Large pyrolysis plants (not part of this study)	Wood	Pyrolysis oil	8-9	Product can be used as a heating oil substitute, is transportable and can be stored for days to months, or even longer with hydrogenation. No gas network required.	Inconsistent composition, without hydrogenation with many acid, ketone, aldehyde and ether/alcohol groups; difficult to process. Limited possibilities for incorporating H ₂ and storing H ₂ in this way.
Large gasifiers (DFB)	Wood, dry biomass; technically also black pellets, refuse-derived fuel (from municipal, commercial, and industrial waste), only with Air pollution control	Syngas (H ₂ /CO/CO ₂ /CH ₄ /C ₂ H ₄), conversion to methane for the natural gas network	7-8	Tried and tested, high efficiency of wood to methane conversion (>61%); flexible H ₂ addition: PtG in times of low electricity prices (grid stabilisation, sector coupling); CO ₂ separation inherent to the process, which is then available for CCU/S; methane costs: 15-20 Rp/kWh.	Only feasible from several MW of power; 20-40 MW feasible in Switzerland, above that transport costs in inland areas are too high; requires a gas network nearby
Large gasifiers (two-step, pyrolysis and gasification)		Conversion to SAF methanol	7 (MeOH) 8-9 (SAF)	Product more valuable than methane; does not require a natural gas network nearby. CO ₂ separation inherent in the process, which is then available for CCU/S;	Little tested, lower efficiency due to higher temperature; flexible H ₂ addition not tested
Hydrothermal gasification High temperature <u>without</u> catalysis	Sewage sludge, green waste, manure, food processing residues, etc. All pumpable biomasses, including suspensions in H ₂ O and organic fractions	Salts, metal, syngas for upgrading for feed-in to the natural gas grid	8	Can utilise material flows that are not combustible but also not (100%) fermentable. Higher carbon yield than fermentation; nutrient separation inherent.	Few details known, little experience; high capital costs. Product gas is a mixture with higher processing costs.
Medium-temperature hydrothermal gasification <u>with</u> catalysis		Salts (phosphorus) and methane/CO ₂ /(H ₂) for upgrading for feed-in to the natural gas grid	7	Methane as main product, little upgrading required; can utilise material flows that are not combustible but also not (100%) fermentable. Higher carbon yield than fermentation. Nutrient separation inherent.	Few details known so far, little experience; high capital costs
Processing of CO ₂ or raw biogas with hydrogen to methane for feed-in to the gas grid	Biogas from sewage sludge	Renewable methane for natural gas grid	8-9	Various technologies successfully demonstrated, including those without upstream CO ₂ separation (higher efficiency); biogas prices 9-20 Rp/kWh, depending on size and electricity prices	Requires gas grid; must be flexible and should be combined with standard processing to avoid expensive electricity hours.

3 Résumé et synthèse

Ce rapport présente un aperçu de plusieurs options technologiques pour convertir différents substrats de biomasse en énergie (chaleur et électricité), en gaz renouvelables et en charbon végétal (biochar). Il aborde l'état actuel du développement technologique et de la mise en œuvre pratique, en particulier en Suisse et en Europe, synthétise les connaissances et les enseignements tirés des projets passés et en cours, et fournit des estimations de coûts pour les technologies mentionnées. De plus, le rapport analyse qualitativement les avantages et les inconvénients de ces technologies ainsi que leur rôle potentiel dans un futur système énergétique suisse visant à réduire les émissions de gaz à effet de serre à zéro net. Le Tableau 3.1 récapitule les technologies présentées dans ce rapport, leurs matières premières/combustibles utilisés, ainsi que leurs avantages et inconvénients spécifiques.

Gazéificateurs de bois pour applications de couplage chaleur-force (CCF) et installations de production de charbon végétal

Des gazéificateurs de bois sont disponibles auprès de différents fabricants en Europe, avec des puissances allant d'environ 35 kW_{el} à 1 MW_{el} et plus. La plupart des gazéificateurs nécessitent des copeaux de bois secs et de taille relativement homogène. Une densité apparente élevée est nécessaire au bon déroulement de la gazéification. Le bois humide destiné à la combustion doit être séché et séparé des particules fines et grossières. Les systèmes de gazéification du bois destinés à alimenter un moteur à combustion atteignent un rendement électrique brut de 25 % à 30 % à charge nominale. Le rendement brut pour la production de chaleur utile additionnelle est d'environ 50 %. Si le séchage du combustible est nécessaire, une part importante de la chaleur est utilisée à l'interne du processus. Cette proportion dépend de l'humidité du bois, de l'efficacité du séchoir et des conditions ambiantes saisonnières. Avec des copeaux de bois humides, environ 20 % de l'énergie est consommée pour le séchage.

Les technologies modernes de couplage chaleur-force (production combinée de chaleur et d'électricité), lorsqu'elles fonctionnent de manière optimale, permettent de respecter les prescriptions en matière d'émissions de polluants atmosphériques. Dans certains cas, les émissions des centrales couplées chaleur-force sont largement au-dessous de ces prescriptions. Cependant, l'expérience montre que le bon fonctionnement de telles installations exige un niveau élevé de surveillance. Si de nombreuses centrales à gazéification installées il y a dix à vingt ans ont été mises hors service après quelques années seulement en raison de problèmes d'exploitation non résolus ou de coûts de maintenance disproportionnés, la plupart des technologies actuellement disponibles promettent un fonctionnement à long terme. On s'attend donc à ce que les coûts de maintenance diminuent avec l'expérience et se rapprochent de ceux des systèmes de chauffage au bois⁹.

Contrairement aux chauffages à bois automatiques, les installations de gazéification et de production de charbon végétal présentent l'avantage de produire de l'électricité ou du charbon végétal comme produits principaux, et de la chaleur (sous-produit). Les installations de couplage chaleur-force à gazéification du bois atteignent des rendements similaires à ceux des centrales couplage chaleur-force utilisant la combustion de biomasse suivie par un processus à vapeur (chaudière à bois avec une turbine à vapeur). Cependant, comparées aux installations à vapeur, les installations de couplage chaleur-force à gazéification du bois offrent la possibilité de produire de l'électricité à une puissance nettement inférieure.

Les principaux inconvénients des installations de couplage chaleur-force à gazéification du bois et des installations de production de charbon végétal sont les suivants :

- des coûts plus élevés que ceux de la chaleur produite par les chaudières à bois, c'est-à-dire des coûts d'investissement, de maintenance et, par conséquent, des coûts de production d'énergie, en supposant que tous les produits soient évalués selon leur contenu énergétique

⁹ Installations pour bois énergie selon l'ordonnance suisse sur la protection de l'air (OPair).

et que tous les systèmes fonctionnent avec le même nombre d'heures annuelles à pleine charge.

- Les conditions de fonctionnement et les exigences d'intégration du système nécessaires pour atteindre un nombre élevé d'heures annuelles à pleine charge limitent le potentiel d'exploitation économique des installations couplage chaleur-force, car la demande de chaleur, hormis pour les procédés industriels, se manifeste principalement en hiver.

Pour une variante de base d'une installation de couplage chaleur-force à gazéification du bois, dans les conditions actuellement considérées pour les applications typiques en Suisse, les coûts de production d'énergie pour l'électricité et la chaleur utile sont estimés à environ 200 CHF/MWh¹⁰. Les coûts de production d'énergie sont principalement influencés par le prix du combustible et le nombre d'heures annuelles à pleine charge. Dans la variante de base, les coûts du combustible représentent plus de 50 % des coûts totaux, les coûts du capital environ 30 % et les coûts de maintenance moins de 20 %. Par conséquent, l'utilisation de résidus de bois conformes aux exigences de qualité des gazéificateurs rend cette application nettement plus intéressante que l'utilisation de combustibles ligneux commerciaux. Des prix du bois-énergie élevés ou un fonctionnement axé sur la demande de chaleur avec un nombre réduit d'heures de fonctionnement à pleine charge par an entraînent une augmentation significative des coûts de production d'énergie par kWh.

Malgré leur coût relativement élevé, les installations de couplage chaleur-force à gazéification du bois peuvent être utilisées de manière rentable, par exemple dans les usines de transformation du bois qui utilisent des résidus de bois non traités issus de la production et qui ont besoin d'une partie de la chaleur disponible pour le séchage du bois. Leur utilisation dans les réseaux de chauffage à distance est également envisageable, l'installation de couplage chaleur-force à gazéification du bois étant alors dimensionnée pour couvrir la demande de base et atteindre ainsi un nombre élevé d'heures de fonctionnement à pleine charge.

Production de gaz renouvelables : gazéification de la biomasse sèche et gazéification hydrothermale ainsi que méthanisation des gaz biogènes

La chaîne de procédés de conversion de la biomasse ligneuse sèche en méthane renouvelable par gazéification thermo-chimique comprend plusieurs étapes successives : le traitement de la matière première (séchage), la gazéification, la purification et le traitement du gaz, la méthanisation (éventuellement avec ajout d'hydrogène issu du procédé Power-to-Gas, PtG) et le traitement final du gaz. Le principal défi consiste à sélectionner les combinaisons technologiques optimales pour une efficacité énergétique et économique maximale.

Les technologies de gazéification se divisent en systèmes autothermiques/directs et allothermiques/indirects. Les gazéificateurs directs nécessitent de l'oxygène pur au lieu de l'air afin d'éviter toute contamination par l'azote, ce qui entraîne une efficacité moindre et des coûts d'investissement et d'exploitation plus élevés. À l'inverse, les gazéificateurs indirects, tels que le gazéificateur à double lit fluidisé (Dual-Fluidised-Bed, DFB), séparent physiquement la zone de gazéification endothermique de la zone de combustion, produisant ainsi un gaz exempt d'azote. Les gazéificateurs DFB, qui ont fait leurs preuves dans plusieurs installations pilotes en Autriche, en Suède et en France, fonctionnent à des températures relativement basses (environ 830 °C) et produisent un gaz riche en méthane (jusqu'à 10 %). Cependant, ce gaz contient également des quantités importantes d'hydrocarbures insaturés, susceptibles de contaminer les catalyseurs de méthanisation classiques à lit fixe, ce qui impose une étape de purification et de traitement complexe et coûteuse. Une autre solution consiste à utiliser la gazéification en deux étapes, où la pyrolyse est suivie d'une gazéification par carbonisation à haute température (> 1000 °C) pour produire un gaz de synthèse très propre et

¹⁰ 6000 heures à pleine charge par an ; prix du bois-énergie : 60 CHF/MWh ; coûts d'entretien annuels : 5 % des coûts d'investissement ; durée d'amortissement : 20 ans ; taux d'intérêt : 3 % par an

exempt de goudrons. Bien que ce procédé simplifie la purification en aval, le gaz de synthèse¹¹ obtenu présente une très faible teneur en méthane (< 1 %), ce qui le rend moins efficace pour la production de gaz naturel de synthèse (GNS, à teneur élevée de méthane), mais plus adapté à la synthèse de carburants liquides (par synthèse du méthanol) ou par le procédé Fischer-Tropsch, dans lequel seules les molécules de H₂ et CO ou CO₂ sont utilisées, mais pas de méthane.

Le choix du réacteur de méthanisation (lit fixe ou lit fluidisé) est crucial pour la rentabilité de la production de gaz naturel de synthèse (GNS). Une installation de démonstration de méthanisation à lit fixe à grande échelle, située à Göteborg, en Suède, a combiné avec succès un gazéificateur à double lit fluidisé (DFB) à un système de méthanisation à lit fixe. Cependant, la présence d'hydrocarbures insaturés dans le gaz issu du DFB a nécessité un prétraitement coûteux avant son introduction dans les réacteurs adiabatiques à lit fixe. L'installation a été mise hors service en raison de conditions économiques défavorables (coût élevé du bois et faibles revenus issus de la vente de GNS). La méthanisation à lit fluidisé représente une solution plus robuste pour le gaz produit par le gazéificateur DFB, comme l'a démontré une installation pilote de 1 MW à Güssing, en Autriche. Son principal avantage réside dans sa capacité à convertir directement les hydrocarbures insaturés en méthane sans cokéfaction du catalyseur. Ceci simplifie considérablement la purification du gaz, ce qui permet d'améliorer le rendement chimique et de réduire les coûts d'investissement. Le concept de lit fluidisé est développé pour une plus grande flexibilité du niveau d'utilisation, permettant l'ajout flexible d'hydrogène issu d'électrolyseurs au sein des systèmes PtG. Le CO₂ produit naturellement peut ainsi être converti en méthane supplémentaire grâce à l'H₂ disponible.

La méthanisation directe du biogaz brut (contenant du CO₂) représente une application avancée du procédé Power-to-Gas, où l'hydrogène issu de l'électrolyse est mélangé au biogaz pour convertir le CO₂ qu'il contient en méthane supplémentaire. La méthanisation biologique utilise des colonnes à bulles agitées contenant des micro-organismes, fonctionnant souvent à une pression de 10 bars. Cependant, elle requiert des réacteurs nettement plus grands que la méthanisation catalytique. Cette dernière utilise des réacteurs plus de dix fois plus petits, ce qui représente un avantage considérable en termes d'investissement. De plus, les réacteurs catalytiques permettent d'atteindre une efficacité globale élevée en utilisant la chaleur du procédé pour alimenter en vapeur des électrolyseurs à oxyde solide haute température (SOEC).

Les estimations disponibles concernant les coûts de production du méthane renouvelable (GNS) issu de la gazéification du bois, avec ou sans ajout d'hydrogène, présentent actuellement une grande incertitude. Ceci s'explique principalement par le faible nombre d'études portant sur la production de méthane renouvelable à partir du bois, et le nombre encore plus restreint d'études ayant examiné l'ajout d'hydrogène d'un point de vue économique. Les principaux facteurs de coût sont les coûts d'investissement liés à l'infrastructure de gazéification et les coûts d'exploitation pour l'approvisionnement en bois. Les estimations des coûts de production du GNS présentent une variabilité importante, allant de 5 à 28 ct./kWh_{GNS}. Les estimations les plus élevées et les plus basses ne peuvent être considérées comme représentatives des conditions actuelles en Suisse, car la limite inférieure de cette fourchette correspond à des caractéristiques technologiques très optimistes et à des prix du bois très bas, tandis que la limite supérieure représente un choix de technologies peu judicieux. Les coûts typiques du biométhane synthétique issu de ce procédé sont d'environ 12 ct./kWh_{GNS}.

Il existe également peu d'analyses technico-économiques concernant la conversion directe du biogaz brut (contenant du CO₂) en biométhane avec de l'hydrogène afin d'obtenir des rendements en méthane plus élevés. Par conséquent, les incertitudes sont élevées et les fourchettes de coûts estimées sont larges. Trois composantes de coût sont essentielles : les coûts du capital, le coût du

¹¹ Un mélange de CO et H₂, ainsi que, selon le procédé de production, de CO₂, de vapeur d'eau, de méthane, d'éthène/éthane/éthyne, d'aromatiques, de goudrons, de composants soufrés, etc.

biogaz brut et le coût de l'hydrogène (déterminé par le coût des électrolyseurs et celui de l'électricité). En Suisse, les coûts de production du GNS sont généralement estimés entre 10 et 20 centimes suisses (ct./kWh).

La gazéification hydrothermale (GHT), qui consiste à convertir la biomasse et d'autres matériaux carbonés dans des conditions supercritiques, est particulièrement adaptée au traitement des déchets de biomasse humides, tels que les boues d'épuration. L'avantage du fonctionnement dans des conditions supercritiques réside dans l'absence de séparation de phases entre la vapeur et le liquide, ce qui permet d'obtenir une phase fluide unique dont la densité est environ deux fois inférieure à celle de l'eau liquide. Par conséquent, une vaporisation n'est pas nécessaire et la consommation d'énergie associée est supprimée. Deux concepts différents ont été développés : la gazéification hydrothermale à haute température et la gazéification hydrothermale catalytique. L'estimation des coûts de la GHT présente une incertitude importante, car seules quelques installations ont été construites à ce jour et n'ont pas encore été exploitées dans des conditions réalistes sur une période prolongée. Pour le traitement des boues d'épuration, la gazéification hydrothermale en flux continu (sans digestion anaérobie en amont) semble présenter des coûts du capital et d'exploitation inférieurs à ceux de la méthode de référence classique (digestion anaérobie suivie d'incinération des boues), malgré d'importantes incertitudes. Ceci suggère que la gazéification hydrothermale, qui produit plus de méthane et moins de CO₂ que la combinaison de la production de biogaz et de l'incinération des boues, est une technologie particulièrement adaptée aux installations de traitement des déchets décentralisées de petite et moyenne capacité.

Rôle de la gazéification/pyrolyse de la biomasse et de ses produits (gaz renouvelables et charbon végétal) dans le système énergétique suisse

Les centrales de couplage chaleur-force à gazéification du bois et les installations de charbon végétal présentent des coûts de production d'énergie nettement supérieurs à ceux des centrales de production de chaleur classiques. Par conséquent, ces centrales doivent fonctionner plus longtemps que les chaudières conventionnelles et sont donc généralement conçues pour couvrir uniquement les besoins en chaleur de base. Ainsi, les centrales couplage chaleur-force à gazéification du bois et la production de charbon végétal peuvent compléter d'autres systèmes de production de chaleur, mais une substitution n'est généralement pas possible.

Lorsqu'on considère le potentiel du bois énergétique comme alternative aux combustibles fossiles pour un approvisionnement énergétique neutre en CO₂, la production de chaleur à haute température devrait être privilégiée, car les autres solutions renouvelables pour cette application manquent actuellement ou présentent souvent un faible rendement et un coût élevé. La production de chaleur à basse température à partir du bois doit être réduite au minimum, car celle-ci peut être fournie par de la chaleur ambiante et des pompes à chaleur alimentées par de l'électricité renouvelable. Les générateurs de chaleur fonctionnant exclusivement au bois ne devraient être utilisés que pour couvrir les pics de consommation, tandis que les centrales couplées chaleur-force à gazéification du bois et les installations de charbon végétal doivent être conçues pour un fonctionnement continu en charge de base.

La production de charbon végétal permet d'utiliser des résidus de biomasse de faible qualité, impropres à la combustion et à la gazéification en raison de leur faible densité apparente ou de leur forte teneur en cendres. L'utilisation de ces résidus pour la production de charbon végétal permet ainsi d'élargir la gamme de biomasse utilisable et, grâce aux sous-produits de cette production, de contribuer à l'approvisionnement énergétique de la Suisse et potentiellement de réduire la concentration de CO₂ dans l'atmosphère. Cependant, la production de charbon végétal présente un potentiel de substitution aux combustibles fossiles inférieur à celui de l'utilisation du bois pour la production de chaleur à haute température. Les centrales couplage chaleur-force à gazéification du bois et les centrales à vapeur de cogénération de plus grande capacité peuvent fournir de l'électricité renouvelable pour le fonctionnement des pompes à chaleur en hiver. La principale différence entre

les centrales couplage chaleur-force à gazéification du bois et les centrales thermiques au bois avec système vapeur réside dans le fait que les premières permettent l'utilisation du bois-énergie dans des systèmes plus petits et décentralisés, mais exigent une qualité de combustible élevée, tandis que les secondes, bien que limitées à des capacités plus importantes, peuvent également valoriser le bois issu des déchets. Par conséquent, les deux technologies sont complémentaires et l'utilisation d'installations de couplage chaleur force par gazéification du bois n'entraînera pas de changement significatif dans la contribution du bois énergétique à l'approvisionnement énergétique de la Suisse. Globalement, l'utilisation d'installations de couplage chaleur-force par gazéification du bois et d'installations de production de charbon végétal restera principalement une application complémentaire aux chaudières à bois et aux centrales à vapeur de cogénération.

La contribution potentielle à l'approvisionnement énergétique du méthane renouvelable issu de la digestion anaérobie, de la gazéification hydrothermale, de la gazéification du bois et du Power-to-Gas devrait également viser une utilisation optimale de la ressource limitée qu'est le bois. Le gaz naturel de synthèse (biométhane, GNS) devrait idéalement être utilisé pour fournir de la chaleur à haute température dans les procédés industriels qui ne peuvent pas être facilement électrifiés, et le cas échéant pour couvrir les pics de demande dans les réseaux de chauffage et pour le chauffage des bâtiments dans les centres-villes densément peuplés dépourvus de tels réseaux. La conversion des déchets biogènes, en particulier ceux à forte teneur en eau, en GNS est le moyen le plus simple d'éviter les impacts environnementaux et de rendre l'énergie transportable et stockable là où un réseau de gaz existe. Cela permettrait d'utiliser les déchets biogènes humides domestiques (boues d'épuration, déchets verts, lisier, résidus de production alimentaire, etc.) sous forme de GNS, de stocker l'électricité autrement inutilisable grâce à la technologie Power-to-Gas et d'approvisionner l'industrie (chaleur à haute température) et les réseaux de chauffage à distance (périodes de pointe).

Tableau 3.1 : Aperçu des technologies, y. c. avantages et inconvénients spécifiques.

Technologie	Entrants/Substrats	Produits	TRL (technological readiness level)	Avantages (coûts de revient du produit principal, valeur du sous-produit)	Inconvénients (coûts de revient du produit principal, valeur du sous-produit)
Petits gazéificateurs de bois avec couplage chaleur force (CCF)	Bois à exigences élevées en matière de combustible (densité apparente minimale, faible taux de poussière, teneur en eau limitée ou séchage)	Chaleur et électricité	8-9	Flexibilité de l'approvisionnement en électricité grâce à une production d'électricité décentralisée à faible puissance, pour la charge de base ou la production d'électricité à la demande	Tous : Du point de vue économique, et en raison des coûts du capital spécifiques élevés, un fonctionnement de plus de 6 000 heures à pleine charge par an est nécessaire, ce qui limite leur utilisation pour le chauffage des bâtiments et le chauffage à distance. Gazéificateurs simples : les sous-produits nécessitant un traitement séparé (par exemple, eaux de condensation chargées en hydrocarbures).
Installation de charbon végétal (également appelées « installation de pyrolyse »)	Bois et autres biomasses à faibles exigences en matière de combustible (conviennent également aux matériaux à faible densité apparente et à forte teneur en cendres, comme les digestats issus de la fermentation)	Charbon de bois ou charbon végétal et chaleur	8-9	Potentiel d'utilisation décentralisée de la biomasse pour les matières non adaptées à la combustion et à la gazéification. Applications : - Remplacement du charbon de bois importé, dont l'impact environnemental est discutable. - Stockage du carbone en agriculture ou dans des produits comme le béton.	À l'instar des gazéificateurs à bois : nombre élevé d'heures de fonctionnement à pleine charge annuel.

Technologie	Entrants/Substrats	Produits	TRL (technological readiness level)	Avantages (coûts de revient du produit principal, valeur du sous-produit)	Inconvénients (coûts de revient du produit principal, valeur du sous-produit)
Grandes installations de pyrolyse (ne font pas partie de cette étude)	Bois	Huile de pyrolyse	8-9	Ce produit peut être utilisé comme substitut au mazout, transportable et se stocke de quelques jours à plusieurs mois ; par hydrogénation, sa durée de stockage est encore plus longue. Ne nécessite pas de réseau de gaz.	Composition hétérogène : sans hydrogénation, il contient de nombreux groupes acides, cétones, aldéhydes et éthers/alcools, ce qui complique sa transformation. Possibilités d'incorporation et de stockage de l'hydrogène limitées.
Gazéificateurs de grande capacité (DFB)	Bois, biomasse sèche ; Black Pellets, combustible dérivé de déchets (issus de déchets ménagers, commerciaux et industriels) également possible d'un point de vue technique, mais uniquement si les prescriptions en matière d'émissions de polluants atmosphériques sont respectées.	Gaz de synthèse (H ₂ /CO/CO ₂ /CH ₄ /C ₂ H ₄), conversion en méthane pour le réseau de gaz naturel.	7-8	Rendement élevé et éprouvé de la conversion du bois en méthane (>61 %) ; ajout flexible d'H ₂ : PtG pendant les périodes de bas prix de l'électricité (stabilisation du réseau, couplage sectoriel) ; séparation du CO ₂ inhérente au procédé, le CO ₂ est ensuite disponible pour le CCU/S ; coût du méthane : 15-20 ct./kWh	Possible qu'à partir de plusieurs MW de puissance ; 20 à 40 MW sont possibles en Suisse, au-delà les coûts de transport à l'intérieur du pays sont trop élevés ; nécessite un réseau de gaz à proximité
Carburateurs de grande taille (à deux étapes, pyrolyse et gazéification)		Conversion en méthanol durable pour l'aviation (Sustainable Aviation Fuel, SAF)	7 (MeOH) 8-9 (SAF)	Produit plus précieux que le méthane ; ne nécessite pas de réseau de gaz naturel à proximité. Séparation du CO ₂ inhérente au procédé, le CO ₂ est ensuite disponible pour le CCU/S ;	Peu éprouvée, efficacité moindre en raison de la température plus élevée ; ajout flexible d'H ₂ non testé
Gazéification hydrothermale à haute température <u>sans</u> catalyse	Boues d'épuration, déchets verts, lisier, restes issus de l'industrie agroalimentaire, etc.	Sels, métaux et gaz de synthèse destinés à être injectés dans le réseau de gaz naturel	8	Peut valoriser des flux de matières non combustibles mais non fermentables à 100 %. Rendement en carbone supérieur à celui de la fermentation ; séparation des nutriments inhérente au procédé.	Peu de détails disponibles, expérience limitée et coûts du capital élevés. Le gaz produit est un mélange qui nécessite un traitement plus complexe.
Gazéification hydrothermale à température moyenne <u>avec</u> catalyse	Toute biomasse pompable, y compris les suspensions aqueuses et les fractions organiques	Sels (phosphore) et méthane/CO ₂ /(H ₂) pour valorisation en vue de leur injection dans le réseau de gaz naturel	7	Le méthane est le principal produit, nécessitant peu de transformations ; peut valoriser des flux de matières non combustibles mais non fermentables à 100 %. Rendement en carbone supérieur à celui de la fermentation. Séparation des nutriments inhérente au procédé.	Peu de détails à ce jour, peu d'expérience ; coûts du capital élevés
Traitement du CO ₂ ou du biogaz brut avec de l'hydrogène pour produire du méthane destiné à être injecté dans le réseau de gaz	Biogaz issu des boues d'épuration	Méthane renouvelable pour le réseau de gaz naturel	8-9	Diverses technologies ont été démontrées avec succès, y compris celles sans séparation de CO ₂ en amont (efficacité supérieure) ; prix du biogaz de 9 à 20 ct./kWh, selon la taille et les prix de l'électricité.	Nécessite un réseau de gaz ; doit être flexible et combiné avec un traitement standard pour éviter les heures d'électricité coûteuses.

4 Gasification for combined heat and power production, carbonization for biochar production

4.1 Introduction

This chapter describes the aim of the work and introduces definitions used in connection with small-scale biomass gasification plants and biochar production. It also presents legal requirements and recommendations for efficiency levels that currently apply in Switzerland.

4.1.1 Aim of the work on biomass gasification and biochar

The aim is to describe and evaluate the state-of-the-art of the technologies for biomass gasification and carbonization to produce electricity and heat (referred to as combined heat and power (CHP)), biochar and heat, or electricity, biochar and heat. With respect to the situation in Switzerland, the report focuses on automated systems in the size range of 100 kW to 5 MW energy input based on the heating value¹² of the biomass, also referred to as "fuel input". The investigated size range of gasifier CHP plants is of specific interest for Switzerland, as it promises relatively high electrical efficiencies at significantly smaller plant sizes than CHP plants based on steam cycles. Consequently, the advantages and disadvantages of gasifier CHP and biochar plants shall be described, and the economy of gasification and carbonization routes shall be evaluated and compared with established applications for biomass combustion.

4.1.2 Definitions on biomass gasification and biochar production

By heating solid biomass in the absence of an oxidizing agent (usually air) or with an under-stoichiometric amount of oxidizing agent, products in all three aggregate states are formed as follows:

- The gaseous product called **wood gas**, **producer gas**, or **synthesis gas** is a combustible gas and, in the case of air-blown processes, mainly consists of N₂, CO₂, CO, H₂, CH₄, non-methane hydrocarbons, NH₃, H₂S, and other volatile compounds. When wood gas is released during the pyrolysis process, it also contains condensable compounds, which may result in liquid droplets during gas cooling. Condensable compounds are usually undesired by-products in the case of CHP applications, since they need to be removed prior to a compressor (in case of turbo-charged engines) or prior to an internal combustion (IC) engine. The organic fraction of the condensable products is also referred to as tar or condensable organic compounds (COC). Further, the wood gas contains solid particles, which consist of ash constituents (K, Ca, Na, P, Cl, and other elements) and carbon structures such as coke or charcoal and soot.
- The liquid product is called **pyrolysis oil**. It consists of organic liquid compounds (tar), water, and impurities, including solid particles. Pyrolysis oil is the desired product in case of pyrolysis processes, which aim at the production of a liquid biofuel. To enable a significant yield of pyrolysis oil, a very high heating rate of the biomass and very fast cooling of the released gases is needed in an inert environment in the absence of oxygen at typical temperatures in the range of 450° to 500° C. Consequently, the process aiming at a liquid product is also referred to as fast or flash pyrolysis.
- Solid product: Coke, **charcoal**, or **biochar** consists of carbon with small proportions of minerals and ideally no organic matter. It is therefore largely inert and stable in the long term.

¹² In the present report "heating value" refers to the lower heating value and plant sizes are described by the fuel input based on the lower heating value as in the Swiss Ordinance on Air Pollution Control (OAPC).

