Bio-FlexGen

Business models analysis

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Summary

Summary of Deliverable

This deliverable details the operational modelling and investment analyses performed through the Bio-FlexGen project, which aims to develop and validate a flexible and highly efficient renewable energy CHP (Combined Heat and Power) technology.

The operational modelling and investment analysis are performed on the business use cases described in D 3.7 (Swedish use cases) and D 3.8 (Spanish use cases). It has been postulated that it can be of benefit to the production portfolios to include a flexible and highly efficient renewable energy CHP technology.

To test this theory, Swedish and Spanish use cases have been modelled with and without BTC (Biomass-fired Top Cycle) CHP technology for a reference year of 2021. It has been found that including BTC CHP technology in the portfolio of Swedish and Spanish use cases consistently produces more electric power to participate and trade in different electricity markets; thus, resulting in higher benefits. These benefits can be quantified over a range of metrics: decreased dispatch costs; increased revenue; increased renewable dispatch; decreased fossil fuel dispatch or decreased CO_2 emissions.

Results from the Swedish use cases show that when one CHP unit, belonging to the plant KV1 (Kraftvärmeverket) in TvAB (Tekniska Verken AB; Swedish district heating company) portfolio is replaced with BTC units, the generated profit is higher in all simulation runs, disregarding the investment cost. The generated profit is even higher for business use case 2, where we assume that TvAB is providing balancing power while trading in both day-ahead and mFRR (manual Frequency Restoration Reserve) markets. Moreover, simulation runs for sensitivity analysis show that the portfolio's total profit highly depends on the biomass prices. However, when equivalent annual investment cost is compared with the annual profit generated by BTC units, we see that annual investment cost is at least 2.5 times higher than the annual profit.

Results from the Spanish industrial use cases show that the inclusion of BTC technology can achieve higher total profits and reduction of CO2 emissions in all cases, even when considering the investment costs. A sensitivity analysis considering 2023 prices for electricity, secondary reserves, biomass, and fossil fuels resulted in higher profits as well, although lower than those of the baseline 2021 scenario. Usage of renewable, electrolyzer-based hydrogen as kiln fuel for cement production was also investigated. Under the assumptions made in the study, results showed that burning on-site produced hydrogen is costlier than burning fossil fuel.

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Abbreviations

BTC	Biomass-fired Top Cycle
CAPEX	Capital expenditures
CHP	Combined Heat and Power
COP	Coefficient of Performance
CWT	Cooling Water Tower
DA	Day-Ahead (market)
DH	District Heating
ENTSO-E	European Network of Transmission System Operators
EPC	Engineering, procurement, and construction company
GME	Biomass provider in Spain
HP	Heat Pump
HRSG	Heat Recovery Steam Generator
MC	Moisture Content
mFRR	Manual Frequency Restoration Reserve
MILP	Mixed Integer Linear Programming
OPEX	Operating expenditures
PPU	Power Production Unit
RH	Relative humidity
SD	Shut-down
SF	Scaling Factor
SU	Start-up
TDC	Total Direct Cost
TIC	Total Indirect Cost
TvAB	Tekniska Verken AB (utility)
GAMS	General Algebraic Modeling System
RISE	Research Institutes of Sweden

1 Introduction

This deliverable outlines the mathematical modelling and investment analyses of integrating a novel CHP technology (BTC) in the production portfolio of the Swedish district heating company located in Linköping city and in the portfolio of Spanish chemical company (Sodium Sulphate production) as well as cement production company. The analysis has been performed by developing Mixed Integer Linear Programming (MILP) models for optimal scheduling, considering each use case in detail. The objective of these scheduling models, broadly, is to maximize the total profit over a considered time period, and includes deducing an optimal operation schedule, characterized by the amount of production and state (on/off) of the different production units in the considered portfolio or use case.

The deliverable is structured as follows:

1) Section 2 outlines the estimated technology and economical build parameters for the novel BTC CHP technology, which serves as input data for the optimization models. Some parameters are general for all use cases, while some are specific for each use case.
2) Section 3 outlines assumptions and data inputs for the use cases. This includes system data in Sweden and Spain for the considered reference year, like day-ahead and balancing market

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prices, as well as business use case specific data such as that of the production portfolios of the Swedish district heating company and Spanish industrial companies.

3) Section 4 details the optimization models developed for the Swedish business use cases, for both benchmark cases (considering only existing production portfolio) and BTC CHP integration cases.
4) Section 5 details the optimization models for Spanish business use cases.
5) Section 6 provides results and discussion, performs sensitivity analysis as well as investment analysis to calculate financial indicators for Swedish use cases.
6) Section 7 provides results and discussion, performs sensitivity analysis as well as investment analysis to calculate financial indicators for Spanish use cases.
7) Section 8 concludes and provides suggestions for future work.

2 Estimated Technical and Economical Parameters for BTC Technology

2.1 Introduction

The optimization models used in in this deliverable rely on technical and economical parameters of the BTC to assess the use cases properly. These assumptions relate to transient behavior (start-up, ramp and shut down times), full load and part load performance and cost (investment or so-called CAPEX).

The use cases have been described in D3.7 [1] and D3.8 [2], but in short, they can be described as follows:

- **Use Case TvAB**: For Swedish Energy Utility TvAB a FLEX CHP plant operating on chips from forest residue was investigated. Hourly data for e.g. ambient condition and district heating temperatures over a 5-year period (2017-2022) was provided by TvAB [3] to create average monthly simulation profiles November to April. A topping boiler was assumed to lift temperature levels from what BTC can produce to required level by TvAB. All waste heat of BTC is used for heat production whereas power produced is assumed sold on the power market. Note that the Topping boiler is not included in the plant model and in the description below, but in the system model instead.
- **Use Case Sulquisa**: For Spanish chemicals process industry Sulquisa a down-scaled FLEX CHP plant was investigated that runs on a fuel called GME [4]. Internal power demand is set to be 6 MWe and heat demand varies over the season but in average is set to be 21 tph steam at 12 bar and 190 ˚C (around 12 MWth). In this case a new type of high temperature heat pump was suggested to lift the temperature of the flue gas condenser exit water from around 77 ˚C to the required level of 190 ˚C steam. Final cooling of flue gas condenser water is done in a cooling tower/battery.
- **Use Case CEMEX Power-Gen:** For the Spanish Cement industry CEMEX a FLEX plant was investigated operating on GME fuel (like the Sulquisa use case). CEMEX has two facilities as part of this use case, Alicante and Alcanar, whereas Alcanar is the bigger one and used as reference. Internal power demand varies over the season but days with very high demand, power needs to be imported from grid (and days with low demand power can be sold to grid).

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In this use case there is no heat demand meaning flue gas condenser heat of the BTC is cooled by a cooling tower.

- **Use Case CEMEX CHP:** For the Spanish Cement industry CEMEX a FLEX plant was used as basis for the study again operating on GME fuel. In addition to power, this use case demands heat for drying of two different fuel lines, a new line for AF (alternative fuel) and an existing line for Petcoke. The AF fuel line can use a belt dryer with flue gas condenser hot water as heat source, whereas the Petcoke line needs to be heated directly with flue gas at higher temperatures which can take place after the ECO section of the heat recovery steam generator of the BTC.
- **Use Case CEMEX Hydrogen:** For Spanish Cement industry CEMEX, one use case consists of hydrogen production for use mainly in their production. It was decided to rely on hydrogen import from electrolysers instead of using the HYFLEX concept of T3.1 [5] where hydrogen is produced from biomass. Hydrogen will be used also for quick start-up of the FLEX plant but when committed operate with biomass like in the above use cases. For this reason, this use case is not described further here.

The method used for assessing parameters required, is the following:

1) Transient data: Starting from previously estimated start-up sequences described in D3.1 [5] a more rigorous analysis was made that has improved reliability of transient data and sequences (still however, no transient simulation has been made).
2) Full load and part load performance including P-Q diagram: starting from the FLEX plant model as described in D3.1 [5] modifications were done to the use cases to describe them as good as possible. The part load characteristics used was taken from an internal development project at Phoenix Biopower called ZP10 [6] and adapted to the use cases.
3) Cost data: CAPEX is based on internal data from Phoenix BioPower and has been scaled and adapted for each use case.

2.2 Transient parameters

The transient analysis is qualitative and based on engineering approximations. The use of hydrogen is preferred for quick start-up of the plant but in all use cases biomass is assumed as main fuel in normal operation.

2.2.1 Start-up, ramping and shut down time estimations

BTC can be started from cold, warm, or hot conditions and for obvious reasons the start-up time is longer the colder the plant is. This leads to a recommended strategy to keep the plant in warm or hot mode if restart is planned within a short period of time to avoid unnecessary start-up costs and loss of production time.

In simplified way, the start-up of the gasification system is divided into following:

- ✓ Start of auxiliary boiler, if not already available [1h].
- ✓ Circulation of hot water to jacketed vessels like the gasifier and gas cooler to 250-300 ˚C [6h].
- ✓ Gasifier fired with start-up fuel until bed is at biomass ignition temperature (600 ˚C). Incoming air could possibly also be heated e.g. by electric heaters. [6h]
- ✓ Start feeding biomass to gasifier running in combustion mode until operating temperature of vessels are reached (900 ˚C) [6 h].

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- ✓ The above ramp rate is restricted to 50 K/h thermal gradient of refractory wall which then gives a minimum 18 h start time from cold conditions.
- ✓ Now the plant is ready to enter gasification mode.

Start-up of the Top Cycle gas turbine should happen any time in the start-up phase of the gasification system, e.g. if power is needed urgently then rather early and if the start-up fuel is expensive then rather late in the process. In a simplified way, following happens.

- ✓ The engine is started with a start-up (gaseous) fuel.
- ✓ The downstream heat recovery steam generator (HRSG) is heated with help of the auxiliary steam boiler (30 min from cold to 110 ˚C in the drum, and further 25 min to 170 ˚C representing warm start-up). Gradient is assumed 3 K/min (plus margin).
- ✓ The generator is used as motor to reach ignition speed of shaft (10 min). Ramp up to low load (about 10 %).
- ✓ During this time the steam drum will start steaming, and steam will flow to the BTC systems.

As both the gasification system and the engine are ready, the combined operation of BTC can start.

- ✓ Operation in the gasifier is switched to gasification and initial syngas is flared. Compressed air from the engine is taken to the gasifier and pressure and load is gradually increased until at correct level for feeding the gas turbine.
- ✓ The total time from heating at atmospheric combustion in gasifier (900 ˚C) to pressurized gasification is expected to be 1.5 h for stable syngas production.
- ✓ At 10% load, the engine is ready to shift to syngas operations. The fuel valve is gradually opened at the same time as the gas turbine start-up fuel flow is turned down until the plant runs only on biomass. This sequence takes 1 hour.
- ✓ The ramping to minimum load (30 %) will follow by allowing fuel and air flow to increase.

In the normal load range:

- ✓ Ramp rate is restricted to 3 % electrical load per minute.
- ✓ In the case a gaseous fuel such as hydrogen is used instead for normal operation, the Top Cycle has a minimum load of 20 % and ramp rate is 11 %/min.
- ✓ Load changes are possible by regulating the air flow in the compressor and fuel flow.

The table below summarizes start-up and ramp times as discussed above (time format in hours:minutes).

Table 1: Summary of start-up and ramp times for BTC and Top Cycle.

Description	**BTC (biomass)**	**Description**	**H2TC (hydrogen)**
Heating of gasification system to 300 C	06:00	Heating of drum to 110 C	00:30
Heating of gasification system to 600 C	06:00	Further heating to 170 C	00:25
Heating of gasification system to 900 C by means of combustion of biomass	06:00	Synchronization	00:10

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Transition to gasification mode	01:30	20% load	00:03
Fuel transition start up fuel syngas	01:00	N/A	N/A
Cold start to minimum load	20:30	Ditto	01:08
Warm start to minimum load	14:30	Ditto	00:38
Hot start to minimum load	02:30	Ditto	00:13
Ramp rate cold to minimum load	n/a	Ditto	7%
Ramp rate minimum load to full load (%/min)	3%	Ditto	11%
Minimum load to full load ramp time	00:30	Ditto	00:07
Cold start to full load	21:00	Ditto	01:15
Warm start to full load	15:00	Ditto	00:45
Hot start to full load	03:00	Ditto	00:20
Minimum electrical load	30%	Ditto	20%

The start-up process can also be illustrated as in Figure 1 (example cold start-up when Top Cycle is in fast dispatch i.e. starts immediately and runs on hydrogen until plant is ready for syngas operation).

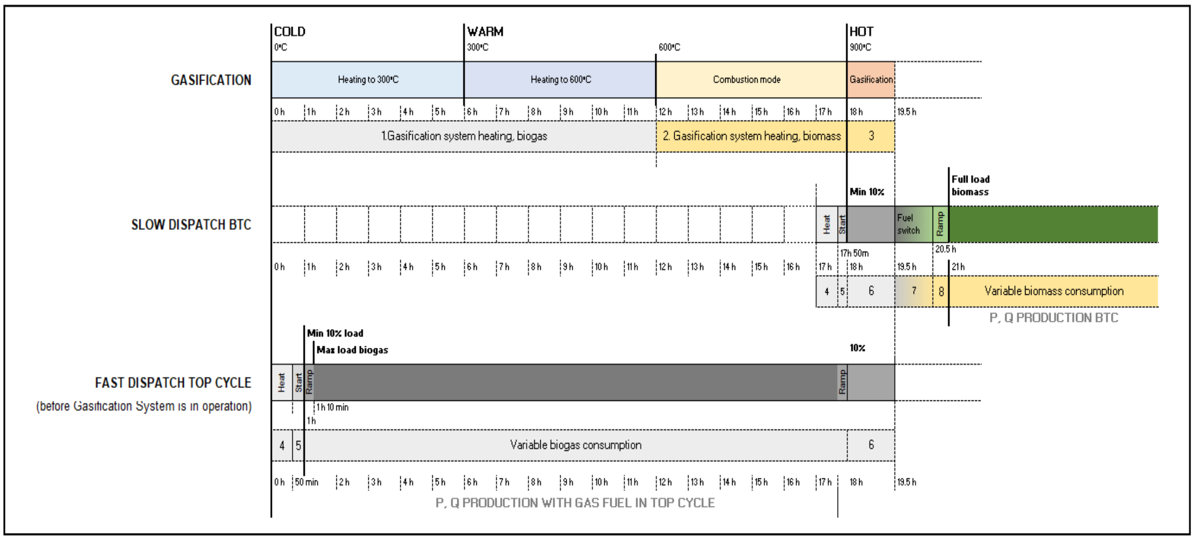

Figure 1: Start-up illustration with time stamps for gasification, Top Cycle and BTC plant.

For shut-down time estimations the reversed approach can be applied but adding some margin to allow a rather large syngas volume to adjust to reduced load. So instead of a 3 %/min. start-up ramp for BTC operation 1-2 %/min is probably more feasible as a shut-down ramp. However, it can be assumed that a shut-down ramp for Top Cycle operation with hydrogen is the same as the start-up ramp i.e. about 11%/min. Again, to allow the plant to restart quickly the plant should in most cases be maintained in hot or warm conditions. It can be assumed that the plant is in hot condition if it has been stopped and idle less than 2 h, in warm condition if stopped and idle for less than 24 h and finally in cold condition if idling more than 24 h.

2.2.2 Start-up costs

There are costs associated with start-up such as fuel and power consumption. They are given in Table 2 and are based on estimations, and later used in the optimization models of this task.

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Heat losses are assumed compensated with electrical tracing or similar.

Heating of material is based on following energy balance where M is component mass, C_p is specific heat of component (steel is assumed at 0.5 kJ/kgK) and temperature gradients dT/dt are assumed limited to 50 K/h for the gasifier and 3 K/min for steam boiler drum.

$$Q = M \times C_p \times \frac{dT}{dt} \quad (2.1)$$

Table 2: Start-up consumption of power, biogas and biomass per sequence.

	Sequence	Average el. consumption, MW	Average biogas consumption, MW	Average biomass consumption, MW
1	Gasifier heating cold-warm (biogas)	0.1	1.5	0
2	Gasifier heating warm-hot (biomass)	0.2	0	1.5
3	Gasifier combustion – gasification transition	0.2	0	2
4	HRSG heating cold-warm	0.05	0.7	0
5	Gas turbine start-up	0.5	7	0
6	Gas turbine biogas 10% load	-2.5	14	0
7	Syngas fuel transition	-2.5	7	7
8	BTC syngas ramp	-10	0	30
9	HRSG warm stand-by	0.05	0.2	0
10	Gasification warm stand-by	0.1	0.3	0
11	Gasification hot stand-by	0.2	0	2

2.3 Performance parameters

2.3.1 Full load assessment

The Swedish use case can be seen as a reference FLEX case and developed in D3.1 [5] whereas the other use cases are modifications depending on certain requirements on e.g. heat and on ambient conditions etc. The Sulquisa use case is a down-scale FLEX plant to better match their power and heat requirements. The main assumptions and requirements of the use cases are shown in Table 3 and the performance results shown in Table 4.

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Some remarks:

- TvAB case is based on the average of 6 monthly profiles over the years 2017-2022 and does not include the topping boiler.
- The operating profile as given in Sulquisa use case showed three typical heat demands over the year, at 11.7, 15 and 21 MW with an inlet temperature of 80 ˚C. It was decided to use the 15 MW profile as design case providing appr. 22 t/h steam at in- and outlet conditions given.
- The fuel used in Swedish use case is a reference fuel specification for Nordic Forest residues used by Phoenix whereas the Spanish use cases assumes GME as suggested by the industry partners [4].

Table 3: List of assumptions used in performance models of the use cases.

	Unit	TvAB	Sulquisa	CEMEX PowerGen	CEMEX CHP
Fuel		Forest residue at MC=50 %	GME at MC=13 %	GME at MC=13 %	GME at MC=13 %
Ambient conditions (season average)		T=3.1 C, P=1.013 bar (sea level), RH=60%	T=14 C, P=0.926 bar (700 m), RH=62%	T=18 C, P=1.005 bar (70m), RH=70%	T=18 C, P=1.005 bar (70m), RH=70%
Operation type		CHP (district heating network)	Co-generation with heat pump	Powergen	Co-generation flue gas dryer and belt dryer
Power requirement	MWe	N/A	6.0	28.59*	28.59*
Heat pump COP		N/A	3.0 at full load, 2.0 at min load	N/A	N/A
Heat requirement	MWth	DH temperature requirement by TvAB**	15.0	N/A	2.86 (AF dryer) +2.5 (PetCoke dryer)*
Heat sink type	MWth	District heating	Heat pump and CWT	CWT	Belt dryer and CWT

*) Day of maximum consumption

**) Achieved with a topping boiler not considered here

Table 4: Summary of performance at full load for the different use cases.

	Unit	TvAB	Sulquisa	CEMEX PowerGen	CEMEX CHP
Net power	MWe	20.72	6.78	20.99	20.84
BTC available waste heat	MWth	21.22	14.88	21.86	20.89
Heat supply	MWth	13.17 (DH)*	15.0 (process)	N/A	2.86 (AF dryer) and 2.50 (PetCoke dryer)
Fuel dryer heat	MWth	8.05 (MC=15 %)	N/A	N/A	N/A
Cooling tower	MWth	N/A	4.88	21.86	18.03
Fuel input	MWth	42.02	29.60	47.53	49.39
Net efficiency	%	49.31	22.91	44.16	42.19
Total efficiency	%	80.65	73.58	44.16	53.05

*) before topping boiler

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2.3.2 Part load assessment and P-Q diagrams

The part load assessment of the use cases was not carried out by simulations but by scaling of results from an internal development project at Phoenix BioPower called ZP10 [6]. The part load results are therefore not as reliable as the full load results but still good enough given all other uncertainties. Most of the use cases are combined heat and power or co-generation type of plants and will therefore have certain power versus heat production characteristics (P-Q diagrams). Ideally a P-Q diagram should include a window of operation points for more flexibility, however, as can be seen in some diagrams below this is not always the case. Another parameter used in combined heat and power operation is the alfa value (or electric yield) defined as the ratio of power to heat production, and normally goes down with load both due to the net plant efficiency going down with load, at the same time as the waste heat generation does not follow the same rate of decline.

2.3.2.1 TvAB use case

The power versus heat production follows in the Swedish use case nearly a straight line and includes no operating window as for each electrical load point there will be one specific heat load point as the waste heat from the flue gas condenser needs to be cooled by a given amount for each load point. The alfa value shows a downward trend and is reduced approximately by 50 % over the load range.

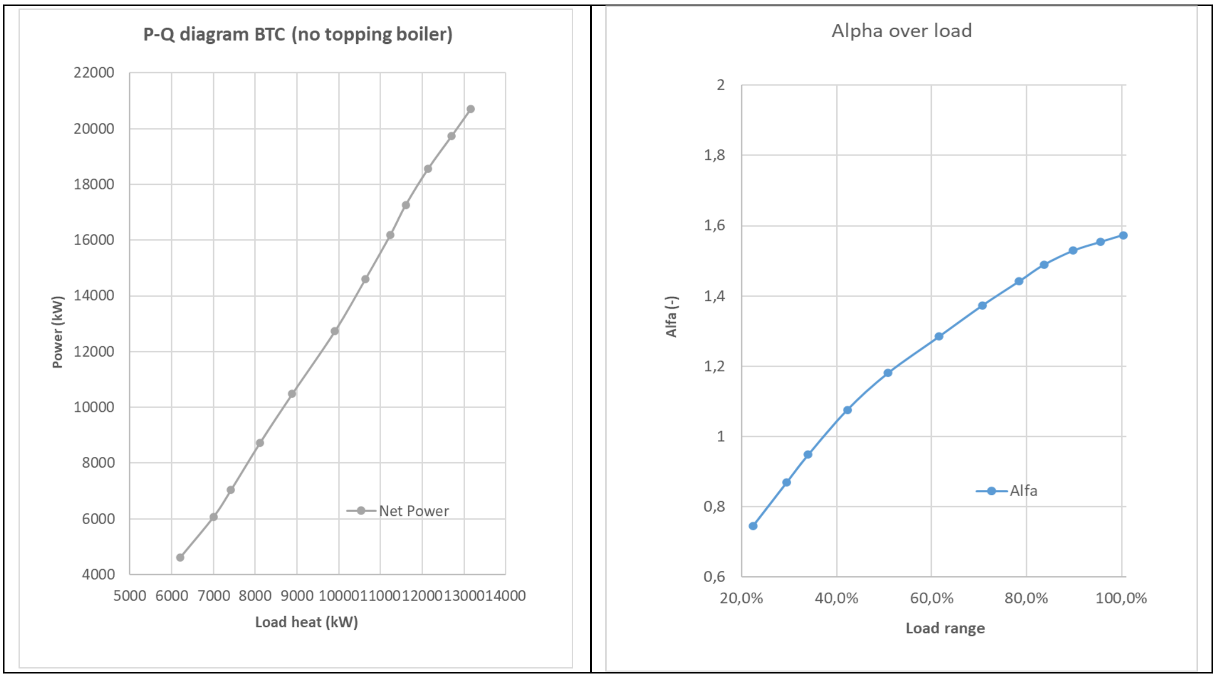

Figure 2: Swedish use case. P-Q diagram left, and alfa as function of electric load to the right.

2.3.2.2 Sulquisa use case

For the Spanish use case Sulquisa three operating profiles were identified together with a no heat load case used as reference. The heat *profile 1* needs to achieve 11.7 MW of heat, *profile 2* 15 MW and *profile 3* 21 MWth respectively, according to data from Sulquisa [2]. It can be assumed that one heat pump HP1 at 15 MW and one additional heat pump HP2 of 6 MW are installed, to achieve *profile 3*. The small heat pump is then turned off in operating *profile 1 and 2*, whereas for *profile 1* the 15 MW heat pump is in operation at partial load (11.7/15=78%). The COP of the heat pump is defined as useful heat Q, divided by power input P and is estimated at 86 % of the theoretical COP. The theoretical COP depends only on exit temperatures (in Kelvin) of the source and sink as follows:

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$$COP = {}^{Q}/_{P} = \eta_{th}\ x\ COP_{th} \ \ where\ COP_{th} = \frac{T_{sink}^{out}}{(T_{sink}^{out} - T_{source}^{out})} \qquad (2.2)$$

As exit temperature on the source (flue gas condenser side) depends on how much heat is extracted in the heat pump, COP goes down somewhat with higher heat extraction like in *profile 3*. COP of *profile 1* would be at maximum if it was not for the needs to operate at partial load. The part load estimation is based on an assumed COP of 2 at an assumed minimum load of the heat pump of 40% over the estimated COP at full load at 3.10. Linear interpolation then gives COP of 2.70 at 78 % load. Heat pump configuration and performance are summarized in Table 5.

Table 5: Heat pump configuration and performance.

	Profile 1	Profile 2	Profile 3
HP arrangement	HP1 at 78 % part load, HP 2 closed	HP1 at 100 % load, HP2 closed	HP1 and HP2 at full load
Fraction of operating time	35%	60%	5%
COP	2.70	3.00	2.80
Heat requirement (MWth)	11.7 (0.78x15+0)	15 (15+0)	21 (15+6)
Power requirement (MWe)	4.33	5	7.5

The P-Q and alfa diagrams for Sulquisa in Figure 3 shows there exists a wide operating range where heat production can be anything from zero to the curve limited by *profile 3*. However, as heat production goes up the net power goes down as of increased power consumption of the heat pump. The decline of alfa value for *profiles 2* and *3* shows a bump in the curves due to limited heat available from BTC flue gas condensers at reduced load.

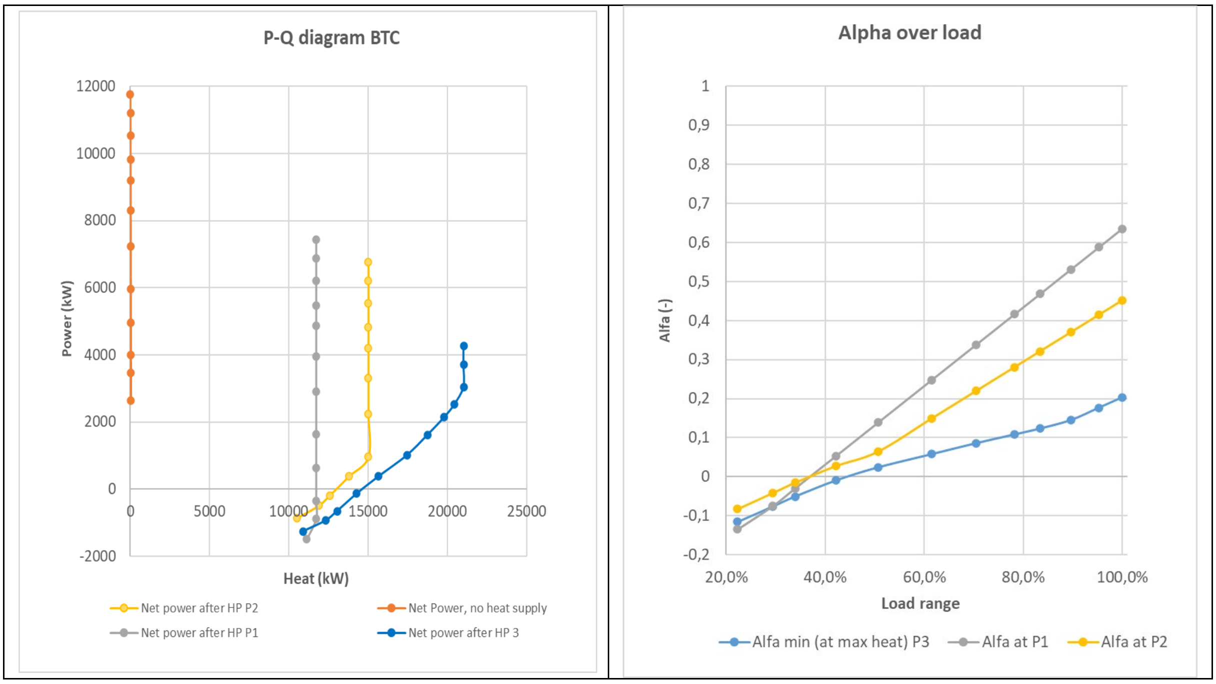

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Figure 3: Spanish use case Sulquisa. P-Q diagram left, and alfa as function of electricity load to the right (note 4 profiles shown with the extremes no heat and maximum heat respectively forming the boundary).

2.3.2.3 CEMEX use cases (PowerGen and CHP)

For CEMEX the following use cases will be presented.

- PowerGen without any heat demand (all waste heat is cooled by cooling tower)
- CHP where heat is extracted both from flue gases and from hot water from flue gas condenser for drying of materials.
- Hydrogen case. Here it was decided to use hydrogen from electrolysers (i.e. no HYFLEX plant with H2 from biomass). Also, it was decided to use H2 only for start-up but biomass for normal operation. For this reason, this use case is identical to the other two use cases and will not be treated here.

For the PowerGen case obviously no P-Q nor alfa diagram can be displayed as there is no heat production. However, a part load characteristic is shown in Figure 4 with net plant efficiency, net power and cooling duty variation over the load range.

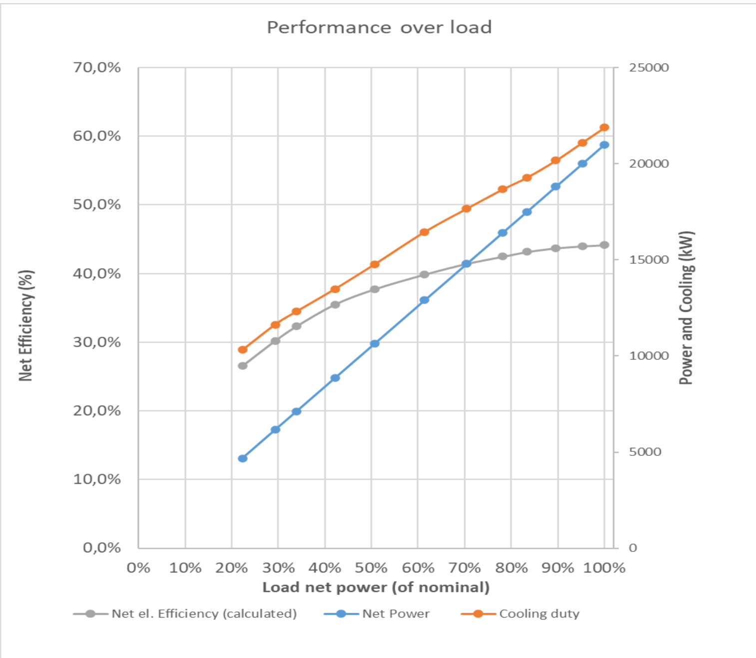

Figure 4: Part load characteristics for CEMEX power-gen case.

