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REGULAR ARTICLE

Energetic and economic cost of nuclear heat − impact on the cost of desalination

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Abstract. An exploratory study has been carried out to evaluate the cost of heat supplied by a pressurized water reactor type of nuclear reactors to thermal desalination processes. In the context of this work, simplified models have been developed to describe the thermodynamics of power conversion, the energetics of multi-effect evaporation (MED), and the costs of electricity and heat cogenerated by the dual-purpose power plant. Application of these models show that, contrary to widespread belief, (nuclear-powered) MED and seawater reverse osmosis are comparable in terms of energy effectiveness. Process heat can be produced, in fact, by a relatively small increase in the core power. As fuel represents just a fraction of the cost of nuclear electricity, the increase in fuel-related expenses is expected to have limited impact on power generation economics.

1 Introduction

With almost 75 million cubic meter per day of worldwide installed capacity [1], desalination is the main technology used to meet water scarcity. About two third of this capacity is produced by reverse osmosis (RO) (Fig. 1). The remaining one third is produced mainly by thermal desalination plants – multi-effect evaporation (MED) and multi-stage flash (MSF), mostly in the Middle East.

Seawater desalination is an energy-intensive process.[1] According to [2], the lowest energy consumption – and the closest to the minimum set by thermodynamics ($1.06\,\mathrm{kWh\,m^{-3}}$) [3] – is achieved by RO processes equipped with energy recovery devices. Seawater RO (SWRO) electricity utilization ranges, in fact, between 4 and $7\,\mathrm{kW_eh\,m^{-3}}$ [4]. Some plants, producing large amount of desalinated water, claim even lower energy consumption; $3.5\,\mathrm{kW_eh\,m^{-3}}$ for Ashkelon, Israel [4]; and 2.7–$3.1\,\mathrm{kW_eh\,m^{-3}}$ (depending on temperature and membrane ageing) for Perth, Australia [5].

Thermal desalination processes consume heat,[2] in addition to electricity. Heat consumption varies between 40 and $65\,\mathrm{kWh_{th}\,m^{-3}}$ for MED, and 55–$80\,\mathrm{kWh_{th}\,m^{-3}}$ for MSF [2]. MSF's electric power consumption is higher than MED's because of pressure drops in flashing chambers and the possible presence of brine recirculation loops [6]. MSF's pumping power varies between 2.5 and $5\,\mathrm{kWh_e\,m^{-3}}$ [7]. MED manufacturers claim specific electricity consumptions lower than $2.5\,\mathrm{kWh_e\,m^{-3}}$.

1.1 Power consumption: thermal desalination systems vs. membrane-based processes

Thermal desalination systems are often coupled to power generation units to form "integrated water and power plants" (IWPPs) in which steam is supplied to the desalination unit by the power plant.

The cost of process heat provided by such plants is traditionally evaluated based on the "missed electricity production" – steam diverted to the process is no longer used for electricity production – leading, systematically, to higher energy costs for the thermal desalination processes compared to RO. MED's steam supply costs between 4 and $7\,\mathrm{kWh_e\,m^{-3}}$ of "missed electricity production" according to [2]. If we add 1.2–$2.5\,\mathrm{kWh_e\,m^{-3}}$ of pumping energy, we end up with an equivalent electric power consumption in the range $[5.2$–$9.5]\,\mathrm{kWh_e\,m^{-3}}$.

Rognoni et al. [8] suggested an alternative way to evaluating the cost of heat "duly considering the benefits of cogeneration". The approach no longer views process heat as a "missed electricity production", but, rather, as "a result of a (limited) raise in the primary power" – the power released from combustion. According to this approach, the

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[1] Energy is, in many cases, the largest contributor to the desalted water cost, varying from one-third to more than one-half of the cost of produced water.

[2] MED's top brine temperature (TBT) generally varies between 60 and 75 °C. MSF's TBT is higher, 90–110 °C.