The division into the three fractions depends on the fuel properties, such as water and ash content, and the operating conditions, particularly temperature, the availability of the oxidizing agent, and the residence time in the different zones of the process. Accordingly, the thermochemical processes are described as follows:

- If the producer gas is the main product for a subsequent combustion process, the initial conversion process is referred to as **gasification**. The product gas or wood gas is usually used in an IC engine for cogeneration of heat and power. Coke or charcoal is usually an undesired residue, but in some cases, a combination of gasification for CHP and carbonization to biochar is also possible. The transition between carbonization and gasification is therefore fluent, and the name is usually given based on the main product, which can be identified based on the energy content, the mass fraction, or the added value.
- If the pyrolysis oil is the main product, the process is referred to as **pyrolysis**. In this case, coke and synthesis gas are by-products. These can be used within the process and, in the case of coke, can also be mixed with the pyrolysis oil to produce an energy-rich sludge that can replace fossil heavy fuel oil for further processing.
- When charcoal, coke, or biochar is the main product, the process is referred to as **carbonization**. If the intended use is a fuel for barbecue, the product is referred to as charcoal (*German*: Holzkohle). For applications in agriculture, material technology, the building industry, or other purposes, the product is also known as biochar (*German*: Biokoks, Biokohle, or, more recently, "Pflanzkohle"). If coke is the main product, synthesis gas is a by-product that can be combusted for internal heat supply for the reactor and/or a dryer and optionally to generate useful heat, e.g., for district heating. If combustion takes place in an IC engine, CHP production is possible. If all three products, i.e., biochar and power and heat, are aimed at, the process can either be described as a gasifier CHP plant with biochar production or as a biochar plant with CHP, depending on the relevance of the main product.

If an over-stoichiometric air supply for the oxidation of all fractions is introduced in one single component of the conversion plant, the process is called combustion. The main product is then a flue gas that contains no chemically bound energy, with heat being the only energy output of the process. Combustion is highly exothermic and thus a self-sustaining and autothermal process, where the heat is produced in the main process. On the opposite, a pyrolysis reactor is operated with an external heat transfer to the reactor and thus a so-called allothermal process.

Certain technologies consciously combine various process steps, which is also referred to as a multi-stage process. One example is the two-stage or the multi-stage gasification, which consists of an externally heated pyrolysis reactor followed by a gas-phase combustion and a reactor to gasify the initially formed charcoal.

Although the described processes can be distinguished due to the main products, reactions of all described processes occur in each of the described processes as follows:

- Pyrolytic decomposition occurs as the initial step of both gasification and combustion.
- Gasification reactions occur in combustion.
- Combustion reactions occur in certain zones of a biomass gasifier.

Although all thermochemical processes involve pyrolytic decomposition, only the production of pyrolysis oil as the main product is referred to as pyrolysis in the technical literature. In more recent documents on biochar, the production of biochar is also referred to as pyrolysis. That makes it difficult to distinguish between carbonization and pyrolysis in the original sense. Consequently, the present report describes and distinguishes the following processes:

Biomass gasification for CHP production with biochar production as an optional supplement.

Biomass carbonization for biochar production with heat utilization and optional power production.

The carbonization, gasification, and pyrolysis processes often require the use of dry fuel with a maximum 10% moisture content, which is why such plants often have a drying unit that is supplied with waste heat from the process¹³ and/or with heat from synthesis gas combustion.

Since IC engines are sensitive to solid particles and condensable compounds, gas cleaning is usually applied, resulting in a solid and/or liquid waste stream. Elemental and organic carbon available in these residues is accounted as waste in the case of exclusive CHP production, while it can be accounted as a valuable product when biochar production with quality requirements for biochar is also aimed at.

4.1.3 Legal requirements and recommendations in Switzerland

Stationary energy production plants need to fulfill requirements on air pollution control and on energy efficiency. Requirements on air pollution are described in the ordinance on air pollution control (OAPC or Luftreinhalte-Verordnung (LRV) [1]. For the execution of the LRV, the cantons apply the following recommendations

- Cercl'Air recommendations 31r [2], 31f [3] and 31p [4]
- Recommendations by Nussbaumer et al. (2022) [5] with supplementary information in [6]

The following principles are applied:

There are different types of plants for biochar production or for the pyrolysis or gasification of wood with subsequent use of the gas. To determine the limit values in accordance with the LRV, the systems are classified according to their primary purpose as follows:

- Plants with the primary aim of producing biochar are generally assessed in accordance with the regulations for wood combustion plants.
- Installations with the primary aim of producing gasification and electricity are generally assessed on the basis of the regulations for gas engines.
- Installations with the primary aim of producing gasification and heat are generally assessed in accordance with the regulations for gas-fired installations.
- Mobile, open systems (“low-tech systems”) are not regarded as state-of-the-art for pyrolysis plants. It is not possible to receive an operation permission for such systems.

In addition, the recommendations by Maurer (2021) [7] and by Schwilch et al. (2023) [8] on behalf of the Swiss Federal Office for the Environment (BAFU) are applied for the use of biochar, partly based on the European Biochar Certificate (EBC) [9].

In case of public fundings¹⁴, requirements on energy efficiency are applied based on the following documents:

- Anforderungen des Bundes für Investitionsbeiträge für Biomasseanlagen [11]
- Energiegesetz (EnG, [12])
- Energieförderungsverordnung (EnFV, [13]).

¹³ The main product of a gasifier connected to an IC engine is mechanical energy or electricity. The main product of a biochar plant is biochar. Consequently, the heat from these two processes (as well as the heat that must be removed from Rankine processes) is referred to as “waste heat”. Waste heat from such processes can be partially or completely used for district heating or other purposes, while the rest needs to be dissipated into the environment via heat exchangers. The utilized part of the waste heat then appears as useful heat.

¹⁴ With respect to biochar, it must be noted that the Swiss Federal Council decided in 2023 to refrain from funding the use of biochar in soils, until the positive and negative effects of the irreversible introduction of biochar into the soil have been assessed.

Since the use of biochar is not covered by the legal documents [11] to [13], a quality requirement developed on behalf of the Swiss Federal Office of Energy (BFE) is additionally applied [14]. To enable a comparison of CHP plants and biochar plants, the energy content of biochar is considered with its heating value and, therefore, identical to the value of useful heat leaving the process. Based on this, the requirement of EnFV 2.2.3 [13] for CHP plants is extended as described in the next formula and illustrated in Figure 4.1. The following minimum requirement applies based on gross annual efficiencies:

Heat + Biochar + 1.75 Electricity \geq 70%.

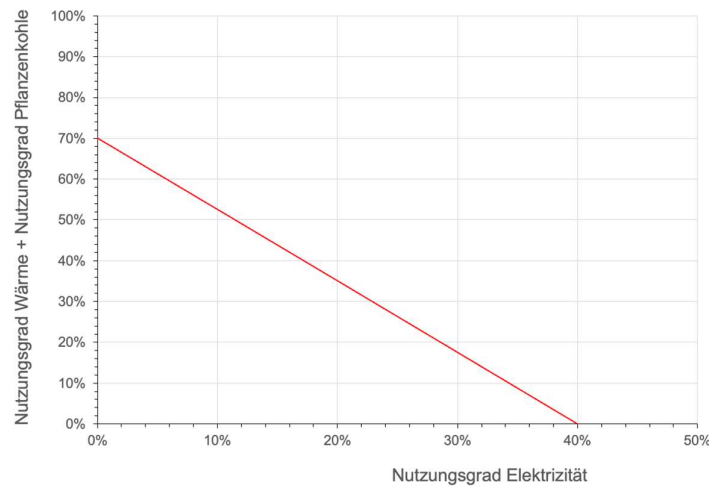


Figure 4.1: Minimum requirements for the production of heat, electricity, and biochar from biomass as introduced in [14] based on the EnFV 2.2.3 [13] and extended with biochar as a product with the following definitions: "Nutzungsgrad" = Gross annual efficiency; "Wärme" = utilized heat; "Elektrizität" = produced electricity; "Pflanzenkohle" = produced biochar based on its lower heating value.

Due to the definitions in the legal documents [11] to [13], heat used for drying purposes is accounted as useful heat. Consequently, gross efficiencies of the conversion plants are calculated using the heating value of the moist biomass prior to a drying process as input energy.

For the operation of biochar plants, proof is required of the raw material used, the planned use of the biochar, and the requirements to be met. If biochar is used in Swiss agriculture, compliance with the Swiss national guidelines on the use of biochar in agriculture must be demonstrated [8]. In addition, the recommendations of Maurer (2021) [7] on the legal handling of biochar in Switzerland must be fulfilled. Among other things, this includes compliance with a maximum PAH content of 4 mg/kg in accordance with the guidelines of the European Biochar Foundation [9].

4.2 Technology description

This chapter describes the fundamentals of thermochemical biomass conversion processes and introduces the definition of the excess air ratio to describe the stoichiometry of the reaction. In addition, the dimensioning of heating systems for supplying heat to buildings or thermal networks is presented, and the integration of CHP systems with the aim of economical operation through high-capacity utilization and utilization of the main part of the waste heat is described.

4.2.1 Thermochemical conversion for gasification and carbonization

The availability of oxidant is an important parameter in thermochemical processes. In case of air-blown processes, the main parameter is the excess air ratio λ (λ) that describes the ratio

between the locally available amount of air and the amount of air needed for a stoichiometric reaction.

Figure 4.2 illustrates the flame temperature of a complete combustion of wood in the combustion regime $\lambda \geq 1$ under adiabatic conditions. The regime of $0.8 \dots 0.9 < \lambda < 1$ describes incomplete combustion with under-stoichiometric oxygen availability. Gasification of wood with air is typically performed in a regime of $0.25 < \lambda < 0.35$ with a maximum cold gas efficiency at $\lambda = 0.3$, as shown in Figure 4.3.

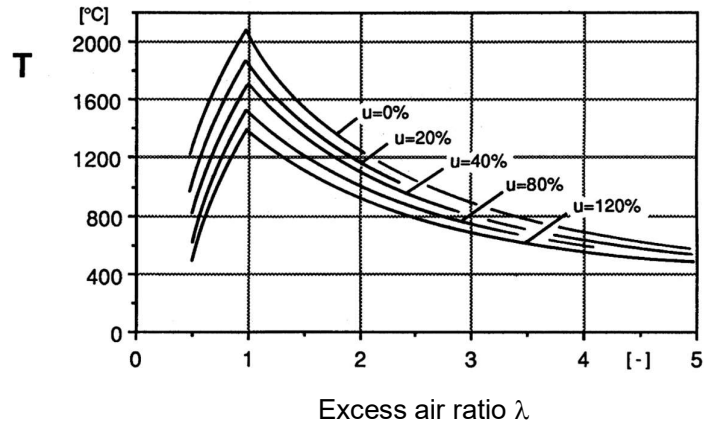


Figure 4.2: Adiabatic flame temperature for the conversion of wood as a function of the excess air ratio for different fuel humidities u (based on dry fuel, hence $u=100\%$ corresponds to a moisture content $M=50\%$) [15].

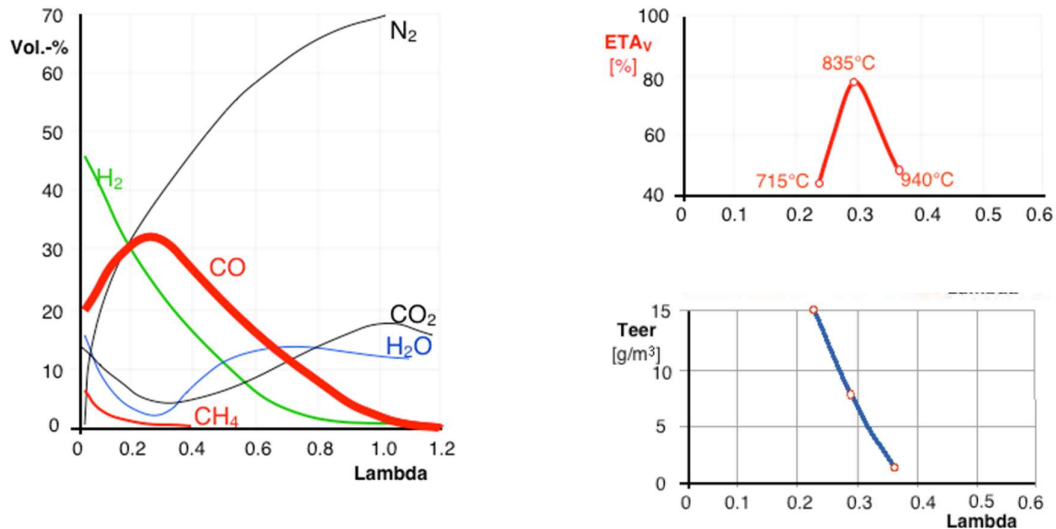
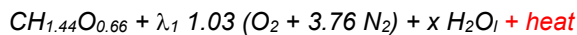
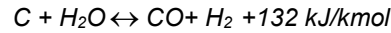


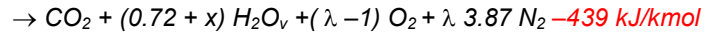
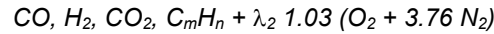
Figure 4.3: Gas composition during biomass gasification (left), gasification efficiency (right above), and tar concentration in the gas (right below) as a function of the excess air ratio λ . Graphs by T. Nussbaumer after data from [16] (left) and [17] (right).

Wood exhibits a typical composition which can be summarized by $CH_{1.44}O_{0.66}$ if fuel constituents such as N, K, Cl, etc. are neglected. The conversion of wood can be described by the following reactions:





(3) combustion of producer gas



In conventional biomass gasifiers, the pyrolytic decomposition (1) and the gasification processes (2) occur in the same reactor but in different zones and with a total excess air ratio of λ_1 in the range of 0.25 to 0.35. The heat is then produced in the reactor, and the process is called autothermal. Since the endothermic conversion of carbon by $C + CO_2 \leftrightarrow 2 CO$ called Boudouard reaction, exhibits an equilibrium on the product side of CO at temperatures $> 900^\circ\text{C}$, high reaction temperatures are needed in the main gasification zone in a gasifier. To assist consecutive reactions in the ideal order and to achieve high temperature in the main reaction zone, many gasifiers apply a principle with different consecutive zones, such as e.g. in co-current downdraft gasifiers designed for IC engine applications, with the following four zones from the top to the bottom:

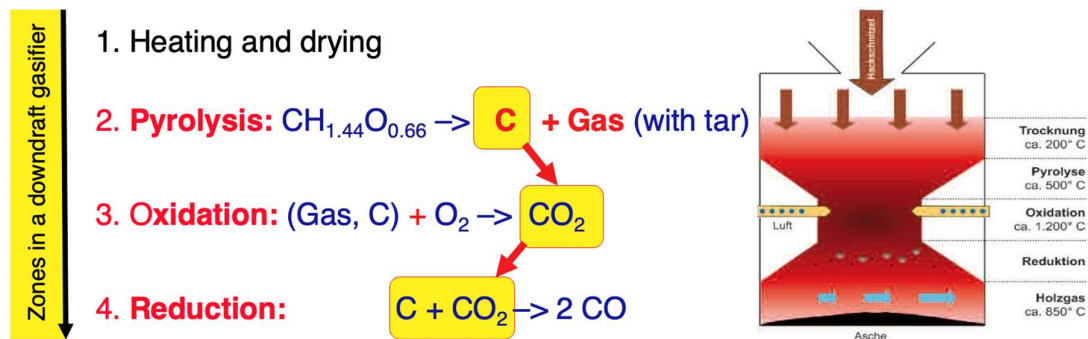


Figure 4.4: Description of the main reactions in the zones of a co-current downdraft gasifier.

Right: Principle of Spanner Re² gasifier. Source: <https://re2.energy/de/> and [18].

If all pyrolysis gases pass the hot reduction zone with a sufficient residence time, the resulting producer gas exhibits a low content of tars and is therefore well suited for IC engine applications. Since the producer gas after the hot zone exhibits a high temperature, a cooling with heat transfer to the solid fuel in the reactor is usually applied by the principle of a counter-current heat exchange. For this purpose, the gasifier is often designed as a counter-current heat exchanger with two concentric cylinders and the hot producer gases flowing in the ring gap.

To further reduce the tar content in the producer gas, two-stage or multi-stage gasifiers are applied, as shown in Figure 4.5. In such systems, the pyrolytic decomposition occurs in a first reactor which is externally heated as an allothermal process. The pyrolysis gas (including organic compounds) is oxidized to CO_2 and H_2O in a subsequent combustion chamber (reactor 2) with injection of air and water vapor. In a final gasification reactor, the charcoal from the first reactor is injected and gasified with CO_2 and H_2O contained in the flue gas from reactor 2.

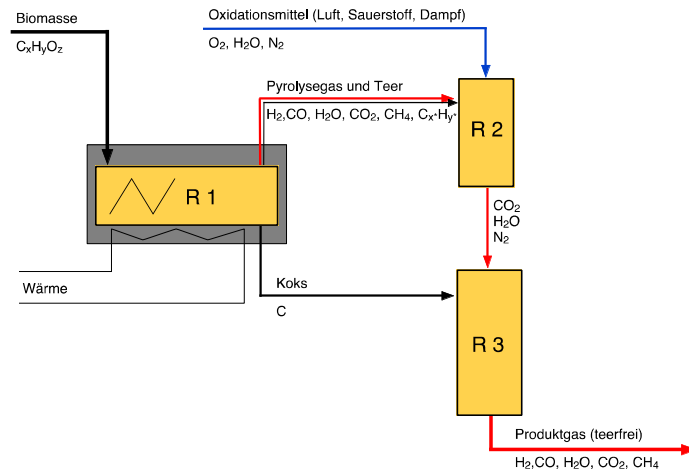


Figure 4.5: Principle of two-stage or multi-stage gasification with three reactors [19]. R1: Pyrolysis reactor (solid to solid and gas) with external heating, usually as a fixed-bed reactor with installations for material transport (screw or stirrer). R2: Combustion chamber (gas/gas reactor) for the oxidation of pyrolysis gas and tar to CO_2 . R3: Gasification reactor for the gasification of solid charcoal with CO_2 and H_2O (no O_2), designed as a fixed-bed or a flow-current reactor.

In the case of biochar production, the gasification reactions (2) are suppressed by a limited oxygen availability and a significantly lower temperature compared to gasification processes. A biochar reactor is externally heated. The biochar production corresponds to the process described in Figure 4.5 without leaving out reactor 3 and using the charcoal from reactor 1 as the final product, and the heat from reactor 2 for heating. However, in the case of multi-stage gasification, there are only minor requirements on the purity and quality of the charcoal for the gasification in a consecutive reactor, while in the case of biochar production, stringent quality requirements need to be met. In case of a utilization for animal feeding and/or for a utilization on soils, the concentration of polycyclic aromatic hydrocarbons (PAH) is limited. Consequently, reactors for biochar production need to guarantee the destruction of organic material by sufficient residence time at a sufficient temperature in the pyrolysis or carbonization reactor.

Considering the above described reactions (1), (2), and (3) of the thermochemical conversion of $CH_{1.44}O_{0.66}$, the combustion reactions (3) occur in a consecutive combustion chamber of an IC engine or for heat production in a boiler in both gasifier plants and biochar plants. To achieve near-complete combustion, the excess air ratio λ_2 in this reaction needs to be around 1 in the case of IC engines with three-way-catalysts or > 1 in the case of a combustion chamber for heat production.

During pyrolytic decomposition and gasification, fuel nitrogen in biomass is mainly converted to HCN and NH-compounds (-NH, -NH₂, and NH₃) in the gas phase and partly oxidized to nitric oxides (NO_x). In the resulting flue gas after the combustion of the producer gas, the following types of pollutants can be distinguished:

1. Unburnt pollutants such as CO, CH₄, C_xH_y, tar, soot, unburnt carbon, H₂, HCN, NH₃, and N₂O. These pollutants are summarized as products from incomplete combustion (PIC) and comprise all aggregate states, i.e., gases, liquid particles, and solid particles.
2. Water (H₂O_v) and pollutants from complete combustion, besides CO₂, especially NO_x (NO and NO₂), and (from natural wood) minor concentrations of SO₂.
3. Solid particles from ash constituents such as KCl, CaO, K₂O, MgO, P₂O₅, and Na₂O.
4. From contaminated biomass fuels, such as e.g. waste wood, additional pollutants can be emitted in significant concentrations. If organic chlorine is available in the fuel, e.g., from PVC, HCl is formed. Further heavy metal emissions can occur (e.g., Pb, Zn, Cu, Cd), and increased emissions of SO₂ and NO_x result from increased Sulphur and nitrogen content of the fuel.

To reduce pollutant emissions in flue gases of biomass boilers, particle separation is commonly achieved by electrostatic precipitation (ESP) or by filtration in fabric filters. However, NO_x emissions are commonly significantly higher than in the flue gas of modern fossil fuel heating and IC engines. In case of gasifier CHP, solid and liquid particles in producer gases need to be reduced to very low levels to avoid damage in compressors and engines, which is achieved by producer gas cleaning, e.g., by filtration. Consequently, particle emissions in the exhaust gas of IC engines are commonly significantly below the emission limit values of biomass boilers. In case of IC engines with three-way-catalysts, NO_x emissions are significantly lower than from biomass boilers and are also achieved if a near-stoichiometric engine operation is ascertained by a lambda-control.

In the case of biochar production plants, the remaining gas exhibits a reduced concentration of CO and CO_2 with correspondingly increased H_2 concentration. Although it exhibits a relatively low heating value, the gas is suited to be combusted in a gas burner for heat production.

4.2.2 Integration of biomass plants in heat production and district heating

For the implementation of CHP plants and biochar plants, the following characteristics need to be considered:

The efficiency to convert biomass to electricity in the investigated CHP plants is in the range of 20% to 30%, and the biochar yield is smaller than 50% based on energy content. To ascertain an efficient use of the energy wood and a constant operation of the plants (which is an important precondition for an undisturbed operation and low pollutant emissions), the plants should utilize all the waste heat or at least a high part of it. In addition, a significant heat utilization is also necessary to meet the legal requirements of the authorities (cantons) or the funding agents (where applicable), as described in chapter 4.1.3.

In the case of heat supply for buildings, an annual load duration curve of the heat demand is shown in Figure 4.6 applies in Switzerland for Zurich as an example of the midlands. Heating systems for buildings usually achieve 2000 to 2500 annual full load operation hours. Consequently, a reasonable process integration of CHP plants often applies a dimensioning of the heat output to e.g., 30% of the nominal heat demand as shown in the example in Figure 4.7, which enables an operation of around 6000 annual full load hours. Thanks to the heat consumption of the drying process, this value can be increased for gasifier CHP and biochar plants to an estimated value of 40-50% to ascertain approximately 6000 hours of operation. In addition, a certain part of the waste heat is commonly dumped by a cooling system, which is installed for safety reasons and control purposes.

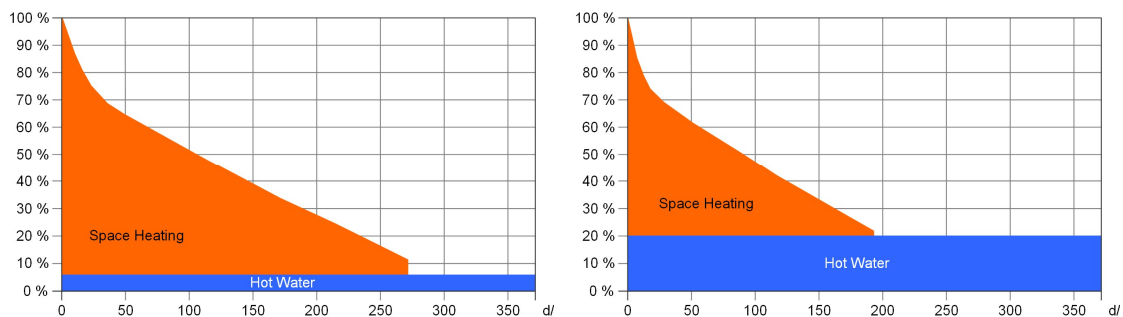


Figure 4.6: Annual load duration curve of the heat load demand for a residential building for domestic hot water and space heating (design according to Zurich, daily mean temperature -7°C). Left: Building standard from 1970. Right: Building standard from 2020. Source: [20].

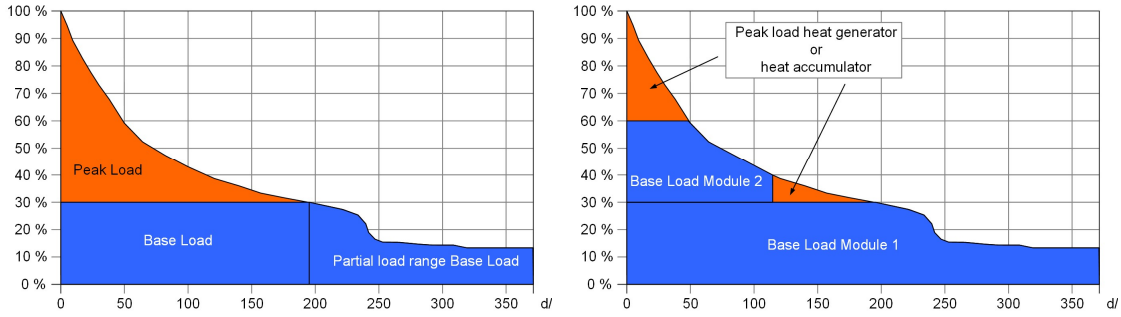


Figure 4.7: Left: Breakdown of the annual duration curve into base load and peak load, with base load enabling an operation at nominal load and partial load from 50 % to 100 % nominal load. Right: Covering the base load with two base load modules. Source: [20].

The full load hours depend on the dimensioning of heat supply systems as follows:

The full load operation of 6000 h/a (as assumed for the base case in the following chapters) corresponds to a plant design with either a high share of process heat supply and/or a base-load operation for a thermal network. In the latter case, the CHP module is dimensioned to typically 30 % to 40 % of the maximum heat demand of the thermal network. Example:

- The smallest Gasifier CHP module size is 50 kW_{el}
- This corresponds to 150 kW energy output (50 kW_{el} + 100 kW_{heat}) and to 176 kW fuel input.

A typical thermal network would correspond to the following district heat supply:

$$100 \text{ kW CHP heat} / 0.30 = 333 \text{ kW} \text{ or } 100 \text{ kW CHP heat} / 0.40 = 250 \text{ kW.}$$

Consequently, the following rule applies for this type of gasifier CHP, where the efficiency for increasing plant size remains nearly constant since the size increase is achieved by adding additional CHP modules of the identical technology:

Power output of a gasifier CHP = 50% of the heat output of the gasifier CHP

$$= 15\text{-}20\% \text{ of the heat demand of the district heating network.}$$

4.3 Overview of state-of-the-art technologies

This chapter introduces the most common technologies for biomass gasification and carbonization in the size range from 100 kW to 5 MW, where mainly fixed bed reactors and variants thereof are applied and operated at ambient pressure with air. Basic advantages and disadvantages of the different reactor types are discussed, and examples of plants in operation in Switzerland are described. Since the conversion efficiency to electricity in CHP plants and to biochar in carbonization plants is limited, waste heat from the process is commonly used as a by-product.

4.3.1 Fixed-bed gasifiers for biomass CHP

Co-current gasifiers

In the past decades, a large variety of biomass gasification systems has been developed for decentralized power production in IC engines in the size range of 20 kW_{el} to more than 1 MW_{el}. Most of them are based on a **co-current** gasifier by a **downdraft** principle followed by a gas cleaning system which usually consists of a main filter for particle removal and often a second filtration step

applied as a safety measure to protect the IC engine from damage due to occasional breakthrough of particles.

Since the conventional principle of co-current downdraft is not suited or only limitedly suitable for scale-up, the gasifier components were often limited to a size referring to less than 200 kW_{el}. To enable larger size plants, cascades of gasifiers are often applied in two versions, i.e., cascading several gasifiers to feed one engine and/or cascading modules of gasifier CHP plants consisting of one gasifier and one engine.

In many cases, the gas cleaning leads not only to solid residues but also to liquid residues referred to as tar and usually available in a mixture with wastewater. Since this can lead to unexpectedly high maintenance and disposal costs, many gasifier CHP plants were put out of order after a limited operation period. One example is the CHP plant in Stans (NW) based on eight downdraft gasifiers developed in Switzerland, feeding two gas engines. For this size (typically from 400 kW_{el}), gas engines from Jenbacher (AUT) are available, which achieve high efficiencies, and which were optimized not only for natural gas but also for producer gas from biomass gasification.

Since IC engines are sensitive to particles, the particle separation prior to the engine needs to guarantee a low particle concentration in the producer gas prior to entering the turbocharger and the engine. If significant particle formation in the engine is excluded (which, due to experiences so far, is true for the applied Otto engines), the particle concentration in the exhaust gas after the engine is usually significantly lower than the applicable emission limit value.

To meet the emission limit values of NO_x emissions for stationary engine applications in Switzerland, the following two technologies are applied:

1. Selective catalytic reduction (SCR) with injection of a reducing agent and use of a catalyst in the exhaust gas. Examples: Spanner Re², Wegscheid Entrenco.
2. Lambda-controlled engine operation and use of a three-way catalyst. Example: Lipro Energy.

More recent developments of similar principles have been introduced to the market, e.g., from Spanner Re², a company from Germany which currently has more than 1000 CHP modules in operation worldwide, from which 12 are running in Switzerland. The technology is described in Figure 4.9 and Figure 4.10. Due to relatively small power sizes of the gasifiers, IC engines from car or truck manufacturers are commonly applied, except in cases of applications of several gasifier modules, which also offer the opportunity to feed one larger Jenbacher gas engine by the producer gas from several gasifiers. Similar gasifier CHP plants are available from Wegscheid Entrenco (GER) (e.g. Figure 4.14), Burkhardt (GER) or Glock (AUT), and in operation in Switzerland.