For the CHP case the heat demand for drying materials is given from CEMEX and their operational data to be

- 2.86 MWth at 85 ˚C for so called AF drying (maximum heat demand over the year). Here it was decided to use a new belt dryer utilizing heat from flue gas condenser hot water. This heat is for free and even reduces the need for cooling tower duty.
- 2.50 MWth at around 200 ˚C for drying petcoke (maximum heat demand over the year). Here it was decided to use an existing direct drum dryer utilizing hot flue gases from the BTC heat

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recovery steam generator. The requirement is that the flue gases after drying and absorbing evaporated water from the material still is above the dew point (before entering the flue gas condenser). For this reason, the ECO section of the HRSG was decreased in size (alternatively it can be bypassed) corresponding to a gas exit temperature of 210 ˚C (instead of 145 ˚C). This reduces steam production in BTC, and net plant efficiency goes down.

As heat demand is relatively small the alfa value is rather high but reduces at low loads as noted above. Also, as the heat can be reduced to zero and the plant still operate, the P-Q window is restricted only by the maximum heat demand and zero heat demand, see Figure 5.

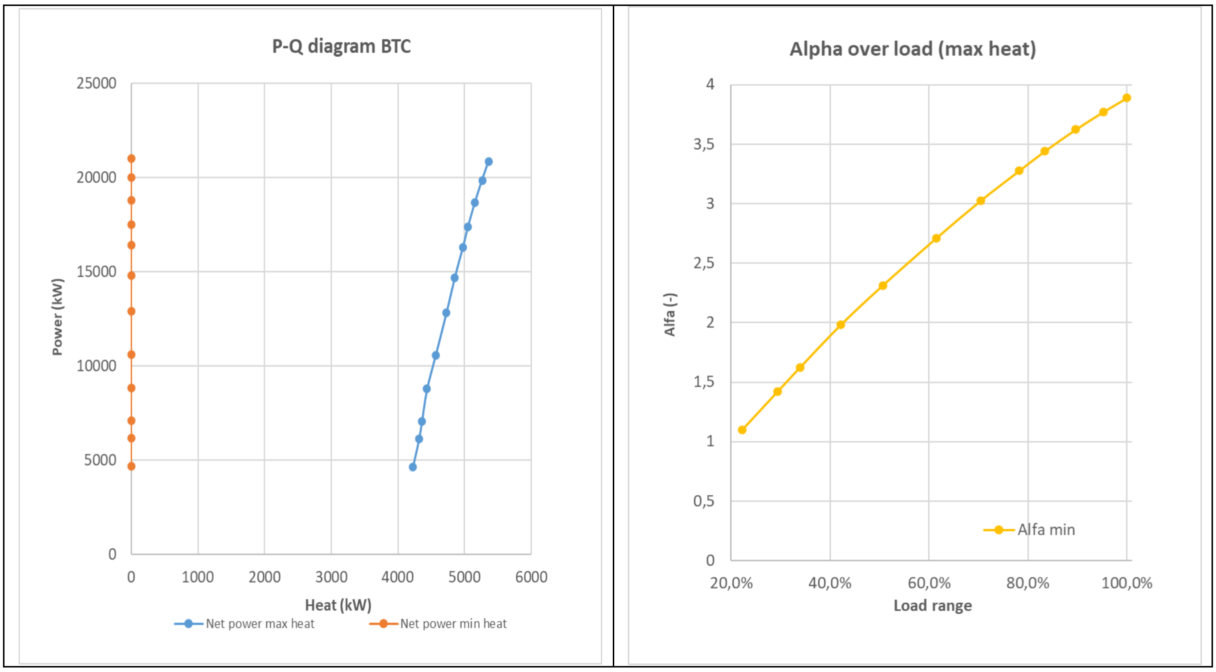

Figure 5: CEMEX CHP use case. P-Q diagram left, and alfa as function of el. load to the right.

2.4 Cost parameters

2.4.1 CAPEX

For investment cost or so-called CAPEX Phoenix Biopower has used internal information based both on supplier and literature data. The CAPEX consists of the following items adding up to the Total Plant Capital Costs.

1. All main equipment such as fuel feeding and gasifier in the Gas production unit (GPU) and Gas turbine and heat recovery boiler in the Power production unit (PPU) gives the **Total Direct Cost (TDC)**
2. Cost of Engineering and General Facilities gives the **Total indirect cost (TIC).**
3. Adding TDC and TIC to EPC service fee gives the **EPC Plant Cost.**
4. Adding owner's engineering/supervision and Contingency to EPC Plant cost gives the **Total Plant Costs**

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5. Finally adding Equipment royalties, operator training, start-up cost and working capital to Total Plant Costs gives the **Total Plant Capital Costs**

The $CAPEX^{ref}$ of a reference case was identified for the Swedish use case (TvAB), whereas the $CAPEX^{i}$ of other use cases was derived from scaling of the gross electrical power P_{gross} using a scaling factor *SF* as follows.

$$CAPEX^{i} = CAPEX^{ref}\, x \left(\frac{Pgross^{i}}{Pgross^{ref}}\right)^{SF} \qquad (2.3)$$

Based on the reference case using fuel dryer and no cooling tower nor any heat pump following adjustments were carried out for the subsequent Spanish use cases (note that CEMEX H2 case is identical to CEMEX PowerGen using biomass during operation and is not described here):

Sulquisa:

- Cost for heat pumps to achieve Profile 3, i.e. 15+6 MWth, was added with a cost function found in [7],
- Cost for fuel dryer of the reference case subtracted before scaling,
- Cost for a small cooling tower added (scaled supplier information)

CEMEX Power-Gen:

- Cost for a cooling tower added (scaled supplier information)
- Cost for fuel dryer of the reference case subtracted.

CEMEX CHP:

- Cost for fuel dryer of the reference case subtracted,
- Cost for cooling tower added (scaled supplier information),
- Cost for AF belt dryer added based on scaled dryer cost of the reference case.
- Any cost for PetCoke dryer ignored as reuse of existing equipment assumed.

Note that for the reference case CAPEX is somewhat different from D3.1 as there was a mistake in that report by assuming both on-site nitrogen generation and purchase of nitrogen. An updated cost analysis as the one done in D3.1 and divided into FLEX with and without on-site N2 production and with and without on-site pelleting gave the most favorable case to be the one with on-site N2 production with help of an ASU and no pelleting. As the cost for the ASU unit is now added the new CAPEX is higher than in D3.1.

2.4.2 Cost Summary

Assumptions used for estimation of CAPEX are shown in Table 6 (reference to some of these parameters can be found in D3.1 [5]). The actual calculated cost numbers for the use cases are shown in Table 7.

Table 6: Assumptions used in cost analysis.

Scaling factor in CAPEX estimation	Variable O&M (€/MWh_fuel)	Fixed O&M percent of CAPEX	Biomass price (€/MWh_fuel)
0.75	2.07	3%	Varies with use case

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Depreciation time (years)	Interest rate	Interest cost during construction (% of CAPEX)	Operation time (h)
25	8%	3 %	Varies with use case

For both TvAB and Sulquisa average values are presented as they are based on operating profiles (6 monthly for TvAB during heating season and 3 for Sulquisa as of heat demand variation over the year).

Table 7: Total plant capital cost (CAPEX) breakdown for use cases.

	Unit	**TvAB**	**Sulquisa**	**CEMEX PowerGen**	**CEMEX CHP**
CAPEX	M€	90.0	58.0*	86.9*	88.1*

* Scaled from Gross Power, and scaling factor given in Table 6.

3 Data Inputs and Assumptions for business use cases

This section presents the assumptions made for the modelling of the business use cases as well as the required input data and its sources.

3.1 Data Inputs and Modelling Assumptions - Sweden

This section outlines the data sources and assumptions for the Swedish business use case study. The business use case in Sweden investigates utilization of the new CHP technology in the production portfolio of a district heating company from both technical and economical perspectives. The district heating company here is TvAB, the district heating supplier for the city of Linköping in Sweden.
Two sets of data have been collected: system data in Sweden (such as day-ahead and balancing market prices) and business use case specific data such as technical and economic parameters relevant to the district heating portfolio of TvAB.

The following subsections outline the data sources and assumptions used for the scheduling model for district heating production, in terms of market prices, heat demand, TvAB portfolio description and BTC modelling considerations.

3.1.1 System data-Sweden

Sweden has four price zones: SE1, SE2, SE3 and SE4. Linköping city in Sweden is located in SE3 price zone. In order to simulate a price driven, optimal dispatch model describing TvAB's production portfolio, day-ahead and mFRR market prices for SE3 are collected with hourly resolution. Day-ahead and mFRR market prices are available through the ENTSOe transparency platform [8].

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3.1.2 Business use case specific data: District heating

Figure 6 is representing TvAB's production portfolio, which consists of six CHP units, four flue gas condensation units, three peaking heat-only boilers and a heat storage. Note that in the KV1 plant, boilers 1 and 3 are modelled as an aggregated CHP unit (CHP1 in Figure 6) as they have a common PQ region. This is to only consider operation in PQ region in an aggregated way; the fuel cost (SEK/MWh) for each of these boilers is different and total fuel costs for these boilers are calculated based on the individual production from these units.

Hourly heat demand for reference year 2021 is received from TvAB. Production data of all units are received from TvAB and summarised in Table 8. Also, in this regard, reports [9] and [10] detail the primary data and operation of the two main CHP plants owned by TvAB, namely 'KV1' and the 'Waste Plant' or 'Gärstadverket' respectively.

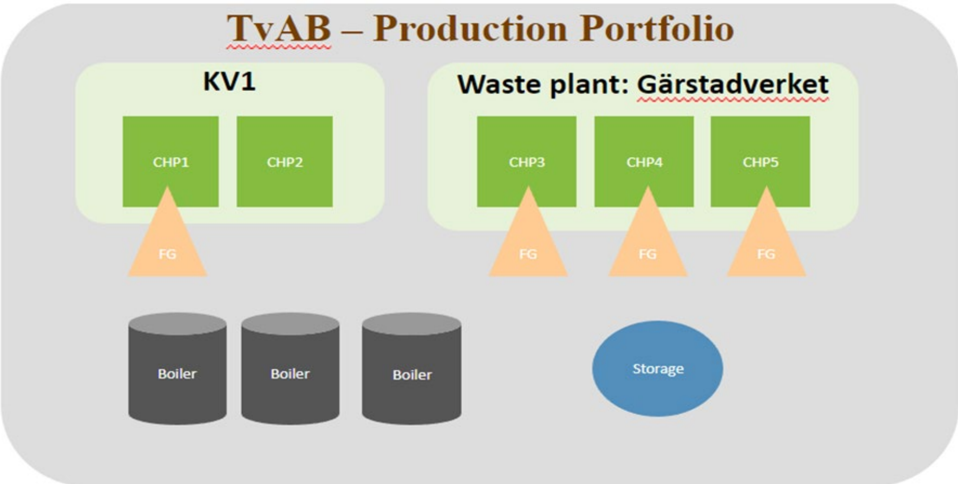

Figure 6: Portfolio representation of TvAB district heating system.

Table 8: Production data and parameters of the units.

Unit #	Technology: relation	Fuel	Fuel cost (SEK/MWh)	Max (th.) Capacity (MW)	Min (th.) Capacity (MW)	Efficiency	Power - heat ratio	Emission rate (ton/MWh)
1	**CHP**: boiler 1 of KV1	Recycled wood	350	60	30	0.8	0.26-0.31	0
2	**CHP**: boiler 2 of KV1	Bio-oil based	2000	120	30	0.8	0.17-0.31	0
3	**CHP**: boiler 3 of KV1	Recycled wood	290	60	30	0.8	0.26-0.31	0
4	**CHP:** boilers 1-3 of waste plant	Waste	0	75	20	0.9	0.154	0.2
5	**CHP**: boiler 4 of waste plant	Waste	0	66	44	0.9	0.3	0.2
6	**CHP**: boiler 5 of waste plant	Waste	0	83	55	0.9	0.34	0.2
7	**Flue gas condensation:** connected to boiler 3 of KV1	-	0	13	0	-	-	0
8	**Flue gas condensation:** connected to boilers 1-3 of waste plant	-	0	10	0	-	-	0

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9	**Flue gas condensation**: connected to boiler 4 of waste plant	-	0	14	0	-	-	0
10	**Flue gas condensation:** connected to boiler 5 of waste plant	-	0	10	0	-	-	0
11	Peaking heat boiler	Oil-based	2500	45	10	0.9	-	0.5
12	Peaking heat boiler	Oil-based	2500	40	10	0.9	-	0.4
13	Peaking heat boiler	Bio-oil based	2000	40	10	0.9	-	0

Note that for the waste plant, TvAB receives income/revenue for treating the waste to be used as fuel. When this income is combined with the costs related to processing the waste and the costs arising from carbon emissions due to waste incineration, the total marginal cost for the waste plant becomes nearly zero. As a result, the CHP units of the waste plant become the least expensive units for production in the model, expected to operate most of the time with maximum production.

While an approximate emissions rate of 0.2 ton/MWh is considered for the production from the waste plant, these emissions are calculated based on the final optimization result of the model, but not included additionally (or separately) as a ‘cost component’ in the model, since the net marginal cost for this plant is considered to be zero as explained above.

Table 9: Startup and operation related parameters.

Unit #	Start-up time (hours)	Cost (SEK/start)	Minimum up time (hours)	Minimum down time (hours)	Ramp up limit (MW/h)	Ramp dn limit (MW/h)	PQ segments (q1,p1), (q2,p2) (MW)	Minimum Time in Heat-Only Mode (hours)
1	24	250k	72	72	NA	NA	(48,12.5), (91.5,28.5)	2
2	8	250k	2	12	90	90	(20,3.4), (90, 28.4)	2
3	24	250k	72	72	NA	NA	(48,12.5), (91.5,28.5)	2
4	24	250k	72	72	NA	NA	(17.3, 2.7), (65,10)	2
5	24	250k	72	72	NA	NA	(34,10), (51,15)	2
6	24	250k	72	72	NA	NA	(41,14), (62,21)	2
7	NA	NA	NA	NA	NA	NA	NA	NA
8	NA	NA	NA	NA	NA	NA	NA	NA
9	NA	NA	NA	NA	NA	NA	NA	NA
10	NA	NA	NA	NA	NA	NA	NA	NA
11	4	250k	2	12	NA	NA	NA	NA
12	4	250k	2	12	NA	NA	NA	NA
13	4	250k	2	12	NA	NA	NA	NA

Table 9 presents the data related to start-up and other operational constraints considered for TvAB units. All start-ups are assumed to be cold start-ups, associated with a start-up duration and start-up cost. However, note that there is no start-up considered for the flue gas condensation units. In

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addition, while a shut-down time of one hour is considered for all units, the shut-down cost for these is assumed to be zero. Note again that the units of the waste incineration plant are expected to almost always be in operation, as these mainly serve to meet the base heat demand in the district heating network with very low operating cost. As a result, start-ups for any unit(s) of the waste plant may be rather infrequent compared to other units. 'Minimum up' of the units corresponds to the minimum time that a unit must remain online or committed once started, while 'minimum down time' refers to the minimum time the unit must be kept off-line once shutdown. Limits on up and down ramping, over a 60-minute period, apply only for the bio-oil boiler of the KV1 plant. Combined heat and power production of the CHP units is constrained to follow a simple linear relationship in the form of a straight-line segment, so that no feasible region or window is considered. Here, (q_1, p_1) and (q_2, p_2) are the two endpoints of the PQ segment, as illustrated in Figure 7, considered for the CHP unit(s). Finally, CHP units with back pressure turbines can also operate in heat-boiler mode, producing only heat (and no power), if needed. This is again illustrated by the horizontal line on x-axis in Figure 7. In this case, some minimum time of operation in the heat-boiler mode is considered before the unit can switch to full CHP mode again; however, a similar constraint is not applied while changing from CHP mode to heat-only mode. As shown in Table 9, a minimum time of 2 hours is considered, for operation in heat-only mode, for all CHP units in the TvAB portfolio.

Additionally, the Linköping district heating system also has a heat storage with a maximum capacity of 2.5 GWh. Maximum charge/discharge rates for the storage are 150 MW, while minimum storage level is assumed to be 20% of the maximum capacity. Hourly loss rate of the storage is insignificant and hence considered to be zero.

Besides, internal (auxiliary) power consumption in the district heating facility is considered to be 10 MW for every hour during wintertime and 6 MW hourly during summertime. In this regard, it is also assumed that this internal consumption is met by production from own CHP units and not by purchasing any electricity from the grid, that would result in additional taxes. The total capacity of heat sinks (comprising mainly the local river) for heat discharge of any excess heat produced, during times of low-heat demand, is assumed to be a maximum of 50 MW. A carbon tax of 1200 SEK/MWh [11] is considered, though it is noted again that the carbon emission costs for the waste plant is covered by the income from treating the waste fuel, so that final emission costs, if incurred, apply only for the production from the peaking heat boilers that are oil-based.

BTC modelling and assumptions

Start-up process: With respect to the start-up process for the BTC, we model the 3 possible types – hot, warm and cold start-ups. These types correspond to down times (of the BTC) of less than 2 hours, 2-24 hours, and higher than 24 hours respectively as described in section 2.2.1. Also, the start-up durations for these are 3 hours, 15 hours and 21 hours respectively. It can be noted that we do not consider the BTC syngas ramping to full load as part of the start-up process itself, but instead we let the model decide on what should be the production from the BTC unit. The 30 minutes of this ramp duration is instead added to the 1.5 hours gasification process (see 2.2.1) and helps to keep the various durations for different sequences in the start-up process aligned for our models that have an hourly resolution. As outlined in section 2.2.2, there are varying amounts of power, gas (biogas considered in the Swedish use case) and biomass consumptions during different sequences in the BTC start-up process. We translate these consumptions and their associated costs into a total, fixed start-up cost for each of the three types of start-ups. The biomass and biogas prices used here and as suggested by TvAB, are 350 SEK/MWh and 1330 SEK/MWh respectively. For simplicity, power consumption or production from the BTC as in Table 2 is neglected, considering that these are rather very small amounts or that they are relevant only for short durations in the start-up process. Therefore, by

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considering the total effective biogas and biomass consumptions in the start-up process, we arrive at the following costs for the different start-up types stated in Table 10.

Table 10: Fuel consumption and start-up costs for BTC start-up types

Start-up type	Total Biomass Consumption (MWh)	Total Biogas Consumption (MWh)	Total Start-up cost (kSEK)
Hot	11	35	50.4
Warm	20	44	65.52
Cold	20	53.7	78.42

Again, the biogas or biomass consumptions during short durations, for example, for the gas turbine start-up lasting only 10 minutes, are not included. Besides, there is some fuel and power consumption when the BTC unit is maintained in warm or hot standby mode. This is however neglected. Additionally, as described in Figure 1, during the long start-up time of 21 or 15 hours for cold or warm start-ups respectively, before the gasification system of the BTC plant is in operation, the top-cycle or gas turbine in the plant can be operated with biogas as the fuel (instead of biomass), producing heat and power if needed. However, this possibility is not considered in our approach. Also, this operation of the top-cycle with biogas, before switching to biomass at the end of the start-up process, may indeed not be economical or chosen by the optimization model, considering that biogas as a fuel is more expensive than biomass.

BTC CHP operation: For the operation of the BTC as a CHP unit, we consider power and heat production from the unit to follow the PQ diagram presented in Figure 2. Although, the BTC plant also has a minimum electrical load requirement of 30% (as presented in Table 1); when we enforce this requirement and fit a linear trendline to the PQ diagram in Figure 2, we set the start and end points of the PQ segment for the BTC plant as (7.035 MWth, 6.23 MWe) and (13.165 MWth, 20.77MWe) respectively. We assume the total efficiency of the BTC unit to be 80.65% (from Table 4) throughout the load range for simplicity. Finally, we also assume that the BTC unit, that is primarily characterized by high power-to-heat ratios compared to conventional CHP units, cannot operate in heat-only mode, i.e., to produce only heat without any power as is possible with the CHP units of TvAB. We also don't consider any minimum up or down times for the BTC, considering that the BTC plant can be started again after it has been down for less than 2 hours, in case of a hot start-up.

Topping Boiler Operation: As described in section 2.3.2.1, a topping boiler is required along with the BTC to raise the temperature levels of the DH flow to that required by TvAB. When the BTC operates, we define the heat production from the topping boiler to be proportional to the heat production from the BTC as:

$$\textbf{Heat (topping boiler)} = \left(\frac{[\text{Required supply temp TvAB}] - [\text{BTC supply temperature}]}{[\text{BTC supply temperature}] - [\text{TvAB DH return temperature}]}\right) * \text{Heat (BTC)}$$

while the heat production from the BTC will be decided by the optimization model.

In this regard, BTC supply temperature is considered constant at an average value of 77 ˚C, while Tekniska Verken's DH supply and return temperatures - average values for different months are taken from Figure 8 of D3.1 [5]. Finally, assumed efficiency (while calculating fuel consumption and cost) for the topping boiler is 90%.

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Other costs: We also consider a variable O&M cost of about 23 SEK/MWh of fuel consumption for the BTC unit, based on the cost data received from Phoenix BioPower.

Modelling considerations and assumptions for participation in mFRR market

For participation in the mFRR market in Sweden, the requirement is to activate 100% of the offered regulation capacity within 15 minutes. In this regard, the actual technical capability, and other limitations relevant to regulating the production of units must be considered. For the CHP units in TvAB's portfolio, it is assumed that the waste plant that covers the base heat demand in the system does not participate or contribute to offering any regulation (i.e., increase or decrease in its production with respect to a planned day-ahead schedule), so that only units of the KV1 plant may have different production levels corresponding to day-ahead and up or down regulation volumes. Besides, the regulation capability of even these units is limited, in the order of magnitude of approximately 15 MW steam output in 15 minutes. This is translated to an estimate of about 3 MW regulation capacity, with respect to the power production of these units, considering an average power-to-heat ratio of 0.3. Besides, TvAB still does not prefer to regulate very often; however, in the scheduling model, we do not impose any additional limitations with respect to the frequency of providing regulation by these units. For the BTC unit, we consider the (electrical) ramp rate of 3% per minute, so that this makes feasible an increase or decrease of 9.3 MW in 15 minutes. Note here that symmetrical capabilities have been assumed for the BTC unit for both up and down regulation.

3.2 Data inputs and modelling assumptions - Spain

This section presents the data sources and assumptions considered for the four Spanish use cases. Depending on the case, different technologies are used -either in CHP (heat and electric power) or PowerGen (electric power only) mode- for industrial purposes.

First, the data sources for the Spanish system are referenced, particularly day-ahead and balancing market prices. Then, specific data for each of the four **benchmark cases** are presented, including technical parameters of the generating units, fuel usage and prices, and production requirements. Finally, data inputs and assumptions for the **updated model** -with integrated BTC operation- are presented.

On a note on Spanish balancing market prices, all balancing products are procured in a competitive market-based mechanism. The transmission system operator publishes the reserve requirements for the following day after the day-ahead market. The market players can submit their offer bands (i.e. capacity availability for secondary regulation) to the corresponding balancing market within the gate closure period.

Balancing market products in Spain can be capacity or energy, but market procurement exists only for capacity. Only prequalified units can submit the balancing offers, and secondary regulation capacity is priced at the uniform clearing price of the market.

3.2.1 Price data

Spanish day-ahead and secondary reserves availability prices corresponding to 2021 are gathered in hourly resolution from ESIOS [12]. While day-ahead prices account for the price at which electricity

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is sold to the grid, we assume a 5% increase in order to get the costs at which electricity is purchased from the grid.

3.2.2 Benchmark use cases specific data

Use case Sulquisa

Sulquisa produces Anhydrous Sodium Sulphate of mineral origin. As described in Deliverable 3.8 [2], their process is intensive in thermal and electrical energy and is currently supplied through three cogeneration units consisting of natural gas-driven turbines and heat recovery boilers.

The following historical operation data was available for years 2019 and 2022 with an hourly resolution (Deliverable 3.6):

- Process electricity demand [MWh]
- CHP electricity generation [MWh]
- Process steam (heat) demand [MWh]
- Natural gas CHP consumption [MWh]

The benchmark case is therefore based on the available real operation data. The series corresponding to 2019 (pre-pandemic) was chosen as input for the benchmark case. The impact of changing the main fuel (fossil natural gas to biomass) and technology is then addressed after simulating the operation with BTC under the same electricity and thermal energy demands and considering the same revenues and operational costs sources, therefore making both scenarios comparable. Table 11 shows the additional data used in the benchmark case:

Table 11: Additional input data used in Sulquisa's benchmark case.

Parameter	Unit	Value
Natural gas price 2021	[€/MWh]	47.92
CO_2 emission cost	[€/tCO_2]	76
CO_2 emission rate	[tCO_2/MWh]	0.202
Max electricity sell capacity	[MW]	17
CHP units' efficiency	[p.u.]	0.785

Use case CEMEX PowerGen

As stated in Deliverable 3.8, electric energy consumed in both Alcanar and Alicante plants is imported from the electricity grid via long-term delivery agreements. Additionally, both plants can participate in the balancing market through the provision of secondary reserves. Flexibility stems from the cement grinding process in both cases.

Data shown in Table 12 summarizes the inputs used for calculating CEMEX's secondary reserves provision. The contracted power refers to the maximum capacity that can be purchased from the grid:

Table 12: CEMEX's flexibility data used in PowerGen cases (Alicante and Alcanar plants).

Plant	Parameter	Unit	Value
Alicante	Upwards availability	[MW/h]	8

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	Downwards availability	[MW/h]	5
	Contracted power	[MW]	22.1
	Upwards availability	[MW/h]	3
Alcanar	Downwards availability	[MW/h]	3
	Contracted power	[MW]	31

As this use case does not include heat demand, the benchmark case is built upon 2021 Spanish electric energy costs and electricity demand with an hourly resolution (Deliverable 3.6, [13]). Operational (electricity) costs are determined using this data, and no revenue is considered from secondary reserves provision **as CEMEX did not provide these services in 2021**.

Use case CEMEX CHP

This use case applies only to Alcanar plant. In addition to the electricity demand, heat demand is considered for the drying of two different fuel lines:

1. a new (currently nonexistent) drying line for alternative fuels, using BTC's flue gas condenser hot water as heat source. The investment cost for this line is considered for the benchmark case.
2. an existing line for petcoke, currently dried with a hot gas stream produced by the fuel oil kiln combustion process.

In this benchmark use case, the following assumptions are taken:

- ✓ Heat demanded for the drying of both lines is covered by the kiln hot flue gases produced by burning fuel oil.
- ✓ In order to fairly compare the results with those of the BTC model, only the fuel consumption (and costs) associated with burning fuel oil for drying purposes is considered. Additionally, the corresponding CO_2 emissions costs and electricity purchase from the grid account for the remaining operating costs.
- ✓ No provision of operating reserves is considered. Thus, no revenue is taken into account.

Fuel oil costs were asked to remain confidential. Table 13 shows the remaining input data used for determining the benchmark scenario:

Table 13: Input data used in CEMEX's CHP benchmark use case.

Parameter	Unit	Value
CO2 emission cost	[€/tCO2]	76
CO2 emission rate	[tCO2/MWh]	0.265
Kiln efficiency	[p.u.]	0.75

Use case CEMEX Hydrogen

This use case comprises the analysis of two different applications:

1. BTC operation with hydrogen for the start-up sequences: the benchmark case is the same as "CEMEX PowerGen", for both plants. Results will be compared with those obtained for BTC operation with renewable, electrolyzer-based hydrogen **for the start-up sequences only**,

2. Partial fuel change in the kiln: we study the impact of replacing part of the fuel oil burnt in the kiln with electrolyzer-based renewable hydrogen. In order to make both scenarios comparable, it is assumed that the heat provided by burning hydrogen in the updated model equals the heat provided by fuel oil in the benchmark case. Then, operating expenses are based on fuel and fossil carbon dioxide emissions costs. Hydrogen (constant) consumption for both plants, as informed by CEMEX, are shown in Table 14:

Table 14: Annual hydrogen consumption in Alcanar and Alicante plants.

Plant	H_2 consumption
Alcanar	1,040 tonH_2/year
Alicante	810 tonH_2/year

3.2.3 Updated model use cases assumptions and input data

The aim of this section is to describe the assumptions made for the execution of the updated -BTC integrated operation- model for each use case, as well as presenting the input data.

Use case Sulquisa

A down-scale FLEX BTC plant as described in Section 2.3.1 is considered. A 15 MW (profile 2) heat pump is installed downstream the BTC to comply with the quality of vapor demanded. Both electric power consumption and "cold" side heat source (flue gas condenser waste heat) stem from BTC production.

BTC unit's remaining electricity production, which is not consumed by the heat pump, can partially cover Sulquisa's electric power demand; the rest is purchased from the grid. In hours when BTC unit's remaining electricity output exceeds the demand, it can be sold to the market.

Regarding heat demand, a 10 MW natural-gas fueled steam boiler is installed to assist the heat pump by covering peak hours. Excess steam, both from the heat pump and boiler, is cooled down to 80°C by means of a cooling tower.

The following assumptions apply for this and all the remaining use cases:

1. BTC and boiler efficiencies (and heat pump's coefficient of performance) are constant throughout the entire load range.
2. Even though BTC unit's net power production considers the electric consumption of the cooling tower, a cooling cost was added in the model's objective function (€/MWth of excess heat) to penalize and thus reduce excess heat production. This cooling cost was estimated by assuming that the average electric consumption of the cooling power, associated with the operation of the fan and pump, is purchased from the grid at an average electricity cost.
3. The relationship between BTC unit's electric (before HP) and heat power outputs **above minimum values** are linearized.
4. Fuel used for BTC unit's start-up sequences corresponds to that available at each plant: natural gas for Sulquisa, and fuel oil for CEMEX Alicante and Alcanar. All fuel costs, including biomass, are assumed to be constant throughout the entire year.
5. No variable O&M cost is considered, neither for benchmark nor updated cases.
6. Only one shut-down sequence type is modelled for each generator.

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Table 15 shows the input data considered for this case. Each parameter is then referenced in Section 5, together with the updated model mathematical formulation.

Table 15: Input data for Sulquisa's updated model case.

Parameter	Unit	BTC	Boiler	Heat Pump
Max Total Power	MW	26.7	10	15
Min Total Power	MW	9.6	2	7
Max Heat	MW	14.9	10	15
Min Heat	MW	7	2	7
Efficiency/COP	p.u.	0.9	0.8	3
P-Q ratio	-	1.1586		
Ramp Up/Dw	MW/h	48/36	4/4	
UpTime/DwTime	h	4/4	4/4	
CO2 emission rate	ton/MWh	0.018	0.202	

Parameter		Unit	BTC	Boiler
SD Duration		h	1	1
SD Cost		€	388	100
SU Duration	Cold	h	20	
SU Duration	Warm	h	15	
SU Duration	Hot	h	2	2
SU Cost	Cold	€	845	
SU Cost	Warm	€	829	
SU Cost	Hot	€	775	200

Parameter	Unit	Value
Grid connection capacity	MW	17
Cooling cost	€/MWth	0.7
CO2 cost	€/tonCO2	76
Biomass cost	€/MWh	23.19
Natural gas cost	€/MWh	47.92

Use case CEMEX PowerGen

A BTC unit as described in Section 2.3.1 is installed to cover CEMEX electricity demand in both plants, Alcanar and Alicante. It is assumed that the BTC can also provide upwards and downwards secondary reserves, and the excess production can be sold to the market. As this use case does not consider heat demand, all BTC's heat production must be cooled in a cooling tower. Table 16 shows the input data for this use case:

Table 16: Input data for CEMEX PowerGen updated model cases.

Parameter	Unit	BTC
Max Total Power	MW	42.9
Min Total Power	MW	15
Max Heat	MW	21.9
Min Heat	MW	10.3
Efficiency/COP	p.u.	0.9

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P-Q ratio	-	1.3955
Ramp Up/Dw	MW/h	78/60
UpTime/DwTime	h	4/4
CO2 emission rate	ton/MWh	0.018

Parameter		Unit	BTC Alcanar	BTC Alicante
SD Duration		h	1	1
SD Cost		€	472	460
SU Duration	Cold	h	20	20
SU Duration	Warm	h	15	15
SU Duration	Hot	h	2	2
SU Cost	Cold	€	1038	1010
SU Cost	Warm	€	1021	992
SU Cost	Hot	€	944	919

Parameter	Unit	Value
Cooling cost	€/MWth	0.7
CO2 cost	€/tonCO2	76
Biomass cost	€/MWh	23.19
Fuel oil cost	€/MWh	Confidential

Use case CEMEX CHP

In addition to electricity, this use case investigates the operation of a BTC unit to cover a heat demand in Alcanar plant. No provision of secondary reserves is considered.

A 6 MW fuel oil-fed boiler is installed to cover the heat demand during hours when the BTC is offline. Again, excess heat production is cooled down in a cooling tower. The input data is presented in Table 17.

Table 17: Input data for CEMEX CHP updated model case.

Parameter	Unit	BTC	Boiler
Max Total Power	MW	41.8	6
Min Total Power	MW	14.2	1
Max Heat	MW	20.9	6
Min Heat	MW	9.5	1
Efficiency/COP	p.u.	0.9	0.8
P-Q ratio	-	1.4348	
Ramp Up/Dw	MW/h	78/60	4/4
UpTime/DwTime	h	4/4	4/4
CO2 emission rate	ton/MWh	0.018	0.265

Parameter		Unit	BTC
SD Duration		h	1
SD Cost		€	472
SU Duration	Cold	h	20
SU Duration	Warm	h	15
SU Duration	Hot	h	2
SU Cost	Cold	€	1038
SU Cost	Warm	€	1021

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SU Cost	Hot	€	944

Parameter	Unit	Value
Cooling cost	€/MWth	0.7
CO2 cost	€/tonCO2	76
Biomass cost	€/MWh	23.19
Fuel oil cost	€/MWh	Confidential

Use case CEMEX Hydrogen

This use case comprises two applications. First, operation of BTC is modelled in the same way as described in the "CEMEX PowerGen" use case of this same section. Only difference is that hydrogen, instead of fuel oil, is used during the start-up sequences. The reason for considering hydrogen as fuel for these processes is the reduction in the duration of the startup sequences.

Then, as mentioned in section 3.2.2, a partial fuel change in the kiln is studied for both plants. In order to determine the levelized cost of hydrogen (LCOH), which constitutes an input of this case study, the model "Protio (PRogram for Optimizing The Investment and Operation of hydrogen production)" [14] was used. The model can determine the investment decisions and costs (PEM electrolyzer, battery, and solar PV plant) which are required to comply with an annual hydrogen production, as well as calculate operational costs and incomes from selling excess PV electricity to the market. This results in a levelized cost of hydrogen which includes all these costs and incomes. For this purpose, an average solar profile for Alicante site was considered as input, while electricity prices are the same as those used for the benchmark and updated cases. A battery of 4 hours is assumed. Finally, Table 18 shows the input data used in the updated model.

Table 18: Input data for CEMEX H2 updated model cases.

Parameter	Unit	BTC
Max Total Power	MW	42.9
Min Total Power	MW	15
Max Heat	MW	21.9
Min Heat	MW	10.3
Efficiency/COP	p.u.	0.9
P-Q ratio	-	1.3955
Ramp Up/Dw	MW/h	280/210
UpTime/DwTime	h	3/3
CO2 emission rate	ton/MWh	0.018

Parameter		Unit	BTC Alcanar	BTC Alicante
SD Duration		h	1	1
SD Cost		€	1557	1335
SU Duration	Cold	h	1	1
SU Duration	Warm	h	1	1
SU Duration	Hot	h	1	1
SU Cost	Cold	€	3380	2899
SU Cost	Warm	€	3308	2838
SU Cost	Hot	€	3114	2669

Parameter	Unit	Value
H2 cost Alcanar	€/kgH2	3.43

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H_2 cost Alicante	€/kgH2	2.90
Cooling cost	€/MWth	0.7
CO_2 cost	€/tonCO2	76
Biomass cost	€/MWh	23.19
Fuel oil cost	€/MWh	Confidential

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4 Mathematical Formulation for operational/scheduling models: Sweden

This section presents mathematical formulations for the Swedish use cases, where TvAB is interested to investigate whether using efficient cogeneration of BTC technology will enable optimal participation in energy markets and generate extra profit. The first business use case is targeting to trade in the day-ahead market while meeting the heat demand. However, the second business use case considers the opportunity of also providing balancing power. The mathematical formulations developed for the same are based on and adapted from [15], [16].

4.1 Mathematical formulation for district heating system optimization for participation in day-ahead market: business use case 1

4.1.1 Nomenclature

Indices

g	Generation units
p	Aggregated CHP units
k	Storage units
t	Hours in the optimization horizon (t = 1,2, 3,…,T)
s	Segments defining PQ region of CHP units
m	Operation mode of CHP units: full CHP mode (m=1), heat-only mode (m=0)
l	Start-up type

Sets

Ω_G	Set of all generation units
Ω_{CHP}	Set of CHP units
Ω_{HB}	Set of heat boiler units
Ω_{G_SU}	Set of generation units with start-up process
Ω_o	Set of aggregated CHP units (with aggregated PQ region)
Ω_K	Set of storage units
Ω_{FG}	Set of flue gas condensation units
Ω_{CHP}^{p}	Set of CHP units belonging to aggregated CHP unit *p*
Ω_{FG}^{CHP}	Set of CHP units connected to flue gas units
Ω_l	Set of all types of start-ups, hottest to coldest
Ω_{BTC}	Set of BTC CHP units
Ω_{TB}	Set of Top-up heat-boiler units
Ω_{BTC}^{TB}	BTC units connected to top up boiler *b*

Parameters

$\mathrm{C_g^{fuel}}$	Fuel cost of unit *g* (SEK/MWh)
λ_t^{DA}	Day ahead market price at time *t* (SEK/MWh)
λ_t^{up}	Up-regulation market price at time *t* (SEK/MWh)
λ_t^{dn}	Down-regulation market price at time *t* (SEK/MWh)
H_t	System heat demand at time *t* (MW)
$\mathrm{P_t^{self}}$	Internal electricity (self) consumption at time *t* (MW)

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$\mathrm{M}_{\mathrm{g}}^{\max}$	Maximum heat and electricity production capacity of unit *g (*MW)
$\mathrm{M}_{\mathrm{g}}^{\min}$	Minimum heat and electricity production capacity of unit *g (*MW)
η_{g}	Total efficiency of unit *g* (%)
$\mathrm{t}_{\mathrm{p}}^{\mathrm{HO}}$	Minimum time in heat only mode of aggregated unit *p* (hours)
$q_{s,i};p_{s,i}$	Endpoints of PQ segment *s* for all (aggregated) CHP units (MWth, MWe)
V_k^{max}	Maximum level of heat in storage unit *k* (MWh)
V_k^{min}	Minimum level of heat in storage unit *k* (MWh)
V_k^0	Initial storage level of unit *k* (MWh)
$V_k^{ch/dch}$	Maximum charge/discharge rate for the storage unit *k* (MW)
ρ	Hourly loss for storage units
Q_{HD}^{max}	Maximum capacity of heat sink (MW)
$\mathrm{C}^{\mathrm{CO2}}$	Carbon tax per ton of emission (SEK/ton)
ER_{g}	Emission rate of unit *g* (ton/MWh)
$D_{g,l}^{SU}$	Duration of start-up process of the unit *g* for start-up type *l* (hours)
D_g^{suMax}	Maximum duration of start-up times for the unit *g* (hours)
$M_{g,l,\mathrm{i}}^{SU}$	Power output at *i*th interval of start-up ramp of unit *g* (MW)
$t_{g,l}^{SU}$	Minimum downtime for unit g for start-up type *l* (hours)
$C_{g,l}^{SU}$	Start-up cost of unit *g* for start-up type *l* (SEK/start)
$\mathrm{t}_{\mathrm{g}}^{\mathrm{up}}$	Minimum up time of unit *g* (hours)
$\mathrm{t}_{\mathrm{g}}^{\mathrm{dn}}$	Minimum down-time of unit *g* (hours)
$UT_{R\,g}$	Remaining uptime (hours)
$DT_{R\,g}$	Remaining downtime (hours)
D_g^{SD}	Duration of shut-down process of the unit *g* (hours)
$M_{g,i}^{SD}$	Power output at *i*th interval of shut-down ramp of unit *g* (MW)
ω_1, ω_2	Penalties considered in the objective function (SEK/MWh)

Variables

$\mathrm{F}_{\mathrm{g,t}}$	Fuel consumption of unit g at time *t* (MWh)
$\mathrm{P}_{\mathrm{g,t}}$	Electricity production from unit *g* at time t (MW)
$P_{g,t}^{up/dn}$	Up/downward regulation production volume from unit *g* at time t (MW)
$\mathrm{Q}_{\mathrm{g,t}}$	Heat production from unit *g* at time *t* (MW)
$\mathrm{R}_{\mathrm{g,t}}$	Total heat and electricity production from unit *g* at time *t* (MW)
$R_{g,t}^{out}$	Total (heat and power) output above minimum level from unit g at time t (MW)
$N_{g,t}$	Total thermal power output (MW)
$S_{g,t}$	Start-up or shut-down (heat and power) output (MW)
$\mathrm{P}_{\mathrm{t}}^{\mathrm{DA}}$	Electricity sold in day-ahead market at time *t* (MW)
$\mathrm{P}_{\mathrm{t}}^{\mathrm{up/dn}}$	Electricity sold/bought in mFRR market at time *t* (MW)
$V_{k,t}$	Stored heat in the storage unit *k* at time *t* (MWh)
Q_t^{HD}	Heat dissipation at time t (MW)
Q_t^{uns}	Slack variable representing unmet heat demand at time t (MW)
$\mathrm{M}_{\mathrm{p,m,t}}^{\mathrm{agg-chp}}$	Binary variable for choosing CHP or heat-only mode in aggregated CHP unit *p*
$\mathrm{P}_{\mathrm{p,m,t}}^{\mathrm{agg-chp}}$	Electricity production from aggregated CHP unit *p* in mode *m* at time *t* (MWh)
$\mathrm{Q}_{\mathrm{p,m,t}}^{\mathrm{agg-chp}}$	Heat production from aggregated CHP unit *p* in mode *m* at time *t* (MWh)
$\mathrm{U}_{\mathrm{g,t}}$	Binary variable for unit-commitment status (on/off) of unit *g* at time *t*
$Y_{g,t}$	Continuous variable [0,1] for start-up of unit *g* at time *t*
$\mathrm{Z}_{\mathrm{g,t}}$	Continuous variable [0,1] for shut-down of unit *g* at time *t*

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$\delta_{g,l,t}$ Continuous variable [0,1] for start-up type *l* of unit *g* at time *t*
$\mathrm{x_t}$ Auxiliary binary variable for coordinating operation of BTC units and top-up boilers.

4.1.2 Mathematical formulation of benchmark model for day-ahead market:

Objective Function

The objective function in (4.1) minimizes total cost and negative revenue, equivalent to minimizing costs while maximizing the possible revenue. The costs mainly consist of the fuel costs and operating costs arising from the start-up of the production units. Note that the formulation considers the possibility of different types of start-ups, most commonly cold, warm, and hot start-up types distinguished by the amount of time a unit has been in complete shut-down before being started again. C^{CO2} corresponds to the carbon tax for CO_2 emissions. While C^{CO2} is the carbon tax in SEK/ton of emissions and ER_g is the carbon emission rate of unit *g* in ton/MWh, $R_{g,t}$ defined later in equation (4.24), is the total thermal energy (MWh) produced from unit *g* at time *t*. Besides, heat discharge and unserved heat demand are penalized with costs ω_1 and ω_2.

$$\min \sum_{t=1}^{T}\left(\sum_{g\,\in\,\Omega_{G\_SU}}\left(C_g^{fuel}F_{g,t} + \sum_{l} C_{g,l}^{SU}\delta_{g,l,t} + C^{CO2}\,ER_g R_{g,t}\right) + \omega_1 Q_t^{HD} + \omega_2 Q_t^{uns} - \lambda_t^{DA}P_t^{DA}\right) \tag{4.1}$$

The objective function is subject to the following constraints.

Constraints

Electricity balance constraint:

The production from all units must sum up to the power sold on the day-market plus the self-consumption in the district heating system:

$$\textstyle\sum_{g\in\Omega_G} P_{g,t} = P_t^{DA} + P_t^{self} \qquad \forall t \tag{4.1}$$

Here, P_t^{self} denoting self-consumption refers to any auxiliary power consumption by the system. Note that here P_t^{DA} is defined to be a positive variable, so that only the net power production after providing for internal consumption, is considered to be available for trading in the day-ahead market.

<u>For units without start-up conditions:</u>

Thermal Storage:

The constraint (4.3) enforces the heat balance in the system. The change in the heat content of all storage units from time *t − 1* to time *t* equals the difference between the total heat production from all units and the served heat demand of the system at time *t*.

$$\sum_{k\in\Omega_K} V_{k,t} - (1-\delta) * V_{k,t-1} = \sum_{g\in\Omega_G} Q_{g,t} - \left(H_t - Q_t^{uns}\right) \qquad \forall t \tag{4.3}$$

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The variable Q_t^{uns} representing the unserved heat demand is a positive variable limited by the heat demand itself, so that,

$$0 \leq Q_t^{uns} \leq H_t \qquad \forall t \qquad (4.2)$$

Note that when the storage capacity is limited, dissipation of excess heat into available heat sinks can be modelled by introducing a 'heat dissipation variable' Q_t^{HD} in the heat balance equation as in equation (4.5):

$$\sum_{k\in\Omega_K} V_{k,t} - (1-\delta) * V_{k,t-1} = \sum_{g\in\Omega_G} Q_{g,t} - (H_t - Q_t^{uns}) - Q_t^{HD} \qquad \forall t \qquad (4.3)$$

The variable Q_t^{HD} is a positive variable limited by the available heat sink capacity, as it is set in the constraint (4.6).

$$0 \leq Q_t^{HD} \leq Q^{HDmax} \qquad \forall t \qquad (4.4)$$

The consideration of excess heat dissipation into available heat sinks helps in enabling a more flexible operation of the CHP units, e.g. during times of high electricity prices, when it is profitable to produce and sell more power, but the power production otherwise becoming restricted due to limited heat demand and storage capacity. However, it is important to note again that heat discharge is also penalized in the objective function; for the TvAB system, the local river is mainly used to absorb the excess heat during times of low heat demand, but its absorbing capacity is limited and unreliable.

The constraint (4.7) enforces minimum and maximum limits for the heat content in storage units.

$$V_k^{min} \leq V_{k,t} \leq V_k^{max} \qquad \forall k,t \qquad (4.5)$$

Limits on charging and discharging from the storage units are defined by (4.8) as shown below:

$$-V_k^{dch} \leq V_{k,t} - V_{k,t-1} \leq V_k^{ch} \qquad \forall k,t \qquad (4.6)$$

Flue gas condensation units:

$$P_{g,t} = 0 \qquad \forall \in \Omega_{FG}, \forall\, t \qquad (4.7)$$

$$Q_{g,t} \leq M_g^{max} \frac{\sum_{j\ connected\ to\ g} R_{j,t}}{\sum_{j\ connected\ to\ g} M_j^{max}} \qquad (4.8)$$

$$R_{g,t} = Q_{g,t} \qquad (4.9)$$

The power production from flue gas condensation units is zero as defined in constraint (4.9). The heat output from these units is proportional to the total production from the CHP units that are connected to them, given by (4.10). The total thermal output is once again only associated with the heat production, as there is no power production from these units. This is set in (4.11). Also, the fuel consumption for these units is considered to be zero, so that the term relating to fuel costs in the objective function does not consider these condensation units, but only other production units that are also associated with a start-up process.

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Constraints modelling CHP operation:

In many cases, two or more CHP units share a common steam trunk from the boilers to the turbines. In such a case, we consider aggregated heat and power production from those CHP units. From a modelling standpoint, these CHP units share an aggregated PQ region and are considered as belonging to an aggregated CHP unit *p*. However, to maintain a simplified and consistent formulation, we also consider single CHP units with own PQ region as belonging to aggregated CHP units *p*, however these aggregated units contain only one CHP unit.

Also, as described in section 3.1.2, CHP units can operate in either full CHP mode or heat boiler mode. Operation in CHP mode or heat-only mode is modelled by the binary variables $M_{p,m,t}^{agg-chp} \in \{0,1\}$, such that $m = 0$ corresponds to the heat-only mode while $m = 1$ represents the CHP mode. The optimization model decides whether the unit must operate in CHP mode $\left(M_{p,0,t}^{agg-chp} = 0 \text{ and } M_{p,1,t}^{agg-chp} = 1\right)$ or heat-only mode $\left(M_{p,0,t}^{agg-chp} = 1 \text{ and } M_{p,1,t}^{agg-chp} = 0\right)$. Variables $P_{p,m,t}^{agg-chp}$ and $Q_{p,m,t}^{agg-chp}$ then denote the power and heat production in both modes from aggregated CHP unit *p* at time *t*.

The power and heat production of the aggregated unit are the sums of the power and heat production from the individual CHP units belonging to the aggregated unit. This gives the constraints as in equations (4.12) and (4.13).

$$P_{p,1,t}^{agg-chp} = \sum_{\substack{g \in P \\ g \in \Omega_{CHP}}} P_{g,t} \qquad (4.10)$$

$$Q_{p,0,t}^{agg-chp} + Q_{p,1,t}^{agg-chp} = \sum_{\substack{g \in p \\ g \in \Omega_{CHP}}} Q_{g,t} \qquad (4.11)$$

CHP units are characterized by different levels of flexibility, as illustrated by Figures 7 and 8. For the case shown in Figure 7, the operation is restricted to lie on the inclined line segment, giving a fixed power-to-heat ratio. Alternately, as seen in Figure 8, CHP units can have more flexibility such that they can operate at any point of a given feasible (operating) region.

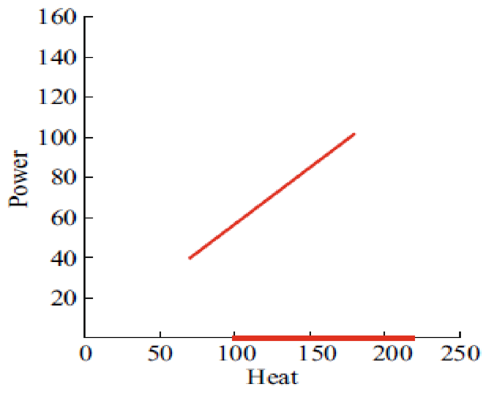

Figure 7: Fixed power-to-heat ratio *[16]*.

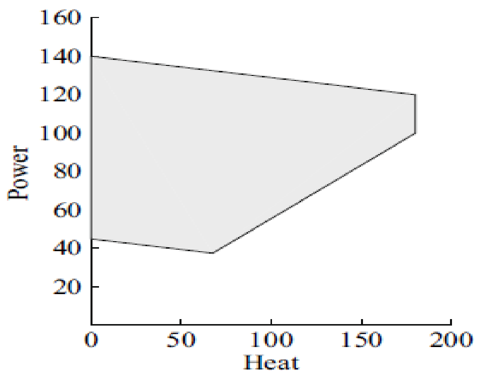

Figure 8: Feasible operating region *[16]*.

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The constraints modelling the operation for these different types are presented in the **Full CHP mode** section. For either of these types, the CHP unit is considered to be operating in full CHP mode, producing both heat and power. The constraints for the heat-only mode of operation are presented in the **Heat-only mode** section.

Full CHP mode:

As discussed above, both power and heat are produced in the full CHP mode. The feasible operation zone, as shown in Figure 8, is defined by the constraints (4.14-4.15).

For all segments $s \in \{1,2,\ldots,N_s\}$:

$If\ q_{s,2} \geq q_{s,1}:$

$$P_{p,1,t}^{agg-chp} \geq \frac{p_{s,2}-p_{s,1}}{q_{s,2}-q_{s,1}}\left(Q_{p,1,t}^{agg-chp} - q_{s,1}\, M_{p,1,t}^{agg-chp}\right) + p_{s,1} M_{p,1,t}^{agg-chp} \qquad (4.12)$$

$If\ q_{s,2} \leq q_{s,1}:$

$$P_{p,1,t}^{agg-chp} \leq \frac{p_{s,2}-p_{s,1}}{q_{s,2}-q_{s,1}}\left(Q_{p,1,t}^{agg-chp} - q_{s,1}\, M_{p,1,t}^{agg-chp}\right) + p_{s,1} M_{p,1,t}^{agg-chp} \qquad (4.13)$$

It is important to mention that these constraints (4.14-4.15) work correctly when the lower segments are specified from left to right (i.e., when $(q_{s,1}, p_{s,1})$ is the leftmost point of the segment) and the upper segments from right to left (i.e., when $(q_{s,1}, p_{s,1})$ is the rightmost point of the segment). Also, note that if the operation of the CHP unit is characterized by a fixed power-to- heat ratio as shown in Figure 7, this can be modelled once again by the same constraints (4.14) - (4.15); however, in this case, $(q_{s,2}, p_{s,2})$ in constraint (4.15) is the same as $(q_{s,1}, p_{s,1})$ in constraint (4.14) and vice-versa, so that only the equality (representing the single line) is met in the feasible solution.

Additionally, the following constraint forces the power and heat outputs in CHP mode to zero when the CHP mode is not activated $(\text{i.e., when } M_{p,1,t}^{agg-chp} = 0)$:

$$P_{p,1,t}^{agg-chp} \leq (max_s p_s)\, M_{p,1,t}^{agg-chp} \qquad (4.14)$$

where $max_s p_s$ represents to the maximum possible power production, as defined by the PQ region of the aggregated unit.

When the PQ region is a single line segment, then we add another constraint to enforce a lower limit on production as follows:

$$P_{p,1,t}^{agg-chp} \geq (min_s p_s)\, M_{p,1,t}^{agg-chp} \qquad (4.15)$$

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Here, $min_s p_s$ corresponds to the lower or leftmost point of the line segment defining the PQ relationship.

Heat-only mode:

The constrains below (4.18-4.20) model the heat-only mode.

$$Q_{p,0,t}^{agg-chp} \geq q_{0,1}\, M_{p,0,t}^{agg-chp} \tag{4.16}$$

$$Q_{p,0,t}^{agg-chp} \leq q_{0,2}\, M_{p,0,t}^{agg-chp} \tag{4.17}$$

$$P_{p,0,t}^{agg-chp} = 0 \tag{4.18}$$

where $q_{0,1}$and $q_{0,2}$ are the minimum and maximum thermal capacity of the aggregated unit *p*.

The constraint (4.21) enforces a minimum operation time in heat-only mode, including the requirement that only one of the two modes is active for the aggregated unit at any given time. Here t_p^{ho}represents the minimum time that the unit must be in heat-only mode.

$$\sum_{\tau=t}^{min\,(T,t+t_p^{ho}-1)} \left(M_{p,1,\tau}^{agg-chp} + M_{p,0,t}^{agg-chp} - 1\right) \leq 0 \tag{4.19}$$

Finally, constraint (4.22) relates the unit-commitment status $U_{g,t}$ with the operation mode of the unit. Here, $U_{g,t}$ represents the unit-commitment status of the CHP unit (belonging to the aggregated unit *p*) with the lowest marginal cost, as the CHP units belonging to an aggregated unit are expected to get dispatched in a merit order according to increasing marginal cost of production.

$$M_{p,1,t}^{agg-chp} + M_{p,0,t}^{agg-chp} = U_{g,t} \tag{4.20}$$

Start-up and shut-down related constraints for CHPs and heat boiler units:

Most of the constraints related to the start-up and shut-down processes presented in this section are based on [15] and are also used, and explained again, in the mathematical formulation for the Spanish use cases in section 5.

Start-up type constraint:

$$\delta_{g,l,t} \leq \sum_{i=T_{g,l}^{SU}}^{T_{g,l+1}^{SU}-1} Z_{g,t-i}, \qquad \forall t \in \left[T_{g,l+1}^{SU}, T\right], \forall l \in [1,L), \forall g \in \Omega_{G\_SU} \tag{4.21}$$

$$\sum_l \delta_{g,l,t} = Y_{g,t}, \qquad \forall t, \forall g \in \Omega_{G_{SU}} \tag{4.22}$$

As $\delta_{g,l,t}$ represents the start-up type of generator g, constraint (4.23) is used to ensure that it can be activated (i.e., take value 1) only if the unit has been down (below its minimum output) within the interval $\left[T_{g,l}^{SU}, T_{g,l+1}^{SU}\right)$. Also, only one start-up type can be selected when the unit starts up (4.24).

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Minimum up- and down-time constraints:

$$\sum_{i=t-t_g^{up}+1}^{t} Y_{g,i} \leq U_{g,t}, \qquad \forall t \in \left[t_g^{up}, T\right], \forall\, g \in \Omega_{G\_SU} \tag{4.23}$$

$$\sum_{i=t-t_g^{dn}+1}^{t} Z_{g,i} \leq 1 - U_{g,t}, \qquad \forall t \in \left[t_g^{dn}, T\right], \forall g \in \Omega_{G\_SU} \tag{4.24}$$

Unit Commitment constraint:

Logical relationship between start-up, shut-down and the unit-commitment variables is defined in equation (4.27) as:

$$Y_{g,t} - Z_{g,t} = U_{g,t} - U_{g,t-1} \qquad \forall t, \forall\, g \in \Omega_{G\_SU} \tag{4.25}$$

Capacity limits constraints:

$$R_{g,t}^{out} \leq \left(M_g^{max} - M_g^{min}\right)\left(U_{g,t} - Z_{g,t+1}\right) \qquad \forall t, \forall\, g \in \Omega_{G\_SU} \tag{4.26}$$

Constraint (4.28) bounds the variable $R_{g,t}^{out}$, representing total thermal output above minimum level, to the difference between the maximum and minimum thermal capacities of the units, also depending on the unit-commitment and subsequent shut-down status of the units.