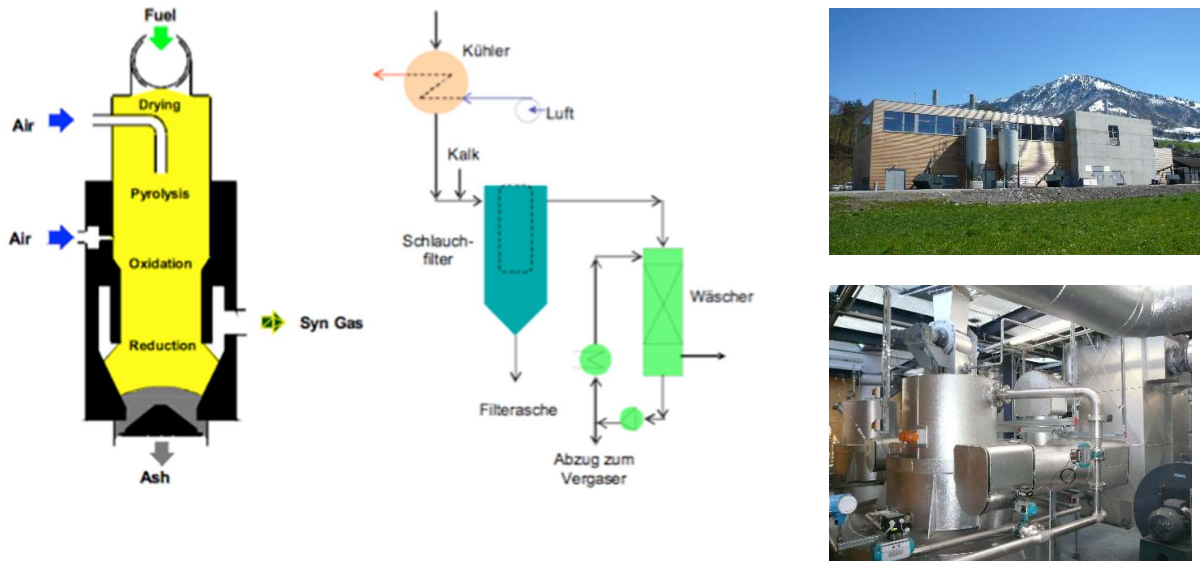


Figure 4.8: Gasifier CHP plant in Stans with eight Pyroforce gasifiers feeding two Jenbacher gas engines with 690 kW_e each [21].



Figure 4.9: Gasifier CHP module from Spanner Re². Top: Dryer. Middle: plant layout. Bottom: new plant before delivery. Source: <https://re2.energy/de/> and [18]. Photos top and bottom right: T. Nussbaumer, 2024.



Figure 4.10: Gasifier CHP plant from Spanner Re² in Switzerland. Left: Gasifier. Right top: View into gasification reactor after operation. Right bottom: Liquid residues (tar). Photos: T. Nussbaumer, 2024.



Figure 4.11: Wegscheid Entrenco gasifier for CHP plants with 135 kW_{el} and 266 kW_{th}.
Source: <https://we-bioenergy.com>, 06.03.2025.

Multi-stage gasifiers

For a few years, Lipro Energy (GER) established a wood gasifier CHP system based on a **multi-stage gasification** in the size range from 50 kW_{el} to approximately 400 kW_{el} described in Figure 4.12 and Figure 4.13. Currently, more than 20 plants are in operation in Europe, with five or more in Switzerland. Thanks to the multi-stage gasification, a nearly tar-free producer gas is achieved, enabling a continuous operation of an IC engine with lambda control and a three-way catalyst.

Consequently, pollutant emissions in the flue gas are significantly below the Swiss emission limit values for all recorded pollutants, i.e., CO, particulate matter, and NO_x.

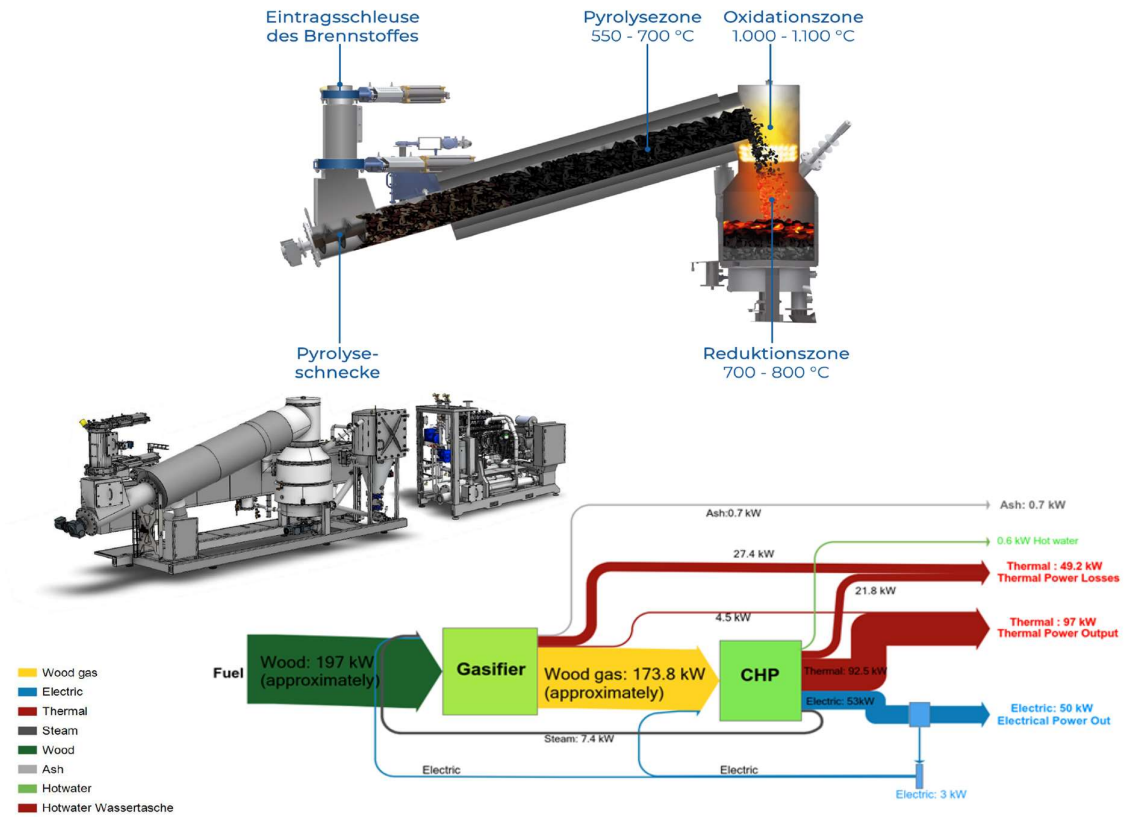


Figure 4.12: Multi-stage gasification system Lipro (Lignin Pyrolysis Reduction Oxidation). Source: <https://lipro-energy.de> 18.10.2024.

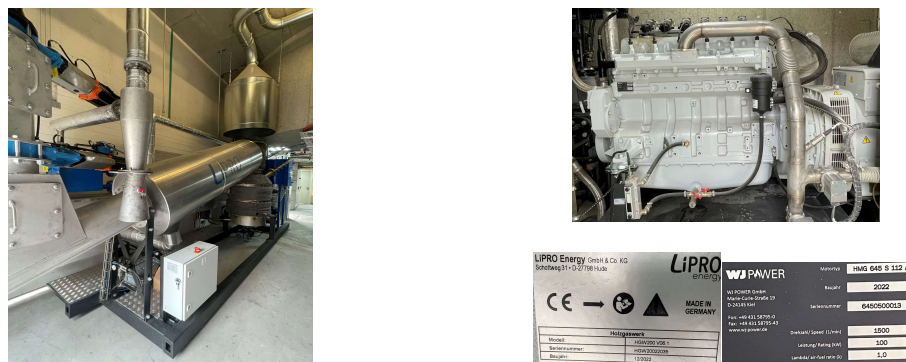


Figure 4.13: Lipro CHP plant in Switzerland with a gas WJ Power engine with lambda control and a three-way catalyst. 200 kW fuel input, 100 kW heat output, and 50 kW_{el} power output. Photo: T. Nussbaumer, 2024.

Counter-current gasifiers

In co-current downdraft gasifiers, low tar concentrations in the producer gas are achieved thanks to a hot charcoal zone upstream of the gas outlet, in which tar molecules are cracked. To enable the producer gas to be used as engine fuel and to avoid high energy losses, the hot producer gas is cooled down, and the heat is usually recuperated by a heat transfer to the inlet air.

In **counter-current** gasifiers with the **updraft** principle, on the other hand, the product gas passes the cold biomass prior to exiting the reactor, resulting in high tar concentrations in the gas. Earlier applications in Scandinavian countries were the use of counter-current gasifiers to replace fossil burners in large boilers for district heating networks. However, counter-current gasifiers are also used for CHP applications. To enable its use as engine fuel, however, tar cracking at high temperature and/or with the use of a catalyst or a tar separation in the gas cleaning section is required. In case of tar separation, the tar is found in the liquid phase, forming an oil in a mixture with water and other compounds. This oil is usually burnt in a boiler to generate heat on site. This technology is used, for example, by the Regawatt gasifier shown in Figure 4.14 where a tar removal is applied by a wet electrostatic precipitation, which leads to a "bio-oil" which is burnt in a boiler to supply district heat. Some plants of this type are in operation in Switzerland [30].

Compared to co-current gasifiers, counter-current gasifiers are capable of using wood with high moisture content. Consequently, a technical drying is not necessary. On the other hand, the tar removal and tar treatment cause additional technical components and maintenance work. Due to this, counter-current gasifiers are usually applied in the size range of more than 3 MW fuel input.

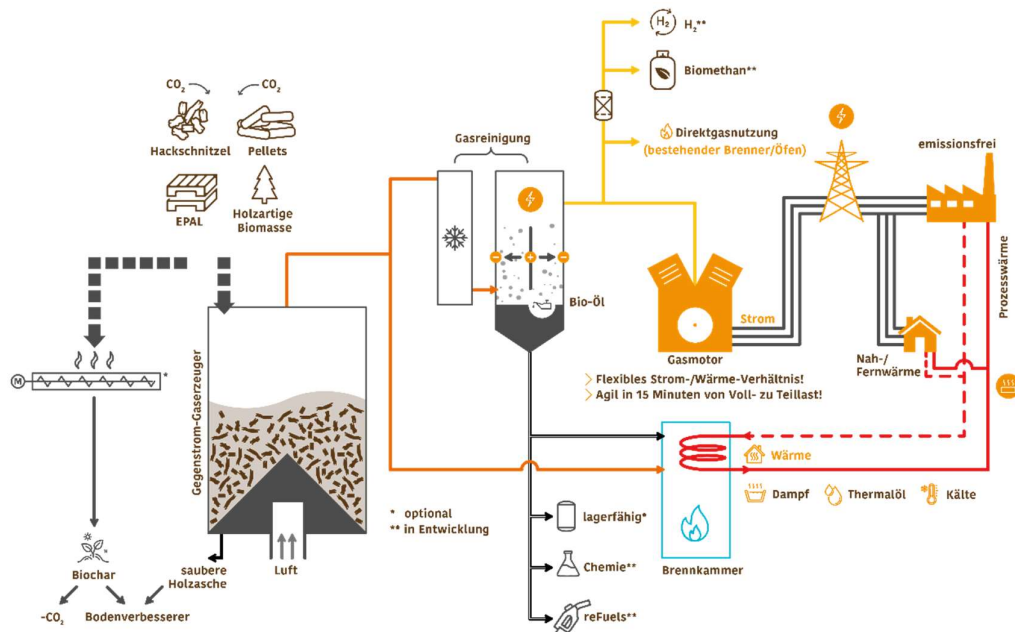


Figure 4.14: Regawatt Gasifier CHP plant. Source: <https://regawatt.de> 04.11.2024.

4.3.2 Biomass carbonization and biochar production

Commercial plants for biochar production resemble pyrolysis reactors. For its practical application, a continuous operation for several thousand hours annually is usually aimed at. As described above, the operation is optimized with respect to the yield of solid charcoal and to meeting the quality requirements for use as biochar, including low PAH concentrations. Figure 4.15 and Figure 4.16 show examples of plants in operation in Switzerland from Biomacon and Pyreg. As indicated by the levels of pollutant emissions, for example, 2, the emissions are significantly below the limit values, particularly with respect to NO_x and particulate matter.

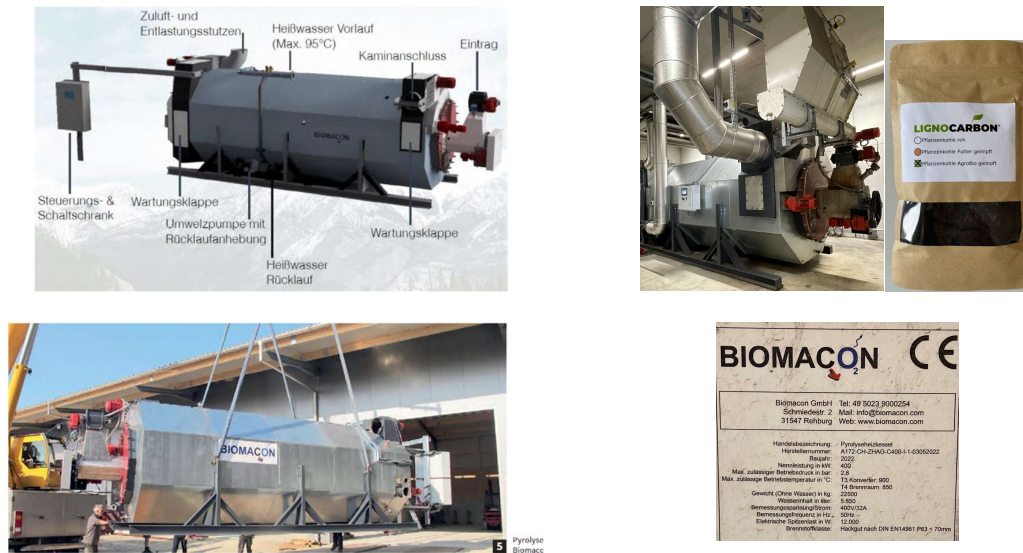
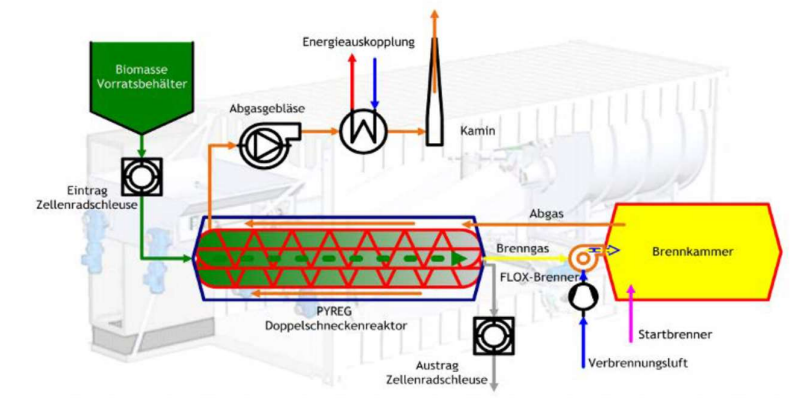


Figure 4.15: Biomacon biochar production plant. Left: Biomacon C400I IB 2019, fuel consumption 1'500 t/a, biochar production 300 t/a, air heater for biomass dryer 650 kW, heat production 1300 MWh/a, biomass drying (summer) 600 MWh/a [22]. Right: plant in operation in Switzerland 2024. T. Nussbaumer, 2024.



Emission	UNIT	VERORA juni 2018 wood	VERORA juni 2018 waste timber 1	VERORA juni 2018 waste timber 2	VERORA juni 2018 waste timber 3	Grenzwert LRV	Column1
Carbon Monoxide	mg/m ³	59	97	112	118	500	CO
Nitrogen Oxide as	mg/m ³	13	18	15	16	250	NOx as NO2
Hydrocarbons	mg/m ³	9	37	27	20		CxHy
Dust	mg/m ³	14	2.3	3.6	5.5	20	Smoke

Figure 4.16: Pyreg biochar production plant. Fuel consumption 2200 m³ wood chips per year, biochar production 550 - 650 m³ per year, plus heat for drying [23].

4.3.3 Biomass gasifier with biochar production

The company Syncraft (AUT) developed a gasification system based on a floating bed reactor. This technology consists of a multi-stage gasification, which combines characteristics of fixed-bed and fluidized-bed gasifiers. It can be applied as CHP plant with the advantage of nearly tar-free producer gas or operated in a mode with production of coke as a second product, which fulfills specific quality requirements for biochar. Due to the significant producer gas output, the biochar yield is reduced correspondingly to typically around 10% based on energy input.

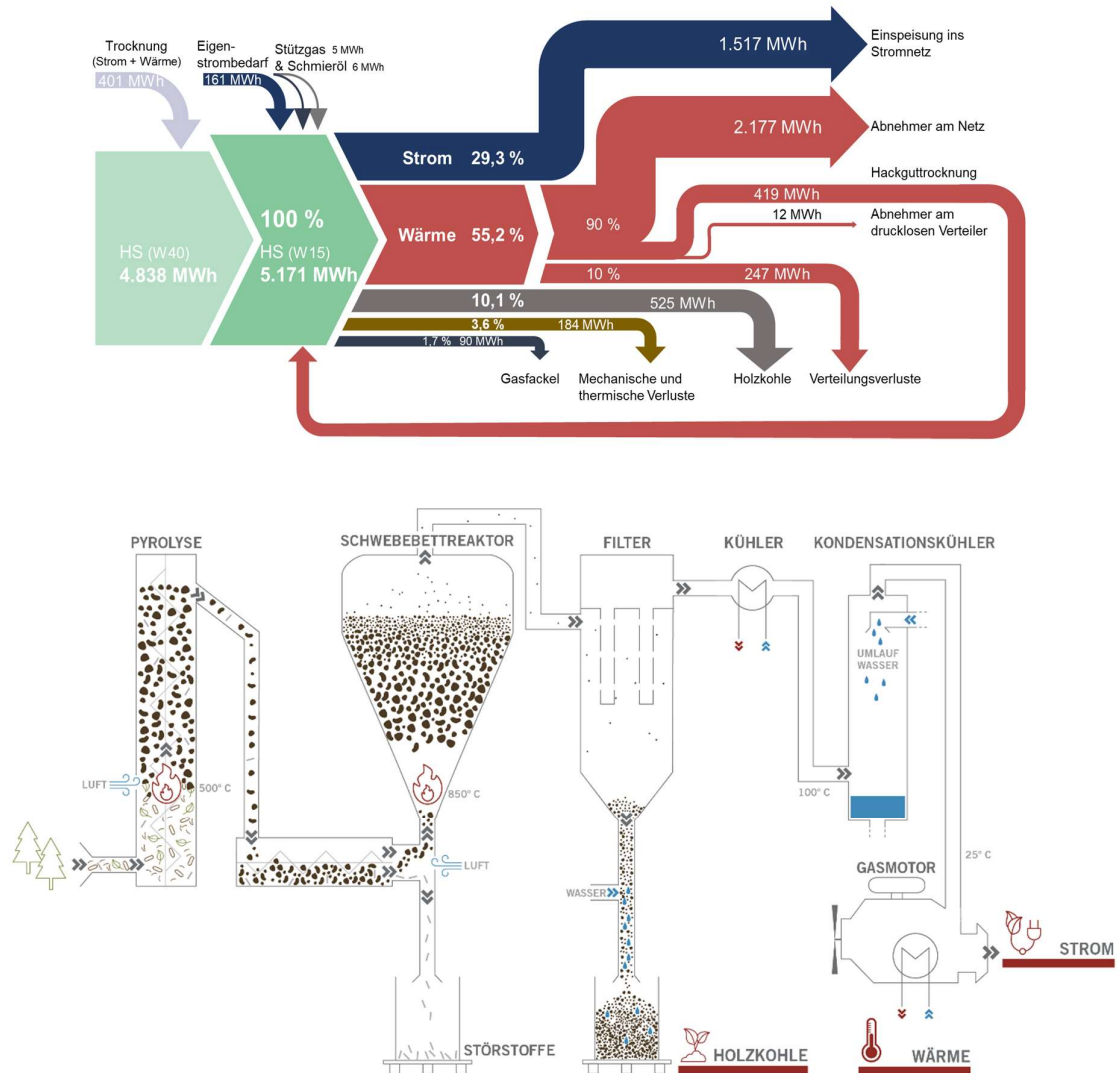


Figure 4.17: Syncraft plant with two-stage gasification with an updraft screw pyrolysis reactor followed by a floating bed gasification reactor. Top: Sankey diagram, below: process flow sheet. Besides producer gas for IC engine applications, biochar is produced as an additional product [24].



Figure 4.18: Synkraft plant in operation in Switzerland. Left: Floating bed reactor, right: Engine, filter detail, biochar. Photos: T. Nussbaumer, 2024.

4.4 Techno-economic assessment

4.4.1 Method

To enable a comparison of the economic effect of different technologies, the specific energy production costs are calculated by the annuity method. The energy production costs include capital cost (capex) and operating costs (OPEX). The operating costs are divided into fuel costs and operating costs without fuel. Operating costs without fuel include maintenance and other indirect cost e.g., for administration and insurance, but are called maintenance costs in the further text. Therefore, the following applies:

$$\text{Annual cost [CHF/a]} = \text{capital cost [CHF/a]} + \text{operating cost [CHF/a]}$$

$$\text{Capital cost [CHF/a]} = \text{investment cost [CHF]} \cdot \text{annuity factor } \alpha \text{ [a}^{-1}\text{]}$$

$$\text{Operating cost [CHF/a]} = \text{maintenance cost} + \text{fuel cost [CHF/a]}$$

The annuity factor α is calculated as a function of the interest rate and the calculation period:

$$\text{for } i = 0: \quad \alpha = \frac{1}{n} \text{ [a}^{-1}\text{]} \quad \text{for } i > 0: \quad \alpha = \frac{i(1+i)^n}{(1+i)^n - 1} \text{ [a}^{-1}\text{]}$$

with i = interest rate [a⁻¹]

n = calculation period [a]

The investigated technologies convert biomass into two or three different products: electricity, heat, and biochar. To enable a comparison, all three types of products are considered by their energy content.

4.4.2 Basic assumptions

By consideration of the number of plants in operation, the gasifier CHP modules from Spanner Re² are, with more than 1000 plants in operation, by far the most applied technology today. Consequently, reliable data on investment costs are available for the three commonly available plant sizes, together with design values on efficiencies from the supplier. In addition, a limited amount of data from plants in operation is available in the literature. Furthermore, data on cost, efficiency, and maintenance were collected by an operator of a plant in operation in Switzerland in 2024. Since the gasifier technology of Spanner Re² exhibits limited opportunities for scale-up, plant sizes exceeding the size of the largest gasifier module are realized by cascading several gasifier modules to the desired size in two available options. On the one hand, several gasifier CHP modules with one IC engine matching the size of one gasifier can be applied, or several CHP modules can be used to fuel one industrial-size IC engine (e.g., from Jenbacher starting from 400 kW_{el}). The industrial IC engine exhibits a higher investment cost but promises higher efficiency and lower maintenance costs. Consequently, both possibilities are applied.

Besides data from Spanner Re², data from gasifier CHP plants of similar size are available from other suppliers, in particular Wegscheid Entrenco (GER), Burkhardt (GER), and Lipro Energy (GER).

Hence, for the present assessment, gasifier CHP plants are introduced as base case with data on investment cost and efficiency resulting from the three different modules of a Spanner Re² plant described in the appendix. These data were validated with punctual data from other gasifier installations, which showed certain deviations but basically confirmed the cost assumptions.

An analysis of the investment cost of the three available module sizes, a factor of 1.4 is found for the economies-of-scale (i.e. the price increase to double the power is 40%).

the cost of a CHP module is 1.4 times the cost of a module with 50% energy output. When exceeding the size of the largest available CHP module, the number of CHP modules is increased. Due to this, the scale effect for further size increase does still apply to the fuel logistics and the infrastructure (including the fuel storage and the dryer), but not to the CHP module. Consequently, a reduced scale factor of 1.1 is assumed for further size increase.

Since the information on investment cost from technology suppliers does not cover all cost factors, additional costs for buildings and fuel logistics, considering land area and building volume are introduced as described in the appendix. The assumptions are valid for sites that are reasonable for gasifier applications in Switzerland and hence do not reflect excessively high cost of urban areas (since installation of gasifiers in such areas is unlikely) or very low cost for rural areas (since the heat demand of such locations is usually limited and thus not suitable for heat-controlled operation of CHP plants).

4.4.3 Assumptions for the base case for gasification CHP

The following assumptions are considered for the gasifier CHP, which is described as the base case, and which results in the energy production cost illustrated in Figure 4.19.

Efficiencies

The assumptions on the gross efficiencies are based on information from the supplier and from literature, as described in the Appendix 7.2 and 7.3 and summarized in Table 4.1. The efficiency data from the supplier refer to a gasifier operation with dry wood with a moisture content of 9%. Here, the energy consumption for drying of forestry wood chips with around 40% moisture is considered with 20% heat consumption referring to a standard drying process with an efficiency in the order of 50% or slightly more. For all co-current gasifiers and for all carbonization processes, the calculations are based on the use of moist wood as fuel input to the plant, while the cases for biomass boilers and counter-current gasifiers do not include a drying process, as these systems are capable of using moist wood. To enable an operation of 6000 full load hours annually, a certain amount of heat is usually dissipated by heat exchange to the ambient, e.g., to enable an operation during summer. This heat dissipation for control purposes varies during the year and is assumed to account for 5% of the fuel input on an annual basis.

Net efficiencies are calculated from gross efficiencies with assumptions on the electricity consumption for the fuel-pretreatment and the plant operation, as shown in Table 4.1. In the case of biomass boilers and biochar production, the electricity consumption leads to a negative electrical efficiency due to the missing electricity generation. Consequently, the electricity consumption for boilers and biochar production is considered in the total efficiencies. While the data in Table 4.1 describe the reference gasification CHP, data for all other processes are given in the Appendix.

Table 4.1: Efficiencies of base case for Spanner Re2 HKA 35, 50 & 70 kWel. Red: assumptions, blue: calculated values. "Input dry wood" describes the efficiencies in the case of dry wood delivered to the plant. "Input moist wood" describes the efficiencies in case of moist wood delivered to the plant, considering the heat consumption for technical drying. Values in brackets: not used for economic calculations for co-current gasifiers, since moist wood is assumed. The net electrical efficiency considers the self-consumption of electricity for the plant. The net efficiency for heat considers the self-consumption of heat for the biomass drying and heat dissipation used for control purposes.

	Product	Symbol	Input	
			Dry wood	Moist wood
Gross Efficiency	Electricity	η_e	28.4%	28.4%
	Heat	η_q	56.9%	56.9%
	Total	η_{tot}	85.3%	85.3%
Gross efficiency weighted by EnFV 2.2.3 = 1 Q + 1.75 EI \geq 70%		η_{ex}	106.6%	106.6%
Self-consumption of heat for dryer			(0.0%)	20.0%
Heat dissipation for control purposes			(5.0%)	5.0%
Self-consumption of electricity			(3.0%)	5.0%
Net efficiencies	Electricity	η_e	(25.4%)	23.4%
	Heat	η_q	(51.9%)	31.9%
	Total	η_{tot}	(77.3%)	55.3%
Net efficiency weighted = 1 Q + 1.75 EI		η_{ex}	(96.4%)	72.9%

Investment cost

a) Investment cost for buildings. For a gasifier CHP plant with 50 kW_{el}, a building volume of 150 m³ with a construction price of CHF 750.- per m³ is assumed, resulting in a total cost of CHF 112'500. The need for building land is estimated to be 50 m² plus 400 m² of sealed land outdoors for drying equipment. For the land, however, an unlimited duration of use is assumed, and the costs are not considered. The building cost for other plant sizes is assumed with a scaling factor according to the square root of the power output.

b) Investment cost for technical equipment. The costs are derived from supplier data and supplemented with cost assumptions for hydraulics and control systems. These costs are assumed as a theoretical minimum, which are commonly exceeded by realized plants in Switzerland today. Data from recently realized plants in Switzerland were collected in various visits and from personnel communication with plant owners and operators. The sources are described in Appendix 7.2 and 7.3 and the data used for the economic assessment are summarized in Appendix 7.4.

As base case, the **technology of a co-current downdraft gasifier CHP** is assumed in a cost analysis of data from Spanner Re² and consideration of additional costs for the implementation of the technology in Switzerland. This technology is proven, and the design and material (mainly black steel) correspond to the lower range of the investment cost. Since the operation of this type of biomass gasifiers demands wood fuel with low moisture content, low content of fines, and low content of ash, a suitable wood dryer from the same manufacturer is included in the cost estimation. In case of dry wood chips available from wood manufacturing, the investment cost and the capex can be reduced by approximately 25%.

Investment cost for plant **construction and operation in Switzerland** at well suited conditions is assumed, which is applicable for moderate costs for building and infrastructure (e.g., in the wood industry or existing heating plants in suburban areas).

Full Load Operation 6000 h/a. For CHP applications in Switzerland, typically 5000 to 8000 full load hours of operation are aimed at. For this type of operation, typically at least 5-10% of the heat production (in some cases more) is transferred to the ambient to enable a stable operation of the CHP module. Consequently, 5% of the dumped heat is assumed in the calculation. The reference value of 6000 h/a applies usually only if the CHP module is designed to supply less than 50% of the maximum heat demand. An example is discussed in the next chapter.

An annuity for an interest rate of 3.0% p.a. for 20 years. This assumption refers to the reference operation with 6000 annual full load hours. The lifetime is, however, assumed to be independent of the full load operation hours. Since the lifetime can depend on the full load hours, the calculations are pessimistic for an operation with fewer annual full load hours and optimistic for more full load hours.