Ramp constraints:

These constrain the difference between the outputs between consecutive timesteps.

$$-RD_g \leq R_{g,t}^{out} - R_{g,t-1}^{out} \leq RU_g \qquad \forall t, \forall\, g \in \Omega_{G_{SU}} \tag{4.27}$$

Total Thermal Output constraints:

The total thermal output, including the same during the start-up and shut-down sequences, is given by constraints (4.30) and (4.31). Note that only one shutdown trajectory is considered for all units.

$$N_{g,t} = M_g^{min}\left(U_{g,t} + Y_{g,t+1}\right) + R_{g,t}^{out} + \sum_{i=2}^{D_g^{sd}+1} M_{g,i}^{sd}\, Z_{g,t-i+2} + \sum_{l=1}^{L} \sum_{i=1}^{D_{g,l}^{su}} M_{g,l,i}^{su}\, \delta_{g,l,(t-i+D_{g,l}^{su}+2)},$$
$$\forall g \in \Omega_{G\_SU}, \forall t \in \left[t_0, T - D_g^{suMax}\right) \tag{4.28}$$

$$N_{g,t} = M_g^{min} U_{g,t} + R_{g,t}^{out} + \sum_{i=2}^{D_g^{sd}+1} M_{g,i}^{sd}\, Z_{g,t-i+2}, \qquad \forall g, \forall t \in \left[T - D_g^{suMax}, T\right] \tag{4.29}$$

Heat and Power Production from total thermal power:

The heat and power production of the units can be derived from the total thermal output, $N_{g,t}$. Since $N_{g,t}$ includes the thermal outputs during the start-up and shut-down ramps as well, constraints (4.32) and (4.33) separate the total thermal output such that it equals the sum of heat ($Q_{g,t}$) and power ($P_{g,t}$) outputs when the unit is up and committed, while being assigned to the slack variable $S_{g,t}$ during the start-up and shut-down processes. This is done to keep the modelling consistent with constraint (4.22), according to which heat and power production from a CHP unit, for example, is non-zero only when the commitment variable $U_{g,t}$ equals 1. Also, constraint (4.34) is required to ensure the same for individual CHP units of an aggregated unit having more than one CHP unit.

$$N_{g,t} = P_{g,t} + Q_{g,t} + S_{g,t} \qquad \forall t, \forall g \in \Omega_{G_{SU}} \qquad (4.30)$$

$$S_{g,t} \leq \left(1 - U_{g,t}\right) M_g^{min} \qquad \forall t, \forall g \in \Omega_{G_{SU}} \qquad (4.31)$$

$$R_{g,t}^{out} + M_g^{min} U_{g,t} = P_{g,t} + Q_{g,t} \qquad \forall t, \forall g \in \Omega_{G_{SU}} \qquad (4.32)$$

Other type-specific constraints:

The following constraints define the fuel consumption $F_{g,t}$ and the total power and heat production $R_{g,t}$ for heat boilers and CHP units. In case of heat boilers, the power production is zero (4.36).

Heat boilers:

$$F_{g,t} = N_{g,t}/\eta_g \quad \forall g \in \Omega_{HB}, \forall t \qquad (4.33)$$

$$P_{g,t} = 0 \qquad (4.34)$$

$$R_{g,t} = Q_{g,t} \qquad (4.35)$$

CHP units:

$$F_{g,t} = N_{g,t}/\eta_g \quad \forall g \in \Omega_{CHP}, \forall t \qquad (4.36)$$

$$R_{g,t} = P_{g,t} + Q_{g,t} \qquad (4.37)$$

Constraints for Initial Conditions:

The parameters UT_{R_g} and DT_{R_g} correspond to the number of hours a unit must stay up or down, respectively, during the initial time periods of the optimization horizon. They are calculated as follows:

$$UT_{R_g} = max\{0, (UT_g - UT_g^0)U_g^0\}$$

$$DT_{R_g} = max\{0, (DT_g - DT_g^0)(1 - U_g^0)\}$$

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Initial conditions are necessary to constrain the operation of the units during the initial time periods of the optimization horizon: (4.40) addresses the initial unit commitment states, while (4.41) and (4.42) complement constraint (4.23) during the initial hours. More importantly, (4.42) ensures that the start-up type variable does not get activated before the corresponding start-up duration.

$$if\ \left(UT_{R_g} + DT_{R_g}\right) \geq 1:$$

$$U_{g,t} = U_g^0,\ \forall t \in \left[t_0, UT_{R_g} + DT_{R_g}\right], \forall g \in \Omega_{G_{SU}} \qquad (4.38)$$

$$if\ DT_g^0 \geq 2:$$

$$\delta_{g,l,t} = 0,\ \forall t \in \left(T_{g,l+1}^{SU} - DT_g^0, T_{g,l+1}^{SU}\right), \forall g \in \Omega_{G_{SU}}, \forall l \in [1, L) \qquad (4.39)$$

$$\delta_{g,l,t} = 0,\ \forall t \in \left[t_0, D_{g,l}^{SU}\right], \forall g \in \Omega_{G_{SU}}, \forall l \qquad (4.40)$$

Benchmark model for day-ahead market: TvAB portfolio

The final proposed MILP model for TvAB current production portfolio is stated in equations (4.43)-(4.44).

$$\boldsymbol{min} \sum_{t=1}^{T}\left(\sum_{g\,\in\,\Omega_{G\_SU}}\left(C_g^{fuel}F_{g,t} + C^{CO2}ER_gR_{g,t} + \sum_l C_{g,l}^{SU}\delta_{g,l,t}\right) + \omega_1 Q_t^{HD} + \omega_2 Q_t^{uns} - \lambda_t^{DA}P_t^{DA}\right) \qquad (4.41)$$

$\boldsymbol{subject\ to}$:

$$(4.2), (4.4)\text{ -}(4.42) \qquad (4.42)$$

where $F_{g,t}, P_{g,t}, Q_{g,t}, R_{g,t}, R_{g,t}^{out}, N_{g,t}, S_{g,t}, P_{p,m,t}^{agg-chp}, Q_{p,m,t}^{agg-chp}, P_t^{DA}, V_{k,t}, Q_t^{HD}, Q_t^{uns} \in \mathbb{R}$, $\delta_{g,l,t}, Y_{g,t}, Z_{g,t} \in$ [0,1] while $U_{g,t}$ and $M_{p,m,t}^{agg-chp}$ are binary variables.

4.1.3 BTC integration in TvAB portfolio

When the Biomass fired Top-Cycle (BTC) CHP unit is integrated into the production portfolio for district heating (by replacing some existing CHP units), its operation is modelled in a very similar way as for other CHP units described in section 4.1.2.

However, some additional constraints for the BTC CHP unit include:

$$P_g^{min}U_{g,t} \leq P_{g,t} \leq P_g^{max}U_{g,t} \qquad \forall\, g \in \Omega_{BTC}, \forall t \qquad (4.43)$$

Constraint (4.45) limits the power production of BTC units between its defined minimum and maximum electrical load (output).

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Also, for the BTC unit that is primarily designed to provide high electrical efficiency, operation in heat-only mode may not be preferred or implemented at all, in practice. In such a case, we simply always enforce the following constraint.

$$M_{p,0,t} = 0 \quad \forall g \in \Omega_{BTC}, \forall t \tag{4.44}$$

Additionally, the supply temperature of a BTC unit is limited to approximately 75-80°C by the available heat in the flue gas condenser and is not sufficient for the Linköping district heating system (more information is provided in deliverable 3.7 and 3.1), where the supply temperature ranges between 95 – 115°C. In this case, the remaining heat power is provided by the complimentary operation of a boiler unit downstream of the BTC, increasing or '*topping up*' the temperature to the instantaneous need in the system. Also, this unit could run on a cheaper fuel (like recycled wood) than that of the BTC [1].

We model the operation of these toping boiler units as explained below:

When the BTC CHP unit is not in operation, the toping boiler may still be preferred and dispatched for heat production as it runs on a cheap fuel. Its operation is then modelled in the same way as for a normal heat boiler presented earlier. However, the top-up boiler always operates when the BTC is in operation to meet the temperature requirement of the grid as explained above. This is modelled as below in constraint (47). Here, the variable with subscript *g2* is used to denote the commitment status of the top-up boiler, while the one with subscript *g1* denotes that of the BTC unit.

$$U_{g1,t} - U_{g2,t} \leq 0 \quad \forall\, (g1, g2) \in \Omega_{BTC}^{TB}, \forall\, t \tag{4.45}$$

When the BTC operates, the heat production from the boiler will be proportional to the heat production from the BTC according to the temperature increase needed, as in below constraint (4.48):

$$Q_t^{TB} = \left(\frac{[Required\ supply\ temp\ TvAB] - \ [BTC\ supply\ temperature]}{[BTC\ supply\ temperature] - \ [TvAB\ DH\ return\ temperature]}\right) Q_{BTC,t} \tag{4.46}$$

However, according to the equation (4.48), the heat production from the top-up boiler will be forced to zero when the BTC is not in operation. Since the top-up boiler can operate even when the BTC is not in operation, the above equation is modified as:

$$Q_{g2,t} = \left(\frac{[\text{Required supply temp TvAB}] - \ [\text{BTC supply temperature}]}{[\text{BTC supply temperature}] - \ [\text{TvAB DH return temperature}]}\right) Q_{g1,t} + Q_{g2,t}\left(U_{g2,t} - U_{g1,t}\right)$$

$$\forall\, (g1, g2) \in \Omega_{BTC}^{TB}, \forall\, t \tag{4.47}$$

We see that the constraint now involves a product of a continuous variable $Q_{g2,t}$ with the binary variables $U_{g2,t}$ and $U_{g1,t}$. This makes the constraint non-linear requiring some reformulation. We use the Big-M formulation here to reformulate and linearize the above constraint using two linear inequalities as follows:

First, let's define a new variable x_t as follows:

$$x_t = U_{g2,t} - \ U_{g1,t} \tag{4.48}$$

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And let $a = \left(\frac{[\text{Required supply temp TvAB}]- \ [\text{BTC supply temperature}]}{[\text{BTC supply temperature}]- \ [\text{TvAB DH return temperature}]}\right)$

For a constant M that is large enough, we reformulate constraint (4.49) as:

$$-Mx_t \leq Q_{g2,t} - aQ_{g1,t} \leq Mx_t \qquad \forall\ (g1, g2) \in \Omega_{BTC}^{TB}, \forall\ t \tag{4.49}$$

When the BTC operates, we have $x_t = 0$, so that

$$0 \leq Q_{g2,t} - aQ_{g1,t} \leq 0 \tag{4.50}$$

which is essentially the same as constraint (4.48) in the form

$$Q_{g2,t} = aQ_{g1,t} \tag{4.51}$$

When the BTC does not operate, we have $x_t = U_{g2,t}$ and $Q_{g1,t} = 0$, so that the constraint (4.51) becomes as

$$-MU_{g2,t} \leq Q_{g2,t} \leq MU_{g2,t} \tag{4.52}$$

As long as the constant M is set to be a large enough value, the heat production of the top-up boiler will then not be constrained by that of the BTC (when the BTC does not operate), but by its own maximum capacity and minimum production limit.

Updated model for day-ahead market: TvAB portfolio with BTC technology

The final proposed MILP model for TvAB production portfolio with integrated BTC CHP technology is stated in (4.55)-(4.56).

$$\mathbf{min} \sum_{t=1}^{T} \left(\sum_{g\ \in\ \Omega_{G\_SU}} \left(C_g^{fuel} F_{g,t} + C^{CO2} ER_g R_{g,t} + \sum_l C_{g,l}^{SU} \delta_{g,l,t} \right) + \omega_1 Q_t^{HD} + \omega_2 Q_t^{uns} - \lambda_t^{DA} P_t^{DA} \right) \tag{4.53}$$

$\boldsymbol{subject\ to}$: (2), (4) – (42), (44) – (47), (50) – (51). (4.54)

where $F_{g,t}, P_{g,t}, Q_{g,t}, R_{g,t}, R_{g,t}^{out}, N_{g,t}, S_{g,t}, P_{p,m,t}^{agg-chp}, Q_{p,m,t}^{agg-chp}, P_t^{DA}, V_{k,t}, Q_t^{HD}, Q_t^{uns} \in \mathbb{R}$,

$\delta_{g,l,t}, Y_{g,t}, Z_{g,t} \in$ [0,1] while $U_{g,t}$ and $M_{p,m,t}^{agg-chp}$ are binary variables.

4.2 Mathematical formulation for district heating system participation in day-ahead and mFRR markets: business use case 2

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grand agreement N° 101037085.

This section develops the mathematical formulation of the second Swedish use case: **SE- Tekniska Verken AB -02.** Note that **SE- Tekniska Verken AB -02** aims at investigating the potential of BTC technology to also provide balancing power when introduced in the Linköping power system.

To include the mFRR market in the formulation, a new set of variables $P_{g,t}^{up}$, $P_{g,t}^{dn}$ (upward- and downward-regulation volume per production unit and timestep) and P_t^{up}, P_t^{dn} (total upward- and downward-regulation bids for mFRR markets) are defined. In addition, parameters λ_t^{up} and λ_t^{dn} that denote upward, and downward regulating market prices are introduced. The two terms, $\lambda_t^{up} P_t^{up}$ and $\lambda_t^{dn} P_t^{dn}$, representing compensation associated with providing up and down regulation respectively, are added in the objective function.

The power production of every unit g is broken down into production volumes corresponding to the day-ahead and mFRR markets as follows:

$$P_{g,t} = P_{g,t}^{DA} + P_{g,t}^{up} - P_{g,t}^{dn} \tag{4.55}$$

Also, the total volumes bid to the day-ahead, up and down-regulation markets are given by:

$$\sum_{g=1}^{N_G} P_{g,t}^{DA} = P_t^{DA} + P_t^{self} \tag{4.56}$$

$$\sum_{g=1}^{N_G} P_{g,t}^{up} = P_t^{up} \tag{4.57}$$

$$\sum_{g=1}^{N_G} P_{g,t}^{dn} = P_t^{dn} \tag{4.58}$$

Additionally, the following constraints make sure that up- and down regulation volumes are not offered at the same time and when there is no need for any regulation (determined by day-ahead and regulating market prices).

$$P_{g,t}^{up} = 0, \; when \; \lambda_t^{DA} \geq \lambda_t^{up} \tag{4.59}$$

$$P_{g,t}^{dn} = 0, \; when \; \lambda_t^{DA} \leq \lambda_t^{dn} \tag{4.60}$$

The volume of down-regulation is constrained by the commitment on the day-ahead market.

$$P_t^{dn} \leq P_t^{DA} \tag{4.61}$$

Also, the activation of up- and down-regulation is limited by what is practically feasible for each unit. Assuming symmetrical capabilities for both up and down-regulation, we have:

$$P_{g,t}^{up} \leq \bar{P}_g^{mFRR} \tag{4.62}$$

$$P_{g,t}^{dn} \leq \bar{P}_g^{mFRR} \tag{4.63}$$

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Finally, the following constraint is required to ensure that regulation is provided only when the unit is committed, otherwise the terms $P_{g,t}^{DA}$ and $P_{g,t}^{dn}$ can take on non-zero values during hours of down-regulation, even when the unit is not committed, to cancel each other, so that the total power production of the unit remains zero.

$$P_{g,t}^{DA} + P_{g,t}^{up} \leq \ (max_s p_s) * U_{g,t} \tag{4.64}$$

Benchmark model for day-ahead and mFRR markets: TvAB portfolio

The final proposed MILP model for TvAB's current production portfolio for participating in both day-ahead and mFRR markets is stated in (4.67)-(4.68).

$$\mathbf{min} \sum_{t=1}^{T} \left(\sum_{g \,\in\, \Omega_{G\_SU}} \left(C_g^{fuel} F_{g,t} + C^{CO2} ER_g R_{g,t} \ + \sum_{l} C_{g,l}^{SU} \delta_{g,l,t} \right) + \omega_1 Q_t^{HD} + \omega_2 Q_t^{uns} - \lambda_t^{DA} P_t^{DA} - \lambda_t^{up} P_t^{up} + \ \lambda_t^{dn} P_t^{dn} \right) \tag{4.67}$$

subject to:

$$(2), (4)\text{-}(42), (57) - (66) \tag{4.68}$$

where

$F_{g,t}, P_{g,t}, Q_{g,t}, R_{g,t}, R_{g,t}^{out}, N_{g,t}, S_{g,t}, P_{p,m,t}^{agg-chp}, Q_{p,m,t}^{agg-chp}, P_{g,t}^{DA}, P_{g,t}^{up}, P_{g,t}^{dn}, P_t^{DA}, P_t^{up}, P_t^{dn}, V_{k,t}, Q_t^{HD}, Q_t^{uns} \in \mathbb{R}$,

$\delta_{g,l,t}, Y_{g,t}, Z_{g,t} \in [0,1]$ while $U_{g,t}$ and $M_{p,m,t}^{agg-chp}$ are binary variables.

Updated model for day-ahead and mFRR markets: TvAB portfolio with BTC technology

The final proposed MILP model for TvAB production portfolio with integrated BTC CHP technology participation in both day-ahead and mFRR markets is stated in (4.69)-(4.70).

$$\mathbf{min} \sum_{t=1}^{T} \left(\sum_{g \,\in\, \Omega_{G\_SU}} \left(C_g^{fuel} F_{g,t} + C^{CO2} ER_g R_{g,t} \ + \sum_{l} C_{g,l}^{SU} \delta_{g,l,t} \right) + \omega_1 Q_t^{HD} + \omega_2 Q_t^{uns} - \lambda_t^{DA} P_t^{DA} \ - \lambda_t^{up} P_t^{up} + \ \lambda_t^{dn} P_t^{dn} \right) \tag{4.69}$$

subject to:

$$(2), (4) - (42), (44) - (47), (50) - (51), (57)\text{-}(66) \tag{4.70}$$

where

$F_{g,t}, P_{g,t}, Q_{g,t}, R_{g,t}, R_{g,t}^{out}, N_{g,t}, S_{g,t}, P_{p,m,t}^{agg-chp}, Q_{p,m,t}^{agg-chp}, P_{g,t}^{DA}, P_{g,t}^{up}, P_{g,t}^{dn}, P_t^{DA}, P_t^{up}, P_t^{dn}, V_{k,t}, Q_t^{HD}, Q_t^{uns} \in \mathbb{R}$,

$\delta_{g,l,t}, Y_{g,t}, Z_{g,t} \in [0,1]$ while $U_{g,t}$ and $M_{p,m,t}^{agg-chp}$ are binary variables.

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5 Mathematical formulation for operational/scheduling models: Spain

This chapter presents the mathematical formulation of the optimization model developed for the four Spanish uses cases. Section 6.1 contains all the nomenclature, parameters, and variables used in the model. Then, the updated model formulation for detailed BTC operation is presented in Section 6.2. The formulation with integrated heat pump operation, used for Sulquisa's use case, is described in Section 6.3. Finally, the formulation including participation in the balancing market, used for CEMEX's PowerGen and Hydrogen use cases, is presented in Section 6.4.

5.1 Model Nomenclature

The proposed model optimizes the operation of a given energy system over a varying scheduling horizon with an hourly resolution.

The energy system can be composed of cogeneration (electric and thermal power generation) and thermal generation units (heat only), which cover an industrial demand. In particular, the BTC (Biomass Top Cycle) consists of a biomass-fired cogeneration unit and includes a gasification unit, which processes raw biomass into syngas (H2 + CO). Syngas is burned in the Top Cycle turbine, and the heat and electricity generated cover an industrial demand and feed the excess electricity generation to the grid. Electricity can also be purchased from the grid.

Table 19 shows the nomenclature used in the model, including heat pump operation and provision of secondary reserves.

Table 19: Spanish model nomenclature

Index	Description
p	Period (e.g., year)
t	Load levels (e.g., hour)
g	Generators (cogeneration or thermal unit)
l	Start-up types associated to generators
sdi	i^{th} interval of the shut-down ramp process
sui	i^{th} interval of the start-up ramp process

Subindex	Description
c	Cogeneration unit (e.g., BTC, CHP)
x	Thermal unit (e.g., boiler)
h	Heat pump unit

Acronym	Description
O	Total power
P	Electric power
Q	Thermal power
OR	Operating reserves
UR	Upward operating reserve
DR	Downward operating reserve

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5.1.1 Parameters

Parameter	Description	Unit
D_t	Duration of each load level (1h, 2h)	h
$P_{d_{p,t}}$	Electric power demand	MW
$Q_{d_{p,t}}$	Thermal power demand	MW
$EC_{p,t}$	Electric energy cost	€/MWh
$EP_{p,t}$	Electric energy price	€/MWh
C^{QNS}	Not served heat cost / cooling cost	€/MWh
C^{CO2}	CO_2 emission cost	€/tCO_2
Ind_{HP}	Indicator of heat pump operation	Yes/No
$GCap$	Grid connection capacity	MW

Generation system

Parameter	Description	Unit
Ind_{c_g}	Indicator of cogeneration unit	Yes/No
Ind_{f_g}	Fuel type (biomass, natural gas, H2)	-
Ind_{h_g}	Indicator of heat pump unit	Yes/No
$Ind_{or_{gc}}$	Indicator of participation in OR market	Yes/No
O_{max_g}	Maximum total output	MW
O_{min_g}	Minimum total output	MW
Q_{max_g}	Maximum thermal power output	MW
Q_{min_g}	Minimum thermal power output	MW
C_g^F	Fuel cost (depends on Ind_{f_g})	€/MWh
η_g	Efficiency	p.u.
COP_{gh}	HP coefficient of performance	MW/MW
$PQslope_{gc}$	Slope of linear PQ curve	MW/MW
RU_g	Maximum ramp-up rate	MW/h
RD_g	Maximum ramp-down rate	MW/h
UT_g	Minimum up time	h
DT_g	Minimum down time	h
ER_g^{CO2}	CO_2 emission rate	tCO_2/MWh

Start-up and shut-down

Parameter	Description	Unit
D_g^{SD}	Duration of shut-down process	h
C_g^{SD}	Shut-down fix cost	€
$O_{g,sdi}^{SD}$	Output at the beginning of the i_{th} interval of the shut-down process	MW
$D_{g,l}^{SU}$	Duration of start-up type l	h
$C_{g,l}^{SU}$	Start-up type l fix cost	€
$O_{g,l}^{Syn}$	Output at which the unit is synchronized for start-up type l	MW
$O_{g,l,sui}^{SU}$	Output at the beginning of the i_{th} interval of the start-up type l	MW
$D_{max_g}^{SU}$	Maximum start-up type duration	h
$T_{g,l}^{SU}$	Minimum number of hours that the unit must be down before start-up type l	h

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Operating reserves

Parameter	Description	Unit
R^{UD}_{max} and R^{UD}_{min}	Maximum and minimum ratios downward to upward OR	p.u.
ORP_{gc}	Secondary availability price	€/MW

Initial conditions

Parameter	Description	Unit
U^0_g	Initial commitment state of unit g	1/0
UT^0_g	Number of hours that g has been online before the scheduling horizon	h
DT^0_g	Number of hours that g has been offline before the scheduling horizon	h
O^0_g	Output at the first load level	MW

5.1.2 Variables

Variable	Description	Unit
$u_{p,t,g}$	Commitment during load level t (binary)	{0,1}
$v_{p,t,g}$	Start-up in load level t (continuous)	[0,1]
$w_{p,t,g}$	Shut-down in load level t (continuous)	[0,1]
$\delta_{p,t,g,l}$	Start-up type l in load level t (continuous)	[0,1]
$e_{p,t,g}$	Energy production of the unit	MWh
$go_{p,t,g}$	Output above minimum output	MW
$o_{tot\,p,t,g}$	Total output of the unit	MW
$gp_{p,t,gc}$	Electric power output above minimum	MW
$gq_{p,t,g}$	Thermal power output above minimum	MW
$p_{p,t,gc}$	Electric power output	MW
$q_{p,t,g}$	Thermal power output	MW
$q_{exc\,p,t,g}$	Excess / not served thermal power output	MW
$p^{fs}{}_{p,t,gc}$	Electric power final schedule	MW
$q^{fs}{}_{p,t,g}$	Thermal power final schedule	MW
$q^{in}{}_{p,t,gh}$	HP inlet thermal power	MW
$q^{out}{}_{p,t,gh}$	HP output thermal power	MW
$p^{in}{}_{p,t,gh}$	HP inlet electric power	MW
$f_{p,t,g}$	Fuel consumption of the unit	MWh
$ur_{p,t,gc}$	Upward operating reserve	MW
$dr_{p,t,gc}$	Downward operating reserve	MW
$p_{buy\,p,t}$	Electric power bought at spot market	MW
$p_{sell\,p,t}$	Electric power sold at spot market	MW
$profit$	Total system profit	€
$revenue$	Total system revenue	€
$costs$	Total system costs	€

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5.2 Model with integrated BTC operation

Objective function

$$revenue = \sum_p \sum_t EP_{p,t}\, D_t\, p_{sell_{p,t}} \tag{5.1}$$

$$costs = \sum_p \sum_t \sum_g \left(C_g^F f_{p,t,g} + \sum_l^L C_{g,l}^{SU} \delta_{p,t,g,l} + C_g^{SD} w_{p,t,g} + C^{CO2} ER_g^{CO2} D_t o_{tot_{p,t,g}} + C^{QNS} D_t q_{exc_{p,t,g}} \right) + \sum_p \sum_t EC_{p,t}\, D_t\, p_{buy_{p,t}} \tag{5.2}$$

$$profit = revenue - costs \tag{5.3}$$

$$\max(profit) \tag{5.4}$$

The model maximizes the total profit (revenue minus operational costs) of the setup for a given set of time steps (t) as a MILP problem (5.3), (5.4). While revenues (5.1) are obtained from selling the excess electricity production to the grid, operational costs (5.2) consist of: fuel consumption, start-up and shut-down fixed costs, fossil carbon dioxide emissions, cooling of excess heat, and grid electricity purchase.

Power balances

$$p_{p,t,gc} = gp_{p,t,gc} + P_{min_{gc}} u_{p,t,gc}\,, \qquad \forall p, \forall t, \forall gc \tag{5.5}$$

$$q_{p,t,gc} = gq_{p,t,gc} + Q_{min_{gc}} u_{p,t,gc}\,, \qquad \forall p, \forall t, \forall gc \tag{5.6}$$

$$gp_{p,t,gc} = PQslope_{gc} \times gq_{p,t,gc}\,, \qquad \forall p, \forall t, \forall gc \tag{5.7}$$

$$o_{tot_{p,t,gc}} = p_{p,t,gc} + q_{p,t,gc}\,, \qquad \forall p, \forall t, \forall gc \tag{5.8}$$

Electric (5.5) and thermal (5.6) power outputs of a cogeneration unit (whose acronym gc also includes BTC units) are defined as the sum of the respective committed minimum output and the additional generation above the minimum. Constraint (5.7) sets the linear relationship between heat and electricity production above minimum outputs: parameter $PQslope_{gc}$ represents the slope of this linear approximation. Lastly, the total output equals the sum of the total electric and thermal power outputs (5.8).

$$q_{p,t,gc} = q^{fs}{}_{p,t,gc} + q_{exc_{p,t,gc}}\,, \qquad \forall p, \forall t, \forall gx \tag{5.9}$$

$$o_{tot_{p,t,gx}} = q^{fs}{}_{p,t,gx} + q_{exc_{p,t,gx}}\,, \qquad \forall p, \forall t, \forall gx \tag{5.10}$$

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Moreover, the thermal power output of cogeneration units can be expressed as the sum of two variables: the "final schedule" heat flow (q^{fs}), which is destined to cover the heat demand, plus the "excess heat" variable (q_{exc}), which represents an excess heat flow that must be cooled by means of, for example, a cooling tower with additional operational costs (5.9). In the case of thermal units, the total output equals the final schedule heat production plus the excess heat (5.10).

$$\sum_{gc} p_{p,t,gc} + p_{buy_{p,t}} - p_{sell_{p,t}} = P_{d_{p,t}}, \qquad \forall p, \forall t \tag{5.11}$$

$$\sum_{g} {q^{fs}}_{p,t,g} = Q_{d_{p,t}}, \qquad \forall p, \forall t \tag{5.12}$$

$$f_{p,t,g} = e_{p,t,g} / \eta_g, \qquad \forall p, \forall t, \forall g \tag{5.13}$$

The electric power balance (5.11) ensures that the electricity demand equals the electric power production of the cogeneration units, plus the difference between power purchased and sold to the grid. Likewise, the heat balance (5.12) equals the heat demand with the final schedule heat production of both cogeneration and thermal units. Constraint (5.13) defines the fuel consumption of any generator as the energy production (including start-up and shut-down) divided by the efficiency.

The rest of the modelling approach draws heavily on the work presented in [15], which introduces a tight and compact formulation for start-up and shut-down trajectories of thermal units.

Start-up type

$$\delta p, t, g, l \leq \sum_{i=T_{g,l}^{SU}}^{T_{g,l+1}^{SU}-1} w_{p,t-i,g}, \qquad \forall p, \forall t \in \left[T_{g,l+1}^{SU}, T\right], \forall g, \forall l \in [1, L) \tag{5.14}$$

$$\sum_{l} \delta_{p,t,g,l} = v_{p,t,g}, \qquad \forall p, \forall t, \forall g \tag{5.15}$$

While $\delta_{p,t,g,l}$ represents the start-up type of generator g, constraint (5.14) ensures that it can be activated (take value 1) only when the generator has been below its minimum output within the interval $\left[T_{g,l}^{SU}, T_{g,l+1}^{SU}\right)$. Additionally, only one SU type can be activated when the unit starts up (5.15).

Minimum up/down times

$$\sum_{i=t-UT_g+1}^{t} v_{p,i,g} \leq u_{p,t,g}, \qquad \forall p, \forall t \in \left[UT_g, T\right], \forall g \tag{5.16}$$

$$\sum_{i=t-DT_g+1}^{t} w_{p,i,g} \leq 1 - u_{p,t,g}, \qquad \forall p, \forall t \in \left[DT_g, T\right], \forall g \tag{5.17}$$

Commitment

$$u_{p,t,g} - u_{p,t-1,g} = v_{p,t,g} - w_{p,t,g}, \qquad \forall p, \forall t - \{t_0\}, \forall g \tag{5.18}$$

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The unitary start-up variable is activated when a unit transitions from an uncommitted to a committed state, meaning that the unit is starting up. Conversely, the shut-down variable is activated when a unit transitions from committed to uncommitted, indicating that the unit is shutting down. Although the commitment variable $u_{p,t,g}$ is the only binary variable, constraint (5.18) forces start-up and shut-down variables to take binary values.

Capacity limits

$$\frac{go_{p,t,g}}{O_{max_g} - O_{min_g}} \leq u_{p,t,g} - w_{p,t+1,g}\,, \qquad \forall p, \forall t - \{T\}, \forall g \tag{5.19}$$

$$\frac{go_{p,t,g}}{O_{max_g} - O_{min_g}} \geq 0, \qquad \forall p, \forall t, \forall g \tag{5.20}$$

The two equations above define the maximum (5.19) and minimum (5.20) operational boundaries for total generation outputs above minimum from committed cogeneration and thermal units. This formulation guarantees that the power output remains within a feasible and realistic range, adhering to the physical constraints of the units.

Operating ramps

$$\frac{go_{p,t,g} - go_{p,t-1,g}}{D_t RU_g} \leq 1\,, \qquad \forall p, \forall t - \{t_0\}, \forall g \tag{5.21}$$

$$\frac{go_{p,t,g} - go_{p,t-1,g}}{D_t RD_g} \geq -1\,, \qquad \forall p, \forall t - \{t_0\}, \forall g \tag{5.22}$$

Equation (5.21) describes the maximum ramp-up capacity, which is the ability of a generating unit to increase its power output between two consecutive hours. Similarly, equation (5.22) delineates the maximum ramp-down capacity, which refers to the capability of a unit to decrease its power output.

Total output

$$o_{tot_{p,t,g}} = O_{min_g}\left(u_{p,t,g} + v_{p,t+1,g}\right) + go_{p,t,g} + \sum_{i=2}^{D_g^{SD}} O_{g,i}^{SD} w_{p,t-i+2,g} + \sum_{l}^{L} \sum_{i=1}^{D_{g,l}^{SU}} O_{g,l,i}^{SU}\ \delta_{p,(t-i+D_{g,l}^{SU}+2),g,l}\,, \quad \forall p, \forall t \in [t_0, T - D_{max_g}^{SU}), \forall g \tag{5.23}$$

$$o_{tot_{p,t,g}} = O_{min_g} u_{p,t,g} + go_{p,t,g} + \sum_{i=2}^{D_g^{SD}} O_{g,i}^{SD} w_{p,t-i+2,g}\,, \qquad \forall p, \forall t \in \left[T - D_{max_g}^{SU}, T\right], \forall g \tag{5.24}$$

The total power output, including SU and SD processes, is modelled for the entire scheduling horizon in constraints (5.23)-(5.24). While constraints (5.16) and (5.17) select the SU type, equations (5.23) and (5.24) fix the corresponding trajectories. Note that $D_{max_g}^{SU}$ corresponds to the duration of the coldest, and thus longest, start-up type of each unit. Only one shut-down trajectory is modelled for each generator.

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Energy production

$$e_{p,t,g} = o_{tot_{p,t,g}} D_t, \qquad \forall p, \forall t, \forall g \tag{5.25}$$

Energy production, including SU and SD sequences, equals the generator's total power output times the duration of each time step (5.25).

Initial conditions

$$o_{tot_{p,t=t_0,g}} = O_g^0, \qquad \forall p, \forall g \tag{5.26}$$

$$\begin{aligned} &if\ \left(UT_{R_g} + DT_{R_g}\right) \geq 1: \\ &u_{p,t,g} = U_g^0, \qquad \forall p, \forall t \in \left[t_0, UT_{R_g} + DT_{R_g}\right], \forall g \end{aligned} \tag{5.27}$$

$$\begin{aligned} &if\ DT_g^0\ \geq 2: \\ &\delta_{p,t,g,l} = 0, \qquad \forall p, \forall t \in (T_{g,l+1}^{SU} - DT_g^0, T_{g,l+1}^{SU}), \forall g, \forall l\ \in\ [1, L) \end{aligned} \tag{5.28}$$

$$\delta_{p,t,g,l} = 0, \qquad \forall p, \forall t \in \left[t_0, D_{g,l}^{SU}\right], \forall g, \forall l \tag{5.29}$$

Initial conditions are required to constraint the operation during the first timesteps of the scheduling horizon: equation (5.26) sets the initial total power output of each unit, (5.27) deals with the initial unit commitment states, and (5.28) and (5.29) complement constraint (5.14) during the first hours. In particular, (5.29) ensures that the SU type variable is not activated before the respective SU duration.

Auxiliary parameters UT_{R_g} and DT_{R_g} represent the number of hours during which the unit must remain up or down, respectively, during the first timesteps of the scheduling horizon:

$$UT_{R_g} = max\{0, (UT_g - UT_g^0) U_g^0\} \tag{5.30}$$

$$DT_{R_g} = max\{0, (DT_g - DT_g^0)(1 - U_g^0)\} \tag{5.31}$$

Bounds on variables

$$0 \leq go_{p,t,g} \leq O_{max_g} - O_{min_g}, \qquad \forall p, \forall t, \forall g \tag{5.32}$$

$$0 \leq e_{p,t,g} \leq O_{max_g}, \qquad \forall p, \forall t, \forall g \tag{5.33}$$

$$0 \leq o_{tot_{p,t,g}} \leq O_{max_g}, \qquad \forall p, \forall t, \forall g \tag{5.34}$$

$$0 \leq p_{buy_{p,t}} \leq GCap, \qquad \forall p, \forall t \tag{5.35}$$

$$0 \leq p_{sell_{p,t}} \leq GCap, \qquad \forall p, \forall t \tag{5.36}$$

$$0 \leq gp_{p,t,gc} \leq P_{max_{gc}} - P_{min_{gc}}, \qquad \forall p, \forall t, \forall gc \tag{5.37}$$

with: $P_{max_{gc}} = O_{max_{gc}} - Q_{max_{gc}}$

$P_{min_{gc}} = O_{min_{gc}} - Q_{min_{gc}}$

$$0 \leq gq_{p,t,g} \leq Q_{max_g} - Q_{min_g}, \qquad \forall p, \forall t, \forall g \tag{5.38}$$

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5.3 Heat pump integration

Depending on the quality of heat demanded, a heat pump can be installed downstream a cogeneration or BTC unit. In this case, heat is extracted from the thermal power output of the cogeneration unit ("cold" side) and is transferred to a hotter temperature sink ("hot" side), which constitutes the thermal power output of the heat pump. To achieve this purpose, the heat pump is required to consume electric power, which also stems from the cogeneration unit. Therefore, balances are accordingly modified, and further variables are introduced to model the operation of the heat pump. These changes are activated when specifying $Ind_{HP} = 'Yes'$.

$$q^{out}{}_{p,t,gh} = gq_{p,t,gh} + Q_{min_{gh}} u_{p,t,gc}\,, \qquad \forall p, \forall t, \forall gh \tag{5.39}$$

The thermal power output of the heat pump is defined as the sum of the committed minimum output and the production above minimum (5.39). Note that the commitment variable corresponds to that of the cogeneration unit, meaning that the heat pump is up whenever the cogeneration unit is, ensuring that heat is delivered in the required quality.

$$q^{in}{}_{p,t,gh} = q^{out}{}_{p,t,gh}(1 - (1/COP_{gh})), \qquad \forall p, \forall t, \forall gh \tag{5.40}$$

$$p^{in}{}_{p,t,gh} = q^{out}{}_{p,t,gh} - q^{in}{}_{p,t,gh}\,, \qquad \forall p, \forall t, \forall gh \tag{5.41}$$

The variable $q^{in}{}_{p,t,gh}$ represents the heat flow of the "cold" side and is defined by means of the heat pump's coefficient of performance, COP (5.40). Electric power consumption is obtained by subtracting the heat power output and input flows (5.41).

$$p_{p,t,gc} = p^{in}{}_{p,t,gh} + p^{fs}{}_{p,t,gc}\,, \qquad \forall p, \forall t, \forall gc \tag{5.42}$$

$$\sum_{gc} p^{fs}{}_{p,t,gc} + p_{buy_{p,t}} - p_{sell_{p,t}} = P_{d_{p,t}}\,, \qquad \forall p, \forall t \tag{5.43}$$

Cogeneration electric power output is affected by the heat pump consumption (5.42). The remaining (or final schedule) electricity production is described by the variable $p^{fs}{}_{p,t,gc}$, and is the main contributor in the electric power balance (5.43).

$$q_{p,t,gc} = q^{in}{}_{p,t,gh} + q_{exc_{p,t,gc}}\,, \qquad \forall p, \forall t, \forall gc \tag{5.44}$$

$$q^{out}{}_{p,t,gh} = q^{fs}{}_{p,t,gh} + q_{exc_{p,t,gh}}\,, \qquad \forall p, \forall t, \forall gh \tag{5.45}$$

$$\sum_{g} q^{fs}{}_{p,t,g} = Q_{d_{p,t}}\,, \qquad \forall p, \forall t \tag{5.46}$$

Similarly, the thermal power output is also affected by the heat pump operation. An excess heat variable is needed to account for the difference between the cogeneration output and the heat flow destined to the "cold" side of the heat pump (5.44). All excess heat must be cooled down, e.g. by means of a cooling tower, and its corresponding operation cost is considered in the objective function.

Finally, the thermal power balance is modified so that the demand can be covered in the required quality by the contributions of thermal and heat pump units only (5.46).

If no heat pump is introduced ($Ind_{HP} = 'No'$), all variables needed to describe its operation are fixed to zero. The bounds on these variables are the following:

$$0 \le q^{fs}{}_{p,t,g} \le Q_{max_g}, \qquad \forall p, \forall t, \forall gh \tag{5.47}$$

$$0 \le q^{out}{}_{p,t,gh} \le Q_{max_{gh}}, \qquad \forall p, \forall t, \forall gh \tag{5.48}$$

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$$0 \le q^{in}{}_{p,t,gh} \le Q_{max\,In_{gh}}, \quad \forall p, \forall t, \forall gh, \quad \text{with: } Q_{max\,In_{gh}} = Q_{max_{gh}}(1 - 1/COP_{gh}) \tag{5.49}$$

$$0 \le p^{in}{}_{p,t,gh} \le P_{max\,In_{gh}}, \quad \forall p, \forall t, \forall gh, \quad \text{with: } P_{max\,In_{gh}} = Q_{max_{gh}} - Q_{max\,In_{gh}} \tag{5.50}$$

5.4 Operation reserves integration

This section describes how operating reserves are integrated within the operation model detailed previously. All modifications and additions should be considered as extensions of the existing model structure rather than as standalone components. These changes are activated when specifying *'Yes'* in the $Ind_{or\,gc}$ parameter for each generating unit capable of providing reserves.

$$o_{tot_{p,t,g}} = O_{min_g}(u_{p,t,g} + v_{p,t+1,g}) + go_{p,t,g} + \sum_{i=2}^{D_g^{SD}} O_{g,i}^{SD} w_{p,t-i+2,g} + \sum_{l}^{L} \sum_{i=1}^{D_{g,l}^{SU}} O_{g,l,i}^{SU}\ \delta_{p,(t-i+D_{g,l}^{SU}+2),g,l}\,, \quad \forall p, \forall t \in [t_0, T - D_{max_g}{}^{SU}), \forall g \tag{5.51}$$

$$o_{tot_{p,t,g}} = O_{min_g} u_{p,t,g} + go_{p,t,g} + \sum_{i=2}^{D_g^{SD}} O_{g,i}^{SD} w_{p,t-i+2,g}\,, \quad \forall p, \forall t \in \left[T - D_{max_g}{}^{SU}, T\right], \forall g \tag{5.52}$$

$$o_{tot_{p,t,gc}} = p_{p,t,gc} + q_{p,t,gc} + ur_{p,t,gc} - dr_{p,t,gc}\,, \quad \forall p, \forall t, \forall gc \tag{5.53}$$

The total output variable for cogeneration units has been updated in equations (5.51)-(5.53) to include quantities of secondary upward and downward operating reserves provided.

$$\frac{go_{p,t,g} - go_{p,t-1,g} + ur_{p,t,gc} - dr_{p,t-1,gc}}{D_t RU_g} \le 1\,, \quad \forall p, \forall t - \{t_0\}, \forall g \tag{5.54}$$

$$\frac{go_{p,t,g} - go_{p,t-1,g} - dr_{p,t,gc} + ur_{p,t-1,gc}}{D_t RD_g} \ge -1\,, \quad \forall p, \forall t - \{t_0\}, \forall g \tag{5.55}$$

Constraints (5.54) and (5.55) are extensions of the original ramping equations and reflect the ramp-up and ramp-down capabilities of the units while considering their contribution to upward and downward balancing reserves.

$$ur_{p,t,gc} R_{min}^{UD} \le dr_{p,t,gc} \le ur_{p,t,gc} R_{max}^{UD}, \quad \forall p, \forall t, \forall gc \tag{5.56}$$

Maximum and minimum ratios between downward to upward reserves set the bounds for the downward operating reserve variable in (5.56).

$$\frac{go_{p,t,g} + ur_{p,t,gc}}{O_{max_g} - O_{min_g}} \le u_{p,t,g} - w_{p,t+1,g}\,, \quad \forall p, \forall t - \{T\}, \forall g \tag{5.57}$$

$$\frac{go_{p,t,g} - dr_{p,t,gc}}{O_{max_g} - O_{min_g}} \ge 0, \quad \forall p, \forall t, \forall g \tag{5.58}$$

To account for the limits on generation capacity above minimum output, equations (5.57)-(5.58) include the provision of upward and downward operating reserves, respectively.

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Finally, additional revenue related to the provision of operating reserves must be reflected on the objective function. The resulting expression is shown on equation (5.59).

$$revenue = \sum_{p}\sum_{t} EP_{p,t}\, D_t\, p_{sell_{p,t}} + \sum_{p}\sum_{t}\sum_{gc}\left(ORP_{gc}ur_{p,t,gc} + ORP_{gc}dr_{p,t,gc}\right) \tag{5.59}$$

If no operation reserves are to be considered for a given cogeneration unit ($Ind_{or_{gc}} = {}'No'$), both variables are fixed to zero. The bounds on these variables are the following:

$$0 \leq ur_{p,t,gc} \leq O_{max_{gc}} - O_{min_{gc}}, \qquad \forall p, \forall t, \forall gc \tag{5.60}$$

$$0 \leq dr_{p,t,gc} \leq O_{max_{gc}} - O_{min_{gc}}, \qquad \forall p, \forall t, \forall gc \tag{5.61}$$

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6 Sweden Results and Discussions

6.1 Modelling Outputs: Metrics of Interest

Key outputs of the optimization model calculations are:

- Committed units per hourly snapshot
- Dispatch volumes, per generator and hourly snapshot
- Charging/discharging volumes, per storage technology and hourly snapshot

These outputs allow for the calculation of a number of metrics, outlined in the following subsections. These metrics are then compared between a base case and the BTC CHP technology cases to quantify the impact of BTC technology integration in the portfolio of Swedish and Spanish industry partners.

Total cost of dispatch

The total cost of dispatch, over the full year of hourly snapshots, is calculated as the sum of fuel cost, cost due to start-up and shut-down, and emission cost of the production units.

Total revenue

For the Swedish use case the total revenue is calculated as the sum of the product of the electricity sold at each hourly snapshot and the market price.

Total profit

Total profit is calculated as total revenue minus total cost.

Proportion of renewable/fossil fuel generation

The proportion of annual generation from a certain generator, or from a technology category i such as fossil fuel or renewable energy, can be calculated as the ratio between the sum of the generator/technology in question and the sum of the total dispatch volumes over the full year.

Carbon Emission

The total carbon emissions from the generation dispatched can be calculated by use of emissions factors for each technology. This quantifies the total embodied carbon per MWh of generation. The total emission is the sum of the product of the fossil fuel generation dispatched multiplied by the emissions factors.

6.2 Results of District heating system for day-ahead market: business use case 1

This section presents the results of Swedish use case 1 simulating the Benchmark and Updated models stated in equations (4.43)-(4.44) and (4.55)-(4.56) respectively for the reference year 2021. The simulation results of these models are based on the day-ahead market prices in 2021 for SE3 bidding zone (as Linköping city is located in SE3) available in ENTSOe transparency platform [8], input data for BTC technology presented in section 2 and input data from TvAB's portfolio presented in section 3.

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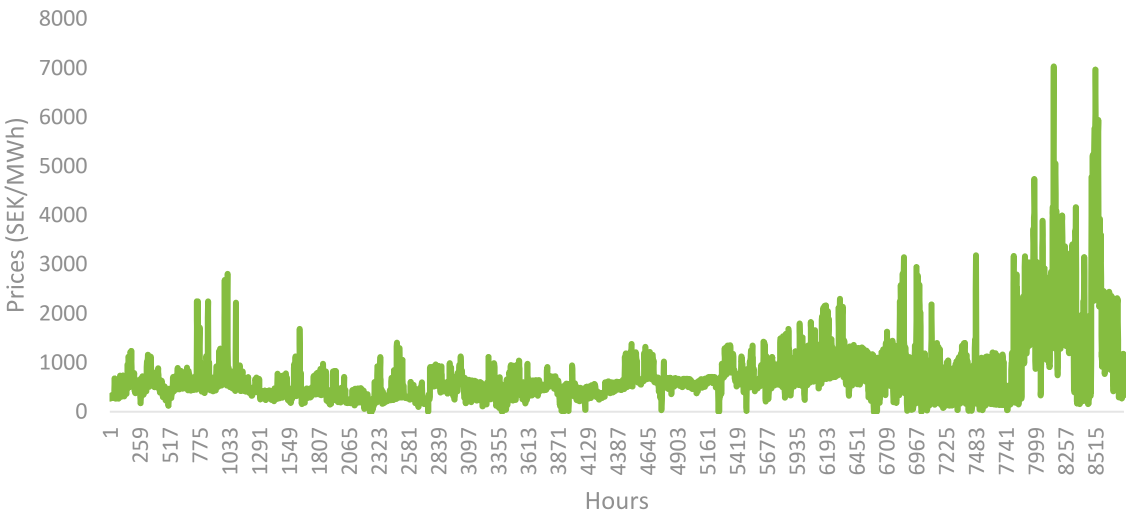
Results are analysed while simulating baseline case and while performing sensitivity analyses changing some of the sensitive input parameters.

The mathematical models are coded in Python/Pyomo. The simulation of these mathematical models was first attempted using a computer with 2.3 GHz and 16 GB of RAM. Different open-source solvers were tried, however none of them supported to simulate the MILP problems for the entire year with hourly resolution. An hourly resolution becomes important considering that the electricity prices can exhibit volatility on an hourly basis. Subsequently, GAMS Development Corporation [17] was contacted for a one-month trial license and attempted solving the model using CPLEX solver [18]. The MILP models were launched with the CPLEX solver and a duality gap of zero, on a computer with the same performance as described before, however, the result was an 'out of memory' message. We then tried to use RISE central computer which has higher memory capacity. When we launched the Benchmark MILP model for the entire year on a Friday, the model didn't reach to the optimal solution even on the following Monday. As a result, we could solve the Benchmark and Updated MILP models for the entire reference year of 2021 only when the duality gap was set to 10%. Also, we have been left with no other options than to analyse the results of both, benchmark and updated models, for the entire year with a duality gap of 10%, and for the chosen months with a duality gap of 2%. The first month is chosen from every season as representative month; thus, the simulations are carried out for March, June, September and December 2021 representing spring, summer, autumn and winter.

First, the simulations are done for a 'baseline' case. We refer baseline as the case which is modelling TvAB's current portfolio for the 'Benchmark model' and replacing one boiler of KV1 with two BTC units in the 'Updated model'. Here two BTC units are used to substitute for the replaced boiler of KV1 so that the resulting thermal capacity between benchmark and updated models with BTC technology are comparable. Furthermore, in addition to the baseline case, other cases are studied to perform sensitivity analyses. The results of the baseline case and other cases are presented in the following subsections.

Results for the baseline case

Figure 9 depicts day-ahead market prices with hourly resolution (upper figure) and TvAB heat demand with daily resolution (lower figure) for the reference year of 2021. We can see that electricity prices as well as the heat demand are higher in the winter months and relatively lower in the summer months.



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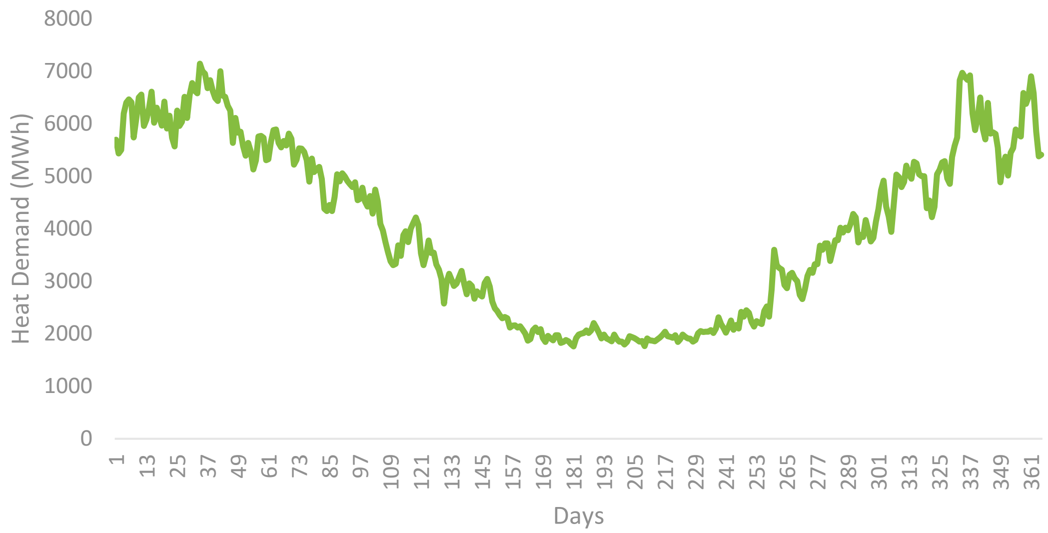
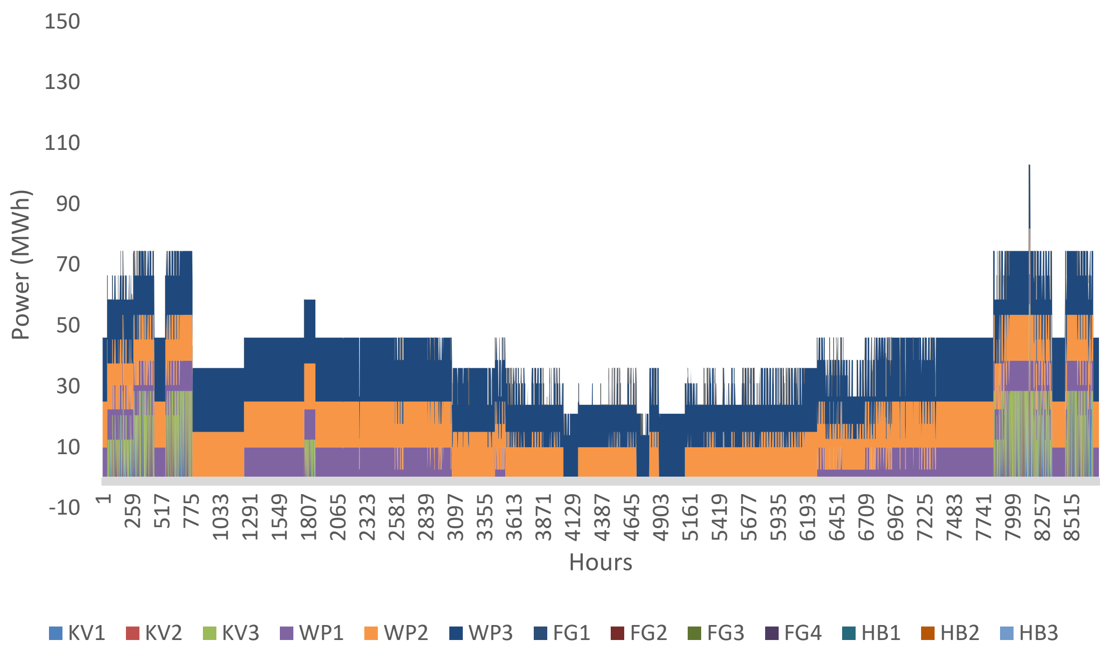


Figure 9: Upper: day-ahead hourly market prices for SE3 and reference year of 2021, lower: TvAB daily heat demand for 2021.

As it was mentioned above, the developed MILP Benchmark and Updated models for day-ahead market are solved with 10% and 2% duality gap for the entire reference year 2021 and for the chosen months respectively. The monthly simulations have been conducted to ensure the consistency in the obtained results. We first present the results for the entire year of 2021, then the results of the chosen months will be presented in Annex 1.

Reference year 2021:



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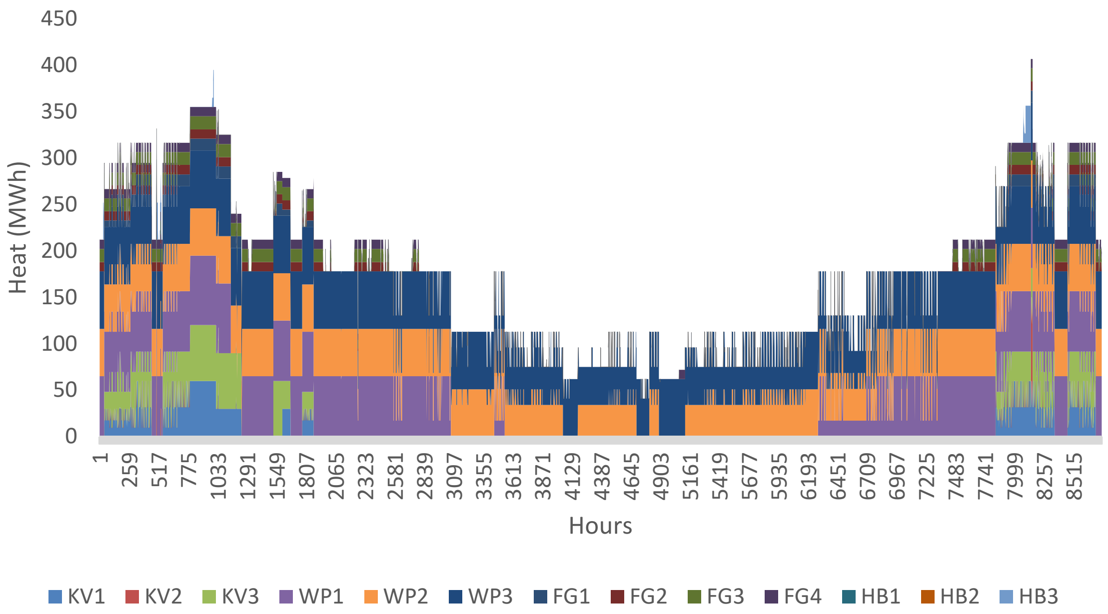
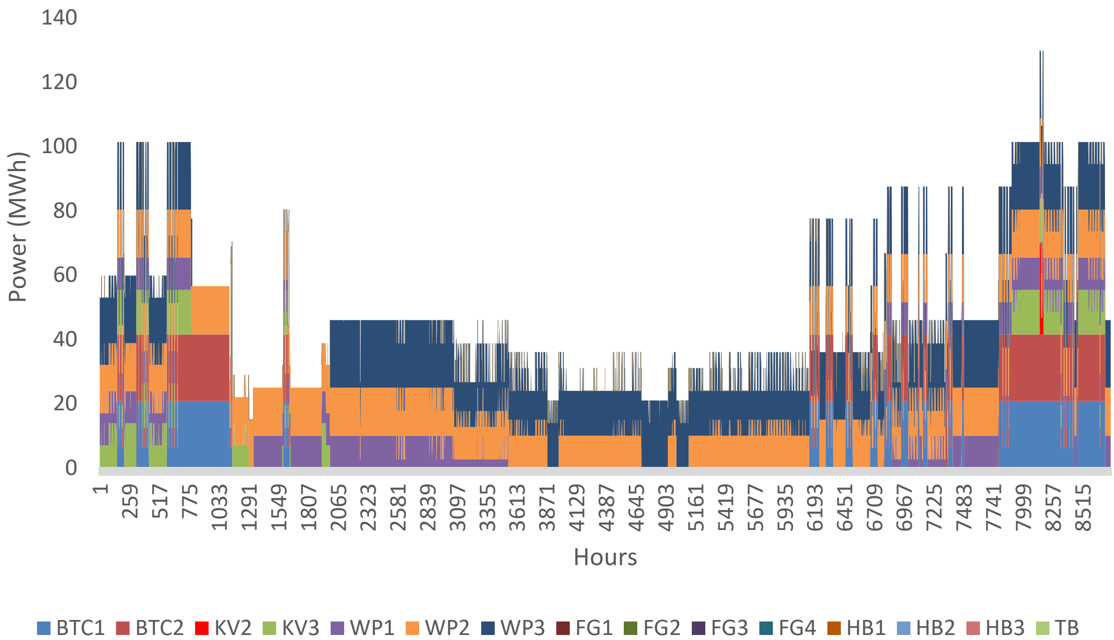


*Figure 10: Heat and power production dispatch using **Benchmark model** for the reference year 2021.*

Heat and power production dispatch from both Benchmark and Updated models is illustrated in Figure 10 and Figure 11 respectively. As heat demand is low in the summer months (see Figure 9), only waste plant is operated to cover the heat demand (see Figure 10 and Figure 11) accordingly, power production is mainly generated from the waste plant (see Figure 10 and Figure 11) to cover the self-consumption and trade in day-ahead market. Moreover, the electricity market prices as well as the heat demand during the summer months are low; thus, it is not beneficial for BTC units to commit; see Figure 11. Note that due to the lack of any cost-effective cooling capacity in the TvAB DHC system (apart the district heating grid) BTC units are restricted to be committed in the low heat demand periods even if the prices are favorable. BTC units are committed during the winter months when day-ahead electricity market prices and the heat demand are high; Figure 9.