Fuel Price 60 CHF/MWh (6.0 Rp/kWh). The average price in Switzerland in 2024 is reported to be around 55 CHF/MWh. For new plants causing an additional demand, a slightly higher price is assumed.

Annual maintenance cost 5% of Invest cost. In practice, the maintenance costs are not linked to the investment cost, and in certain cases higher investment cost (e.g., more expensive material with longer lifetime) enables lower maintenance costs. Nevertheless, the assumption of maintenance cost as a function of the investment cost is reasonable except for the comparison of different technologies.

4.4.4 Sensitivity analysis on the influence of design and operation parameters

Figure 4.20 to Figure 4.25 show the results of a sensitivity analysis describing the influence of the main design and operation parameters as follows:

- **Investment cost 80%, 100%, 120% of typical conditions**
100% corresponds to the calculated cost as the base case.
80% corresponds to optimistic cost with reduced additional expenses compared to the base case, which is possible in case of low costs for building and fuel storage, or with synergies to other biomass utilization at the site.
120% corresponds to moderate additional cost for building and infrastructure, as is often the case to fulfill local requirements in Switzerland. However, at non-ideal conditions (e.g., fuel storage and CHP plant installation in the basement floor, as also common in Switzerland), at least 140% of the reference cost needs to be considered.
- **Full Load Operation 8000 h/a, 6000 h/a, 4000 h/a, 2000 h/a.**
- **Annuity for interest rate of 1.5%, 3.0%, 6.0% p.a. for 20 years of operation.**
- **Fuel Price 30, 60, 120 CHF/MWh.**
- **Annual maintenance cost 2.5%, 5.0%, 10% of Investment cost.**
- **Technology comparison of gasifier CHP and biochar plants**
The aim of this assessment is to determine different technologies that produce electricity or biochar as the main product and heat as a by-product. To this end, the specific production costs for **electricity**, **useful heat**, and **biochar** from wood are to be calculated. The market prices for all three products, however, vary over a wide, overlapping range. While electricity exhibits a higher thermodynamic value than heat, the economic value of electricity in CHP plants is often lower than that of marketable heat. The market price of biochar, on the other hand, is strongly dependent on its quality and utilization. Furthermore, the utilization of biochar is not widely established in Switzerland, and its use in agricultural soils is not supported by the Swiss Federal Council, as described in chapter 4.1.3. Consequently, a reliable economic assessment is only possible for a specific case with well-defined boundary conditions. To enable a generic comparison of the production cost of electricity, heat, and biochar in the present study, all three products are assumed to be based on their energy content.
Besides the base case gasifier CHP from Spanner Re² (further named CHP 1), detailed information of a plant with four CHP modules is available from a recent plant planning in Switzerland from another manufacturer (Wegscheid) offering CHP plants with 135 kW_{el} per unit. This gasifier CHP is slightly more expensive than the base case type and is further described as gasifier CHP 2. As for the base case, a wood dryer from the gasifier manufacturer is considered in the investment cost and in the plant operation. The information on these two gasifier CHP plants is actual (2023 and 2024), valid for Switzerland (which based on information of QM Holzheizwerke[®] has approximately two times as high investment costs as Austria) and therefore relatively reliable reserving that in the past three decades, many gasification plants were put out of order after a relatively short operation period due to unexpected incidents (e.g. excessively high operation costs and/or environmental or safety issues). Besides the gasifier CHP 1 and CHP 2, basic data from the multi-stage gasifier (Lipro), which promises higher gas quality and lower pollutant emissions, were also evaluated, showing that energy production costs in the same range or slightly higher than for the base case are expected.
Besides these gasifier technologies used for CHP production, cost estimations for another multi-stage gasifier (Syncraft) are considered, which also promises high gas quality and low tar content, and additionally, the option to produce around 10% biochar production based on the energy content. Due to the more complex plant design (e.g., floating bed reactor) and construction material (stainless steel instead of black steel), higher investment costs are considered, but

higher efficiencies are also expected based on reported data.

Further, a calculation is performed based on an updraft gasifier from Regawatt, which is applicable for larger sizes than a single downdraft gasifier and which is in operation in some plants in Switzerland. Additionally, two types of biochar production plants (Biomacon and Pyreg) are assessed. For these three technologies, no detailed information on cost is available, and the investment costs are estimated based on oral information from operators. The data on efficiencies are reported in the literature; however, in the case of biochar, assumptions on the energy content of biochar are applied due to the lack of reliable data as described in [26]. Consequently, the main findings of the present evaluation are valid for the gasifier CHP, while the information on other technologies is related to a higher uncertainty.

- **Comparison with biomass boilers for heat production**

To enable a comparison with today's standard utilization of energy wood, namely heat supply for buildings and district heating, the heat production costs of typical biomass boilers according to QM Holzheizwerke® [46] are also illustrated. For biomass boilers, an efficiency of 85% is assumed to supply heat for buildings or thermal networks. Since 6000 full load hours of annual operation are assumed as the base case for gasifier CHP and biochar plants, the heat production costs of biomass boilers are described for the same full load hours. In addition, the heat production costs for boilers are shown for an operation with 2000 full load hours only to describe a pessimistic case for a boiler operated to provide heat for buildings.

- **Comparison with steam plants for CHP based on the Rankine cycle**

Combustion plants using steam boilers and steam turbines for CHP exhibit strong economies-of-scale with respect to both electrical efficiency and investment cost. Consequently, they are commonly applied in the size range of more than 5 MW electrical output and more than 20 MW fuel input, while the largest dedicated biomass plant, which is installed in Denmark, exhibits an electrical output of 150 MW and a fuel input of approximately 600 MW [47]. Earlier investigations showed that steam cycle plants in the size range up to 5 MW electrical output applied in Switzerland exhibit a higher energy production cost than central heating systems [48]. The efficiencies and the energy production costs are similar to those of the investigated gasifier CHP plants; however, in a factor of more than 10 larger plants. Consequently, the advantage of gasifier CHP is to enable similar efficiencies and energy production costs in significantly smaller plant sizes than steam plants.

- **Comparison with combined cycle plants**

Significantly higher electrical efficiencies than steam plants greater than 20 MW and gasifier CHP plants smaller than 5 MW fuel input are possible by a combination of a biomass gasification driving an IC engine or a gas turbine, followed by a recuperation of the flue gas for a subsequent steam cycle. This principle is called Integrated Gasification Combined Cycle (IGCC), and the proof-of-concept was shown in a demonstration plant in Sweden in 2004 with a pressurized circulating fluidized bed gasification driving a gas turbine and generating steam from the exhaust gas to drive a steam turbine [49]. The potential of IGCC plants for an efficient use of energy wood in Switzerland was investigated revealed that the plant size should significantly exceed a fuel input of 100 MW [50].

4.4.5 Results

Figure 4.19 shows the specific energy production cost of the reference gasifier CHP as a function of the fuel input based on the lower heating value. The energy production costs are divided into Capex and Opex, with Opex describing the sum of maintenance costs and fuel costs, which are also indicated separately. Figure 4.20 to Figure 4.25 describe the influence of the design and operation parameters.

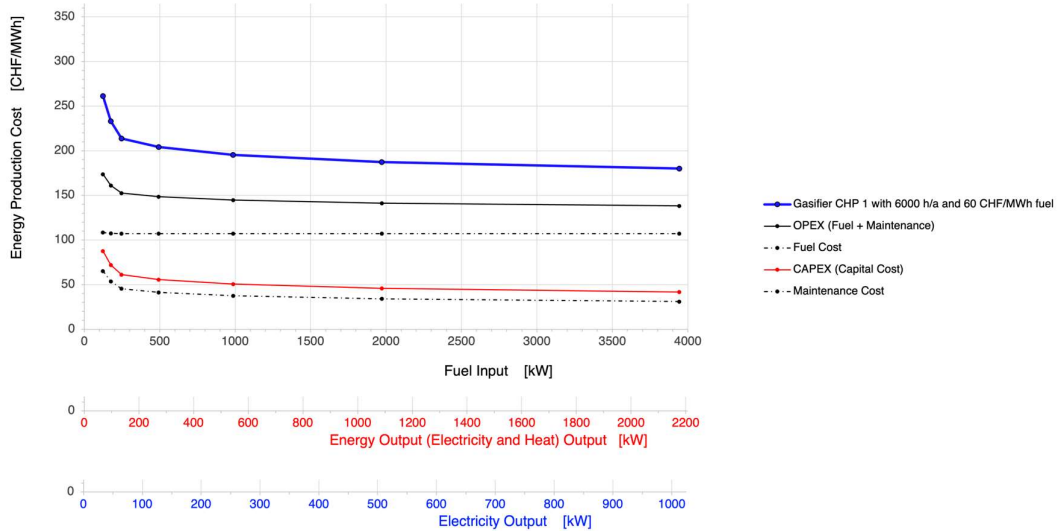


Figure 4.19: Base case for a biomass gasifier CHP plant: Energy Production Cost = Capex + Opex as function of the fuel input based on the lower heating value. The second and third x-axis are valid for the gasifier CHP 1. The second axis corresponds to the approximate energy output of heat and electricity, the third to the approximate electricity output. For the biomass boiler, an efficiency to heat of 85% is assumed; 1000 kW fuel input on the x-axis corresponds to 850 kW heat output.

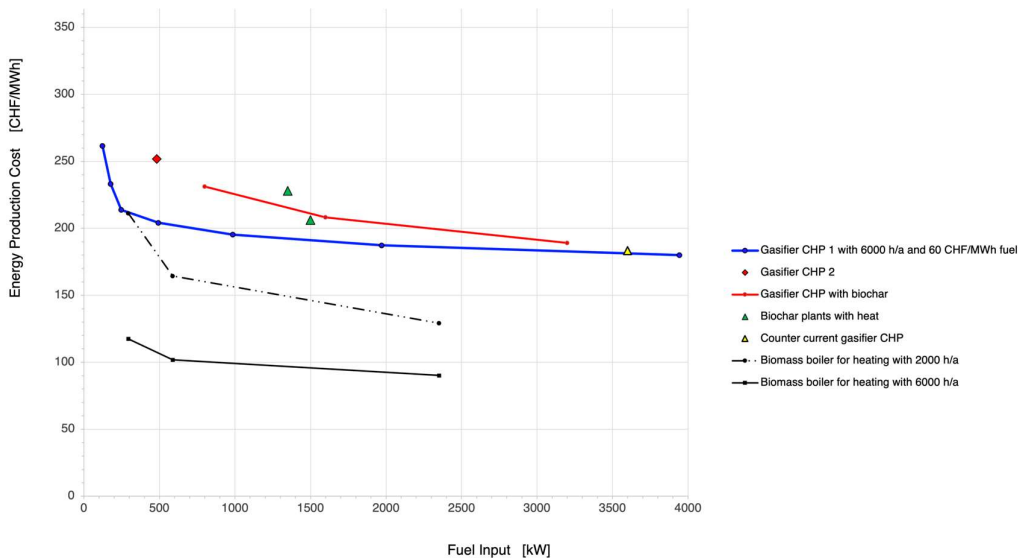


Figure 4.20: Comparison of gasifier CHP 1 (reference co-current downdraft gasifier), gasifier CHP 2, gasifier CHP with biochar production, counter-current updraft gasifier CHP, and biochar plants. In addition, the heat production cost of an automatic biomass boiler is shown for 2000 h/a (as minimum full load hours for monovalent heat supply of buildings), and for 6000 h/a (to enable a comparison with the CHP plants). The second and third x-axis are shown in Figure 4.19 are valid here as well. For the biomass boiler, an efficiency to heat of 85% is assumed, 1000 kW fuel input on the x-axis corresponds to 850 kW heat output.

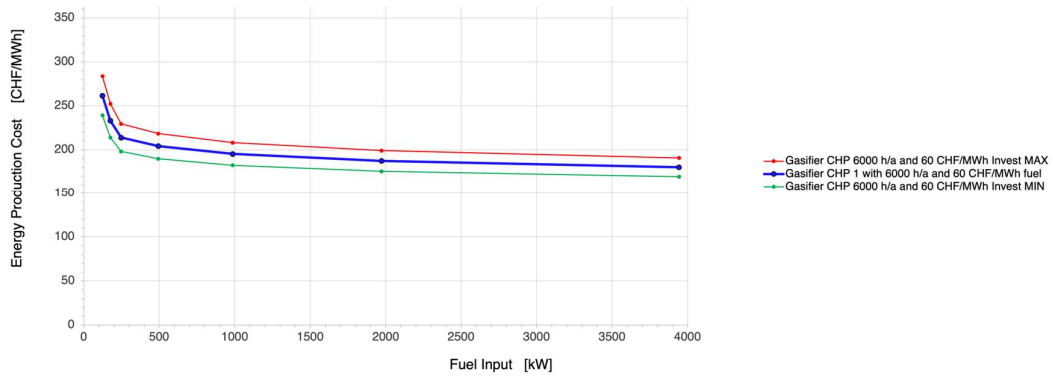


Figure 4.21: Influence of Invest Cost: 80%, 100%, 120% of the estimated real cost in Switzerland 2024.

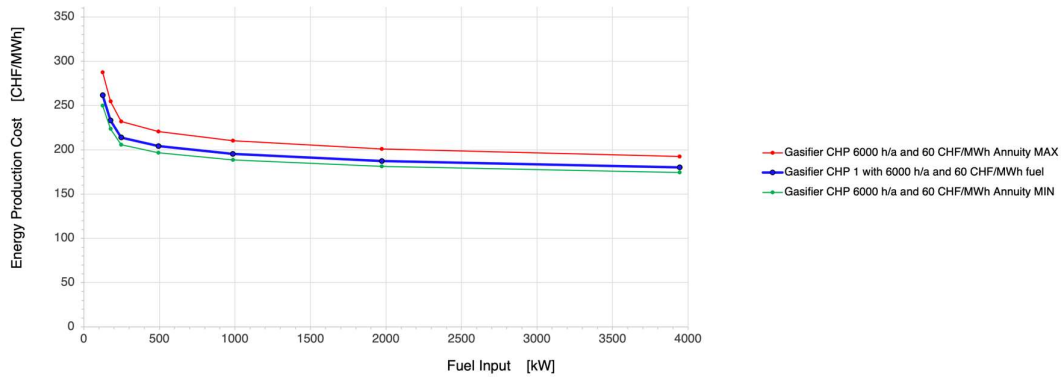


Figure 4.22: Influence of Interest rate: 1.5%, 3.0%, 6.0% p.a. for an annuity with 20 years of operation.

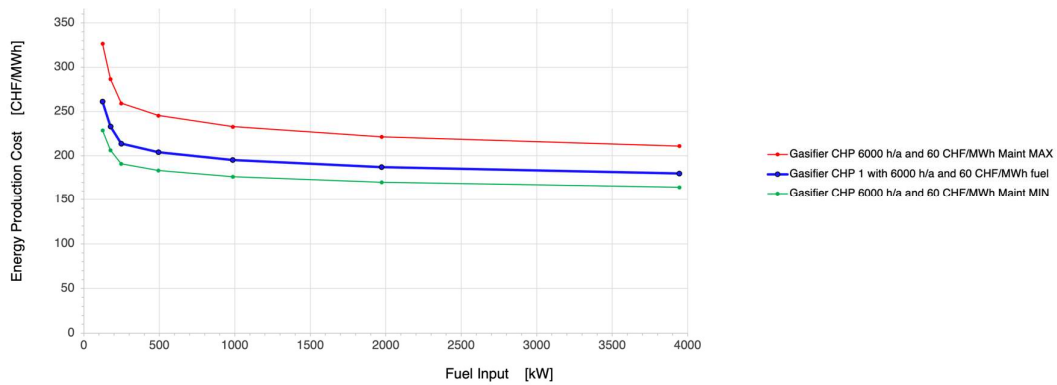


Figure 4.23: Influence of Maintenance Cost: 2.5%, 5%, 10% of investment cost per year.

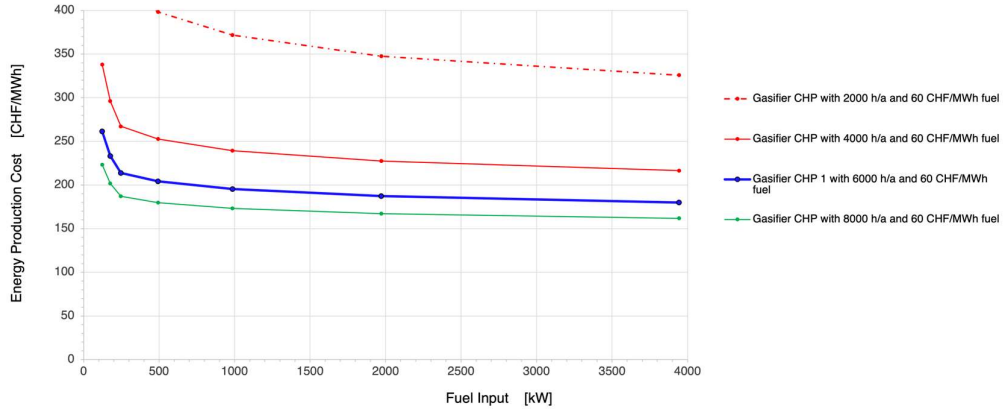


Figure 4.24: Influence of Full Load Operation: 8000 h/a, 6000 h/a, 4000 h/a, 2000 h/a.

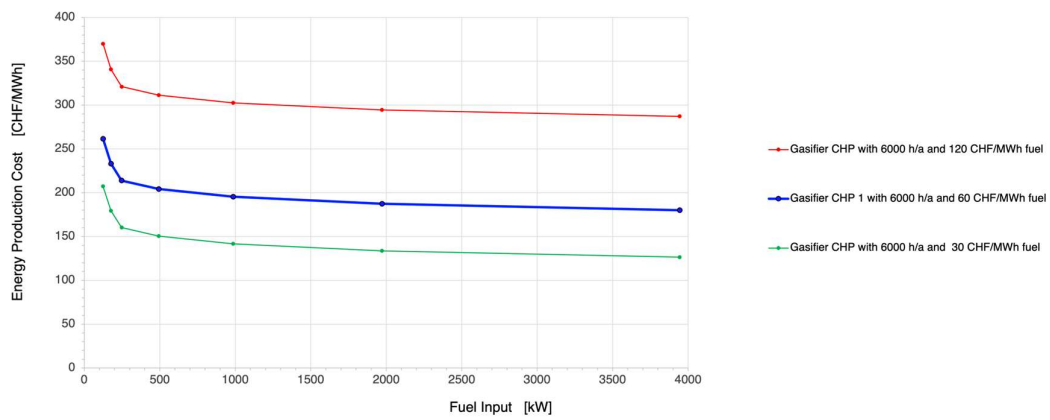


Figure 4.25: Influence of Fuel Price: 30, 60, 120 CHF/MWh (average price in SWI 2024: 55 CHF/MWh).

4.4.6 Discussion

Figure 4.19 and Figure 4.20 show the effect of scale on the energy production costs. However, in the investigated size range, an important effect occurs in the small scale when increasing the plant size from 100 kW to approximately 500 kW fuel input, while a further increase enables only a limited cost reduction for the base case with 6000 annual full load hours and a fuel price of 60 CHF/MWh.

Already at plant sizes of 250 kW fuel input and up, the operation costs of around 150 CHF/MWh clearly dominate with 75% the total costs of approximately 200 CHF/MWh. This would change in the case of significantly lower full load operation and higher fuel prices, which, however, is currently assumed as a theoretical case, since CHP plants are usually designed for high full load operation.

As follows from Figure 4.20, the gasifier CHP 1 is the most economic technology for small scale applications, if the same rate of operational cost is assumed for all technologies. Based on the current assumptions, the resulting differences in energy production costs between the investigated technologies are small. Besides this, and even when considering the high uncertainty of the costs, the comparison with equal valuation of electricity, heat, and biochar based on energy content shows that all types of gasifier and biochar systems exhibit roughly two times as high energy production cost as biomass boilers operated with identical annual full load hours of 6000 h/a. If boilers are operated to supply heat for buildings, 2000 to 2500 full load hours are commonly achieved, resulting in significantly higher heat production costs. In the case of 2000 h/a, the heat production costs from a wood boiler with 250 kW heat output (corresponding to 294 kW fuel input) are approximately doubled and reach a comparable value as gasifier CHP plants, while for larger plant sizes, the heat production costs of biomass boilers remain lower than for gasifier CHP plants even at reduced full load operation.

Due to the far higher energy production costs compared to heat from biomass, all gasifier and carbonization systems investigated here are only of interest if electricity and/or biochar are judged as of higher priority than heat. Due to a cost difference of approximately a factor of 2 in the case of 6000 full load hours, the advantage of electricity and/or biochar compared to heat needs to be judged accordingly.

In line with the observation of the dominant fraction of the Opex, Figure 4.21 shows that an under-estimation or an over-estimation of the investment cost by 20% has only a relatively small effect on the energy production cost. The same is true for the interest rate, as shown in Figure 4.22.

Since the maintenance costs are often under-estimated, the sensitivity analysis shown in Figure 4.23 shows the effect of halving (which today is too optimistic) and doubling (which still underestimates unsuccessful technologies) the maintenance cost. The cost estimations confirm that Opex can become critical in case of high maintenance costs, which can include unexpected disposal of ash, char, and liquid disposals.

As shown in Figure 4.24 and Figure 4.25, the full load hours and the fuel price are by far the most important parameters for the energy production cost of a gasifier CHP. Although not visualized separately, this also applies to all the other investigated technologies due to a similar contribution of the individual cost factors.

While the fuel price for energy wood is assumed to be influenced by the prices for other energy carriers, the full load hours depend on the dimensioning of heat supply systems as described in chapter 4.2.2.

4.4.7 Summary

The collected information is summarized in a qualitative assessment in the following tables.

Table 4.2 "Technology" presents a list of the most important suppliers of gasifier CHP and biochar plants in the investigated size range and summarizes technical parameters and typical investment costs for a turnkey plant in Switzerland, taking into account the building, fuel storage, fuel pre-treatment, and biomass conversion technology of the technologies described from 100 kW to 5 MW fuel input (corresponding to around 35 kW_{el} to 1.25 MW_{el}).

Table 4.3 "Assessment" describes indicative energy production costs in CHF/MWh for typical fuel costs in Switzerland and gives a qualitative assessment of the advantages and disadvantages of the investigated technologies for biomass gasification and carbonization.

Table 4.4 "SWOT analysis" illustrates the strengths, weaknesses, opportunities, and threats of biomass combustion, gasification, and carbonization in systems up to 5 MW fuel input to enable the utilization of sustainably available wood and other biomass in Switzerland and to pursue the following objectives:

1. Achieving a maximum contribution to the Swiss energy supply
2. Ascertaining a minimum environmental impact by a biomass utilization which fulfills the requirements on air pollution, water pollution, and soil contamination, and which is as small as possible within economically reasonable limits
3. Achieving a positive effect on society by considering independence from foreign countries and the effects on national workplaces and wealth.

Table 4.2: Technology: Combustion for heat, gasifier CHP, and biochar plants, which are commercially available and in operation in Switzerland in 2024. ¹⁾ Data from the suppliers. ²⁾ Data from Holzenergie Schweiz 2023 [51] and from suppliers and plant visits in 2024. ³⁾ This gasifier type is not considered in the economic evaluation due to uncertain experiences.

Conversion	Application	Company (country)	Technology	Fuel input per unit	Investment cost for BIT* [CHF/kW]	Fuel flexibility for Moisture M and Ash A	Tar content in the raw gas	Fuel cost	Opex w/o fuel	Units total ¹⁾	Units SW ²⁾
Combustion	Heat	Many suppliers	Grate boiler	0.3 – 5 MW	850 – 2000	high M+A	–	low	low	>1 Mio	>5000
Gasification	CHP	Spanner Re (GER)	Downdraft co-current	125 – 246 kW	3000 – 4500	low	medium	medium	medium	1050	12
		Wegscheid (GER)	Downdraft co-current	200 – 420 kW	3500 – 5500	low	medium	medium	medium	> 130	≥ 3
		Glock (AUT)	Downdraft co-current	80 – 210 kW	(3000 – 4000) ³⁾	(low/medium) ³⁾	(medium) ³⁾	(low/med.) ³⁾	(medium/high) ³⁾	> 50	≥ 4
		Burkhardt (GER)	Updraft co-current Downdraft co-current	190 – 610 kW 500 – 1100 kW	3000 – 4500	low (pellets) low	medium medium	high medium	medium medium	> 250	≥ 2
		Lipro (GER)	Two-stage fixed bed	200 – 340 kW	5000 – 6000	low	low	medium	medium	> 10	≥ 2
		Regawatt (GER)	Updraft counter-current	1 – 5 (20) ⁴⁾ MW	3500 – 4500	high M+A	high	low	high	< 10	≥ 2
	CHP + Biochar	Syncraft (AUT)	Two-stage floating bed	1.4 – 3.5 MW	4000 – 5000	low	low	medium	medium	> 20	≥ 6
Carbonization	Biochar + Heat	Biomacon (GER)	Screw pyrolysis	0.4 – 1.4 MW	3000 – 4000	high A	low	low	low	> 50	≥ 5
		Pyreg (GER)	Screw pyrolysis	0.5 – 6 MW	3000 – 4000	high A	low	low	low	> 50	≥ 2

Technology: *Two-stage fixed bed* = screw pyrolysis followed by fixed bed gasification.
Two-stage floating bed = screw pyrolysis followed by floating bed gasification.

Fuel input per unit: Biomass input multiplied by its lower heating value. This corresponds to the 'Feuerungswärmeleistung' introduced in the Ordinance on Air Pollution Control (Luftreinhalte-Verordnung, LRV) to distinguish the categories for emission limit values by plant size. Small-scale gasifiers are often applied in cascades of two and up to more than 30 units per plant. Gross power production for CHP plants = fuel input x (25-32% efficiency), with the lower value describing applications with small IC engines and the larger value for large IC engines.
⁴⁾ This gasifier type is available up to 20 MW fuel input. The evaluation in the present report considers plant sizes up to 5 MW fuel input.

*** BIT:** Building, Infrastructure, and Technology. The range of the specific cost reflects the scale effect. Consequently, the low value for the specific cost refers to the high value of the fuel input per unit.

Investment cost for BIT: Cost for building and technical equipment for wood storage, fuel pretreatment (drying and sieving), thermal conversion, flue gas cleaning, control system, IC engine, power generator, and feed-in equipment or biochar sales conditioning. As described in chapter 7.4, the costs for BIT exceed the costs for the components for gasifier or biochar plants by a factor of two or more.

Fuel flexibility
low: Limited to dry wood (M < 10% to 20%), low ash (A < 2%), and low share of fines. For this reason, gasifier plants include a dryer.
low (pellets): limited to wood pellets.
high M: Also applicable for biomass with high moisture content (up to 50%).
high A: Also applicable for biomass fuels with increased ash contents (> 5%).
low: < 5% of invest p.a., *medium:* 5% of invest p.a., *high:* > 5% of invest p.a.
medium: wood chips for 60 CHF/MWh in 2024.
high: wood pellets for 120 CHF/MWh in 2024.
low: wood from garden waste, hedges, etc. (collection cost and disposal fee).

Table 4.3: Assessment: Efficiency, air pollution, and experiences for combustion, gasifier CHP, and biochar plants. In this table, all efficiencies describe net values which consider electricity consumption for the plant operation and heat and electricity consumption for fuel drying and sieving for all carbonization systems and for all gasification systems except for the counter-current gasifier from Regawatt. The energy production costs refer to the following assumptions:

- Fuel price of 60 CHF/MWh
- Capital cost for an annual interest rate of 3.0% for a calculation period of 20 years
- Operation with 6000 annual full load hours (except for the high values for the biomass boilers, which is valid for 2000 annual full load hours).
- Efficiencies: η_e = electrical efficiency, η_q = heating efficiency, η_b = biochar efficiency, η_{tot} = total efficiency = $\eta_e + \eta_q + \eta_b$, $\eta_{ex} = 1.75 \eta_e + \eta_q + \eta_b$.

Conversion	Application	Company (country)	Fuel input per unit	Net Efficiencies				Exergetic Value w. El = 1.75 η_{ex} [%]	Impact on air pollution PM NO _x VOC	Quantity of experience	Reliability and success due to experience (independent of quantity of exp.)	Energy production cost [CHF/MWh]
				η_e [%]	η_q [%]	η_b [%]	η_{tot} [%]					
Combustion	Heat for 6000 h/a Heat for 2000 h/a	Many suppliers	0.3 – 5 MW	-3	82-88		82-85	78-82	Low	High	High	90–120 130–220
Gasification	CHP	Spanner Re (GER)	125 – 246 kW	23-26	32-38		55-64	72-84	Low	Medium	Medium	180–250
		Wegscheid (GER)	200 – 420 kW						Low	Medium	Medium	
		Glock (AUT)	80 – 210 kW						uncertain	uncertain	uncertain	
		Burkhardt (GER)	190 – 610 kW 500 – 1100 kW						Low	Medium	Medium	
		Lipro (GER)	200 – 340 kW						Very low	Small	High	
		Regawatt (GER)	1 – 5 (20) ⁴⁾ MW						23-24	40-45		
	CHP + Biochar	Syncraft (AUT)	1.4 – 3.5 MW	23-24	31-36	8-12	64-70	81-88	Low	Medium	Medium	
Carbonization	Biochar + Heat	Biomacon (GER)	0.4 – 1.4 MW		35-45	35-40	77-78	75-77	Low	Medium	Medium	
		Pyreg (GER)	0.5 – 6 MW						Low	Medium	Medium	

Table 4.4: SWOT analysis for gasification: Strengths, weaknesses, opportunities, and threats of biomass gasification in systems up to 5 MW fuel input compared to biomass combustion, aiming at an optimum energetic utilization in Switzerland based on the objectives described in the text above.