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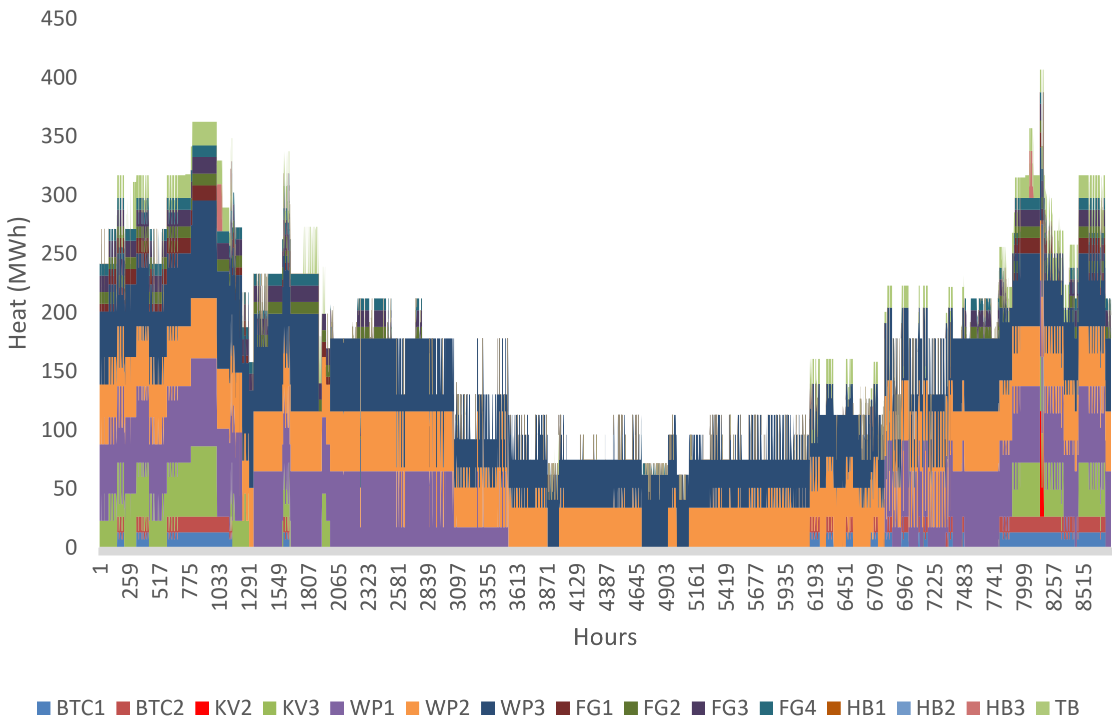
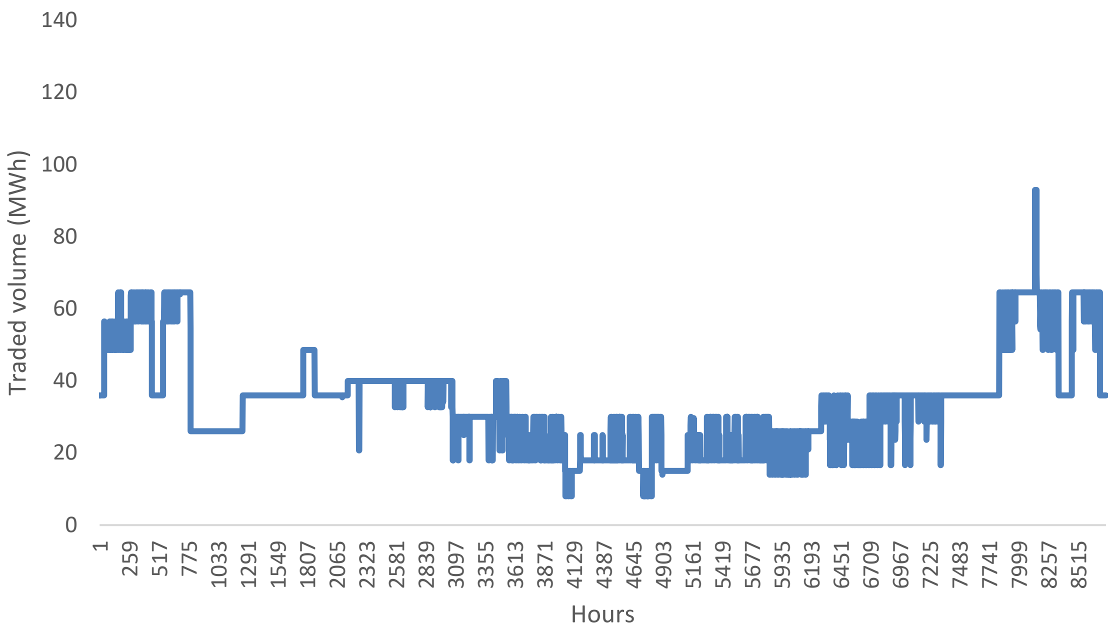


*Figure 11: Heat and power production dispatch using **Updated model** for the reference year 2021.*

Figure 12 illustrates the traded volumes in day-ahead market from both Benchmark and Updated models during the reference year of 2021. From Figure 12, it is obvious that, bigger volumes are traded in day-ahead market for those months when the market prices are high and BTC units are committed. However, the trading behavior is similar during the summer months when the market prices are low and consequently BTC units are not committed.



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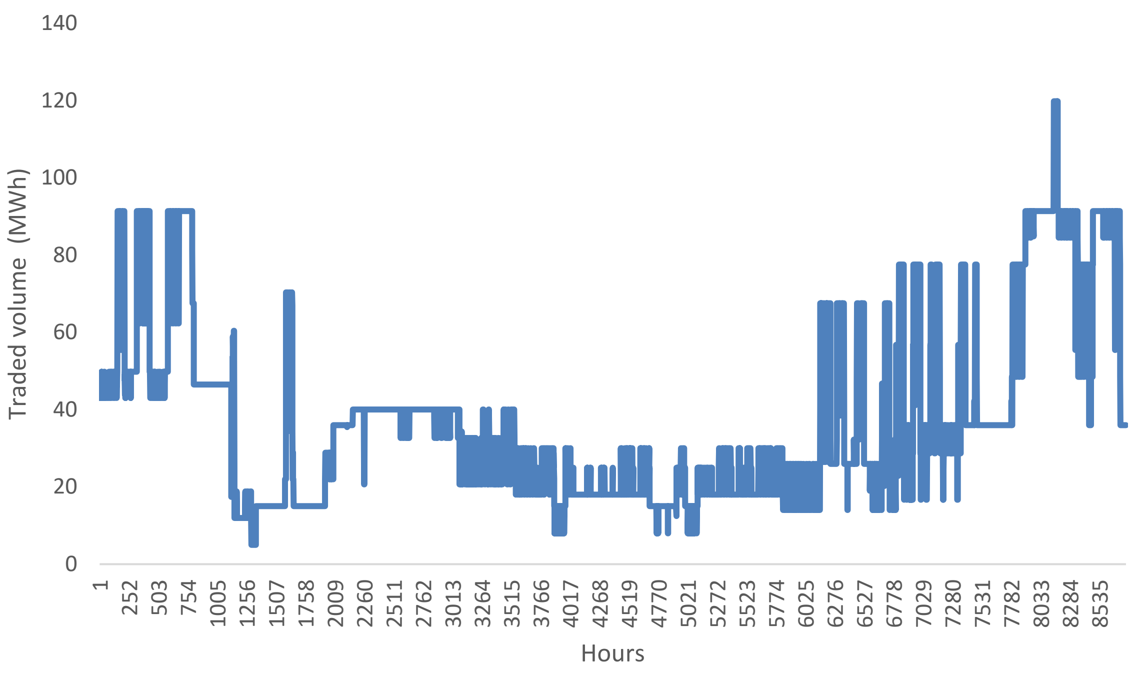

*Figure 12: Power quantity traded in day-ahead market, year 2021. Upper: results from **Benchmark model**, lower: results from **Updated model**.*

Table 20 summarizes dispatch volumes, cost and carbon results for both Benchmark and Updated models. The table shows that the electric power dispatch is 10.3% higher for the Updated model compared with that of Benchmark model. This results in 32.3% increase in dispatch cost, 30.3% increase in revenue and 29.12 % increase in profit respectively. Moreover, the Updated model results in 18.8% increase in proportion of renewable energy dispatch, 4.2% decrease in proportion of fossil fuel dispatch and thus, 2.22% decrease in carbon emission.

Table 20: Dispatch, revenue, cost, and carbon results for baseline case and for reference year 2021.

Metric	Benchmark model	Updated model	% difference
El. power dispatch (GWh)	372	410.3	10.3% increase
Heat power dispatch (GWh)	1547	1547	-
Proportion renewable dispatch (%)	18%	21.4%	18.8% increase
Proportion fossil fuel dispatch (%)	82%	78.6%	4.2% decrease
Total cost of dispatch (MSEK)	102.5	135.6	32.3% increase
Total revenue (MSEK)	258.6	337	30.3% increase
Total profit (MSEK)	156.1	201.6	29.12% increase
Carbon emissions ($MTCO_2$)	315	307.9	2.22% decrease

Both Benchmark and Updated models are simulated with 2% duality gap for the chosen months (December, September, June and March 2021). The simulation results are presented in Annex 1.

6.3 Results of District heating system for day-ahead and mFRR markets: business use case 2

This section presents the results of **Swedish business use case 2** simulating the **Benchmark** and **Updated** models stated in equations (4.67)-(4.68) and (4.69)-(4.70) respectively for the reference year

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2021. In the similar way, the simulation results of these models are based on the day-ahead and mFRR market prices in 2021 for SE3 bidding zone available in ENTSOe transparency platform [8], input data for BTC technology presented in section 2, and input data from TvAB presented in section 3.1.2.

For Swedish business use case 2 also the results are analysed while simulating baseline case: **Benchmark model** preparing optimal offers in day-ahead and mFRR markets and **Updated model** (one KV1 boiler is replaced with two BTC units) deriving optimal offers for both day-ahead and mFRR markets. It is important to notice that it is assumed that KV1 and BTC units are participating in mFRR market in both Benchmark and Updated models. The waste plant is covering the base heat load and is not participating in mFRR markets.

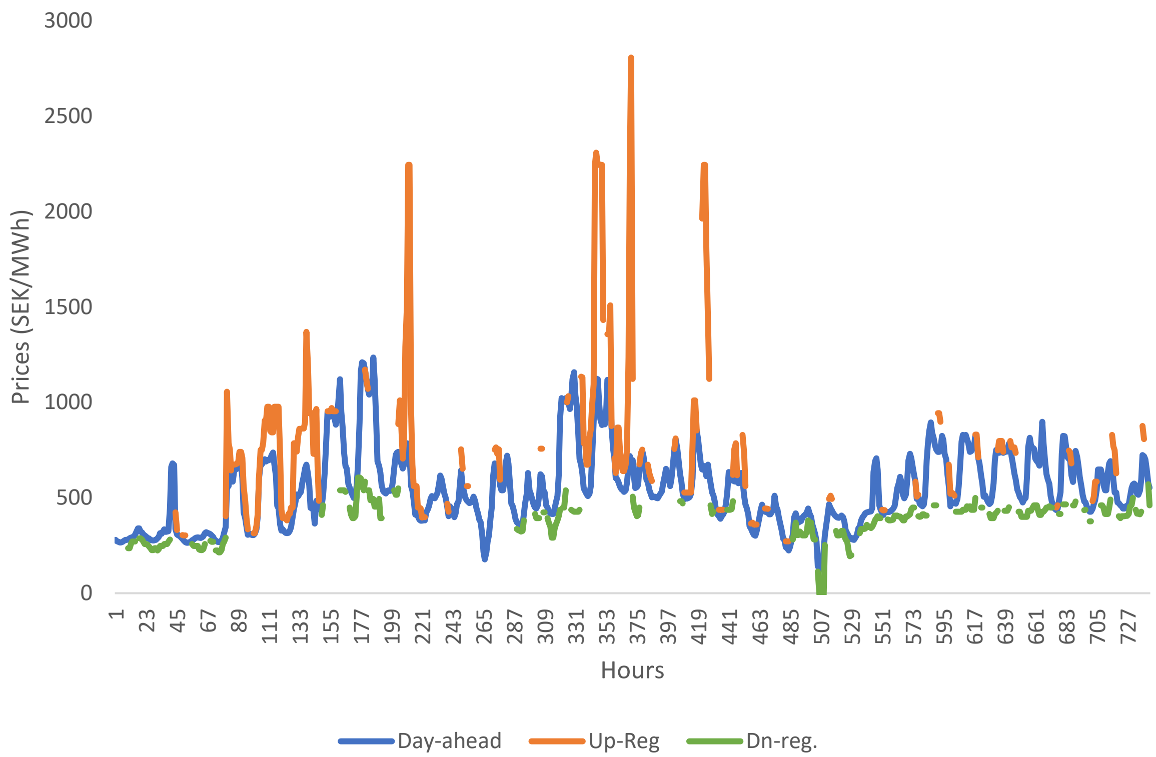

Figure 13: Day-ahead and mFRR market prices for January, 2021.

Figure 13 is plotted to see the price dynamics in day-ahead and mFRR markets for an example month January (to ensure clear visibility, only January is plotted instead of the entire year 2021). Figure 13 shows that during some hours in January up-regulations happened (meaning that the market had shortage in power), during some hours down-regulation happened (market had excess power) and some hours neither up- nor down-regulation happened. Up-regulation prices are always higher than day-ahead market prices: orange curve in Figure 13. Down-regulation prices are always lower than day-ahead market prices; the green curve in Figure 13. Once again, the developed MILP Benchmark and Updated models for day-ahead and mFRR markets are solved with 10% duality gap for the entire reference year 2021.

Reference year 2021:

In a similar way, the heat and power production dispatch from both Benchmark and Updated models is illustrated in Figure 14 and Figure 15 respectively. In this case also BTC units are committed in the winter months when the market prices are high but are not committed in the summer months when the market prices as well as the heat demand are low. Two units of waste plant are meeting the

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low heat demand in the summer months in both Benchmark and the Updated model; Figure 14 and Figure 15.

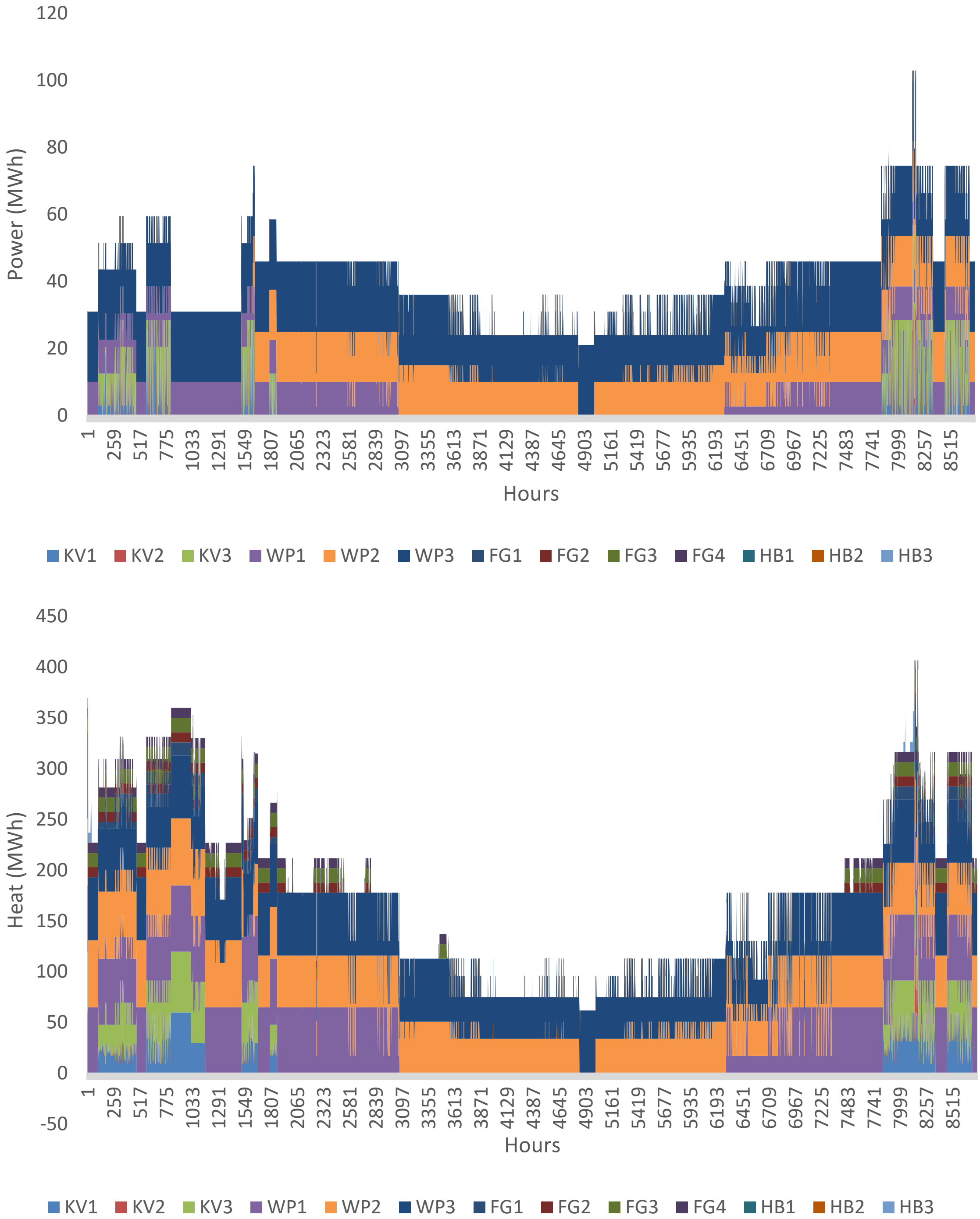

*Figure 14: Heat and power production dispatch using **Benchmark model** for day-ahead and mFRR markets, reference year 2021.*

Figure 16 depicts the traded volumes in day-ahead and mFRR markets from both Benchmark and Updated models. It can be seen that the Updated model, thanks to the BTC units, has more power quantity to trade in day-ahead market and offer flexibility in mFRR markets. Both Benchmark and Updated model cases trading in mFRR markets are taking place in the winter months, where both heat demand and market prices are high enough to commit KV1 and BTC CHP units. It should be noted, however, there are no tradings in mFRR market during the summer months, see Figure 16. This is

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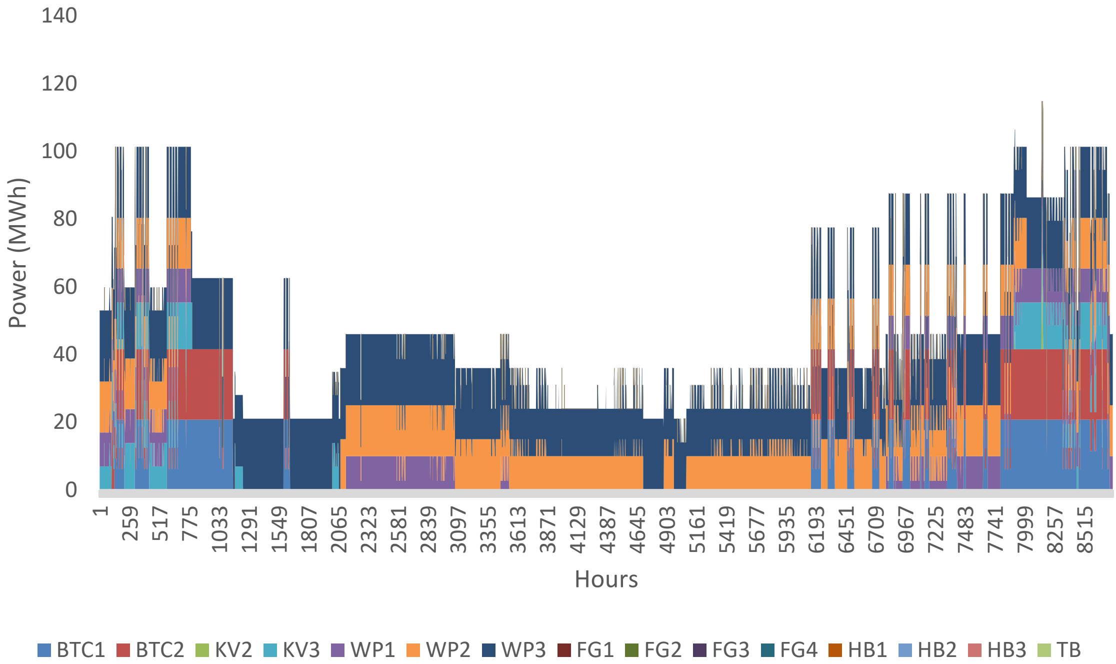
because the waste plant is the main committed CHP to cover the heat demand during the summer months (see Figure 14 and Figure 15), and we assumed the waste plant is not participating in mFRR market. Thus, we can improve the Benchmark and Updated models participating in both day-ahead and mFRR markets assuming the waste plant is also providing balancing power. It is important to note that, the comparison analyses of the Benchmark and Updated models are not affected by this assumption.



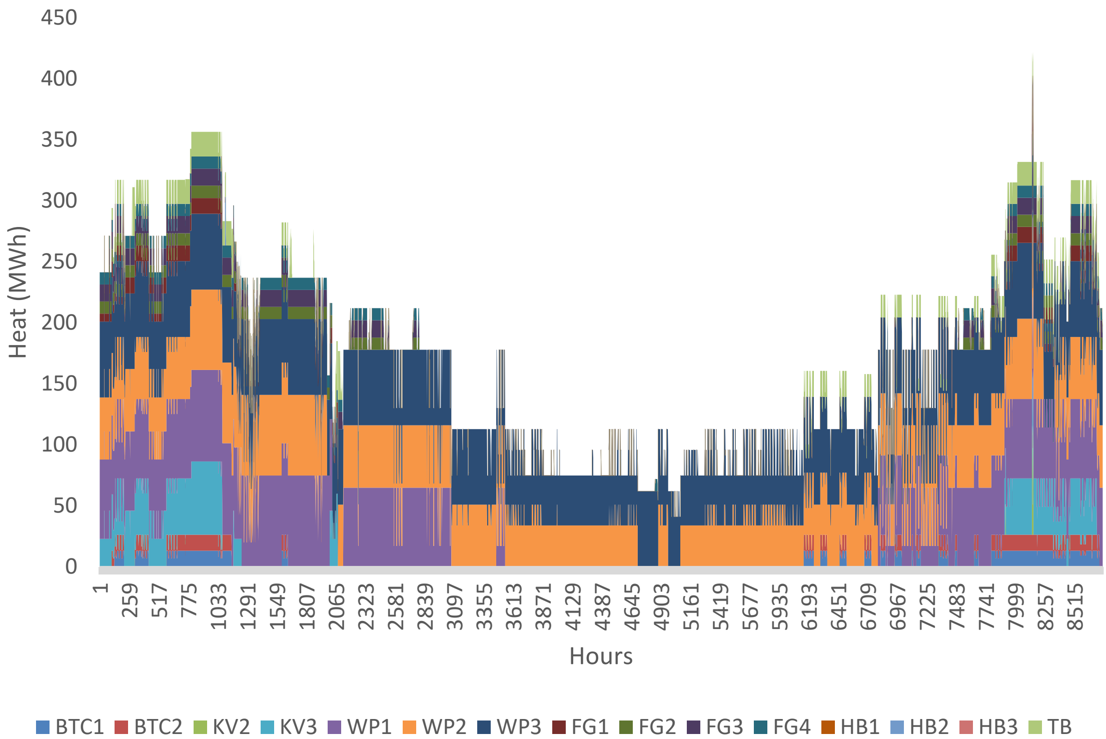


*Figure 15: Heat and power production dispatch using **Updated model** for day-ahead and mFRR markets**,** reference year 2021.*

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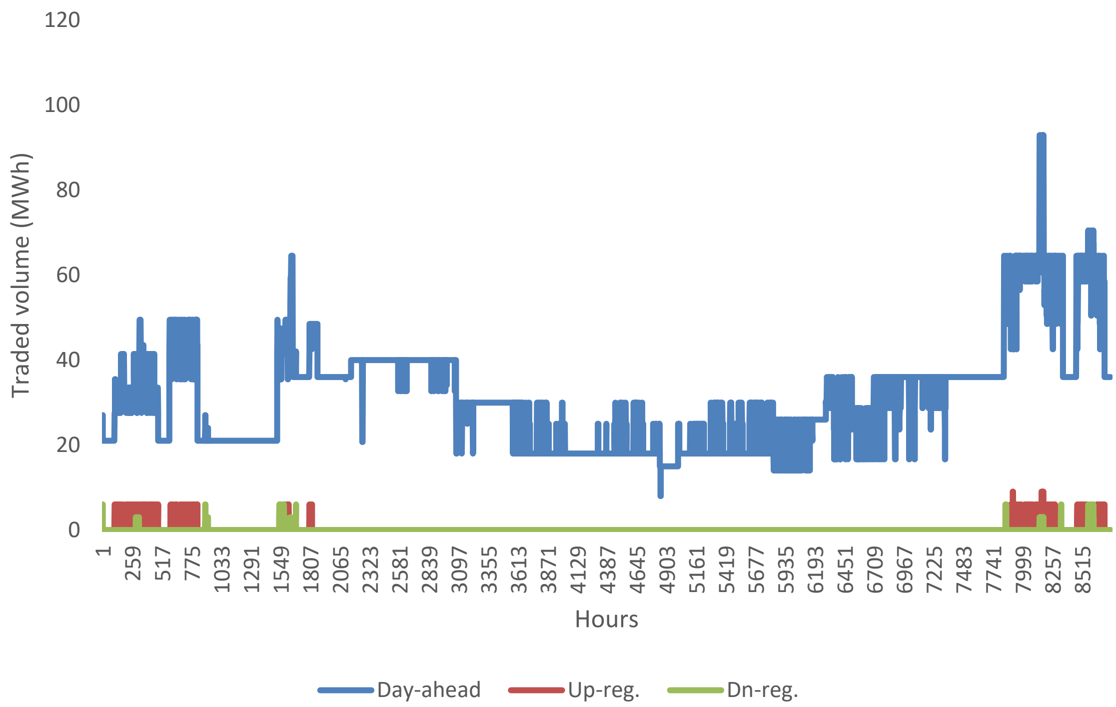

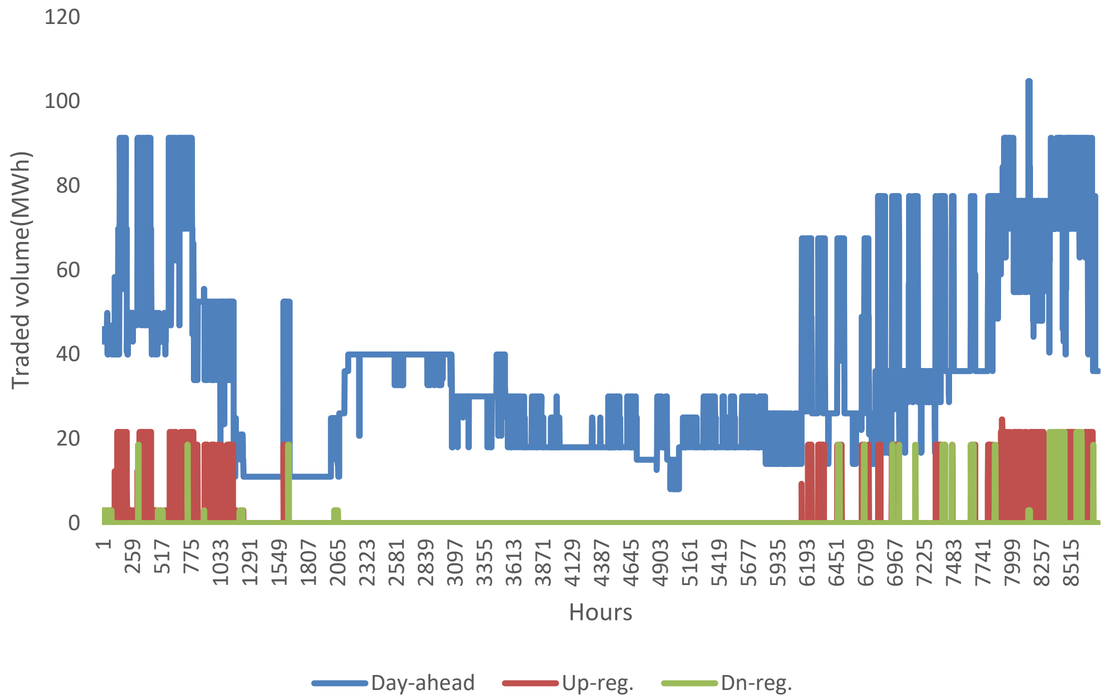

*Figure 16: Power quantity traded in day-ahead and mFRR markets, year 2021. Upper: results from **Benchmark model**, lower: results from **Updated model**.*

Table 21 shows the dispatch, cost, revenue and carbon results comparing the Benchmark case with the Updated model case (the BTC integration case). It can be seen over the eight metrics explored that the Updated model with BTC integration and addressing two coordinated markets shows increased performance when compared with the Benchmark model participating in two, day-ahead and mFRR markets. Here also, the electric power dispatch is 15.6% higher for the Updated model compared with that of Benchmark model, which results in 40.5% increase in dispatch cost, 35.77% increase in revenue

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and 33 % increase in profit respectively. Moreover, the Updated model results 27% increase in proportion of renewable energy dispatch, 5.5% decrease in proportion of fossil fuel dispatch and thus, 2.5% decrease in carbon emission.

Table 21: Dispatch, revenue, cost, and carbon results for baseline case (day-ahead and mFRR markets) and for reference year 2021.

Metric	Benchmark model	Updated model	% difference
El. power dispatch (GWh)	352.33	407.3	15,6% increase
Heat power dispatch (GWh)	1547	1547	-
Proportion renewable dispatch (%)	17%	21.6%	27% increase
Proportion fossil fuel dispatch (%)	83%	78.4%	5.5% decrease
Total cost of dispatch (MSEK)	92.98	130.6	40.5% increase
Total revenue (MSEK)	251.84	341.93	35.77% increase
Total profit (MSEK)	**158.85**	**211.3**	33% increase
Carbon emissions ($MTCO_2$)	314.5	306.5	2.5% decrease

Comparison summary of Swedish Business Use cases

Table 22 summarizes the results from all four models: Benchmark model for day-ahead market, Benchmark model for both day-ahead and mFRR markets, Updated model for day-ahead market and Updated model for both day-ahead and mFRR markets. Comparing the Benchmark models (the Benchmark model for day-ahead market and Benchmark model for day-ahead and mFRR markets) with the Updated models (the Updated model for day-ahead market and Updated model for day-ahead and mFRR markets), we see that both cases the Updated model generates higher profit, higher proportion of renewable dispatch and thus lower carbon emissions. Comparing day-ahead market Benchmark and Updated models with day-ahead and mFRR markets Benchmark and Updated models can be noted that both Benchmark and Updated models increase their performance having the possibility to trade in both day-ahead and mFRR markets. Finally, the highest profit and the lowest carbon emissions are generated by the Updated model, where BTC is integrated in TvAB's portfolio, and it is assumed that TvAB is participating in both day-ahead and mFRR markets.