Strengths	Weaknesses
<ul style="list-style-type: none"> Gasification enables power production from wood and other solid biomass in small and medium-scale plants from typically 100 kW to 5 MW fuel input at significantly (i.e., up to doubled) higher electrical efficiency than combustion-based CHP plants with heat engines. Gasification enables lower air pollutant emissions on particulate matter (PM) and NO_x compared to biomass boilers, e.g., in the case of staged gasification and use of lambda-controlled IC engines with three-way-catalysts. 	<ul style="list-style-type: none"> Small co-current gasifiers have high fuel quality requirements (i.e., low moisture and fines), which limit the fuel potential and cause additional costs for the fuel pre-treatment compared to biomass boilers or counter-current gasifiers, which, however, are typically in the size range of 5 MW fuel input and more. The net efficiency of electricity and heat generation is lower than the net efficiency of dedicated heat generation from biomass boilers. The use of gasification is therefore usually only promising if the electricity price exceeds the heat price, which is hardly the case in Switzerland at present.
Opportunities	Threats
<ul style="list-style-type: none"> The generation of renewable power from biomass in the cold season with low solar radiation contributes to reducing the winter electricity shortage and supplements PV electricity from buildings. The available size range of gasification CHP offers interesting opportunities for the decentralized use of local forestry wood and of wood residues in the wood processing industry, fitting the Swiss scale of infrastructure and industry. 	<ul style="list-style-type: none"> The requirements on the fuel quality, the personnel skills, the operation costs, and the energy consumption for drying and fuel-pretreatment to ensure a reliable and environmentally friendly plant operation are often underestimated. As a result, some of the plants are operated uneconomically and/or with increased environmental pollution, and/or are taken out of service prematurely. CHP systems must be operated in a heat-controlled manner to achieve high energy utilization. This leads to a limitation of the annual full load hours or, due to high investment costs, to very high energy generation costs, or it can support an undesired operation of CHP systems with heat dissipation to the environment, resulting in a low efficiency. The operation of gasifier CHP plants with typically around 6000 annual full load hours reduces the potential use of energy wood, contributing to a seasonal energy storage by a limited operation of boilers during heat demand peaks in winter.

Table 4.5: SWOT analysis for carbonization and biochar production: Strengths, weaknesses, opportunities, and threats of biomass carbonization and biochar production in systems up to 5 MW fuel input compared to biomass combustion, aiming at an optimum energetic utilization in Switzerland based on the objectives described in the text above.

Strengths	Weaknesses
<ul style="list-style-type: none"> • Carbonization systems are capable to convert low quality biomass with low bulk density and/or high ash content into biochar and heat, which are not directly usable in combustion and gasification plants. • Well-operated carbonization plants enable low air pollutant emissions. 	<ul style="list-style-type: none"> • The net efficiency of biochar and heat generation is similar to the net efficiency of heat generation from biomass boilers. The use of carbonization is therefore only promising if the biochar price achieved exceeds the heat price. Consequently, biochar applications with high economic value are feasible. This is not the case for the substitution of imported barbecue charcoal, which would be a more effective application than the sequestration of biogenic carbon in Switzerland, with the ongoing import of biogenic carbon from uncertain sources.
Opportunities	Threats
<ul style="list-style-type: none"> • Low-grade biomass residues, which are not suitable for conventional biomass boilers and co-current gasifiers, and which today appear as waste, can be valorized. The use of this additional resource can thus increase the potential of biomass resources for energy and products. • Biochar from low-grade biomass residues in Switzerland can be used as a substitute for imported charcoal, which has a high environmental impact due to unsustainable sources (e.g., tropical wood), inefficient conversion in Eastern Europe, and long transportation routes. • The production of biochar offers various applications, e.g. in animal husbandry and/or as soil conditioner in agriculture or use in other soils and/or as an additive in construction materials (e.g., in steel and concrete). In these applications, biochar can substitute non-renewable resources and/or act as a negative carbon emissions technology. 	<ul style="list-style-type: none"> • While the incorporation of carbon into steel and concrete, for example, promises an environmentally friendly use of biochar, its use in agricultural soils in Switzerland is restricted due to recommendations and requirements from the Federal Office for the Environment and the Federal Office for Agriculture to prevent possible contamination. • As for gasification, a heat-controlled operation is needed, thus leading to a limited number of annual full-load hours or to potential heat dissipation. • As for gasification, the operation of gasifier CHP plants with typically around 6000 annual full load hours reduces the potential use of energy wood as seasonal energy storage.

4.5 Conclusions

4.5.1 Assessment of the state-of-the art of the technologies

Biomass gasifier CHP and biochar production plants are available from various manufacturers in Europe in a size range from approximately 35 kW_{el} up to more than 1 MW_{el}. Most systems require dry wood chips of relatively homogeneous size distribution, thus excluding fine and large particles. Further, a high bulk density is required to enable a smooth operation of the gasification process. In case of moist wood delivered to the plant, such as forestry wood chips, drying and a separation of fine and large particles is required. The suppliers of gasification systems offer suitable equipment for the fuel pretreatment by drying and sieving.

If operated as a gasifier CHP by fueling an internal combustion engine, gross electrical efficiencies of 25-30% are achieved at nominal load. In addition, useful heat is available. The gross efficiency for useful heat generation is in the order of close to twice that of the electrical efficiency. However, if fuel drying is required, a significant share of the heat is used internally for that purpose. The share depends on various parameters such as initial moisture content, efficiency of the dryer, and seasonal ambient conditions. Detailed information on net efficiencies is scarce, but an estimation of an average energy consumption in the order of 20% based on the fuel input for drying is assumed.

The described technologies are, in general, capable of fulfilling the requirements on the air pollutant emissions; the most advanced systems are even capable to undercut the emission limits for particulate matter (PM), CO, and NO_x by factors. Nevertheless, experiences from operators and authorities show that the correct operation of such plants is complex and requires a high level of supervision. There is less long-term experience with the operation of gasifiers and biochar plants than with biomass boilers. However, while many gasifier plants installed 10 to 20 years ago were put out of order after some years due to unresolved operation problems or excessively high maintenance costs, most of the technologies available nowadays promise to allow for long-term operation. It is therefore to be expected that maintenance costs will fall with increasing experience and approach the level of biomass boilers. Besides, some recently introduced technologies were still not successful and are likely to disappear from the market, most likely for the following reasons: Some systems are not capable to meet the emission limit values in daily operation, leading to high maintenance costs, or do not achieve a reliable operation with conventional wood fuels, as described in [6].

In comparison to automatic wood boilers, gasifiers and biochar plants offer the advantage of electricity generation or biochar production, respectively, as the main target, while heat is available as a by-product. Compared to steam cycle plants, gasifier CHP systems offer the opportunity to implement CHP plants with similar efficiencies and costs but in significantly smaller sizes. Therefore, gasifier CHP enable supplementary applications to steam cycle CHP plants.

The main disadvantages of gasifier CHP plants and of biochar plants are:

- the higher cost, i.e., investment cost, maintenance cost, and consequently energy production cost compared to heat from wood boilers if all products are accounted for by their energy content and all systems are operated with identical annual full load hours,
- the restrictions on operation and system integration that must be observed to avoid heat dissipation to the environment and to achieve a high overall efficiency with a high number of full load hours, which is a prerequisite for the economic operation of CHP systems.

For a base case gasifier CHP and conditions assumed for typical applications in Switzerland in 2024, energy production costs for electricity and useful heat in the order of 200 CHF/MWh are estimated for an operation with 6000 annual full load hours, an energy wood price of 60 CHF/MWh, annual

maintenance cost of 5% of the investment and capital conditions for a calculation period of 20 years at an interest rate of 3% per year.

The economic evaluation shows that the fuel price and the full load hours exhibit the most important influence on the energy generation cost. For the base case, the fuel cost accounts for more than 50% of the total cost, followed by the capital cost (around 30%) and the maintenance cost (less than 20%). Consequently, the application becomes much more attractive when wood residues that meet the quality requirements for gasifiers are available on site in the wood industry, compared to an operation that is dependent on the purchase of commercial wood fuels. On the other hand, however, higher energy wood prices or a heat-controlled operation with lower annual full load hours lead to a significant increase in the energy production cost.

4.5.2 Potential contribution to the Swiss energy supply

Gasifier CHP and biochar versus biomass boilers

Biomass gasifier CHP, biochar plants, and a combination of both exhibit significantly higher energy production costs than dedicated heat production plants. Consequently, gasifier CHP plants and biochar plants (as well as significantly bigger steam plants) are commonly dimensioned for longer operation periods than heat-only boilers and commonly aim at 6000 annual full load hours and more. To fulfill this requirement, CHP and biochar plants are commonly dimensioned to supply the base load heat demand with less than 50% of the nominal load of buildings or district heating networks. Consequently, biomass gasifiers and biochar production can potentially complement other heat generation systems, while a 1:1 substitution is usually not possible.

When considering the potential of energy wood as a substitute for fossil fuels for a CO₂-neutral energy supply, priority must be given to the use of wood and other biomass fuels for high-temperature process heat, as other renewable solutions for this application are lacking or lead to low efficiencies and high costs. The production of low-temperature heat from wood, on the other hand, must be reduced to a minimum, while the majority of low-temperature heat must be provided by ambient heat and heat pumps powered by renewable electricity [25], [26], [27]. The provision of heat for buildings from energy wood should be limited to a minimum and therefore to cover peak-load demands in periods with a shortage of renewable electricity to operate heat pumps. Gasifier CHP plants and biochar plants are not suitable for such an application, as they must be dimensioned for year-round base load operation. On the other hand, biochar can contribute to reducing carbon emissions and carbon dioxide removal from the atmosphere, but with less potential to replace fossil fuels than is the case with the use of energy wood for high-temperature process heat [26]. Gasifier CHP plants as well as steam cycle CHP plants at larger sizes, on the other hand, can provide renewable electricity in winter to power heat pumps. When operated with a high number of full load hours, however, this application also makes a smaller contribution to the Swiss energy supply than biomass boilers that are only operated in winter for peak load [26]. Therefore, the use of gasifier CHP plants and biochar plants will mainly remain a supplementary application to wood-fired boilers and steam cycle CHP plants.

Gasifier CHP plants compared to steam cycle CHP plants

The use of energy wood in gasifier CHP plants has a similar effect on the Swiss energy supply as the use in steam cycle CHP plants. The main differences are that gasifier CHP plants enable the use of energy wood in smaller plants, however, with high requirements on the fuel quality, while the implementation of steam cycle CHP plants is limited to larger size plants, but additionally enables the use of energy wood from the waste-stream, such as urban waste wood. Consequently, the two

technologies complement each other, while the use of gasifier CHP plants will not lead to a significant change in the contribution of energy wood to the energy supply of Switzerland.

Biochar plants

The production of biochar from energy wood generally reduces the contribution of wood to the energy supply to less than 50% compared to the use of wood for heat and electricity generation. Furthermore, biochar plants are typically operated for 6000 annual full load hours or more. A contribution to seasonal storage by covering peak-load heat demand in winter is therefore not possible. On the other hand, biochar production enables the use of low-grade biomass residues that are not suitable for combustion and gasification due to their low bulk density and high ash content. The use of such biomass residues for biochar production can thus increase the usable biomass assortments and enable an additional contribution to the Swiss energy supply through negative carbon emissions and the use of waste heat from biochar production.

5 Renewable gases by hydrothermal gasification or by methanation of biogenic gases

In this chapter, conversion pathways from biomass to gaseous energy carriers are described, specifically i) hydrothermal gasification of wet biomass wastes, ii) methanation of producer gas from gasification of woody residues, incl. the option to add hydrogen from electrolysis, and iii) direct methanation of biogas. The methanation of pure CO₂ or the addition of hydrogen into anaerobic digesters is beyond the scope of this report, all the more so, as the costs are higher (in case of CO₂ separation prior to methanation) or downstream CO₂ separation is needed due to incomplete conversion (in case of in-situ methanation). The technology description will cover feedstock preparation, main conversion steps, and upgrading steps, as well as simulations, cost studies, and experience with pilot and demonstration plants.

Further, their possible contribution to a resilient and sustainable energy system 2050, and open research questions or development needs will be discussed.

5.1 Thermochemical Gasification and methanation with Power-to-Gas

The process chain from woody biomass or other carbonaceous feedstock (such as straw or refuse-derived fuel) to methane comprises several steps: Feedstock preparation/drying, gasification, gas cleaning and conditioning, methanation (here with hydrogen addition), upgrading, see Figure 5.1. For all these steps, different technologies exist. For an energy and cost-efficient process, optimal technology combinations have to be chosen. The technologies will be discussed in the following section; the section will be concluded by an overview of pilot and demonstration plants with their specific technology choices.

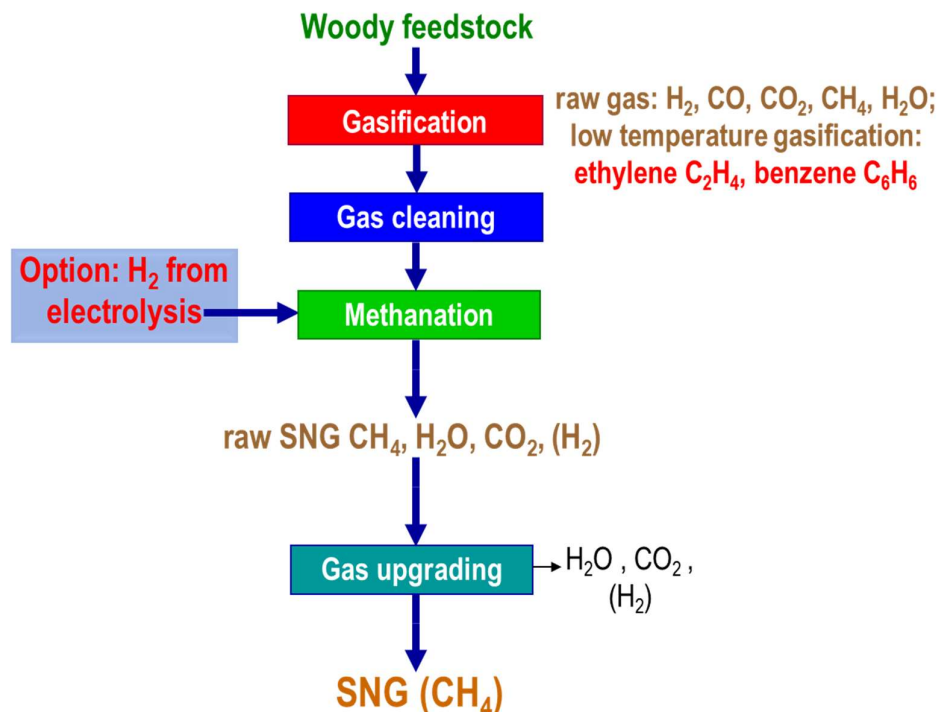


Figure 5.1: Process chain to renewable methane: Wood to Synthetic Natural Gas (SNG) with Power-to-Gas [4.1].

5.1.1 Feedstocks and preparation

Feedstock for gasifiers should fulfil two main requirements: they should be as dry as reasonably possible with the given technical and economic boundary conditions; and the particle size and shape should fit the gasifier type in order to allow for sufficiently fast conversion.

The most common feedstock for biomass gasifiers until today, especially for fluidised bed gasifiers, is wood chips, often directly from forestry. They are dried in the air for some time, or in belt driers, if abundant heat is available. Besides wood residues, other relatively dry feedstocks (straw, digestate) or waste such as refuse-derived fuel, solid recovery fuel, and automotive shredder residues have been used as fuel recently. For these, pelletisation can be needed to make them compatible with the gasifier's solid inlet section. Cheaper, but even more wet biomass, such as harvesting residues can be torrefied to dry them, reach the right level of brittleness, and prepare for pelletisation.

For feedstock other than clean wood or for feedstock combinations, the ash content and the ash melting temperature should be checked to avoid ash agglomeration inside the gasifier and to identify suitable mineral additives. Further, the legislation on air pollution might be decisive whether a certain feedstock can be used in a gasification plant with the given flue gas treatment.

5.1.2 Gasification + gas cleaning

In a gasifier, four main process steps have to happen: i) drying of the feedstock to remove water (around 100°C), ii) pyrolysis to remove volatile compounds such as tars and oxygenates (acids, aldehydes, ketones, etc.), leaving relatively pure carbon/char, iii) gasification of the char with oxygen, steam and or CO₂ producing hydrogen and CO; iv) partial or sub-stoichiometric combustion of char and sometimes burnable gas compounds to deliver the heat for the endothermic gasification and drying steps.

Depending on the arrangement of these four sub-processes, different gas qualities and compositions are reached. Figure 5.2 below shows a typical autothermal or direct gasifier, in which all four steps happen in the same vessel, i.e., the flue gas from combustion is contained in the product gas leaving the gasifier, e.g., in the Andritz/Carbona gasifier that is part of a CHP in Skive/Denmark [4.2]. As nitrogen cannot easily be separated from methane (only by cryogenic distillation), autothermal gasifiers can only be used in process chains towards methane, when pure oxygen instead of air is used for the partial combustion, usually in steam/oxygen blown bubbling or circulating fluidised bed gasifiers, see also the section on Torrgas below. This is connected to lower efficiency and additional CAPEX and OPEX to supply the pure oxygen [4.2].

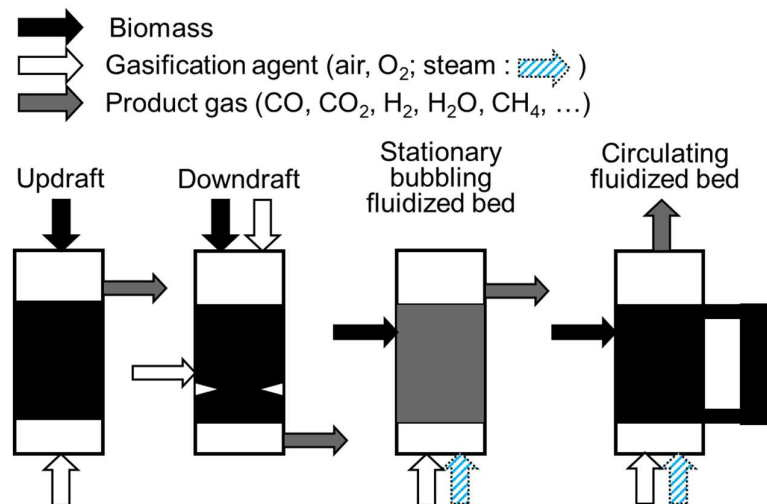


Figure 5.2: Autothermal/direct gasifiers combining drying, pyrolysis, gasification, and partial combustion in one vessel.

To obtain nitrogen-free gasification gas, allothermal or indirect gasifiers can be used that comprise an (endothermic) gasification zone and a combustion zone. Different gasifier types have different means of heat transfer between the two zones. The so far most successful one is the Dual Fluidised Bed gasifier, which was realised in different versions in Austria (500 kW TU Vienna, 8 MW Güssing, 8 MW Oberwart, 1 MW BEST Simmering), Netherlands (850 kW TNO Petten), Sweden (32 MW GoBiGas), France (1 MW GAYA), U.S: (1 MW Westbiofuels, Silvagas), Germany (Uni Stuttgart), and Thailand (3.8 MW) [4.3]. It combines methane-rich gasification at low temperatures (about 830°C) with a combustion zone at 950°C, while the heat is transported by circulating bed material (sand or olivine), see Figure 5.3 below.

The high methane content of about 10% in the product gas makes it a very suitable gasifier for the production of renewable methane with high efficiency. However, the methane content is connected to a relatively high content of a few % of unsaturated hydrocarbons (ethylene, benzene) that cause catalyst coking, especially in fixed bed methanation reactors and thus may necessitate complex gas cleaning [4.4]. Alternatively, a fluidised bed methanation reactor can be used that can cope with unsaturated hydrocarbons and thus allows for simplified gas cleaning [4.5].

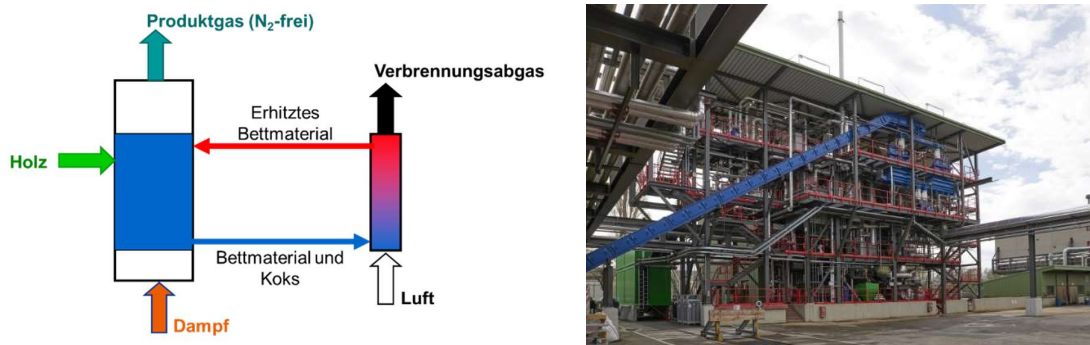


Figure 5.3: Allothermal/indirect Dual Fluidised Bed gasifier developed by TU Vienna (referred to as Fast internally Circulating Fluidised Bed FICFB): Scheme (left), photo of the recently built plant in Simmering (BEST), (right) [4.6, 4.7].

Starting with the Carbo-V technology, two-step gasification concepts have been realised that apply low temperature pyrolysis to obtain burnable gases and vapours on the one hand, and relatively pure char on the other hand. In the next step, the gases/vapours are combusted to indirectly heat a high temperature gasification step in which the char is gasified with steam at >1000°C. The concept needs a thorough heat integration to reach high chemical efficiencies. Such gasifiers obtain a relatively clean, tar-free syngas of mainly H₂, CO, and CO₂ that allows for simpler gas cleaning. While the very low methane content (< 1%) is disadvantageous for the production of renewable methane, it allows for direct synthesis of other molecules such as methanol, DME, or FT-Diesel. Two typical examples that have been demonstrated up to 1 MW scale are shown below: Woodroll[®], see Figure 5.4; Torrgas, see Figure 5.5. The recently developed process by Haffner seems to work in a similar way; based on the very limited public information, no efficiency or cost advantages can be expected from this technology.

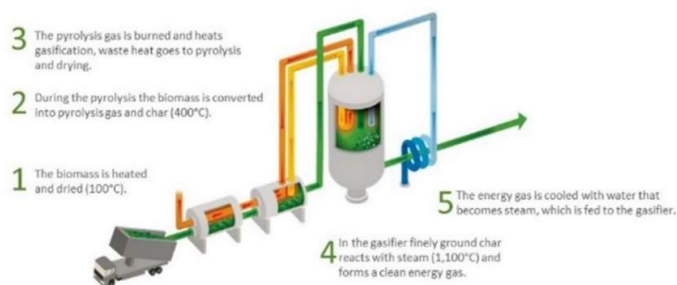


Figure 5.4: Two step gasification: Woodroll[®] [4.8].

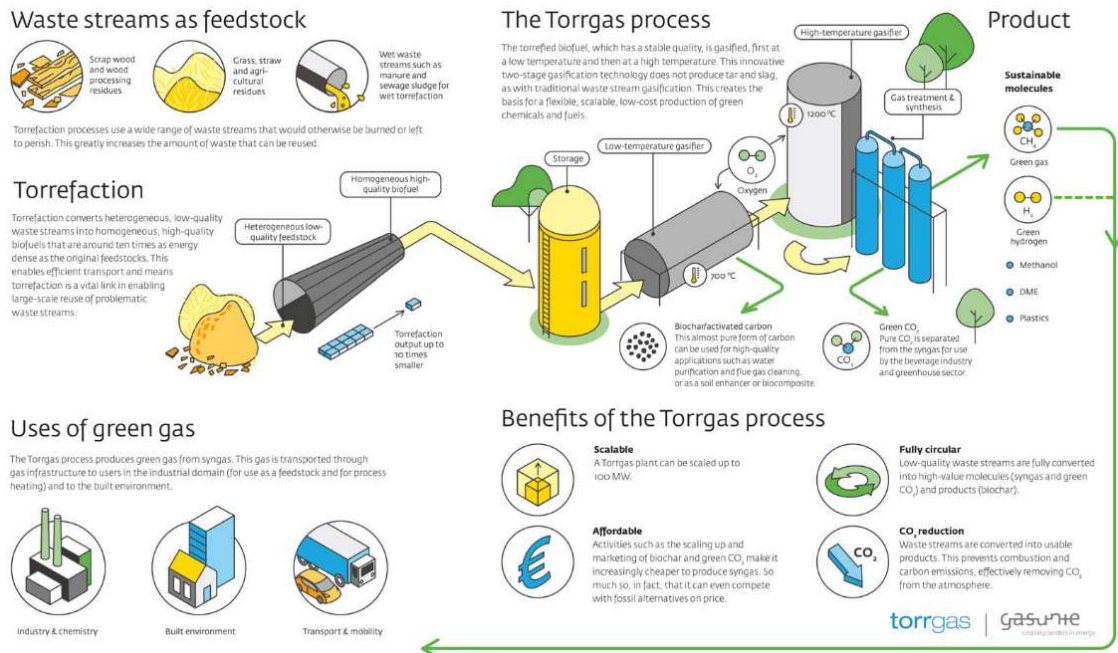


Figure 5.5: Two-step gasification: Torrgas [4.9].

In all cases, the product gas from the gasification has to be cleaned and conditioned. For this, water condensation, filters, tar scrubbers, and/or active carbon beds and deep desulphurisation are needed. Depending on the combination of gasifier and methanation reactor type, the gas cleaning can be very complex, as was shown in the GoBiGas project. The challenge lies in unsaturated hydrocarbons and in the presence of organic sulphur molecules such as thiophenes. While the large gas cleaning effort chosen for the GoBiGas plant might be economically viable in very large plants (> 100 MW) as is typical for Scandinavia, smaller plants for central Europe with its completely different wood logistics need simplified gas cleaning and thus more robust methanation reactors, such as fluidised bed reactors. Alternatively, very clean gasification gas from the two-step gasifiers could be used at the price of lower overall process efficiency.

5.1.3 Methanation + Upgrading/PtG

In catalytic methanation reactors, a nickel-based catalyst is brought into contact with the cleaned, sulphur-free gasification gas. Sulphur contents below 1 ppm are necessary to allow for long catalyst activity. Temperatures above 300°C are fully sufficient to start the methanation reaction at typically a few bar pressure. The combination of strong heat of reaction and thermodynamic equilibrium limitation necessitates strong heat management. In large-scale coal-based SNG plants (400 MW - 1 GW), very clean syngas in the right stoichiometric ratio is converted in a series of adiabatic fixed bed reactors with intermediate and recirculation cooling [4.5].

Without adaptations, this reactor concept could suffer from catalyst deactivation when used for gasification gas from Dual Fluidised Bed gasifiers. In the GoBiGas plant (32 MW input, originally planned as a demo for an 80 MW plant), large active carbon beds for benzene removal and a hydrotreatment reactor and a “pre-methanator” for ethylene conversion are used (see Figure 5.6), while the adiabatic reactors are responsible for converting the last 40% of carbon oxides [4.10, 4.4]. A similar concept was followed by TNO within the ESME process [4.11, 4.4].

In the GoGreenGas project, a Plasma-based reformer is used to create very clean syngas that is then converted in a series of adiabatic reactors with staged feed addition and intermediate cooling/condensation [4.12].

In Power-to-Gas applications starting from CO₂ or biogas, cooled fixed bed reactors with catalyst or bubble columns with micro-organisms have been used successfully; for both technologies, TRL 8/9 has been reached [4.13 – 4.16], see Figure 5.6. So far, both reactor types have not yet been used for conversion of gasification gas at higher TRL, but are the subject of ongoing EU projects:

Sempre-BIO: green waste/woody residues are converted in a Trommel pyrolysis at TRL 7, followed by biological syngas methanation at TRL 5 (Terrawatt).

Biomethaverse: Wood chips, logging residues, municipal waste are converted in a two-step Woodroll[®] gasifier at 6 MW (TRL 7), followed by trickle bed biological (TRL 5?) with/without H₂ addition. In earlier projects, the same clean syngas was used for a few weeks in a structured methanation reactor based on catalytically coated metal monoliths (KIT, EU project DemoSNG, [4.17])

METHAREN: O₂-blown downdraft gasification is combined with a catalytic, “milli-structured” reactor; the concept is now at TRL and shall reach TRL 7 at the end of the project.

Especially in combination with producer gas from Dual Fluidised Bed gasifiers, catalytic bubbling fluidised bed reactors have raised a lot of interest due to their ability to convert unsaturated hydrocarbons without catalyst deactivation [4.5]. Based on the German Comflux process from the Seventies, the reactor concept was further developed in Switzerland and adapted to demonstrate successfully at up to 1 MW the production of renewable methane from DFB gas with a high efficiency of 61-62% chemical efficiency (from LHV wood input to LHV methane output) in 2009 [4.4, 4.6]. Afterwards, the concept was picked up by the French company engie SA and demonstrated at their research site (GAYA, [4.18]). In recent years, the Swiss partners further developed the technology to be load flexible and allow for flexible hydrogen addition within the EU project HyFuelUp [4.19]. Meanwhile, this flexibility has been proven by pilot-scale experiments (up to 250 KW) at the TRL 6 plant of Paul Scherrer Institute [4.20].

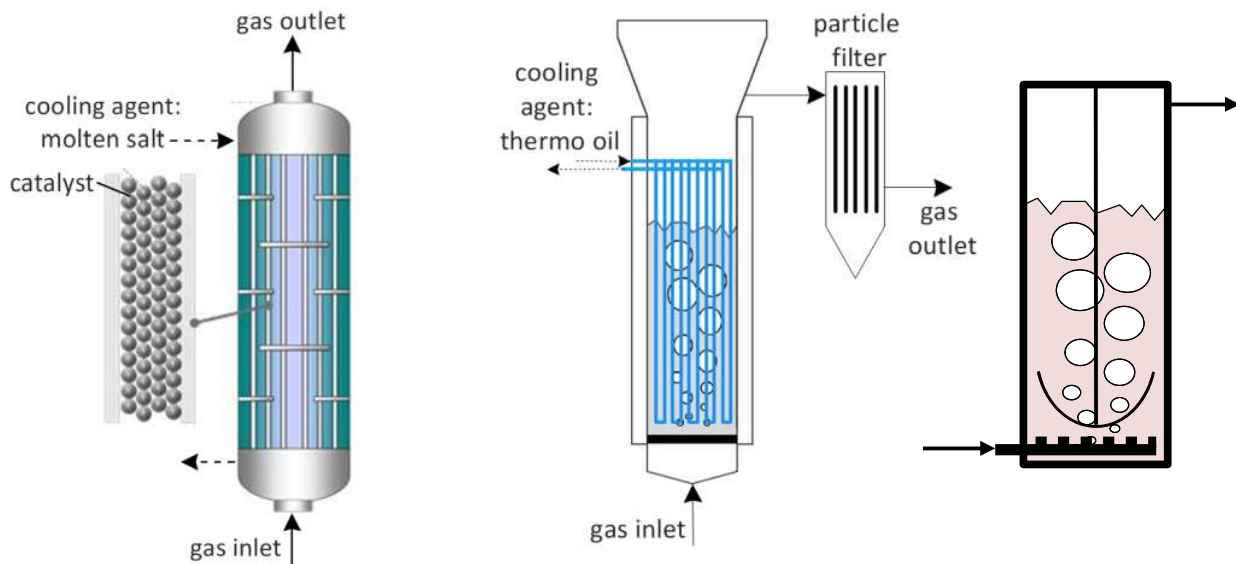


Figure 5.6: Different methanation reactor types: cooled fixed bed, bubbling fluidized bed, stirred bubble columns.

5.1.4 Realised (pilot) plants TRL 7-9 (SNG from wood)

In the following section, pilot and demonstration plants (TRL 7-9) for the production of SNG from woody biomass are presented. An overview is given in Table 5.1, more details are given in Table 5.2 at the end of the section.

Table 5.1: Pilot and demonstration plants to produce renewable methane (renewable SNG) from wood.

Name	Place	Investor/Funding	Technology (supplier)	Size	Status
GoBiGas	Göteborg, Sweden	Göteborg Energi (municipal utility)	DFB gasifier (repotec/Metso), fixed bed methanation (Haldor Topsoe)	20 MW _{SNG}	Moth-balled since 2018
ESME	Petten, NL	ECN/TNO (public funding NL)	DFB gasifier (TNO/Synova), fixed bed methanation (TNO)	5 kW _{SNG}	Project ended 2018
BioSNG	Güssing, Austria	EU, <i>swiss electric research</i> , WIBAG	DFB gasifier (repotec), fluidised bed methanation (CTU)	1 MW _{SNG}	EU-project ended 2009
HyFuelUp	Tondela, Portugal	EU, SBFI (CH); Circle Molecule (company)	CFB gasifier (Host engineering), fluidised bed methanation (AlphaSYNT)	500 kW _{SNG}	Under construction
GAYA	St. Fons, France	engie (company, ex Gaz de France)	DFB gasifier (repotec), fluidised bed methanation (engie)	400 kW _{SNG}	Operational
GoGreen Gas	Swindon, UK	Cadent Gas Ltd., APP, Progressive Energy Ltd.	BFB gasifier (Outotec), Plasma reformer (APP), fixed bed methanation (Vesta)	150 kW _{SNG}	Project ended 2019

Gothenburg Biogas (GoBiGas)

The *Gobigas* plant in Sweden (Figure 5.7) combines Dual Fluidised Bed gasification as demonstrated in commercial scale in Güssing Austria with fixed bed methanation. The plant with a capacity of 32 MW_{th} input and 20 MW_{SNG} output was meant as a demo plant (TRL 8) for an 80 MW_{SNG} commercial plant at the same site in the Gothenburg harbour and its favourable biomass logistic options. The demo character of the plant explains the technology choice that might not be optimal for a 20 MW_{SNG} plant [4.10, 4.21].



Figure 5.7: Gothenburg BioGas plant in Sweden, commissioned 2014 [4.10].

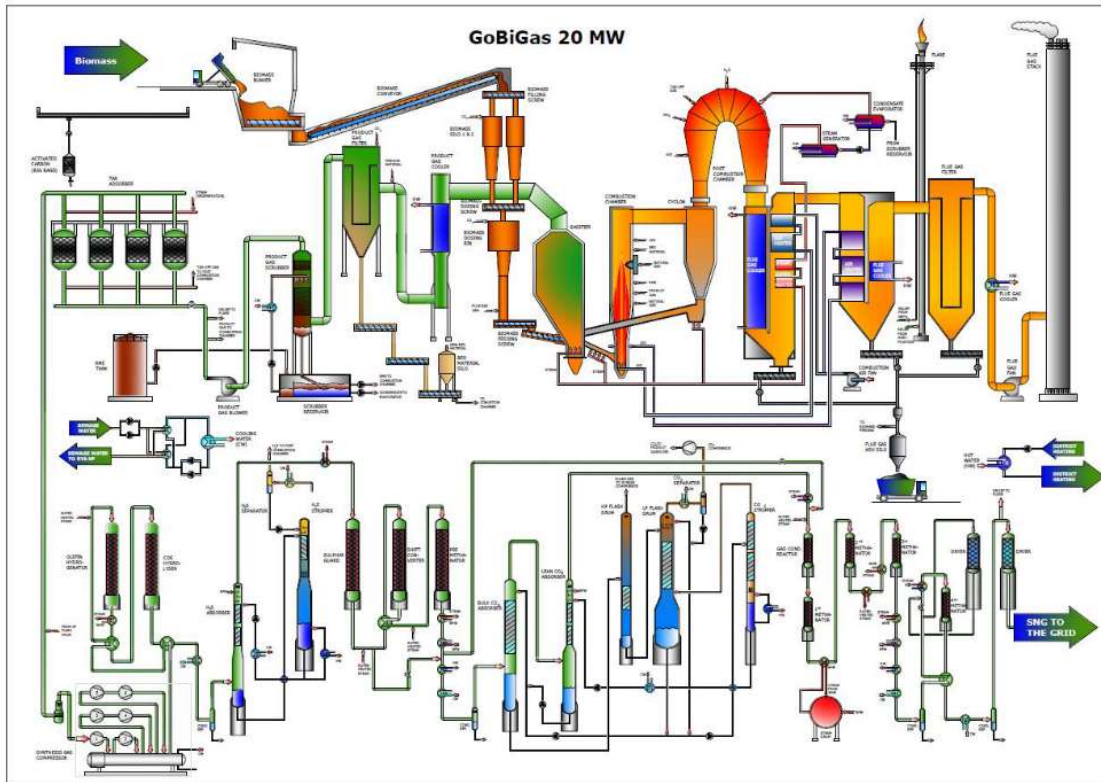


Figure 5.8: Gothenburg BioGas plant in Sweden, commissioned 2014 [4.10].

The idea was to scale up the successful Dual Fluidised Bed gasification with its methane-rich product gas (delivered by the companies reptec GmbH and Metso) by a factor of 4 and to combine it with adiabatic fixed bed methanation delivered by Haldor-Topsoe A/S (Figure 5.8). Fluidised bed methanation was not chosen by the investor Göteborg Energi because the technology and the company offering it to the market were, back then (2010) not considered sufficiently mature to deliver also the planned (but never built) 80 MW_{SYNG} plant. Haldor-Topsoe A/S, on the other side, had delivered engineering packages for methanation of coal gasification gas in China with a scale-up to 1 GW. The methane-rich syngas from the DFB gasifier contains a high amount of unsaturated hydrocarbons, around 3% ethylene and other olefins, as well as around 1% aromatics, mainly benzene, toluene, and xylene. This necessitates a complex gas cleaning section comprising four large, regularly regenerated active carbon beds (upper left corner) to remove the aromatics, and visible in the lower left quadrant of Figure 5.8, a hydro-treating reactor to convert part of the olefins and carbonyl sulphide, followed by a H₂S scrubber and a nickel-based “pre-methanator” at moderate temperature to completely convert the olefins.

A large compressor section (lower left corner of Figure 5.8) increases the pressure to 16 bar upstream of the gas cleaning section to allow for sufficient gas flow through the latter and the series of five adiabatic (i.e., not cooled) fixed bed reactors and the intermittent coolers incl. condensers and driers.

The complete plant was successfully commissioned and operated; however, due to changing economic boundary conditions (e.g., strong subsidies for biomethane production in the neighbouring country Denmark), the operation was stopped, and the plant is mothballed to allow for operation again in case of a better market situation.

ESME (ECN System for methanation)

A similar concept was followed by the Energy Research Centre of the Netherlands in Petten, which is now part of the Dutch research organisation TNO. TNO has developed its own type of dual fluidised

bed gasification, named Milena, resulting in a slightly different gas composition than the one used in Göteborg or Güssing. The main technical difference is that in the Milena, gasification takes place in a riser-type fluidised bed and the combustion in a bubbling fluidised bed, while in the Austrian FICFB concept, it is the other way around. For the long-duration 500h test of their ESME concept, a TRL 5 plant with 5kW capacity was connected to a slip stream of the 800 kW Milena gasifier at the ECN site in Petten (North Holland) [4.22, 4.11] via a hot oil scrubbing system *OLGA*, to remove polyaromatic compounds. The gas cleaning section and the series of fixed bed methanation reactors with intermittent and recycle cooling resemble that of the *GoBiGas* plant [4.4]. A scale-up to 4 MW was planned in Alkmaar, but never realised.

EU project BioSNG

The favourable combination of a dual fluidised bed gasifier and downstream fluidised bed methanation was identified already in 2003 and lead after some preliminary tests at TRL 4/5, to a patent application by Paul Scherrer Institut. The main advantage of the fluidised bed methanation is the ability to convert not only typical syngas components, but also the unsaturated hydrocarbons into valuable products without coking of the catalyst. This allows for significant simplification of the gas cleaning and the synthesis/upgrading section with fewer units (only about half, see Figure 5.9, Figure 5.10), less temperature changes, lower CAPEX, and slightly higher efficiency due to lower pressure drop [4.4]. The process concept was thoroughly tested in long-duration field tests in Güssing/Austria at TRL 5 (10 kW_{SNG} plant *COSYMA*, duration up to 1000h) until 2007, before a 1 MW_{SNG} Process development unit at TRL 7 was built in Güssing within the European Union project *BioSNG* with significant financial contribution of *swiss electric research* and the Austrian state of Burgenland [4.5]. In 2008/2009, the plant was commissioned and operated successfully and could deliver H-gas quality bio-SNG to a local filling station.



Figure 5.9: Process development unit TRL 7, operated within the European Union project *BioSNG* in 2008/2009 [4.6].

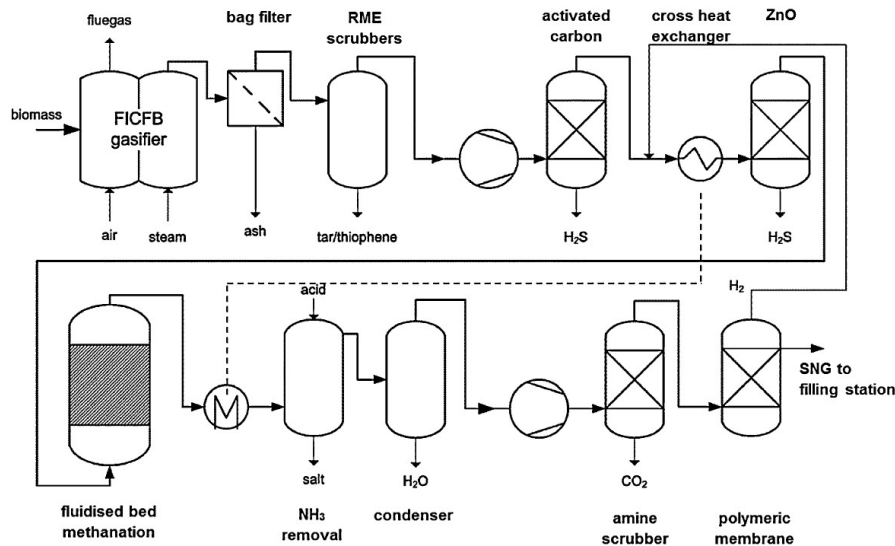


Figure 5.10: Process development unit TRL 7, operated within the European Union project BioSNG in 2008/2009 [4.6].

HyFuelUp and GanyMeth

The fluidised bed methanation technology demonstrated with the EU project *BioSNG* was further developed by PSI, and its application was expanded to Power-to-Gas, i.e., the conversion of renewable hydrogen with biogenic gases containing carbon oxides to methane. By long-duration tests using a TRL 4/5 container-based plant for up to 1100h with real biogas [4.23-4.25] and by a broad experimental program with the TRL 6 pilot plant *GanyMeth* at PSI (200 kW nominal output), it could be shown that the technology is able to convert both biogas and gasification gas from different gasifier types. For example, conversion of gasification gas from Dual fluidised bed gasifiers (ethylene and methane rich), from circulating fluidised bed gasification (CO and CO₂ rich), and from sorption enhanced gasification (hydrogen and methane rich) was successfully tested. Conversion of gasification gas in the methanation reactor leads to a mixture of methane and CO₂, where the latter allows it to let it react with added hydrogen to obtain more product within Power-to-Gas applications. To demonstrate the flexibility of the fluidised bed reactor concept, a constant feed of gasification gas (mixed from different gas bottles) was complemented by varying amounts of hydrogen, such that methane yield could be doubled or even nearly tripled with the same reactor design.

The know-how from this and previous research is transferred to a Swiss SME (AlphaSYNT GmbH) and forms the basis for the construction of a TRL 7 pilot plant within the European Union project *HyFuelUp*. This project will connect a flexible methanation plant (500 kW) to a biomass gasifier in Tondela/Portugal [4.19] with the aim of demonstrating flexible addition of hydrogen from a solid-oxide electrolyser (enabling seasonally flexible Power-to-Gas). The work is ongoing; the commissioning of the plant is expected in 2026.

GAYA site (incl. EU project Butterfly)

Also in France, the advantages of dual fluidised bed (DFB) gasification and fluidised bed methanation reactors were observed, especially for sites far from harbours with therefore limited wood logistics. In 2010, the company engie (formerly known as Gas de France, GdF) started a program to develop both technologies, the gasification and the fluidised bed methanation. While for the gasification, the company repotec GmbH was involved, which had also delivered the engineering for the Güssing and Gothenburg DFB gasifier, the work on fluidised bed methanation was based on the published results of the R&D work of the Swiss groups, which had demonstrated the advantages within in the European Union project *BioSNG* in 2009. Within the project called *GAYA*, a 640 kW gasifier and a 400 kW methanation unit (both TRL 7) were constructed in St. Fons/France [4.18]. The gas cleaning seems to

be similar to that used in the EU project *BioSNG*. For the gasification, the range of possible feedstocks was expanded from pure forestry wood chips to 30% fraction of Solid Recovered Fuel (SRF). Methanation of the syngas was shown for a range of gas compositions, pressures, and temperatures.

Within the on-going EU project *BUTTERFLY* [4.26], a sorption-enhanced DME (di-methyl-ether) plant from TNO in the Netherlands will be connected to the gasifier, whose feedstock range will be expanded to black pellets (produced from wet organic residues), Refuse-Derived Fuel RFD, and Automotive Shredder Residue ASR.

Based on the results of their work with fluidised bed methanation, scale-up to commercial scale (TRL 8/9 plant in Le Havre) is planned within the project *Salamandre* with the aim of delivering liquefied biomethane (bio-LNG) for ships of the large maritime company CMA-CGM. In January 2024 the PRE-FEED study was ordered [4.27]. Recent articles in the French press from January 2025 indicate that the project has been stopped. It is unclear whether that happens due to a lack of financial support, or because the expected price of the bio-LNG is too high for the present ship fuel market, or because CMA-CGM changed their strategy to de-fossilise their ships. So far, no official statement by engie can be found.

GoGreenGas

The GoGreenGas project in UK aimed at a value chain starting from waste streams such as municipal solid waste [4.12]. An autothermal bubbling fluidised bed gasifier was used that was blown with steam and pure oxygen, i.e., the products of the combustion are part of the gasification gas, leading to higher CO₂ content. A plasma reformer by APP Plasma at up to 1200°C was combined with several acidic and caustic scrubbers, a hydrodesulphurisation unit, and a final ZnO bed to handle the high amount of tars and other impurities to be expected from the waste gasification. As a result, a very clean syngas without any unsaturated hydrocarbons is produced, which allows for converting it in a series of adiabatic fixed bed methanation reactors. The applied *Vesta* process by Foster Wheeler uses a methanation catalyst from Clariant and manages the heat production in the reactors by intermittent cooling, steam addition, and staged reactant feed addition. A TRL 5 plant was operated up to 56h; the scale-up plant was built but not commissioned anymore due to a lack of funding. The advantage of the process is the option to use low-grade waste streams as feed; the disadvantage is the high electricity consumption and costs for the plasma reformer and the pure oxygen generation.

Table 5.2: Realized and announced (pilot) plants TRL 7-9 for renewable SNG production from biomass and waste derived fuel by gasification.

Name of project	GoBiGas	ESME	BioSNG	HyFuelUp/GanyMeth (PSI)
Location of plant	Gothenburg (Sweden)	Petten (Netherlands)	Güssing (Austria)	Tondela (Portugal)/ Villigen (Switzerland)
Product 1	Renewable methane	SNG	Renewable methane	Renewable methane
Output [MW]	20 MW	5 kW (slipstream)	Up to 1MW (slip stream of gasifier)	500 kW (slip stream of gasifier)/ 250 kW
Product 2		-	-	pure CO ₂
Output [MW]		-	-	-
Feedstock 1	Wood chips	Wood chips	Wood chips	Lignocellulosic waste
Input [MW]	-	5 kg/h	8 MW	2 MW
Feedstock 2	-	-		Renewable hydrogen (flexible addition)
Input [MW]	32			Up to 500 kW
TRL	8/9	TRL 5; 4 MW _{th} (TRL 7/8) planned, but never realised	7	7 (Tondela) / 6 (only methanation, Villigen)
Status (e.g. operation hours)	Moth-balled, because national promotion schemes were not competitive with other countries		TRL 7 plant > 500h (2009); TRL 5 plant > 1000h (2007)	TRL 7 in construction (Tondela) TRL 6 in operation: ongoing campaigns (Villigen)
Investment, Year	160 M€ (2010-2016)	> 500h	4 M€ (2006-2009)	not disclosed, but << 10 M€ (2022-2026)
Lead	Göteborg Energi (municipal utility); Haldor Topsoe (gas cleaning + synthesis)	ECN (now TNO)	Repotec, TU Vienna (gasification); CTU/PSI (methanation)	Host engineering (Gasification); AlphaSYNT/PSI (methanation)
Technology Feedstock prep.	Drying?	-	Drying outside	Drying
Technology gasification	Dual fluidised bed (Valmet/repotec)	Dual fluidised bed at 830°C (MILENA technology by ECN)	Dual fluidised bed (repotec)	Circulating fluidised bed
Technology gas cleaning	Cold scrubbers, active carbon beds, HDS	Warm oil scrubber (OLGA technology by ECN); Hydro-desulphuration, Guard beds	Oil (RME) Scrubber, active carbon, ZnO	Tar cracker, active carbon, ZnO
Technology Methanation	Pre-reformer for C2+, several adiabatic fixed beds in series with intermediate cool./ condensation	Preformer and two adiabatic fixed bed reactors in series	One cooled fluidised bed reactor at low pressure	One cooled fluidised bed reactor at low pressure
Technology Upgrading	Amine scrubber, Drying	CO ₂ separation (not built at TRL 5); Drying, final methanation reactor	Amine scrubber, Drying, H ₂ membrane	PSA, Drying, H ₂ membrane
Cost estimation	60€/MWh _{SNG} @200 MW output		160-200 Fr/MWh @ 2.67 MW output	
References	4.10, 4.21, 4.28	4.11, 4.22	4.5, 4.29	4.19

Table 5.2 continued.

Name of project	GAYA (operated)/ Salamandre (plan)	Gaya Butterfly	GoGreenGas	Torrgas
Location of plant	St. Fons (France)/ Le Havre (France)	St. Fons (GAYA site, France)	Swindon (UK)	Delfzijl/Groningen (The Netherlands)
Product 1	Renewable methane	DME	SNG	SNG
Output [MW]	400 kW/20 MW	Several kg/h	Up to 150 kW (slip stream)	Ca. 15 (plan)
Product 2	- /Heat	SNG	Plasmarok (vitrified slag)	Biochar
Output [MW]	- /5 MW	Max. 0.4	-	7000 t/a
Feedstock 1	70% Waste wood chips, 30% Solid Recovered Fuel (SRF)	Black pellets: produced from wet organic residues; RDF: Refuse-Derived Fuel; ASR: Automotive Shredder Residue	Refuse-derived fuel (waste)	residual woody biomass
Input [MW]	-		100 kg/h = 360 kW	
Feedstock 2	-	Hydrogen	Electricity for Plasma etc.	
Input [MW]	0.64 operated/ 32 (plan)		Ca. 25 kW (calculated)	
TRL	TRL 7 operated (400 kW, GAYA)/ Salamandre: TRL 8/9, planned for 2025	TRL 7	TRL 5; TRL 7/8 plant (5 MW _{th}) was built, but never commissioned (lack of funding)	Gasifier: TRL 7-8 (1 MW _{th})
Investment (Year)	175 M€ (2010-2020)	10.5 M€ (2023-2026)		
Status (e.g. operation hours)	PRE-FEED given to Maire/Nextchem in 01/2024	Under construction	Several runs of up to 56 h operation	
Lead	Engie	TNO, engie	APP Plasma (gasification, gas cleaning); Foster-Wheeler/Clariant (Vesta methanation)	
Technology Feedstock preparation	?	Drying, torrefaction, pelletising	Drying	Torrefaction
Technology gasification	Dual fluidised bed (repotec)	Dual fluidised bed at 830°C	Bubbling fluidised bed Steam/ Oxygen Blown at 700-800°C	Two-step gasification (LT/HT)
Technology gas cleaning	Oil (RME) Scrubber, active carbon beds etc.	Oil (RME) Scrubber, active carbon beds etc.; Sorption-enhanced fixed bed synthesis for DME	Plasma reformer at 1100-1200°C, acidic and basic scrubbers; metal oxides (ZnO); olefin hydrogenation, COS hydrolysis	Scrubbers, drying
Technology Methanation	One cooled fluidised bed reactor at low pressure	One cooled fluidised bed reactor at low pressure	WGS reactor, 4 adiabatic methanation reactors with staged gas feeding, intermittent cooling, Drying, LT methanation after CO ₂ removal	Not disclosed
Technology Upgrading	Amine? 60 kt/a CO ₂ used in the project France kerEAUzen	Amine? Drying	Hot potassium hydroxide scrubber, Drying	Not disclosed
Reference	4.18, 4.27	4.26	4.12	4.9

5.1.5 Realised (pilot) plants TRL 6-9 (Direct methanation of biogas)

Direct methanation of biogas is a process in which biogas, a mixture of methane and carbon dioxide from an anaerobic digester, is mixed with hydrogen and converted with the aim of producing more methane from the CO₂ and hydrogen. Due to the similarity to methanation of gasification gas, the same reactor types can be used, cf. to Figure 5.6. While methanation of gasification gas was demonstrated in larger scale only for catalytic methanation, in the methanation of biogas, biological methanation is also applied. For the sake of clarity, only such plants are reported here that convert cleaned biogas and were tested in larger scale of at least TRL 6. Plants that work with separated, pure CO₂ are not in focus, as the separation of CO₂ is an additional step connected with costs and efficiency losses. For more information on these and further technologies that may not have reached pilot scale (yet), please refer to [4.5, 4.15, 4.16, 4.48].

Limeco, Dietikon

As shown in Table 5.3, the two largest operating plants are biological methanations. In Dietikon (Switzerland), the company Hitachi-Zosen Inova built a commercial plant based on the stirred bubble column. This technology was developed by Microbenergy and demonstrated at 165 kW in Stadallendorf (Germany) before HZI acquired the company Schmack Biogas with the Microbenergy technology from Viessmann. On the site of Limeco AG in Dietikon, the electricity produced by the waste incineration plant is used to operate a 2.5 MW PEM electrolyser without the need to pay a grid use fee. The produced hydrogen is mixed with the raw biogas from the neighbouring wastewater treatment plant in a 50 m³ tank and converted to > 98% biomethane that can be injected into the gas grid [4.49, 4.50]. The reactor contains a water phase in which the micro-organisms live and metabolise the hydrogen. As the solubility of hydrogen in water is quite low, this limiting step is improved by applying a pressure of 10 bar and by strongly stirring the mixture to obtain small hydrogen bubbles with accordingly large gas-liquid mass transfer area. Besides the electricity for the stirrer, also the necessary nutrients for the microorganisms cause operational costs, although way lower than the cost for the hydrogen.

Electrochaea

A similar reactor type (stirred bubble column) as in Dietikon was developed by electrochaea, a start-up now residing in Germany. The main difference is the choice of the microorganisms. While Microbenergy/HZI relies on mixed microorganisms, electrochaea tested many different archaea types and identified the most productive one. This choice leads to higher productivity per volume; accordingly the reactors have a slightly higher aspect ratio (height over diameter). The other aspects (high methane content, large water phase, stirring, 10 bar pressure, nutrients, etc.) are the same. The technology has also been tested for methanation of pure CO₂ at Zuchwil (Switzerland) within the European Union project Store&Go [4.15].

Hitachi Zosen Inova

In Gabersdorf (Austria), Hitachi Zosen Inova built a catalytic fixed bed reactor based on the combined experience from the reactor developments of Tokyo University and Hitachi Zosen Corporation in Japan (starting in the 90s) and from ZSW (Zentrum für Solare Wasserstoffherzeugung) and Solarfuel/etogas in Stuttgart, who also built the so far largest Power-to-Gas plant in Werlte Germany [4.13]. While in Japan and in Werlte, the reactors operate with pure CO₂ and hydrogen, in Gabersdorf, biogas is used as feedstock with hydrogen from an electrolyser. At temperatures above 250°C and pressures of less than 10 bar, a nickel-based catalyst enables the production of about 120 kW of methane from the fed hydrogen [4.51]. Due to the exothermic character of the methanation reactor, the hot spot in the boiling-water-cooled reactor reaches 575°C. More than 90% methane and less than 10% residual hydrogen content are reached in one reactor, which allows injection into the gas grid according to Austrian rules for biomethane.

Topsoe A/S

Similar to the reactor concept realised in Gabersdorf, Topsoe A/S and University of Aarhus, Denmark, operated two boiling-water cooled reactors containing Topsoe's proprietary high-temperature stable nickel catalyst with a condensation step in between the two reactors. This way, a very high methane content of > 97% is reached. The stable catalyst allows for hot spots up to 680°C without catalyst deactivation [4.52]. The speciality of this plant is the excellent heat integration between the exothermic methanation reactor and a very efficient high-temperature electrolyser (SOEC). The steam produced by boiling water cooling is fed to the electrolyser, whose efficiency from electricity to hydrogen is above 90% due to the higher energy content of the steam compared to cold water. As a result, the overall efficiency from electricity to methane increases from 55-60% (with PEM or alkaline electrolyzers) to 75-80% (note that the efficiency of methanation is around 80% for all processes due to thermodynamics) [4.52, 4.48].

AlphaSYNT/PSI

Like the Topsoe fixed bed reactor technology, catalytic fluidised bed methanation has been successfully demonstrated for both the methanation of biogas and of gasification gas. Like all catalytic reactors, fluidised bed technology offers significantly smaller reactors than biological methanation. As all methanation reactors are pressurised vessels made from stainless steel, the size factor of more than a factor 10 for reactors of the same methane output gives a significant advantage in the capital costs [4.14]. As heat transfer in fluidised bed reactors is better than in fixed bed reactors, hot spots can be avoided, and the reactor size is further decreased to about half to 2/3. The technology was tested in long-duration [4.23] and in a pilot-scale plant at PSI, reaching >90% methane in one reactor (without membrane upgrading). To reach higher methane and lower hydrogen contents, a membrane upgrading unit can be added. The flexibility of the system for part load operation, including the membrane unit, was successfully demonstrated [4.25].

Table 5.3: Commercial and pilot/demonstration plants for direct methanation of biogas.