Table 22: Dispatch, revenue, cost, and carbon results for all four models.

Metric	Benchmark model DA market	Benchmark model for DA & mFRR markets	Updated model for DA market	Updated model for DA and mFRR markets
El. power dispatch (GWh)	372	352.33	410.3	407.3
Heat power dispatch (GWh)	1547	1547	1547	1547
Proportion renewable dispatch (%)	18%	17%	21.4%	21.6%
Proportion fossil fuel dispatch (%)	82%	83%	78.6%	78.4
Total cost of dispatch (MSEK)	102.5	92.98	135.56	130.6
Total revenue (MSEK)	258.6	251.84	337	341.93
Total profit (MSEK)	**156.1**	**158.85**	**201.56**	**211.3**
Carbon emissions ($MTCO_2$)	315	314.5	307.88	306.5

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6.4 Sensitivity analysis

A sensitivity analysis has been undertaken to examine the impact of sensitive input parameters on the dispatch results, thus on the economic and environmental metrics. The sensitivity analyses are carried out using developed Updated MILP model for day-ahead market. The Updated MILP model run has been completed for each of the following scenarios by changing sensitive input parameters as follows:

- Scenario 1: It is assumed that one unit of KV1 CHP plant in TvAB portfolio is replaced with only one BTC unit.
- Scenario 2: It is assumed that biomass (biomass used by TvAB- forest residues) price is 300 SEK.
- Scenario 3: It is assumed that biomass (biomass used by TvAB- forest residues) price is 400 SEK.

The results are set out in Table 23.

Table 23: Dispatch, revenue, cost, and carbon results for all studied scenarios.

Metric	Benchmark model	Updated model	Scenario1	Scenario 2	Scenario 3
El. power dispatch (GWh)	372	410.3	373.8	435	393.3
Heat power dispatch (GWh)	1547	1547	1547	1547	1547
Proportion renewable dispatch (%)	18%	21.4%	18.8%	22.4%	20.43%
Proportion fossil fuel dispatch (%)	82%	78.6%	81.2%	77.6%	79.57%
Total cost of dispatch (MSEK)	102.5	135.56	108.7	133	124.1
Total revenue (MSEK)	258.6	337	274.4	352	319.78
Total profit (MSEK)	156.1	201.56	165.65	**219**	195.7
Carbon emissions ($MTCO_2$)	315	307.88	312	307.7	308.8

Table 23 demonstrates that the carbon emissions curve is quite flat as in all cases the Waste plant is covering the base heat load, and it is the only plant in the dispatch mix emitting CO_2. According to Table 23, scenario 2 is outperforming as the highest profit 219 MSEK is reached when biomass price is assumed to be 300 SEK/MWh.

6.5 Investment analysis to calculate financial indicators: Swedish use cases

Initial investment is equal to CAPEX for BTC technology, estimated in Section 2. Yearly return (annual profit) is calculated while simulating optimization models for Spanish and Swedish use cases for an entire year having BTC CHP technology in their production portfolios.

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One way to carry out financial analysis is to calculate **equivalent annual cost** and compare it with the annual profit while integrating BTC technology.

Equivalent Annual Cost $=\frac{CAPEX}{A(t,r)}$ where t is the number of periods and r is the annual interest rate and $A(t,r)$ is calculated as follows.

$$A(t,r) = \frac{1 - \frac{1}{(1+r)^t}}{r}$$

The following subsection performs investment financial analysis using the Equivalent Annual Cost investment analysis tool and simulation results of the previous subsections. Investment analysis results for Swedish use cases are carried out below.

Investment analyses results for Swedish use cases

According to Table 6 and Table 7 the CAPEX for TvAB Swedish business use case is estimated 90 M€ which is equal to 1014MSEK. It is assumed 25 years of depreciation of the plant and 8% interest rate (see Table 7). Investment analyses are carried out for two different values of interest rate: 6% and 8%. Table 24 summarizes economic values for different interest rates.

Table 24: Equivalent annual cost and A(t,r) values for different interest rates.

	6% interest rate	8% interest rate
$A(t,r)$	12.78	10.67
Equivalent annual cost=CAPEX/ $A(t,r)$	79.3MSEK	94.98MSEK

Table 25 and Table 26 calculate Equivalent annual cost and annual BTC profit for different scenarios. Let's recall that **Scenario 1** assumes one unit of KV1 CHP plant in TvAB portfolio is replaced with only one BTC unit. **Scenarios 2 and 3** assume biomass price 300 SEK and 400 SEK respectively.

Table 25 shows that the lowest annual cost-annual profit ratio is obtained in the case of **scenario** 2 (with lowest biomass prices) and in the case of updated model participating in both day-ahead and mFRR markets. In **scenario 2 and in updated model** participating in both markets the equivalent annual cost is higher than annual BTC profit 2.49 and 2.45 times respectively. These values are 2.98 and 2.94 respectively when the interest rate is assumed 8%; see Table 26.

Table 25: investment analyses for 6% interest rate (Eq.-equivalent).

	Day-ahead market				Day-ahead and mFRR markets
	Updated model	Scenario1	**Scenario2**	Scenario3	**Updated model**
Eq. annual cost (MSEK)	158.6	79.32	**158.64**	158.64	**158.64**
Annual BTC profit (MSEK)	54.25	23	**63.82**	46.75	**64.68**
Cost/Profit	2.92	3.45	**2.49**	3.39	**2.45**

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Table 26: investment analyses for 8% interest rate.

	Day-ahead market				Day-ahead and mFRR markets
	Updated model	Scenario1	**Scenario2**	Scenario3	**Updated model**
Eq. annual cost (MSEK)	189.98	94.99	**189.98**	189.98	**189.98**
Annual BTC profit (MSEK)	54.25	23	**63.82**	46.75	**64.68**
Cost/Profit	3.5	4.13	**2.98**	4.06	**2.94**

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7 Spain Results and Discussions

7.1 Metrics of interest

The following metrics are considered:

- **Electric power dispatch [GWh]:** total sum of technology-dispatched electric power volumes.
- **Electric power bought [GWh]:** total sum of electric power volumes purchased from grid.
- **Electric power sold [GWh]:** total sum of electric power volumes sold to the market.
- **Secondary reserves [GW]** ***(if applies to the use case)*****:** total sum of upwards and downwards operating reserves provided.
- **Heat power dispatch [GWh]** ***(if applies to the use case):*** total sum of technology-dispatched thermal power volumes.
- **Proportion fossil dispatch [%]** ***(if applies to the use case):*** ratio between the total sum of fossil-fueled generators' dispatch volumes and the total sum of the total dispatch volumes. The remaining portion corresponds to renewable dispatch.
- **Fossil carbon dioxide emissions [MtonCO$_2$/year]** ***(if applies to the use case):*** total sumproduct of each generator's total dispatch volume, the corresponding emission rate, and carbon emission cost.
- **Total dispatch cost [M€/year]:** total sum of fuel cost, start-up and shut-down costs for BTC and boiler units, CO2 emission costs, excess heat cooling costs, and grid power purchases.
- **Equivalent annual investment cost [M€/year]:** calculated as described in Section 6.5, while considering an annual interest rate of 8% and 25 years of depreciation.
- **Total dispatch revenue [M€/year]:** total sum of revenues generated by selling electricity to the market and by providing upwards and downwards secondary operating reserves.
- **Total profit [M€/year]:** calculated as total dispatch revenue minus total dispatch cost minus equivalent annual investment cost.

7.2 Results

This section presents the results of all Spanish use cases for the benchmark and updated model scenarios, respectively, for the reference year 2021. While the benchmark case considers the current technology and fuel used in each plant, the updated model scenario considers the replacement of that technology with a BTC unit in assistance of boiler or heat pump units, depending on the use case.

The updated model was coded in Python using Gurobi as optimization solver [19]. Simulations were run having the entire calendar year as scheduling horizon.

Use case Sulquisa

Figure 16 shows the operating profile results of the updated model. The electricity profiles are presented on top, while the heat profiles are shown on the bottom figure. Additionally, the 2021 day-ahead market prices are included at the top, and the units' online states are included at the bottom.

When comparing the electric power dispatch results of Table 27, the BTC delivered, overall, 31.2% less electricity than the 3 CHP units Sulquisa has currently installed. Note, however, that the total

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electric power dispatch accounts for electricity production covering the internal demand plus the excess production, which is sold to the market. During hours when the generating units are unable to cover the demand, it must be purchased from the grid. Electricity purchase also happens during hours of low market costs, when the BTC decreases production. This can be clearly seen in Figure 17 (red box). Note also that the BTC remains online during the entire year.

Also note that in the updated model the BTC is delivering part of its electric output to the heat pump. As a result, more electricity must be bought from the grid to cover the demand, and the excess production is 70.6% less than in the benchmark case. Consequently, the total revenue is also lower in the updated scenario. However, the optimization model chose to sell the excess electric power production during hours of high electricity prices, thus the difference in total revenue is -63%.

Heat power dispatch, on the other hand, is equal in both scenarios, meaning that the units are able to comply with the steam demand. This does not mean that heat production equals the demand at each time step: excess heat production may occur, both from the boiler and heat pump, but the corresponding cooling cost is taken into account in the model's objective function.

As a result of replacing the main fuel from natural gas to biomass, the proportion of fossil dispatch drops to 10.4% in the updated scenario, a percentage for which the natural gas-fueled steam boiler production assisting the heat pump is the cause of. Additionally, fuel change implies in this case a reduction in fuel costs: under the assumptions made, biomass is 52% less expensive than natural gas in 2021 scenario.

The optimized scheduling decisions, added to the reduction in CO2 emission costs and fuel costs make the updated case almost 60% less costly than the benchmark scenario. Even when considering the equivalent annual investment cost, accounting for investments in BTC, heat pump, boiler, and cooling tower, the final total profit ends up being 25.2% higher than in the benchmark case, which represents a difference of more than 4 M€/year.

Table 27: Results Sulquisa use case.

Metric	Benchmark	Updated	Difference
El. power dispatch [GWh]	82.26	56.61	-31.2%
El. power bought [GWh]	1.10	9.11	730.2%
El. power sold [GWh]	24.97	7.34	-70.6%
Heat power dispatch [GWh]	126.82	126.82	-
Proportion renewable dispatch [%]	0%	89.6%	-
Proportion fossil dispatch [%]	100%	10.4%	-89.6%
CO2 emissions [MtonCO2]	0.042	0.008	-81.6%
Total dispatch cost [M€]	-18.96	-7.60	59.9%
Eq. annual investment cost [M€]	0.00	-5.47	-
Total dispatch revenue [M€]	2.94	1.09	-63.0%
Total profit [M€]	**-16.02**	**-11.98**	**25.2%**

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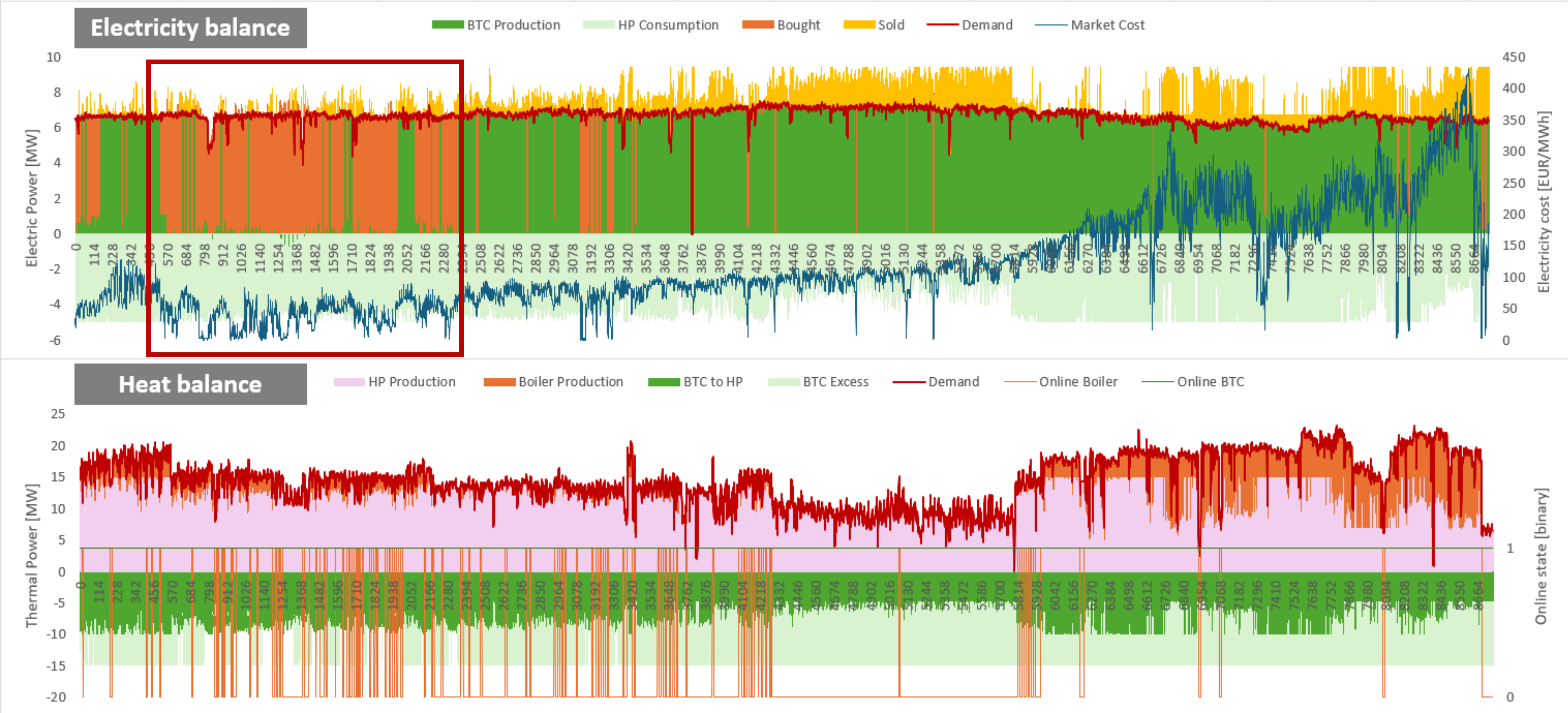

Figure 17: Operation profile results, Sulquisa use case. Year 2021.

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Use case CEMEX PowerGen – Alcanar and Alicante plants

Table 28 benchmark scenario cost results correspond to the cost of purchasing electric power from the grid to cover the demand in both plants. This is the reason why a comparison in CO2 emission does not apply in this use case. Note that CEMEX did not provide secondary operating reserves during 2021, meaning that no revenues are considered in the benchmark case. Also, no heat demand is studied.

In the case of Alcanar plant, simulation results of the updated model show that a BTC delivers 141.67 GWh of electricity, choosing to sell 20.56 GWh of this production during hours of high electricity prices, and covering the rest of the demand by purchasing from the market during hours of lower costs. The overall reduction in electricity purchase is 79.2%. Even accounting for BTC's operating costs, the total dispatch cost ends up being 39.3% lower than in the benchmark scenario. Dispatch revenues coming from selling excess electricity and providing operating reserves sum up to 6.91 M€. Finally, when considering the annualized BTC investment cost, the total profit results being 32.6% higher (6 M€/year) than the benchmark case.

The following observations apply to Alicante plant: taking into account that, while BTC capacity is assumed equal in both locations, Alicante's demand is almost 30% lower, meaning that BTC is able to increase excess electric power volumes sold at the market, thus increase revenues. The final profit results being 45.3% higher (5.85 M€/year) than the benchmark case.

Table 28: Results CEMEX PowerGen use cases.

Alcanar			
Metric	**Benchmark**	**Updated**	**Difference**
El. power dispatch [GWh]	0.00	142.52	-
El. power bought [GWh]	154.00	32.04	-79.2%
El. power sold [GWh]	0.00	20.56	-
Secondary reserves [GW]	0.00	132.52	-
Total dispatch cost [M€]	-18.44	-11.19	39.3%
Eq. annual investment cost [M€]	0.00	-8.14	-
Total dispatch revenue [M€]	0.00	6.91	-
Total profit [M€]	**-18.44**	**-12.42**	**32.6%**

Alicante			
Metric	**Benchmark**	**Updated**	**Difference**
El. power dispatch [GWh]	0.00	141.67	-
El. power bought [GWh]	109.12	11.68	-89.3%
El. power sold [GWh]	0.00	44.23	-
Secondary reserves [GW]	0.00	135.48	-
Total dispatch cost [M€]	-12.92	-9.04	30.0%
Eq. annual investment cost [M€]	0.00	-8.14	-
Total dispatch revenue [M€]	0.00	10.11	-
Total profit [M€]	**-12.92**	**-7.07**	**45.3%**

Use case CEMEX CHP – Alcanar plant

A heat demand is added in this use case for drying purposes in Alcanar plants. Furthermore, no provision of operating reserves applies. Figure shows the updated model operating profile results. Again, electricity profiles are presented on top, while the heat profiles are shown at the bottom. 2021 day-ahead market prices are included in the top figure.

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In the benchmark scenario, heat is provided by the fuel oil-fed kiln flue gases, which cause the fossil carbon dioxide emissions informed in Table . As the electricity demand is covered by the power purchased from the grid, the total proportion of fossil dispatch is not informed.

In comparison with the PowerGen use case, BTC overall electricity production increases, in part because it is not providing secondary reserves. Consequently, the model chooses to increase the volume of electric power sold at the market by almost 44%. The impact of not providing these services can also be noted in the total revenue, which is now 46 % (3.18 M€) lower than in the PowerGen use case. The proportion of fossil dispatch is only 0.95%, and it is caused by burning fuel oil in the assisting boiler assumed in the updated model.

The light green area at the bottom of Figure shows the volumes of excess heat which must be cooled in the cooling towers. Note also how, during low electricity market costs, the BTC shuts down (is offline) in order to minimize dispatch costs. As it happened in Sulquisa's use case, the model chooses to purchase electricity from the grid to cover the demand during these hours.

The equivalent annual cost corresponding to the alternative fuels drying line is taken into account in both scenarios. In the updated case, it also accounts for petcoke drying line, BTC, boiler, and cooling tower CAPEX. Finally, the total profit ends up being 25.9% (5.2 M€/year) higher in the updated case.

Table 29: Results CEMEX CHP use case.

Metric	Benchmark	Updated	Difference
El. power dispatch [GWh]	0.00	153.48	-
El. power bought [GWh]	154.00	30.08	-80.5%
El. power sold [GWh]	0.00	29.56	-
Heat power dispatch [GWh]	28.85	28.85	-
Proportion renewable dispatch [%]	n/a	99.05%	-
Proportion fossil dispatch [%]	n/a	0.95%	-
CO2 emissions [MtonCO2]	0.008	0.006	-21.2%
Total dispatch cost [M€]	-19.97	-10.31	48.4%
Eq. annual investment cost [M€]	-0.11	-8.30	-
Total dispatch revenue [M€]	0.00	3.73	-
Total profit [M€]	**-20.08**	**-14.88**	**25.9%**

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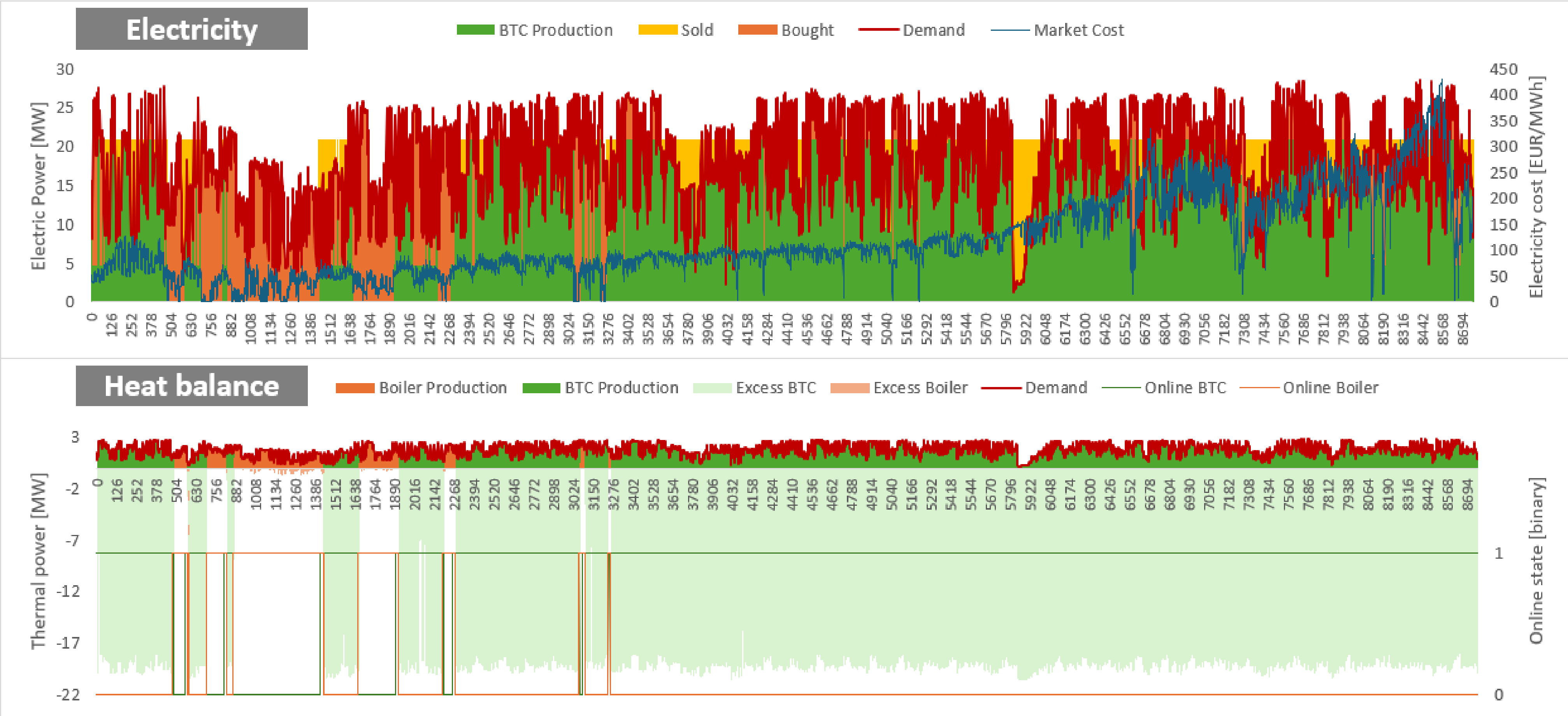

Figure 18: Operating profile results, CEMEX CHP use case. Year 2021.

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Use case CEMEX Hydrogen – Alcanar and Alicante plants

Table 30 shows the results of CEMEX's hydrogen use cases, which investigate the use of renewable, electrolyzer-based hydrogen in both plants for two purposes:

1. **BTC start-up sequences:** while benchmark scenario results remain the same as in the PowerGen use case, simulations of the updated model were done considering the previously calculated levelized costs of hydrogen (LCOH) for each plant, as stated in Section 3.2.3. **The resulting LCOH were: 3.43 €/kgH_2 for Alcanar plant** (91.7 MW PV plant, 10.5 MW battery, and 18.6 MW electrolyzer + storage)**, and 2.90 €/kgH_2 for Alicante (**88.7 MW PV plant, 11.3 MW battery, and 16.4 MW electrolyzer + storage)**.** Using these results, BTC start-up costs for each type were calculated, and the duration of each start-up type was reduced as informed in Section 3.2.3. Results for the updated case show, however, that the difference with those of the PowerGen use case can be considered negligible when taking the entire year as scheduling horizon: the impact of speeding up BTC start-up sequences (at higher costs) is hardly appreciable under the assumptions made in this study.

2. **Partial replacement of fuel oil usage in the kiln:** under the assumption that the same heat is being delivered in the benchmark case by burning fuel oil, and in the updated case by burning renewable hydrogen, the corresponding cost is higher in the updated case for both plants (+96.7% for Alcanar and +63.7% for Alicante), even when the burning of hydrogen does not incur in emissions costs. An expected result taking into account the production cost of renewable hydrogen, which considers investment in electrolyzer, hydrogen storage, battery, and solar PV plant.

Table 30: Results CEMEX Hydrogen use cases.

Alcanar			
Metric	**Benchmark**	**Updated**	**Difference**
El. power dispatch [GWh]	0.00	142.51	-
El. power bought [GWh]	154.00	32.05	-79.2%
El. power sold [GWh]	0.00	20.56	-
Secondary reserves [GW]	0.00	132.52	-
Total dispatch cost [M€]	-18.44	-11.20	39.3%
Eq. annual investment cost [M€]	0.00	-8.14	-
Total dispatch revenue [M€]	0.00	6.91	-
Total profit [M€]	**-18.44**	**-12.43**	**32.6%**

Alcanar - Kiln fuel partial replacement			
Metric	**Benchmark**	**Updated**	**Difference**
Heat power dispatch [GWh]	34.67	34.67	-
Proportion renewable dispatch [%]	0%	100%	-
Proportion fossil dispatch [%]	100%	0%	-
CO2 emissions [MtonCO2]	0.009	0.000	-100.0%
Total dispatch cost [M€]	**-1.84**	**-3.57**	**-93.7%**

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Alicante			
Metric	**Benchmark**	**Updated**	**Difference**
El. power dispatch [GWh]	0.00	141.66	-
El. power bought [GWh]	109.12	11.70	-89.3%
El. power sold [GWh]	0.00	44.22	-
Secondary reserves [GW]	0.00	135.48	-
Total dispatch cost [M€]	-12.92	-9.04	30.0%
Eq. annual investment cost [M€]	0.00	-8.14	
Total dispatch revenue [M€]	0.00	10.11	-
Total profit [M€]	**-12.92**	**-7.07**	**45.3%**

Alicante - Kiln fuel partial replacement			
Metric	**Benchmark**	**Updated**	**Difference**
Heat power dispatch [GWh]	27.00	27.00	-
Proportion renewable dispatch [%]	0%	100%	-
Proportion fossil dispatch [%]	100%	0%	-
Carbon emissions [MtonCO2]	0.007	0.000	-100.0%
Total dispatch cost [M€]	**-1.43**	**-2.35**	**-63.7%**

7.3 Sensitivity analysis

Figure 19 shows the comparison of Spanish day-ahead electricity prices between 2021 (baseline scenario) and 2023. On one hand, Spanish electricity prices increased drastically during the second half of 2021, mainly due to the increase in natural gas prices. On the other hand, 2023 prices were more uniform along the year.

In order to analyze the impacts of a more uniform electricity price profile as input data, it was decided to use the 2023 day-ahead prices and build a sensitivity analysis. Moreover, the 2023 secondary reserves availability prices (Figure 20) were used, as well as the natural gas 2023 average price (39,23 €/MWh, 18% lower than in 2021). The same percentage of reduction in natural gas prices was considered for the fuel oil prices (confidential values).

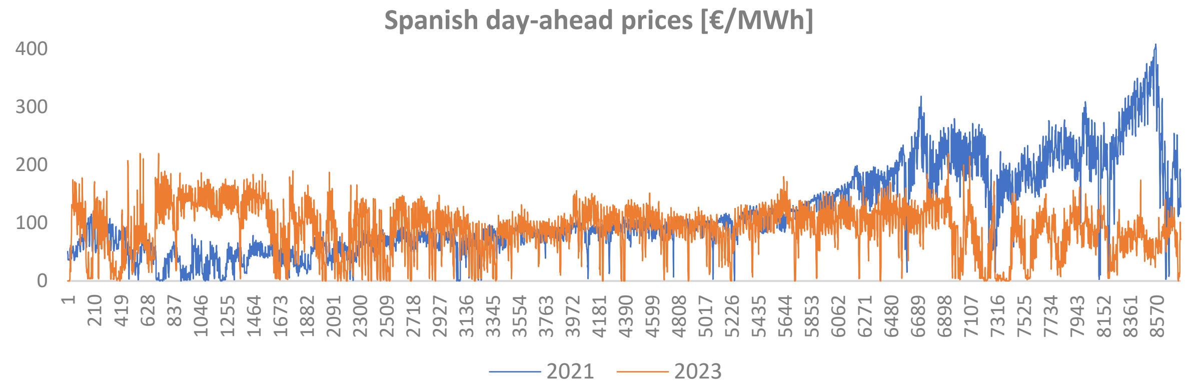

Figure 19: Spanish day-ahead electricity prices for 2021 and 2023.

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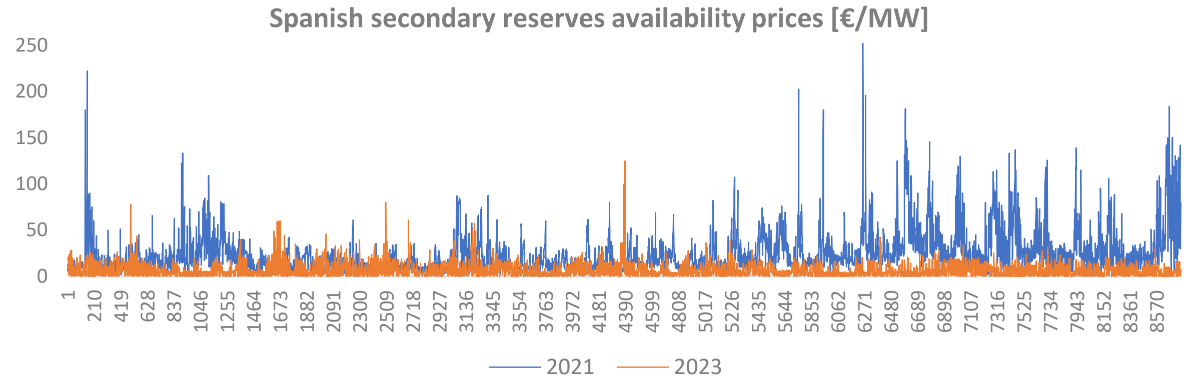

Figure 20: Spanish secondary reserves availability prices for 2021 and 2023.