Company/Institution	Hitachi Zosen Inova	Electrochaea	Hitachi Zosen Inova	Haldor Topsøe A/S	AlphaSYNT/PSI
Place of plant	Dietikon, Switzerland	Avedøre, Denmark	Gabersdorf, Austria	Foulum, Denmark	Zürich, Inwil, Villigen Switzerland
Raw gas source	Commercial anaerobic digestion of sewage sludge	Commercial anaerobic digestion of sewage sludge	Anaerobic digestion of agricultural waste	Anaerobic digestion of agricultural waste and manure	Commercial anaerobic digestion of sewage sludge and green waste
Reactor type	Stirred bubble column	Biological: stirred bubble column	Catalytic: cooled fixed bed	Catalytic: two cooled tubular fixed bed with condenser in between	Catalytic: bubbling fluidized bed with membrane upgrading
TRL	8-9	7-8	7	7	6
Catalyst	Micro-organisms	Specific archaea type	Nickel/zirconia	Nickel/alumina	Nickel/alumina
Cooling system	Cooling water at ambient temperature	Cooling water at ambient temperature	Boiling water inside plates at 28 bar	Boiling water shell side at 65 bar	Thermooil in cooling coils
Reactor temperature	60-65°C	60 - 65°C	230 - 580°C	280 - 680°C	320°C - 360°C
Reactor pressure	10 bar	10 bar	8 barg	20 barg	6 barg
Additional methane production	Ca. 1 MW _{HHV}	550 kW _{HHV}	Ca. 120 kW _{HHV}	45 kW _{HHV}	10 kW _{HHV} TRL 5 plant 78 kW _{HHV} TRL 6 plant
CH₄ concentration	> 98%	> 97%	> 90%, < 9% H ₂	97.9%, < 2% H ₂	97%, < 2% H ₂
Volume main reactor	50 m ³	Ca. 7 m ³ (3600 L liquid)	Ca. 120 L catalyst	Length 2.3 m, diameter unknown	TRL 5: < 2 L catalyst TRL 6: < 50 L catalyst
Additional information	Electricity consumption stirrer: 1.3 - 2.5% of electrolyser-input				
Reference(s)	[4.49 - 4.50]	[4.15]	[4.51]	[4.52]	[4.23 - 4.25]

5.1.6 Simulations, cost calculations

Production of renewable methane (SNG) from wood (incl. addition of hydrogen)

So far, not many studies investigated the production of renewable methane (SNG) from wood, and even less looked at the addition of hydrogen.

Here, it is important to understand certain challenges with respect to the results of such studies: While only two studies rely on real-world costs or realistic pre-engineering studies, the others are system engineering studies by academic groups using plant optimisation techniques and an accepted cost calculation method that relies on cost tables for units of very mature chemical processes.

This important difference leads to a large scatter in cost estimates where the academic studies have a large absolute error of +/- 35% (inherent to the method), while the relative order of technology variation in these types of studies is usually correct. The more realistic studies, on the other hand, reflect the lower maturity of the technology, i.e., they are significantly more conservative. An additional challenge in comparing the different studies lies in the different age and connected overall price levels, as well as in the varying boundary conditions (e.g., lower prices for wood in Scandinavia than in Central Europe).

Further, academic systems engineering studies [4.28, 4.30-4.34] aim at showing the potential of technologies or technology combinations, and thus often obtain slightly higher process efficiencies (as they assume optimal energy integration) and lower prices due to the assumption of favourable boundary conditions.

One of the first studies, even before the invention of the terminus “Power-to-Gas”, was a study by Gassner and Marechal from EPF Lausanne in 2008 [4.30] that investigated the use of an electrolyser to increase the methane yield from a gasification/methanation plant. Using quite optimistic assumptions with respect to electrolyser efficiency (85%, can only be reached by high temperature electrolysis) and with respect to the costs of wood (1.67 Rp/kWh), electricity (2.6-8.9 Rp/kWh) and capital costs of the electrolyser (300 €/kW_{el}), they predicted efficiencies between 65% and 70% and production prices of SNG between 6 and 11 Rp/kWh.

Based on more realistic assumptions and thorough investigation of the technical details of the gas cleaning, methanation and upgrading units, Teske [4.31] obtained efficiencies of around 61.7%, a value similar to the cold gas efficiency found experimentally in the 20 MW GoBiGas plant (up to 62.5%) and in the 1 MW BioSNG plant (around 61%), see previous section.

Dieterich et al. used a standard flow sheeting software (Aspen Plus®) to simulate the combination of an entrained flow-gasification with methanation to produce bio-SNG. They found an efficiency of 57% and prices of around 28 Rp/kWh [4.32]. The slightly lower efficiency and the high price are caused by the use of an entrained flow gasifier. These high-temperature gasifiers need to reach more than 1200°C to obtain full conversion during the short residence time of fuel particles in the reactor (only a few seconds). The obvious disadvantage (high internal energy consumption) is connected to the fact that pure syngas without tars but also without methane is formed. This is an advantage in the production of Fischer-Tropsch Diesel or methanol, but a strong disadvantage in the production of SNG. This and the high capital costs of entrained flow gasifiers are the reasons why none of the built pilot plant uses an entrained flow gasifier. For the same reason, the lower efficiency and the high price predicted for the bio-SNG are no surprise.

The two most reliable sets of information are the real costs of the 20 MW_{SNG} GoBiGas plant [4.28, 4.4] and the cost calculations conducted within a pre-engineering study for a significantly smaller 2.67 MW_{SNG} plant in Switzerland [4.29] that was based on the results of the EU project BioSNG. By taking the economy of scale into account that predicts roughly a decrease of the specific capital costs by a factor of two, and by considering the different process configurations, specific capital costs were derived in the SWEET-EDGE project and the SCCER Joint activity JASM [4.35]:

Table 5.4: Cost estimates for the gasification conversion path to biomethane [4.35, 4.36].

Path	Efficiency	Investment costs	Fixed OPEX/ maintenance costs	Electricity use	Heat production	TRL
	(LHV out/LHV in, %)	(CHF/kW _{chem,LHV})	(CHF/kW _{chem,LHV})	(MWh _{el} /MWh _{chem,LHV})	(MWh _{th} /MWh _{chem,LHV})	
WGM1	62.5	3500	40	0.094	0.09 (at 80 °C)	8
WGEM1	62.5	4008	105	0.1	0.126 (at 80 °C)	7
WGM2	62.5	2315	40	0.094	0.09 (at 80 °C)	7
WGEM2	62.5	2706	91	0.11	0.127 (at 80 °C)	7

Thunmann et al. [4.28] made a cost estimation for a 200 MW plant by extrapolating the costs of the GobiGas plant to a 10 times larger plant. Assuming relatively low wood prices (less than 2 Rp/kWh), which are typical for Scandinavia and its completely different wood logistics, they predict a price for SNG of 5-6 Rp/kWh. Such a low price is not realistic for Switzerland due to the relatively high prices for wood of at least 4 Rp/kWh.

On the other hand, the LIGNOGAZ Study [4.29], which is based on real offers for the different parts and units of the plant, found prices of 16.5 Rp/kWh for relatively small plants (e.g., 5 MW) and real wood prices for the chosen region of around 5 Rp/kWh.

Both studies did not consider the option to add hydrogen from an electrolyser to allow for (flexible) Power-to-Gas. First indicative results in this direction can be expected from the ongoing EU/SBFI project *HyFuelUp* [4.19].

As a summary, the price of renewable methane from wood gasification with or without hydrogen addition is not yet clear; a wide range of predictions exists. Here, the two extreme values (5 Rp/kWh and 28 Rp/kWh) are not realistic for plants to be built in Switzerland due to too optimistic assumptions on wood price and potential plant scale, on the one hand, and an unfavourable choice of technologies, on the other hand.

Therefore, a detailed pre-engineering study would be needed to obtain more reliable numbers for the Swiss boundary conditions which are a prerequisite for any investment decision.

Direct methanation of biogas

The conversion of biogas with hydrogen to obtain more methane from the CO₂ content has been the subject of many studies. Unfortunately, not many of them go into a detailed techno-economic analysis, including the design of all unit operations. The latter is a prerequisite to derive cost estimation according to accepted cost calculation methods that rely on cost tables for units of very mature chemical processes. As mentioned above, such studies have a large absolute error of +/- 35% (inherent to the method), while the relative order of technology variation in these types of studies is usually correct.

In direct methanation of biogas, three cost blocks are decisive: the capital costs (CAPEX), the cost of raw biogas, and the cost of hydrogen, while the other OPEX contribute to max. 10% [4.54]. The raw biogas price depends on the circumstances (costs of anaerobic digester, feedstock price, feedstock logistics); the hydrogen price mainly depends on the electricity costs used in the electrolysis. The capital costs (which in the form of an annuity represent less than a quarter of the biomethane price for most scenarios) again are dominated by the electrolysis costs, up to 85% [4.14, 4.54]. Still, the necessary larger reactors for biological methanation lead to significantly higher costs (factor 2-3) of the methanation system (4.14).

For typical assumptions (e.g., 6 Rp/kWh price of raw biogas, 5 Rp/kWh electricity), [4.14] found biomethane prices between 10 Rp/kWh and nearly 20 Rp/kWh, where the lower value is in the range of economic feasibility. This is caused by the direct methanation of biogas, which saves the capital

costs for the CO₂ separation and increases the value of the methane in the raw gas (6 Rp/kWh) to the level of biomethane (>10 Rp/kWh) by the inherent upgrading. It can be seen from Figure 5.11 that processes with biological methanation lead to 10%-15% higher biomethane prices. The assumed electricity prices of 5 – 7 Rp/kWh show that the process works only at sites or times where/when no grid use fee has to be paid. [4.55] showed that flexible Power-to-Gas, i.e., operating a methanation only in times of lower electricity prices, leads to only a little price increase (12 to 13.5 €-ct/kWh with at least 4500 h/a operation of the electrolysis, which is quite realistic for hydropower plants). Other authors [4.56] find more conservative prices, however, for systems that rely only on photovoltaics as the electricity source for the water electrolysis, which leads to very high prices due to low full-load hours of operation.

In summary, it is expected that the lowest biomethane prices are reached by upgrading biogas from anaerobic digestion at wastewater treatment plants. Upgraded biomethane from agricultural biogas plants is more expensive. The price range for agricultural biomethane probably already overlaps with that of flexible (summer) Power-to-Gas at wastewater treatment plants, as mentioned above.

For biomethane/SNG from biomass gasification, the costs will be somewhere in the upper half of the 10-20 Rp/kWh range (estimated from the [4.29] plus inflation minus cost reduction when scaling up to 20 MW), see the section before. It was shown that hydrogen can also be flexibly added to the methanation of biomass gasification gas. With electrolysis operating hours similar to those assumed for biogas methanation in [4.55], the price of biomethane from PtG with gasification gas should only be a few cents more expensive under Swiss conditions with relatively high wood prices and medium-sized plants of a few 10 MW.

CO₂ captured by scrubbers from waste incineration, wood-fired power plants, cement plants, etc. might, due to its costs, not be used for methane production, but rather for negative emissions or to produce methanol, SAF, or similar.

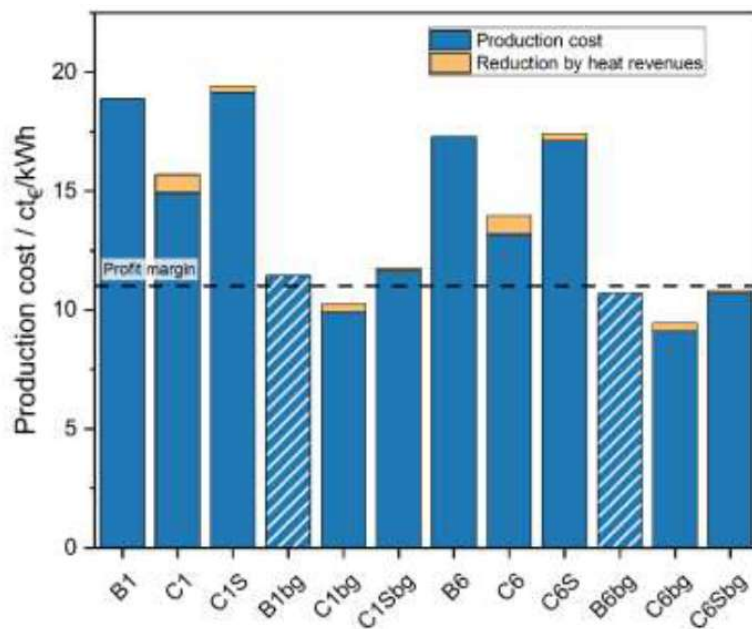


Figure 5.11: Production cost of biomethane for different process variations under the assumptions used in [4.14]. Biological (B) vs. catalytic (C) methanation, data for 1 MW and 6 MW electrolyzer capacity, and with biogas (bg) or pure CO₂ as carbon source. Plants with solid oxide electrolyzer (SOEC, S) have a significantly higher efficiency based on heat integration, but (today) higher CAPEX due to the lower technical maturity of SOEC. The projected cost for biological methanation operated with biogas is indicated with shaded bars. The profit margin indicates a typical biomethane price. With lower production costs, a profit can be achieved [4.14].

5.2 Hydrothermal Gasification (HTG) of wet organic material

The term Hydrothermal gasification (HTG) covers technologies that thermally convert biomass and other carbonaceous materials under super-critical water conditions, i.e., at conditions above the critical point of water (374°C, 221 bar). Other hydrothermal processes, such as liquefaction (HTL) or carbonisation (HTC), operate typically below the critical point and obtain different products, such as a bio crude or biochar, while HTG allows the production of synthesis gas (mainly hydrogen, CO, CO₂) or methane-rich gas mixtures (containing also CO₂ and traces of hydrogen) [4.37]. The use of a catalyst in HTG allows to completely decompose all molecules into gas [4.38]. The advantage of operating at supercritical conditions is that no phase separation between vapour and liquid occurs, and one fluid phase exists with about half the density of liquid water. As a consequence, no evaporation takes place, and the connected energy input is not needed.

This allows for the conversion of very humid feedstock, such as sewage sludge, manure, algae, digestate from anaerobic digestion, and watery waste from food and pharmaceutical production. Usually, these waste streams contain so much water that the necessary heat of evaporation is higher than the energy content in the organic molecules. Some feedstocks necessitate full conversion to destroy harmful molecules; others could also be converted in normal biogas plants by anaerobic digestion. The disadvantage of anaerobic digestion is the incomplete carbon conversion of 40-70%, where the rest of the carbon is contained in the solid leftover referred to as digestate, which also contains all the salts (that would form the ash during normal combustion). In these cases, HTG downstream of the anaerobic digestion allows not only for nearly complete carbon conversion, but also for the recovery of the salts that also contain very valuable nutrients such as phosphorus.

5.2.1 Technology description

In principle, all pumpable feedstocks can be used (important to reach the necessary high pressure). The energy input for the pumping is not very high due to the incompressible nature of water. Still, for economic reasons, the dry matter content should be at least 5%, but better 10-20% (above, viscosity becomes too high), and the organic fraction of the dry matter should be at least 40-50%. Once under pressure, the feedstock must be heated up. This can easily be achieved by a liquid-liquid heat exchanger that recovers the heat of the water stream leaving the reactor. Therefore, the energy input for reaching the high temperatures is limited, and the heat recovery for such processes is typically excellent (>80%, up to 91%) [4.39].

A critical point in the plant is the salt separator. Water at conditions above the critical point has very different solvent properties; it turns from a polar solvent into an apolar solvent. Typical salts that are easily soluble at normal conditions start to form solids (precipitation) or form a highly concentrated phase (brine) once the critical point is reached. On the other hand, organic molecules easily dissolve in supercritical water, which supports their conversion. Relatively small temperature differences are sufficient to “switch” between super- and subcritical conditions and to control the water solvent property. At PSI, it could be demonstrated at TRL 7 that this allows to precipitate salts and their separation in a semi-continuous way from the feedstock [4.39]

After the salt separator, a purification section with fixed-bed adsorbers (e.g., ZnO to chemisorb hydrogen sulphide) may be necessary in case of catalytic HTG to avoid catalyst poisoning by sulphur species and other impurities contained in the feedstock. Then the cleaned salt-free feed can be converted in the catalytic reactor, where organics are converted to biogas. Downstream of the reactor, the effluent heats up the incoming feed and then enters a two-step phase separation to obtain water and the gas phase, which then has to be upgraded to obtain the desired products.

High temperature vs. catalytic HTG

For the main reactor, two different concepts have been developed. Starting at Karlsruhe Institute of Technology as a pioneer, **high temperature hydrothermal gasification** was developed, where at temperatures of 550°C – 700°C, the thermal energy is sufficient to decompose most of the organic matter to a mixture of approximately 30 vol.-% of each methane, hydrogen, and CO₂, the remainder being, e.g., ethane and carbon monoxide. This technology is also developed by the French company Leroux & Lotz and is also the core of the so far largest HTG plant in the Netherlands (20 MW, TRL 8/9, technology supplier SCW systems).

This product gas can be directly used thermally or has to be upgraded to injectable biomethane by methanation or separation of hydrogen and CO₂.

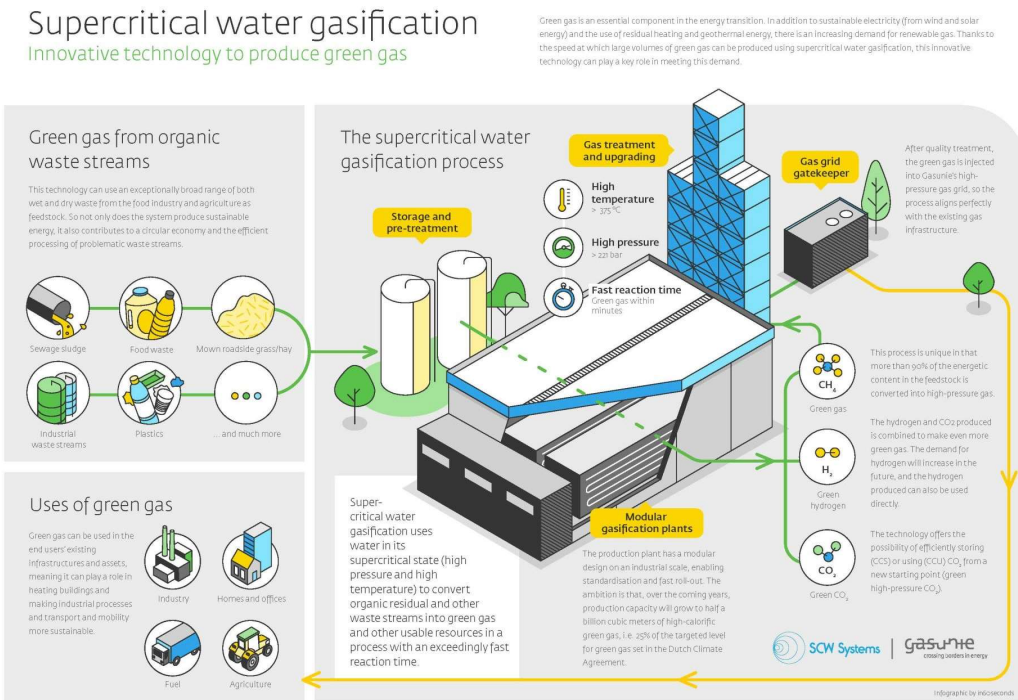


Figure 5.12: Scheme of the high temperature hydrothermal gasification plant in Alkmaar (The Netherlands) [4.37].

Catalytic hydrothermal gasification has been developed so far mainly in Switzerland. It allows for operation at a lower temperature than the critical point, where the presence of catalysts allows the complete conversion of the organic feedstock to mainly methane and carbon dioxide, with low hydrogen concentration (around 5%), only traces of ethane and carbon monoxide. In consequence, the upgrading to biomethane that can be injected into the gas grid is quite easy. Either the CO₂ is separated, e.g., by a membrane or an amine scrubber, or it is converted to additional methane with the addition of hydrogen, e.g., from an electrolyser (Power-to-Gas). This methanation reaction can be conducted either by a methanation reactor downstream or *in situ*, where hydrogen has to be injected along with the feedstock in the hydrothermal gasification process [4.40]. As a catalyst under these demanding (corrosive) hydrothermal conditions, ruthenium on carbon support turned out to be the most active and stable catalyst [4.38]. While the catalytic hydrothermal gasification simplifies the gas upgrading and has lower internal energy demand and CAPEX for most parts of the plant due to the lower temperature, the necessary catalyst feed purification, especially the desulphurisation, causes some additional effort.

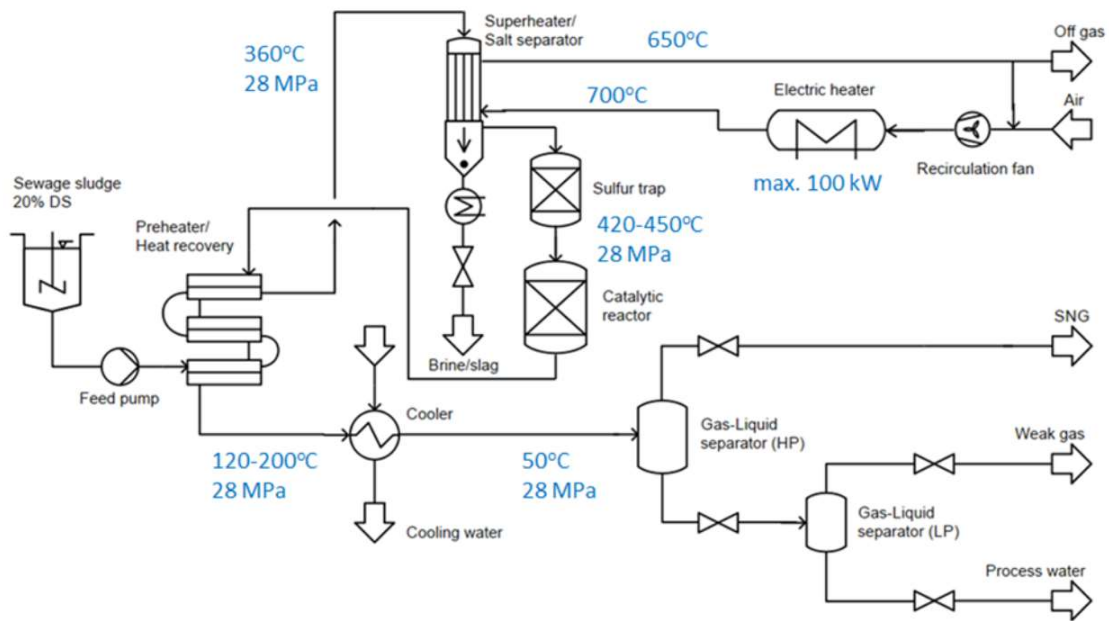


Figure 5.13: Catalytic hydrothermal gasification plant *Hydropilot* at PSI (TRL 7), [4.39].

5.2.2 Realised (pilot) plants TRL 6-9

While a number of R&D activities are ongoing and also building of several larger-scale units has been announced (e.g., TRL7/8 high temperature HTG plant *GHAMA* to be built by Leroux and Lotz in the Ecopark La Barillais in France), only a few plants have been really operated [4.37]. One of them, Alkmaar 1, is an industrial/commercial demonstrator developed by a private company, while the other three are closer to an academic environment. Renewable methane, according to grid injection specifications, is reached by CO₂ separation or downstream methanation (catalytic or biological); hydrogen injection into the high-pressure part has not demonstrated at pilot or demo scale yet. The publicly known details of the plants can be seen in Table 5.5 below.

Table 5.5: Realized and announced (pilot) plants TRL 7-8 for hydrothermal gasification.

Name of project	VERENA	Hydropilot	Alkmaar 1	Supersludge
Location of plant	Karlsruhe (Germany)	Villigen (Switzerland)	Alkmaar (Netherlands)	Dinther (Netherlands)
Product 1	Renewable syngas	Renewable methane	Renewable syngas in HTG, methane in gas upgrading section	Renewable syngas in HTG, methane in gas upgrading section
Output		Around 50 kW		
Product 2	Salts	Salts	Metals	Salts
Feedstock 1	Sewage sludge, methanol, glycerol, maize silage, etc.	Sewage sludge, sludge digestate	Sewage sludge, agricultural and household waste, industrial effluents, plastics.	Sewage sludge
Input	100 kg/h (20% dry matter)	100 kg/h (20% dry matter)	4 * 4t/h (20% dry matter)	150 kg/h (17% dry matter)
Input			20 MW _{th}	
TRL	5-6	6/7	8	6
Status (e.g. operation hours)	Not operated anymore	Operated in campaigns	In operation	unknown
Investment, Year	2 M€ (2004)	2 M€ (2021)	45-55 M€ (2022)	0.7 M€ (2018)
Lead	Karlsruhe Institute of Technology	PSI/treatch Sàrl (technology) Kasag AG (plant construction)	SCW Systems, gasunie	ProBiomass
Technology gasification	High temperature HTG with integrated salt separator (600-700°C, 250-300 bar)	Catalytic HTG with integrated salt separator (400-450°C, 250-280 bar)	High temperature HTG (>>374°C, 250-300 bar), followed by desulphurisation, catalytic methanation and CO ₂ separation	High temperature HTG (650°C, 350 bar), upgrading by biological methanation tested with slip stream
Cost estimation			Guaranteed price 55€/MWh for 12 years	
Reference	4.37	4.37, 4.39	4.37	4.37

5.2.3 Cost estimates of HTG

As only a few plants have been built so far and have not yet been operated under realistic conditions for a long time, cost calculation is difficult. Still, some first estimates exist that show a significant economy of scale. As a result, plants for inputs below 2 t/h seem to be less favourable. On the other hand, for HTG plants without access to harbours, too large plants are connected to unfavourable logistics due to the low energy content of the feedstock that is connected to high transport costs. The resulting window of plants between 2 t/h and 8 t/h for decentral sites fits for example, the needs of many wastewater treatment plants in small and medium-sized towns.

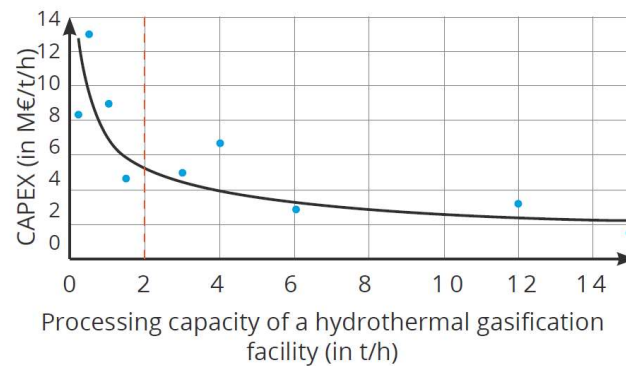


Figure 5.14: CAPEX (M€/t/h) for an HTG project for different capacities; tonnage shown refers to organic waste with max. 20% dry matter and an average calorific value of around 20 MJ/kg [4.37].

With respect to OPEX, one has to keep in mind that the carbon content of the feedstock and thus the possible energy yield strongly depend on the amount of dry matter and its organic fraction. In consequence, the fixed operation costs (electricity for pumps, salaries, maintenance, etc.) are distributed over varying amounts of energetic products [4.37]. The variable costs, mainly feedstock costs, may differ strongly depending on competing uses of the waste streams in focus.

The engineering company AFRY compared in a study several cases of sewage sludge treatment in Switzerland:

- Anaerobic digestion (AD) followed by drying and combustion of the digestate (state-of-the-art today, reference),
- anaerobic digestion with downstream HTG,
- and full stream HTG without upstream anaerobic digestion.

They came to the result that the CAPEX of combining AD with HTG leads to higher CAPEX than the reference case; full stream HTG, however, showed the lowest CAPEX and significantly lower OPEX than the reference case (AD plus sludge combustion) [4.37].

5.3 Potential contribution of renewable CH₄ to a resilient energy system in the future

The potential contribution of renewable methane from anaerobic digestion, hydrothermal gasification, wood gasification, and Power-to-Gas to the future energy system should aim at the optimal use of these limited resources. Therefore, it makes sense to compare the potential sustainable energy supply by biomass (i.e., without compromising material use and food production, or harming the environment) with different potential uses to differentiate better from less optimal solutions.

5.3.1 Use options

Several important aspects have to be considered together:

- As discussed recently by aee [4.41], resources that are not locally restricted should not be used for energy services that can be covered by local resources.
- Given the high potential for renewable electricity generation in Switzerland, especially by hydropower and PV, biomass use should focus on i) hard-to-electrify energy services (e.g., high temperature processes), and on ii) seasonally complementing during times of gaps between supply and demand of electricity or heat.
- Biomass logistics make large plant capacities costly.
- Wet biomass cannot easily be stored for a longer time, i.e., if not used, it has to be disposed to avoid environmental burden (e.g., methane emission).
- Biomass can contribute to negative GHG emissions by sequestration of biogenic CO₂ or carbon.
- With high PV capacity, the renewable energy supply will at least locally be larger than demand in summer and on clear winter days. The same holds true for very windy days if high wind power capacities were available.

These aspects in mind, the aim for optimal use of scarce resources suggests that:

- Transport should be electrified or be covered by hydrogen (trucks and buses for long distances).
- Heating of buildings should be covered mostly by local heat pumps and district heating (preferably with industrial off-heat or central heat pumps); biomass or biogenic energy carriers may be used to cover the demand peaks in winter, best with co-production of electricity (CHP).
- High temperature heat in industrial processes that cannot easily be electrified should be covered by renewable gases (methane or hydrogen), or with direct biomass combustion if equipped with suitable flue gas cleaning and ash handling.
- Converting wet biogenic wastes into methane is the easiest way to avoid environmental issues and to make the energy transportable and storable if a gas grid is available.
- The inherent CO₂ by-product of biogenic methane production could be used for i) Power-to-Gas to use locally renewable electricity that otherwise cannot be used (mainly spring to autumn), or ii) for negative emissions in the rest of the year if a suitable CO₂ logistics is available [4.42].

To increase the resilience and flexibility of the energy system and to decrease dependence on imports, it thus makes sense to keep part of the gas grid for the renewable methane at least in some regions.

This allows using the domestic biogenic wet wastes (sewage sludge, green wastes, manure, residues from food production, etc.), enabling sector coupling and storage of otherwise non-usable electricity, and supplying especially industry with high temperature heat and also district heating systems during peak demand. Further, given the existing infrastructure for gas transport and storage, renewable methane could be one of the energy carriers to cover electricity demand in Winter (“Reserve-Kraftwerke”).