Hydrogen costs of production were re-calculated, resulting in **5.47 €/kgH$_2$ for Alcanar** (80 MW PV plant, 12 MW battery, and 19 MW electrolyzer + storage) **and 5.19 €/kgH$_2$ for Alicante** (77 MW PV plant, 13 MW battery, and 16.5 MW electrolyzer + storage). The higher LCOHs are mainly a consequence of the electricity price profile, as the excess PV electricity that the plant can sell at the market is being done, in average, at a lower cost compared to 2021.

Using 2023 input data, following results were obtained for both benchmark and updated cases:

Use case Sulquisa

When using 2023 prices as input data in the updated model, Table 31 results show a 15% decrease in the volumes of electric power sold in comparison to the 2021 scenario. The model choses to decrease electricity production as a consequence of the overall lower electricity prices. Moreover, dispatch revenues and costs decrease in both the benchmark and updated cases as fuel and electricity prices are lower. Even though the resulting total profit is higher (less costly), the difference between benchmark and updated profit is now reduced by 12%.

Table 31: Sensitivity Sulquisa use case.

Metric	Benchmark	Updated	Difference
El. power dispatch [GWh]	82.26	56.00	-31.9%
El. power bought [GWh]	1.10	8.59	683.0%
El. power sold [GWh]	24.97	6.21	-75.1%
Heat power dispatch [GWh]	126.82	126.82	-
Proportion renewable dispatch [%]	0%	91.8%	-
Proportion fossil dispatch [%]	100%	8.2%	-91.8%
CO2 emissions [MtonCO2]	0.042	0.007	-83.7%
Total dispatch cost [M€]	-16.14	-6.03	62.6%
Eq. annual investment cost [M€]	0.00	-5.47	-
Total dispatch revenue [M€]	2.17	0.63	-71.0%
Total profit [M€]	**-13.96**	**-10.87**	**22.1%**

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Use case CEMEX PowerGen – Alcanar and Alicante plants

Table 32 results show how much of an impact can a uniform electricity price profile has in the dispatch decisions made by the model. Significantly lower secondary reserves availability prices cause a reduction in provision of operating reserves by almost 60% in both plants when comparing it with the 2021 scenario. The updated model then decides to increase electricity production, selling more energy in the market and reducing purchases. Dispatch revenues decrease more than 40%, and while costs are reduced only by 20%, the resulting updated total profits are now lower (more costly) than in the 2021 scenario. However less costly than the benchmark case in both plants, the gap between profits drops almost 80%.

Table 32: Sensitivity CEMEX PowerGen use cases.

Alcanar			
Metric	**Benchmark**	**Updated**	**Difference**
El. power dispatch [GWh]	0.00	151.81	-
El. power bought [GWh]	154.00	28.43	-81.5%
El. power sold [GWh]	0.00	26.24	-
Secondary reserves [GW]	0.00	56.42	-
Total dispatch cost [M€]	-14.10	-8.69	38.4%
Eq. annual investment cost [M€]	0.00	-8.14	-
Total dispatch revenue [M€]	0.00	3.71	-
Total profit [M€]	**-14.10**	**-13.12**	**7.0%**

Alicante			
Metric	**Benchmark**	**Updated**	**Difference**
El. power dispatch [GWh]	0.00	151.31	-
El. power bought [GWh]	109.12	9.46	-91.3%
El. power sold [GWh]	0.00	51.66	-
Secondary reserves [GW]	0.00	58.02	-
Total dispatch cost [M€]	-10.43	-7.51	28.0%
Eq. annual investment cost [M€]	0.00	-8.14	-
Total dispatch revenue [M€]	0.00	6.08	-
Total profit [M€]	**-10.43**	**-9.57**	**8.2%**

Use case CEMEX CHP – Alcanar plant

Table 33 shows the results of CEMEX CHP sensitivity scenario. In this case, as no provision of reserves is considered, the updated revenue drops only 13% when comparing to the 2021 scenario. Proportionally, reduction in dispatch costs is similar to the PowerGen use cases. As a result, total profit in the updated case is 9% higher (less costly) than in the 2021 scenario. As the total profit is 22% higher (less costly) in the benchmark case due to the reduction in electricity and fuel prices, then the gap in profit between benchmark and updated cases drops by 51%.

Table 33: Sensitivity CEMEX CHP use case.

Metric	Benchmark	Updated	Difference
El. power dispatch [GWh]	0.00	160.93	-
El. power bought [GWh]	154.00	24.74	-83.9%
El. power sold [GWh]	0.00	31.67	-

Heat power dispatch [GWh]	28.85	28.85	-
Proportion renewable dispatch [%]	n/a	99.78%	-
Proportion fossil dispatch [%]	n/a	0.22%	-
CO2 emissions [MtonCO2]	0.008	0.006	-21.1%
Total dispatch cost [M€]	-15.46	-8.56	44.6%
Eq. annual investment cost [M€]	-0.11	-8.30	-
Total dispatch revenue [M€]	0.00	3.25	-
Total profit [M€]	**-15.58**	**-13.61**	**12.6%**

Use case CEMEX Hydrogen – Alcanar and Alicante plants

On one hand, when comparing the updated case results in Table 34 with those of the PowerGen use cases, volumes of electric power sold and reserves provided slightly increase in both plants, thus achieving slightly higher revenues. However, and due to a higher hydrogen cost, total costs present the same slight increase, resulting in a more costly dispatch. The gap in total profit between benchmark and updated cases is now even lower than in the PowerGen use cases.

On the other hand, the partial fuel replacement results in Table 34 show that the hydrogen produced under the 2023 prices scenario is considerably more expensive. The total dispatch cost associated to the burning of hydrogen is now more than two times the cost of burning fuel oil, even when considering the emission costs.

Table 34 Sensitivity CEMEX Hydrogen use cases.

Alcanar			
Metric	**Benchmark**	**Updated**	**Difference**
El. power dispatch [GWh]	0.00	154.57	-
El. power bought [GWh]	154.00	25.85	-83.2%
El. power sold [GWh]	0.00	26.42	-
Secondary reserves [GW]	0.00	61.83	-
Total dispatch cost [M€]	-14.10	-8.81	37.5%
Eq. annual investment cost [M€]	0.00	-8.14	-
Total dispatch revenue [M€]	0.00	3.79	-
Total profit [M€]	**-14.10**	**-13.16**	**6.7%**

Alcanar - Kiln fuel partial replacement			
Metric	**Benchmark**	**Updated**	**Difference**
Heat power dispatch [GWh]	34.67	34.67	-
Proportion renewable dispatch [%]	0%	100%	-
Proportion fossil dispatch [%]	100%	0%	-
CO2 emissions [MtonCO2]	0.009	0.000	-100.0%
Total dispatch cost [M€]	**-1.64**	**-5.69**	**-247.7%**

Alicante			
Metric	**Benchmark**	**Updated**	**Difference**
El. power dispatch [GWh]	0.00	154.09	-
El. power bought [GWh]	109.12	7.39	-93.2%
El. power sold [GWh]	0.00	52.34	-
Secondary reserves [GW]	0.00	63.49	-

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Total dispatch cost [M€]	-10.43	-7.64	26.8%
Eq. annual investment cost [M€]	0.00	-8.14	
Total dispatch revenue [M€]	0.00	6.18	-
Total profit [M€]	**-10.43**	**-9.60**	**7.9%**

Alicante - Kiln fuel partial replacement			
Metric	**Benchmark**	**Updated**	**Difference**
Heat power dispatch [GWh]	27.00	27.00	-
Proportion renewable dispatch [%]	0%	100%	-
Proportion fossil dispatch [%]	100%	0%	-
CO2 emissions [MtonCO2]	0.007	0.000	-100.0%
Total dispatch cost [M€]	**-1.26**	**-4.20**	**-233.8%**

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8 Conclusion

This work performs operational modelling and investment analyses based on the business use cases described in Sweden considering the inclusion of novel BTC CHP technology in the district heating system and in Spain including BTC in industrial applications.

To analyze Swedish and Spanish business use cases Mixed Integer Linear Programing models have been developed. Equivalent annual cost tool has been used to carry out investment analysis.

Results from the Swedish use cases show that when one unit of KV1 in TvAB portfolio is replaced by BTC units, the generated profit is higher in all simulation runs, disregarding the investment cost. This outcome is consistent while also analyzing the business use case 2, where we assume that TvAB is providing balancing power while trading in both day-ahead and mFRR markets. Moreover, simulation runs for sensitivity analysis show that portfolio's total profit highly depends on the biomass prices, and if the biomass prices are low, the total profit is the highest. However, with the inclusion of investment expenses for BTC units, we see that annual investment cost is at least 2.5 times higher than the annual profit. BTC dispatch is limited to about 2000 hours, despite high prices and volatility, due to the very low marginal cost of production from waste incineration plant and the lack of any cost-effective cooling capacity, besides the district heating grid. Therefore, especially outside the November-January period, large volumes of electricity generation and revenue are foregone. To increase the viability of investing in BTC in a system dominated by waste-incineration, the case may need to consider investing in cooling capacity and / or consider larger heat storage in order to capture this value.

Further studies could involve improving the modeling of mFRR participation, flexibility provision from waste plant in TvAB portfolio etc. In addition, the future work could consider more scenarios while performing sensitivity analysis.

Results from the Spanish use cases show the potential of BTC technology in different industrial applications. The 2021 scenario results showed that BTC technology could achieve higher revenues and lower costs in all cases to cover electricity and heat industrial demands. Even considering investment expenses, the total profitability increases in all cases compared to the benchmark cases. However, on-site hydrogen production for burning purposes has proved to be more costly than fossil fuels in both 2021 and 2023 scenarios.

The 2023 sensitivity analysis reflected the impact of lower electricity prices and fuel costs on BTC performance, showing lower profitability for BTC. Further studies should consider future scenarios and analyze BTC competitiveness under higher CO_2 emission and fossil fuel costs, and lower electricity prices. Moreover, the usage of renewable hydrogen could be extended to new purposes, such as a way to achieve electricity storage.

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Annex: Swedish business use case 1: monthly simulation results.

To ensure the consistency of the results, both Benchmark and Updated models are simulated with 2% duality gap for the chosen months (December, September, June and March 2021).

December:

Power and heat dispatch quantities for both Benchmark and Updated models are depicted in Figure 21 and Figure 22 respectively. Most of the units are committed to meet the heat demand and generate electricity as both heat demand and the electricity prices are very high (see Figure 9). Consequently, both BTC units are continuously committed during December (see Figure 22), resulting 85.78 MSEK total profit which is 56.3% increase compared to that of Benchmark model case: Table 35.

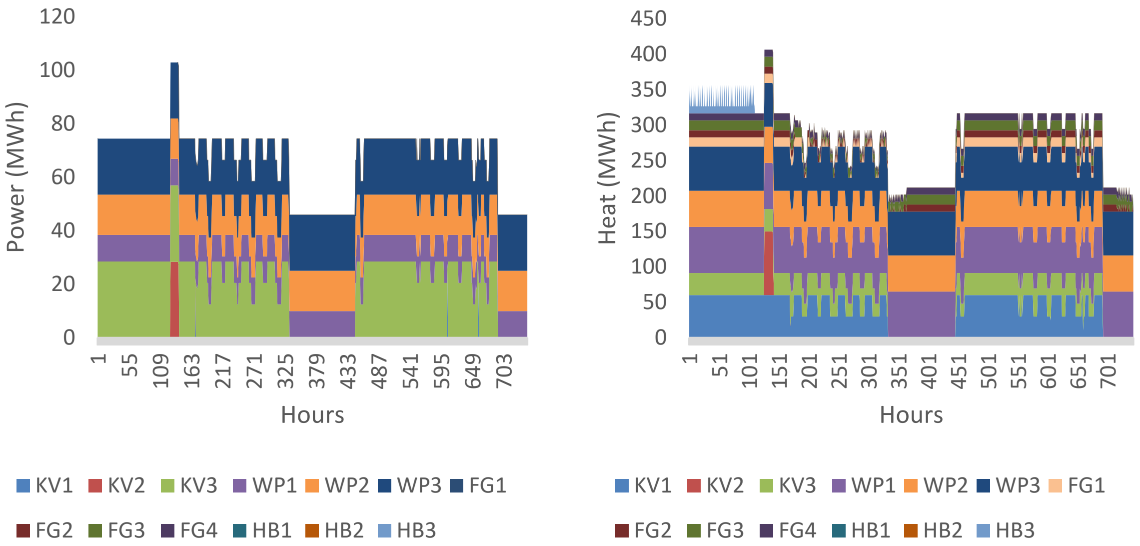

*Figure 21: Heat and power production dispatch using **Benchmark model** for December, 2021.*

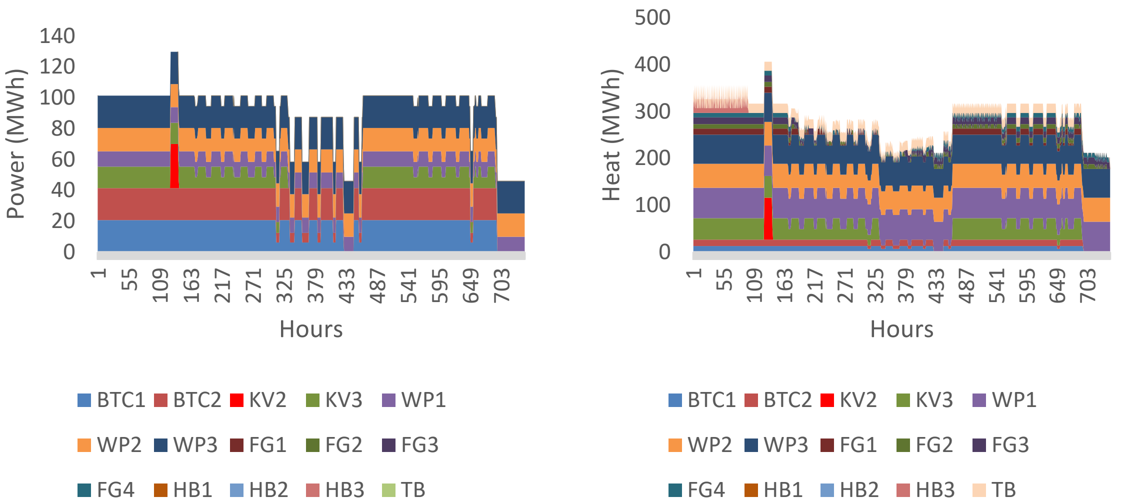

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*Figure 22: Heat and power production dispatch using **Updated model** for December, 2021.*

Table 35: Dispatch, cost, and carbon results for baseline case, December, 2021.

Metric	Benchmark model	Updated model with BTC integration	% difference
El. power dispatch (GWh)	49.8	68.4	37.34% increase
Proportion renewable dispatch (%)	31%	41%	32.3% increase
Proportion fossil fuel dispatch (%)	69%	59%	14.5 % decrease
Total cost of dispatch (MSEK)	35.66	44.74	25.5% increase
Total revenue (MSEK)	90.55	130.5	44% increase
Total profit (MSEK)	54.88	85.78	56.3% increase
Carbon emissions ($MTCO_2$)	33.33	33.33	-

September:

In the same way, the simulation results of September are provided in Figure 23, Figure 24 and in Table 36. Figure 23 shows that, in the Benchmark case, mainly the second and the third units of waste plant are committed to cover the heat demand in September. The first unit of waste plant is supporting to meet the heat demand in the second half of September when the heat demand is increasing. In the case of Updated model instead of the first unit of the waste plant BTC units are getting committed together with the second and the third units of the waste plant to meet the heat demand. As we can see from Figure 24, the BTC units are going through three cold start-ups in the second half of September. This means that, in addition to the lack of cooling possibility, the market prices are not attractive enough to keep BTC units committed continuously. Therefore, we can see a big increase in total dispatch cost compared with the Benchmark case, thus, only 1.43% increase in the total profit.

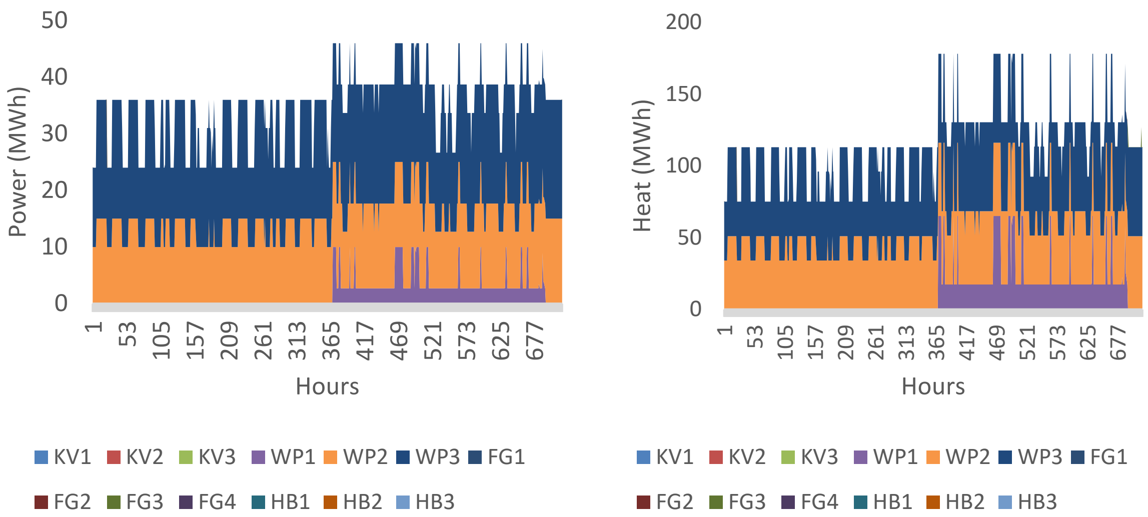

*Figure 23: Heat and power production dispatch using **Benchmark model** for September, 2021.*

Important to note that, the mentioned above commitment of the BTC units in the Updated model case is increasing the proportion of renewable dispatch by 14.7 % and thus, decreasing the carbon emission by 9.97 %; see Table 36.

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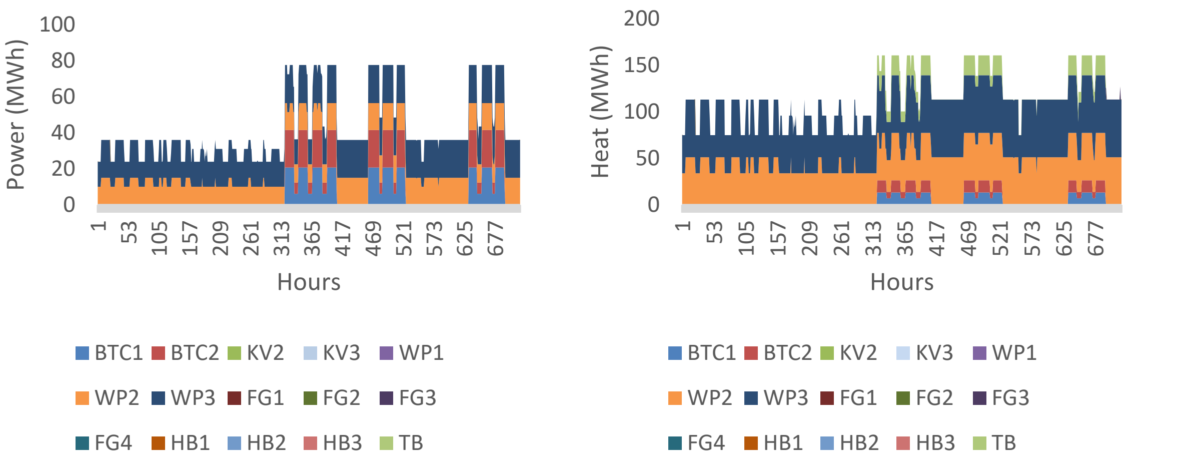

*Figure 24: Heat and power production dispatch using **Updated model** for September, 2021.*

Table 36: Dispatch, cost, and carbon results for baseline case, September, 2021.

Metric	Benchmark model	Updated model with BTC integration	% difference
El. power dispatch (GWh)	24.9	30.9	24% increase
Proportion renewable dispatch (%)	0%	14.7%	14.7% increase
Proportion fossil fuel dispatch (%)	100%	85.3%	14.7% decrease
Total cost of dispatch (MSEK)	0.25	8.3	Big increase
Total revenue (MSEK)	19.11	27.5	44.9% increase
Total profit (MSEK)	18.86	19.13	1.43% increase
Carbon emissions ($MTCO_2$)	21.47	19.33	9.97% decrease

June:

The heat load as well as the electricity market prices are very low during the summer months. Therefore, for both Benchmarks and Updated models, the second and the third units of waste plant are committed to cover the base heat load; see Figure 25 and Figure 26. Consequently, BTC units are not committed during the entire month June. Hence, all economic indicators are identical for both models as it is stated in Table 37.

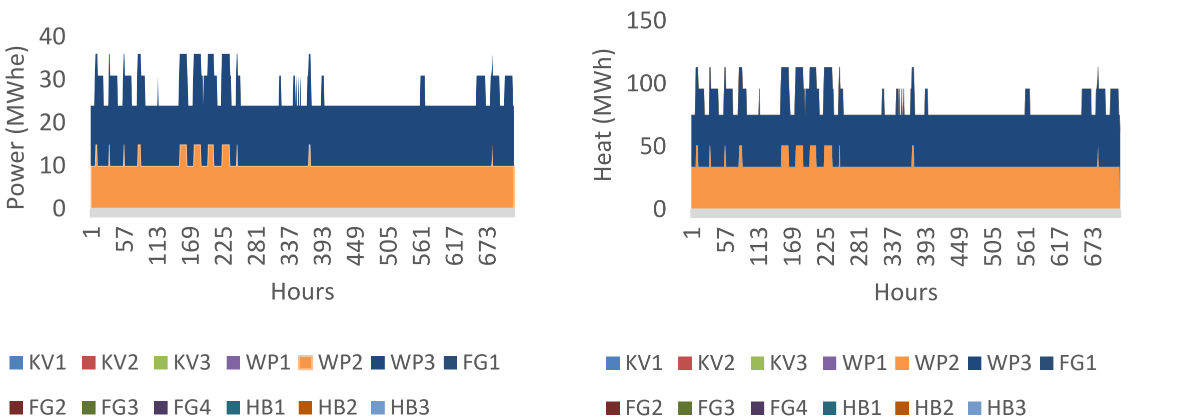

*Figure 25: Heat and power production dispatch using **Benchmark model** for June, 2021.*

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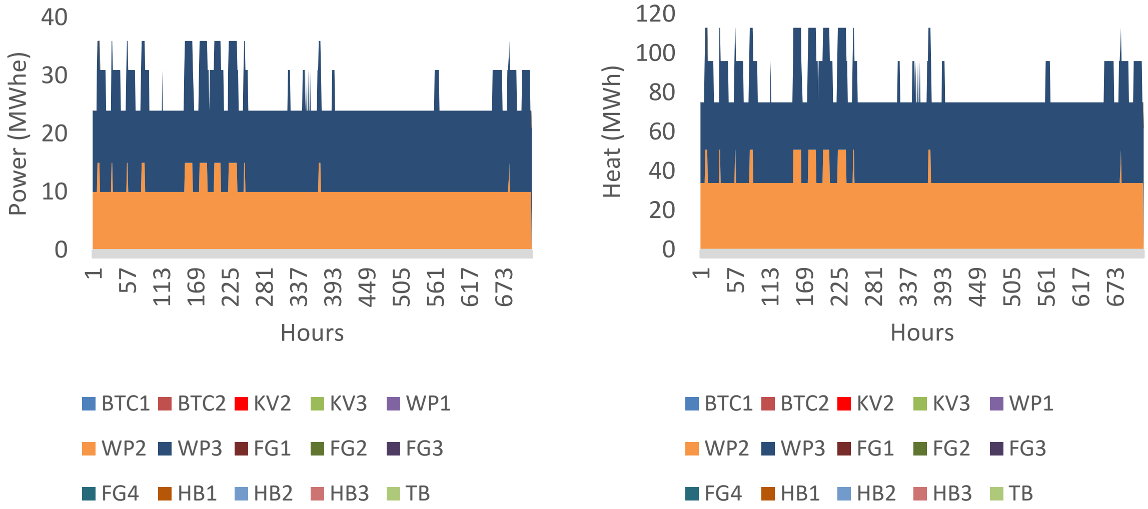

*Figure 26: Heat and power production dispatch using **Updated model** for June, 2021.*

Table 37: Dispatch, cost, and carbon results for baseline case, June, 2021.

Metric	Benchmark model	Updated model with BTC integration	% difference
El. power dispatch (GWh)	19.16	19.16	-
Proportion renewable dispatch (%)	0%	0%	-
Proportion fossil fuel dispatch (%)	100%	100%	-
Total cost of dispatch (MSEK)	0	0	-
Total revenue (MSEK)	5.7	5.7	-
Total profit (MSEK)	5.7	5.7	-
Carbon emissions ($MTCO_2$)	15.78	15.78	-

March:

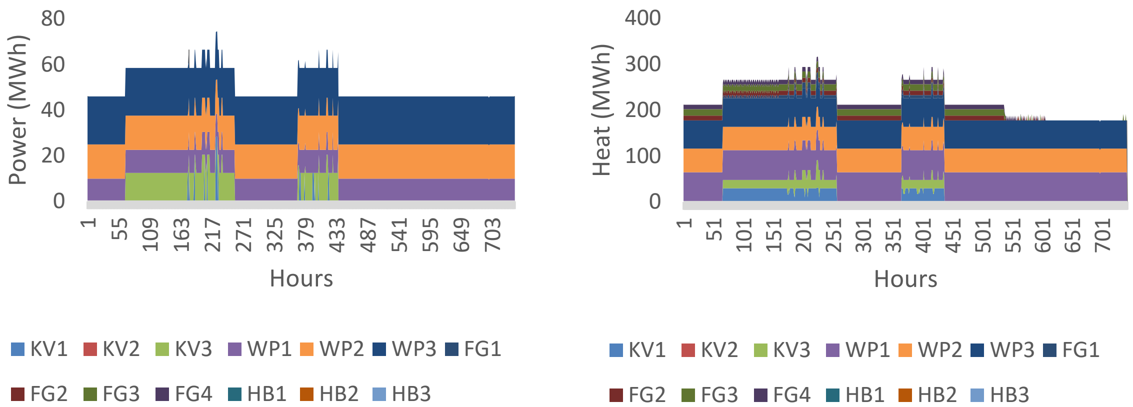

*Figure 27: Heat and power production dispatch using **Benchmark model** for March, 2021.*

The simulation results of both Benchmark and Updated models are presented in Figure 27 and Figure 28 respectively and Table 38. In the second half of the month the heat demand is low; thus, the

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heat demand are met mainly committing three units of waste plant. However, in the first half of month March the heat demand is high, and we can observe from Figure 28 that BTC units are getting committed for some hours. This results around 34% profit increase (see Table 38).

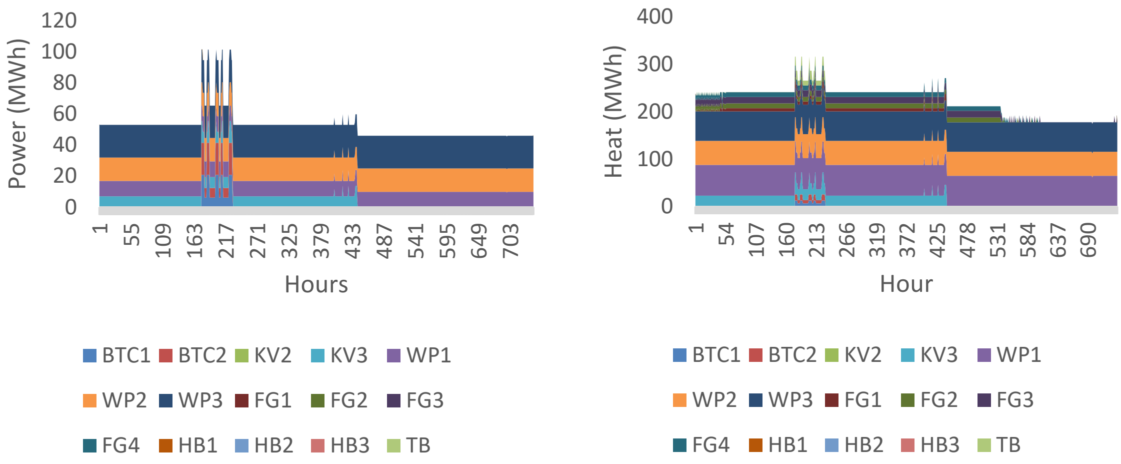

*Figure 28: Heat and power production dispatch using **Updated model** for March, 2021.*

Table 38: Dispatch, cost, and carbon results for baseline case, March, 2021.

Metric	Benchmark model	Updated model with BTC integration	% difference
El. power dispatch (GWh)	37.72	38.8	2.86% increase
Proportion renewable dispatch (%)	18%	18.7%	3.8 % increase
Proportion fossil fuel dispatch (%)	82%	81.3 %	0.85% decrease
Total cost of dispatch (MSEK)	7.7	6.79	11.8% decrease
Total revenue (MSEK)	12.73	13.49	5.97% increase
Total profit (MSEK)	4.99	6.7	34.3% increase
Carbon emissions ($MTCO_2$)	33.3	33.28	0.06% decrease

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