Converting at least part of the sustainable energy wood potential to methane by gasification and methanation, combined with flexible Power-to-Gas, would enlarge the above-mentioned options.

5.3.2 Estimation of demand of renewable gas

In the following, the potential future demand of renewable gases is estimated, due to time limitations; however, with simplified assumptions and thus relatively high uncertainty.

Today, the mainly imported natural gas amounts to about 34 TWh/a (15% of Swiss energy consumption) [4.43], of which around half is used for domestic heating. In consequence, the annual gas consumption varies depending on the severity of the winter season. Besides some of the historic centres of Swiss towns, most heating of buildings should be replaced by heat pumps and district heating with industrial off-heat and/or central heat pumps. Peak demand of the building heating is around 20% of the annual consumption, i.e., around 17 TWh/a for domestic heating, max. 3.5 TWh/a for peak demand of district heating will remain, together with the 17 TWh/a of non-heating use. It is assumed that the peak demand of district heating replacing oil-based heating (20% peak demand of ca. 36 TWh, i.e., max. 7 TWh) [4.43] might be covered by biomass immediately (as no gas grid is available), given that around 12 TWh wood [4.43] is used already now for direct heating, and a non-negligible fraction of the oil heating systems will be replaced by heat pumps rather than by district heating.

Of these remaining 20.5 TWh/a of energy demand that was so far covered by natural gas, a significant part will be electrified (directly or high-temperature heat pumps) or saved by different measures or structural changes in industry. As a very rough assumption, between a quarter and a half of energy demand is to be covered by renewable gases, i.e., 5-11 TWh/a. For comparison, the ZERO basis scenario of the Energieperspektiven 2050+ (BfE, 2021) expects a “biogas” contribution of around 25% for the industrial energy consumption of 95 PJ in 2050, which translates into 7 TWh for 2050. Especially in the North-west of Switzerland, with a connection to the European Hydrogen Backbone, part of this energy demand might be covered by hydrogen. It can be expected that the larger industrial sites (chemical, metallurgical, cement plants) might be directly connected, at least from Cornaux/Cressier via Basel, Solothurn, Aargau, Zürich, to Winterthur; and there may be a connection through the Rheintal from Bregenz until Domat/Ems. It is not yet clear to what extent in such regions the distribution grid will be repurposed for hydrogen. Moreover, many, if not most, regions and communities of Switzerland will not be connected to the hydrogen grid. Overall, there will be a residual need for renewable methane of several TWh/a. As shown in the next section, this fits the domestic production potential for renewable methane.

Further, in such regions, Power-to-hydrogen plants have only limited options to inject hydrogen into the gas grid. Thus, combining the conversion of biomass to renewable methane with flexible addition of hydrogen (i.e., Power-to-Gas in times of low electricity prices) is an attractive option to increase the renewable methane yield while using electricity from decentralized hydropower plants during periods of low or negative electricity prices, e.g., seasons with high PV production.

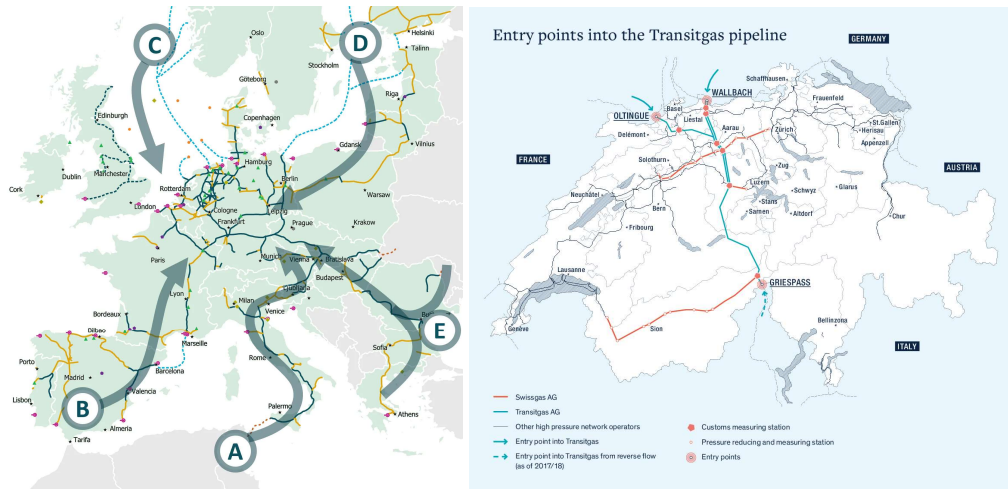


Figure 5.15: Map of the planned European Hydrogen Backbone (left), map of the Swiss natural gas transport grid (right).

5.3.3 Wet and dry biomass potential

The sustainable potential for renewable methane from wet biomass consists, on the one hand, of sewage sludge at wastewater treatment plants, and on the other hand, green wastes and manure.

Wet biomass

Today, around 200 GWh/a of renewable methane is injected into the Swiss gas grid. There are around 100 larger wastewater treatment plants (for > 30000 people) close to the existing gas grid. If all of them change from biogas use in CHP to biomethane injection, another 0.6 TWh of biomethane can be produced. As a by-product, around 120 kt/a biogenic CO₂ has to be separated (or used). If half of that is used from spring to autumn for Power-to-Gas (PtG), the domestic biomethane production of waste water treatment plants could reach 1.1 TWh/a. Around 60 kt/a CO₂ then could be used for negative emissions.

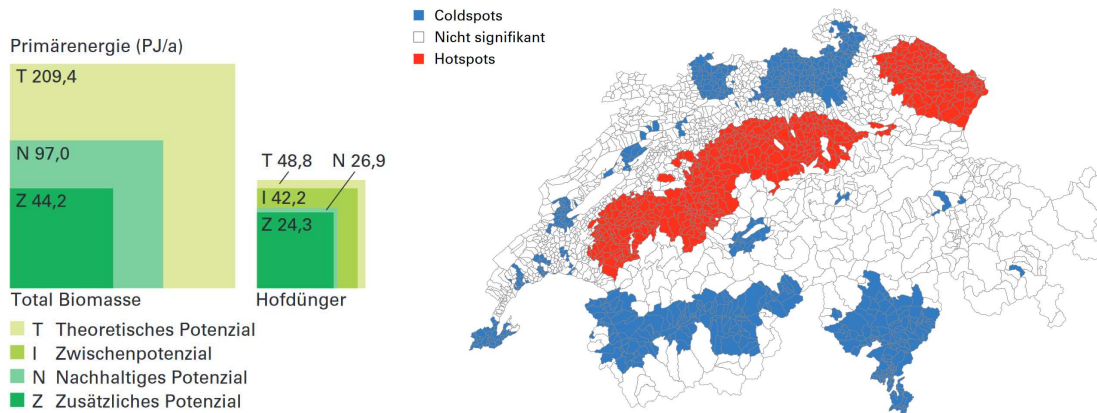


Figure 5.16: Map of Swiss manure potential [4.44].

With respect to manure, the Whitepaper of the SCCER BIOSWEET [4.44] indicates around 24 PJ/a unused potential, especially in the Mittelland between Jura and Alps, see Figure 5.16. If completely used in anaerobic digestion, this translates with an assumed efficiency of 30% into 2 TWh/a of biomethane. A recent study [4-57] found similar numbers, i.e., at a maximum of 2 TWh/a by anaerobic digestion when using the complete potential of agricultural substrates. As hydrothermal gasification (HTG) reaches around 60 % efficiency, this amount could be doubled to 4 TWh/a. With a typical CO₂ content of 40%, flexible Power-to-Gas from spring to autumn (i.e., during 50% of the time), between 0.65 TWh/a (PtG in case of only anaerobic digestion) and 1.3 TWh/a (PtG in case of only HTG). The

realistic potential most probably is lower, but maybe 1-2 TWh/a. Thus, it can be expected that between 1.5 and 3 TWh/a, biomethane can be produced by only the wet biomass residues. This is already close to the residual demand for renewable methane, but could be off by a factor of 2 or 3 due to the uncertainties. Therefore, it is interesting to consider also the sustainable potential for woody biomass that is not yet used, see Figure 5.17.

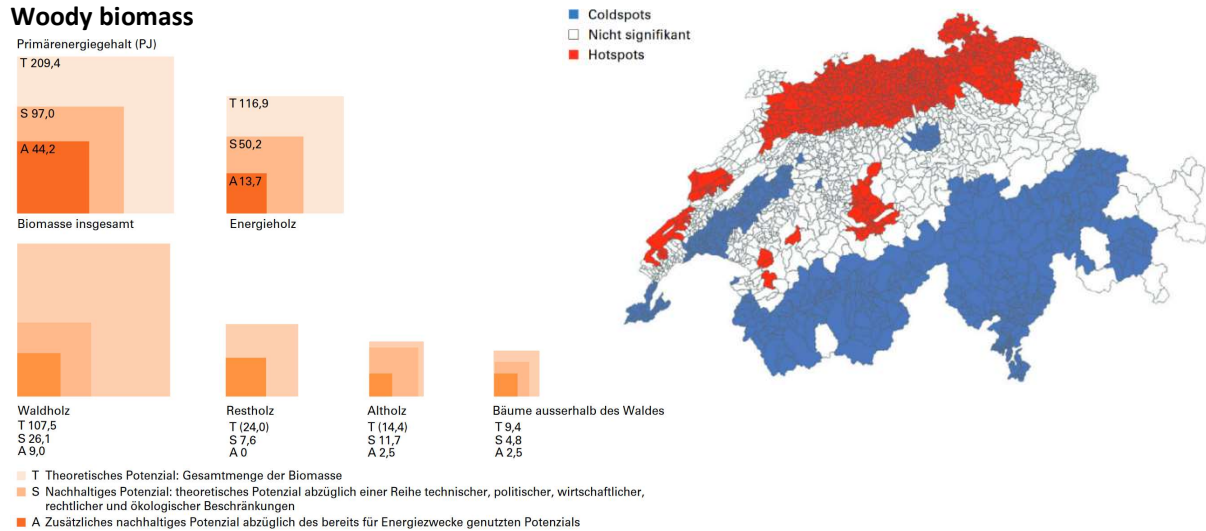


Figure 5.17: Map of Swiss energy wood potential [4.45].

The Whitepaper of SCCER BIOSWEET on woody biomass [4.45] reports about 13.7 PJ/a not yet used sustainable wood (and wood residues), mainly in the Jura and the Prealps region. Other sources see significantly less potential due to the high number of realised and planned wood-based heating systems. Therefore, it is necessary to reconsider the use of wood for the direct heating of buildings. With an efficiency from wood to renewable methane of 60% [4.6], around 2.3 TWh/a of renewable methane could be produced from the mentioned 13.7 PJ/a. As a co-product, around 560 kt of CO₂ could be produced. With the assumption of flexible Power-to-Gas from spring to autumn, around half of that could be used to produce an additional 1.4-1.5 TWh/a of renewable methane. This relates to wood gasification plants of a total 400-500 MW_{th,wood} installed capacity, and a similar total electrolysis capacity (which, however, is used only from spring to autumn). With a typical transport radius of up to 50 km for wood residues, plant capacities of a maximum 30 MW_{th,wood} are obtained, i.e., the mentioned potential could be covered with less than 20 plants in Switzerland. In sum, the contribution from gasification and PtG with woody biomass could reach around 3.5 TWh/a. On the cost side, one has to consider that at today's market prices, only half to two-thirds of that wood can be mobilised, see Figure 5.18.

Still, together with potential from wet biomass (1.5-3 TWh/a), the estimated demand for renewable methane could most probably be covered predominantly with domestic resources.

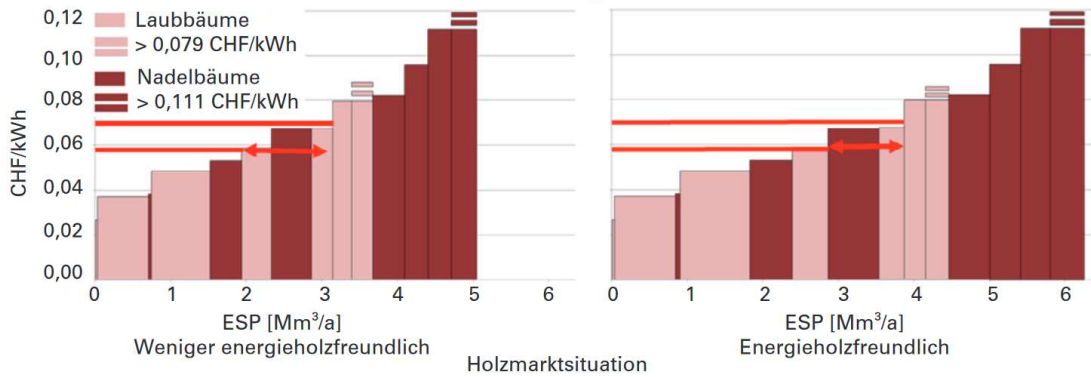


Figure 5.18: Price of energy wood depending on market situation [4.45].

Competing uses of biomass for negative emissions

Given that biomass can also be used for negative emissions, it is interesting to consider the competing potential use. Producing electricity and heat with biomass is connected to combustion and thus diluted CO₂ emissions in flue gas, which are quite costly to capture, especially in the typically small plants. Producing renewable methane as suggested in the previous sections is inherently connected to the co-production of biogenic CO₂. This could be used for negative emissions or for Power-to-X or in a seasonally flexible combination, as mentioned before, see also [4.42]. The maximum amount of CO₂ from converting the so far unused biomass potential to methane is 1200-1600 kt/a. Limitations in mobilising the biomass might decrease this amount to 600-800 kt/a; using half of it for flexible PtG would decrease it further to 300-400 kt/a. This amount can only be used for negative emissions when suitable CO₂ logistics are available (pipeline, train wagons, ...).

In comparison, in the more central waste incineration plants with around 50% biogenic fraction, 2000 kt/a of biogenic CO₂ can be collected. Given that the non-biogenic fraction of CO₂ (also 2000 kt/a) has to be captured and sequestered anyway, it is most probably easier to realise negative emissions at the incineration plants. The same is true for the low biogenic fraction of biogenic CO₂ in the flue gas of cement plants (less than 10%, maximum 250 kt/a). However, in turn, it means that, if not used for negative emissions, up to 2250 kt/a biogenic CO₂ could be used for large-scale Power-to-X at central plants, e.g., for methanol production.

If all of the so far unused biomass potential would be used for negative emissions in form of solid carbon by converting woody biomass in pyrolysis and wet biomass in hydrothermal carbonisation [4.46], an CO₂-equivalent of a 1500 – 3000 kt/a could be obtained as negative emissions, however at the price of: i) less flexibility in the energy system (no flexible PtG, no stored energy carrier for winter peak demand) and ii) more import of hydrogen to cover the need for renewable gases.

Given that many of these options depend on regional boundary conditions such as existing gas grid, electricity surplus, and CO₂ logistics, an optimisation requires simulating different scenarios with a regionally detailed energy system model, i.e., today's standard energy system models (that ignore regional differences) most probably fail to find the best solution.

5.4 Open questions and research needs

The research overview showed that promising experiences, both by simulation studies and pilot plants up to TRL 8, exist. Still, a number of questions remain open, which will be discussed in the next sections, topic by topic.

5.4.1 Gasification and methanation/Power-to-Gas

The methanation of pure CO₂ with hydrogen within Power-to-Gas applications has been investigated for many different reactor types and was realised up to TRL 8/9 for biological and cooled fixed bed

reactors and TRL 6 for structured reactors, bubbling fluidised bed reactors, and bubble columns. Thus, it is more interesting to investigate the upscaling of plants that convert gasification-derived gas with (flexible) hydrogen addition into the main reactor, as this option offers many advantages with respect to efficiency and costs.

The methanation of gasification gas without hydrogen addition has been demonstrated in pilot plants at, depending on the technology, up to TRL 5, 7, and 8. Only two ongoing EU projects so far have started working on pilot plants (TRL 7) that convert hydrogen with gasification gas. While *BUTTERFLY* aims at di-methylether (DME) as the main product and uses methanation as the second step to convert unreacted gas, *HyFuelUp* tries to demonstrate fluidised bed methanation of producer gas from sorption-enhanced gasification with flexible hydrogen addition (flexible PtG). Unfortunately, the already existing circulating fluidised bed gasifier in Tondela/Portugal with a downstream oxygen-blown tar cracker cannot be adapted to a Dual Fluidised Bed gasifier (DFB). Also, the electrolyser will be small due to budget issues within the *HyFuelUp* project, which in turn limits the range of Power-to-Gas operation conditions.

It would be therefore be beneficial to understand the potential of combining a non-oxygen blown gasifier (such as the Dual fluidised bed) with a downstream methanation and full-scale flexible hydrogen addition, demonstrating the process especially under the Swiss economic boundary conditions. Typically, these types of gasifiers produce a gas mixture rich in methane (around 10%) and ethene/ethane (up to 4%), which both significantly increase the overall process efficiency [4.5].

Interesting side aspects could cover the CO₂ separation for negative emissions and/or the use of an efficient high-temperature electrolyser (e.g., SOEC at scale) as well as the heat integration that is important for both.

In a first step, a detailed pre-engineering study for a promising site would be useful to obtain sufficient data (technical, economic, and environmental assessment) for an investment decision for the next step, which should be a demonstration plant at TRL 7 or 8.

5.4.2 Hydrothermal gasification

Open questions in HTG have to be differentiated between high-temperature and catalytic HTG. Due to the milder operation conditions (400°C instead of 600°C), the thermal efficiency in catalytic HTG is already quite good, while it needs further attention in high-temperature HTG. Challenges lie in the choice of proper materials that withstand the hydrothermal conditions for long times; again, this is more pronounced for the high-temperature process.

For widening the range of potential feedstocks, feedstock handling or its pretreatment and operation conditions have to be optimised to allow for high carbon efficiency and thus high energetic yield. Further, the separation of the solids (nutrients, salts, metals) and their upgrading to fertiliser and other marketable products needs more research.

While the pilot experiments so far showed the technical feasibility, and also the catalytic hydrothermal gasification technology undergoes the next scale-up step [4.47], the integration with Power-to-Gas needs attention. Here, a pre-engineering study would be a useful next step that investigates the different options to introduce renewable hydrogen in a flexible way (i.e., when it is available) by either in situ-injection of hydrogen into the HTG or by downstream (catalytic or biological) methanation of HTG gas with hydrogen

5.4.3 Optimal contribution of renewable methane to a future energy system

Like anaerobic digestion, the technologies described in the sections above (thermochemical gasification followed by methanation, methanation of biogas, hydrothermal gasification) allow the conversion of biogenic residues into renewable methane, also referred to as biomethane, renewable natural gas RNG, or Bio-SNG. By flexible hydrogen addition, these processes can also absorb and store

electricity that otherwise cannot be used, e.g., during summer at hydropower plants, and thus help to stabilise the electricity grid and support its resilience. The potential to produce renewable methane is in the same order of magnitude (5-10 TWh) as the residual gas consumption in a future energy system, especially for high-temperature processes in industry, and maybe covering peak demands in district heating. The domestic production of biomethane can thus contribute to value creation in rural areas and to decreasing the dependence on energy imports. The potential benefits of converting wet biomass waste by hydrothermal gasification and woody biomass residues by gasification/methanation with flexible hydrogen addition (PtG) could be estimated in this study only based on rough assumptions. While the maximum values of production potential most probably are correct, the realistic implementation depends on many boundary conditions. These are, e.g., the wood price, electricity price, and its seasonal variation, demand for renewable gases/degree of electrification, demand for negative emissions, availability of a gas grid and renewable hydrogen, district heating systems, CO₂ logistics, and sufficient capacity in the electricity grid, as well as efficiencies and costs of competing pathways. As many of these boundary conditions are inherently different from region to region, the best contribution of biomass resources with their inherent limited spatial and, in the case of wet biomass, even limited seasonal flexibility might differ as well regionally. Therefore, investigating the optimal biomass use necessitates regionally detailed energy system models. It is expected that a relatively small number of example situations could be sufficient to derive recommendations according to the existence/availability (or not) of a methane or hydrogen grid and/or district heating systems, local potential of wet or woody biomass residues, and CO₂ logistics to enable negative emissions. To obtain useful results that can be realised, the model should be path-dependent, i.e., start with the current situation of the regional energy system and predict the changes based on different sets of boundary conditions. This will also help to derive options for optimal regulatory frameworks.

6 Literature

6.1 Section 4

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6.2 Section 5

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7 Appendix – section 3

7.1 Activities and data collection

The collection of fundamental and scientific information is based on the following activities:

- Literature search in internet including EU conferences
- Literature search with personal contact to IEA task on biomass gasification and other experts in EU.

The collection of actual information valid for Switzerland is based on the following activities:

- Visit of five plants in operation in Switzerland in 2024 with interviewing from plant owners and operators. Three plants were gasifier CHP, one plant a biochar plant with heat supply and one plant a gasifier CHP with biochar production.
- Exchange of experience with three representatives from legal authorities, one responsible for the legislation and two for the enforcement of the legislation (ordinance on air pollution control).
- Visit to one plant manufacturer with interview on plant efficiency.
- Request of detailed actual offers on cost and efficiencies from one manufacturer.
- Request of non-binding information on efficiencies and cost from two additional manufacturers.
- Collection of anonymized data from offers and information available as part of expert opinions and quality management on plant planning of various plants in Switzerland.
- Before 2024: Exchange with plant operators in Switzerland during plant monitoring activities.

7.2 Sources for reference gasifier CHP

Data from Spanner Re² validated and supplemented with other data are used for the base case for small-scale gasifier CHP based on the following sources:

1. Literature from Spanner Re² in [17]
2. Oral information during visit in Neufahrn in 2024
3. Correspondence Matthias v. Senfft, Spanner Re² GmbH, D - 84088 Neufahrn i.NB. 04.07.2024:
Eine HKA 35 kostet 170.000,00 € netto, ab Werk. Thermische Leistung 70 KW. Sinnvolles Zubehör jeweils ca. 40.000,00 €.
Eine HKA 50 kostet 202.000,00 €, netto, ab Werk. Thermische Leistung 100 KW.
Eine HKA 70 kostet 254.000,00 €, netto, ab Werk. Thermische Leistung 130 KW.

Die Preise beinhalten **SCR-Kats**, die die NO_x-Werte in den angehängten Datenblätter deutlich senken. (NO_x Reduzierung < 100 mg/Nm³ (Mittelwert) bezogen auf 5 % Sauerstoff.)

Die Inbetriebnahme ist jeweils inkludiert.

Im Anhang übersende ich weitere Informationen zu unseren Anlagen und ein CO₂ Gutachten.

Um eine kWh Strom und gleichzeitig zwei kWh Wärme herzustellen, benötigt man ca. 0,8 - 0,9 kg an trockenen (8 – 12 % Restfeuchte) G 30 – G 40 Holzhackschnitzeln.

Der 6 SBT – 5 kostet 68.000,00 €, netto, ab Werk.

Der 6 SBT – 25 kostet 78.000,00 €, netto, ab Werk.

Der 12 SBT – 25 kostet 98.000,00 €, netto, ab Werk.

Schaltschrank etc. ca. jeweils 16.000,00 €, netto, ab Werk.

Für die laufenden Betriebskosten kann man mit ca. 0,03 € / kWh el. rechnen, dieses beinhaltet Verschleissmaterialien und Arbeitskraft.

Anzahl Holzvergaser-BHKW Stand August 2024: Total 1050 HKA

Davon in der Schweiz: 12 Anlagen an 5 Standorten.

6 x HKA70: Hodel Energie GmbH, CH - 6018 Buttisholz

1 x HKA70: Linard & Nicolin Sonder, CH – 7415 Rodels

2 x HKA50: Gebrüder Sonder

1 x HKA50: Thomas Helfer, CH – 1783 Pensier

1 x HKA50: Grimm & Schmid, CH – 8627 Grüningen.

7.3 Data on other technologies

Information on the heating value of biochar is assumed as from charcoal from [28].

Information on efficiencies and cost on technologies from the following technologies are derived from the sources [29] to [45]: Bioenergie Wegscheid, Syncraft, Lipro, Biomacon, Pyreg, Regawatt.

7.4 Assumptions for techno-economic assessment

Table 7.1 shows the investment cost of the base-case gasifier CHP plant. The real costs are based on information from existing plants in Switzerland and exceed the ideal cost based on offers from the system suppliers and assumptions on auxiliary equipment and buildings in ideal conditions.

Table 7.2 summarizes the efficiencies of all investigated technologies and the resulting investment cost per kW fuel input.

Table 7.1: Investment cost of the base-case gasifier CHP plant.

	Value	Symbol	i d e a l								r e a l			
			Wood CHP Input dry wood	Dryer	Control	Wood CHP Input moist wood	Hydraulics (H)	Technologie (CHP + H)	Building	Total theoretical minimum	Total/ CHP	Total real cost Switzerland	real/ theor.	Total real/ CHP theor.
Invest cost in CHF	35	kWe	170'000	68'000	16'000	254'000	50'000	304'000	94'124	398'124	1.6	669'328	1.7	2.3
	50		202'000	78'000	16'000	296'000	55'000	351'000	112'500	463'500		800'000		
	70		254'000	98'000	16'000	368'000	60'000	428'000	133'112	561'112		946'573		
Specific invest cost in CHF/kWe	35	kWe				7'257		8'686		11'375		19'124		
	50					5'920		7'020		9'270		16'000		
	70					5'257		6'114		8'016		13'522		
Specific invest cost in CHF/kW _{useful}	105	kW _{useful}				2'416		2'892		3'787		6'367		
	150					1'971		2'337		3'086		5'327		
	210					1'750		2'036		2'669		4'502		
Specific invest cost in CHF/kW _{fuel input}	123	kW _{fu}				2'061		2'467		3'230		5'431		
	176					1'681		1'994		2'633		4'544		
	246					1'493		1'736		2'277		3'840		
Scale-up-factor = Cost 200 kW / Cost 100 kW							1.41							

Table 7.2: Efficiencies and resulting investment cost per kW fuel input for all investigated technologies.

	No.	Q _{zu} kW	Gross efficiencies				weighted el. = 1.75	ENV lst / 70%	Self consumption		Net efficiencies				weighted el. = 1.75	Invest cost					
			η _e	η _g	η _{PK}	η _{tot}			η _{ENV}	f	η _e	η _g	η _e	η _g		η _{PK}	η _{tot}	η _{ENV,net}	Min	Med	Max
Gasification CHP (example 1)	1	123	28.4%	56.9%		85.3%	107%	1.52	5.0%	25.0%	23.4%	31.9%		55.3%	73%	3230	4'331	5'431			
		176	29.0%	56.8%		85.8%	108%	1.54	5.0%	25.0%	24.0%	31.8%		55.8%	74%	2633	3'588	4'544			
		246	31.0%	55.0%		86.0%	109%	1.56	5.0%	25.0%	26.0%	30.0%		56.0%	76%	2277	3'058	3'840			
		493	31.0%	55.0%		86.0%	109%	1.56	5.0%	25.0%	26.0%	30.0%		56.0%	76%	2070	2780	3491			
		986	31.0%	55.0%		86.0%	109%	1.56	5.0%	25.0%	26.0%	30.0%		56.0%	76%	1881	2528	3174			
		1972	31.0%	55.0%		86.0%	109%	1.56	5.0%	25.0%	26.0%	30.0%		56.0%	76%	1710	2298	2885			
3944	31.0%	55.0%		86.0%	109%	1.56	5.0%	25.0%	26.0%	30.0%		56.0%	76%	1555	2089	2623					
Gasification CHP (example 2)	2	482	28.0%	56.0%		84.0%	105%	1.50	5.0%	25.0%	23.0%	31.0%		54.0%	71%	3'112	3'890	4'668			
Wood boiler heating plant (QM Holzheizwerke®)		294		85.0%		85.0%	85%	1.21			-3.0%	85.0%		82.0%	80%	1540	2'040	2540			
		588		85.0%		85.0%	85%	1.21			-3.0%	85.0%		82.0%	80%	1045	1'360	1675			
		2352		85.0%		85.0%	85%	1.21			-3.0%	85.0%		82.0%	80%	700	850	1000			
Gasification CHP with biochar	3	800	28.0%	56.0%	10.0%	94.0%	115%	1.64	5.0%	25.0%	23.0%	31.0%	10.0%	64.0%	81%	4000	4'500	5000			
	3*	1600	28.0%	56.0%	10.0%	94.0%	115%	1.64	5.0%	25.0%	23.0%	31.0%	10.0%	64.0%	81%	3333	3750	4167			
		3200	28.0%	56.0%	10.0%	94.0%	115%	1.64	5.0%	25.0%	23.0%	31.0%	10.0%	64.0%	81%	2778	3125	3472			
Counter current gasifier CHP	4	3600	27.5%	57.5%		85.0%	106%	1.51	5.0%	10.0%	22.5%	47.5%		70.0%	87%	3000	3'500	4000			
Biochar plants with heat	5	1350		40.0%	37.0%	77.0%	77%	1.10	5.0%	25.0%	-2.5%	15.0%	37.0%	49.5%	48%	2500	3'000	3500			
	6	1500		46.2%	36.3%	82.5%	83%	1.18	5.0%	25.0%	-2.5%	21.2%	36.3%	55.0%	53%	2500	3'000	3500			

Legend:

Example	Supplier	Sources
1	Spanner Re	Spanner Re, Betreiber Kt. Zürich
2	Wegscheid	Planung 2022 4 x 135 kWe
3	Syncraft	Syncraft, Betreiber Kt. Zürich
4	Regawatt	Regawatt, Richtofferte ohne WKK
5	Biomacon	Betreiber Kt. Zürich
6	Pyreg	Bauböck, 2021
*	Scale-up with factor 2/1.1 for plant with two gasifier CHP modules	
**	Scale-up factor 2/1.2 for one gasifier CHP in stainless steel	