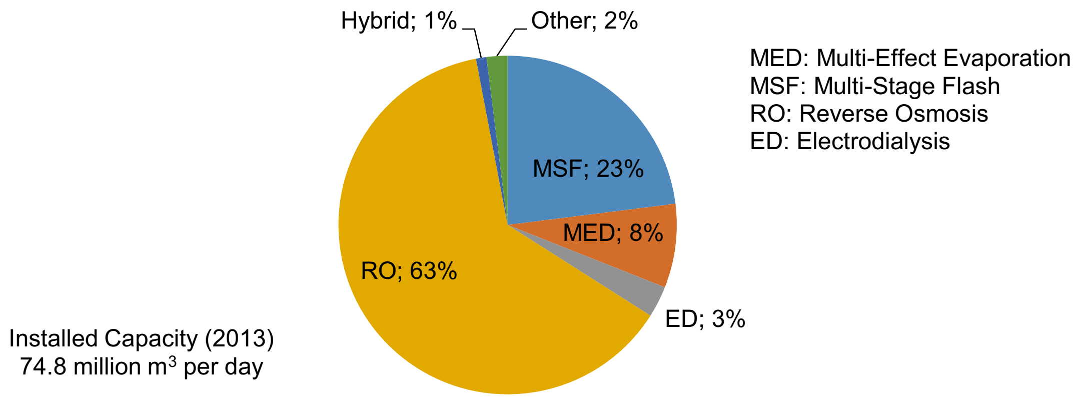

Fig. 1. Total worldwide installed capacity by technology.

energetic cost of process heat is equal to the number of MW_{th} added to the boiler thermal power output. Since fuel represents just a fraction of the cost of electricity, process heat is expected to be cheaper than predictions based on the traditional cost evaluation method. As a result, thermal desalination processes – precisely MED – can be potentially more cost-effective than SWRO. The authors provided two-calculation examples – MED processes fueled by coal-fired power plants in India – for which the cost of desalinated water is 50% lower than SWRO's.

1.2 "Nuclear steam" cost

The cost of process heat depends on the contribution, to the total cost of electricity, of fuel-related expenses – a contribution widely considered to be lower for nuclear-powered electricity generators compared to fossil power plants [9]. Past studies show, in fact, that heat recovery from light water reactors is economically competitive for a number of low temperature applications, including district heating [10] and seawater desalination [11].

The study described in this paper aims at evaluating the – energetic and economic – cost of process heat, supplied by pressurized water reactor (PWR) to a thermal desalination process. The objective is to provide a basis for comparing thermal (MED[3]) and membrane-based (SWRO) desalination processes in terms of energy costs. Simplified models, describing the thermodynamics of a generic PWR power conversion system, the energetics the MED process, and the costs of electricity and process heat produced by the dual-purpose plant (DPP), support this study. These models, and the results of their application, are presented and discussed in the next sections.

2 Energetic cost of heat

The energetic cost of heat was evaluated based on the power conversion system (PCS) architecture described in the next paragraph.

2.1 Power conversion system architecture

Figure 2 illustrates the workflow of the PCS being modeled.

The system is basically a Rankine cycle representative of the technologies commonly applied is PWRs. Steam leaving steam generators (SG) undergoes two expansions in the high-pressure body of the turbine (HPT_1 and HPT_2). The fluid is then dried-up and superheated before supplying the low-pressure stages (LPT_1, LPT_2 and LPT_3). Liquid water extracted from the condenser ($Condenser_2$) is finally preheated and readmitted back to SG.

A steam extraction point was positioned between the outlet of LPT_2 and the inlet of LPT_3. This location allows for a variable quantity ($y = 0$–100%) of steam (the steam normally flowing through LPT_3) to be diverted to an external process. The pressure at the steam extraction point (P_{SteamEx}) may vary between 0.05 bar (pressure at the condenser) and 2.685 bar (pressure at LPT_2 outlet), and the temperature (T_{SteamEx}) between 33 and 129 °C. The range of temperatures generally required by thermal desalination systems generally falls within these limits.

The power plant condenser was (virtually) split in two. In $Condenser_1$, the latent heat of condensation is transferred to the external process. $Condenser_2$ cools the condensates down to 33 °C. The heat duty of each of the two condensers strongly depends on the quantity of steam diverted to the process.

2.2 Thermodynamic model

A thermodynamic model, evaluating the energetic performance of the PCS described in the previous paragraph, was developed using CEA's in-house tool ICV.[4]

[3] MSF is out of scope in this paper, as it consumes higher amounts of energy compared to MED.

[4] ICV simulates the steady-state behavior of components such as boilers, heat exchangers, pumps, compressors and turbines, as well as workflows – typically heat transfer loops and power conversion cycles – based on these components. ICV has a build-in library providing the properties of steam and water [12], including saline-water [13].

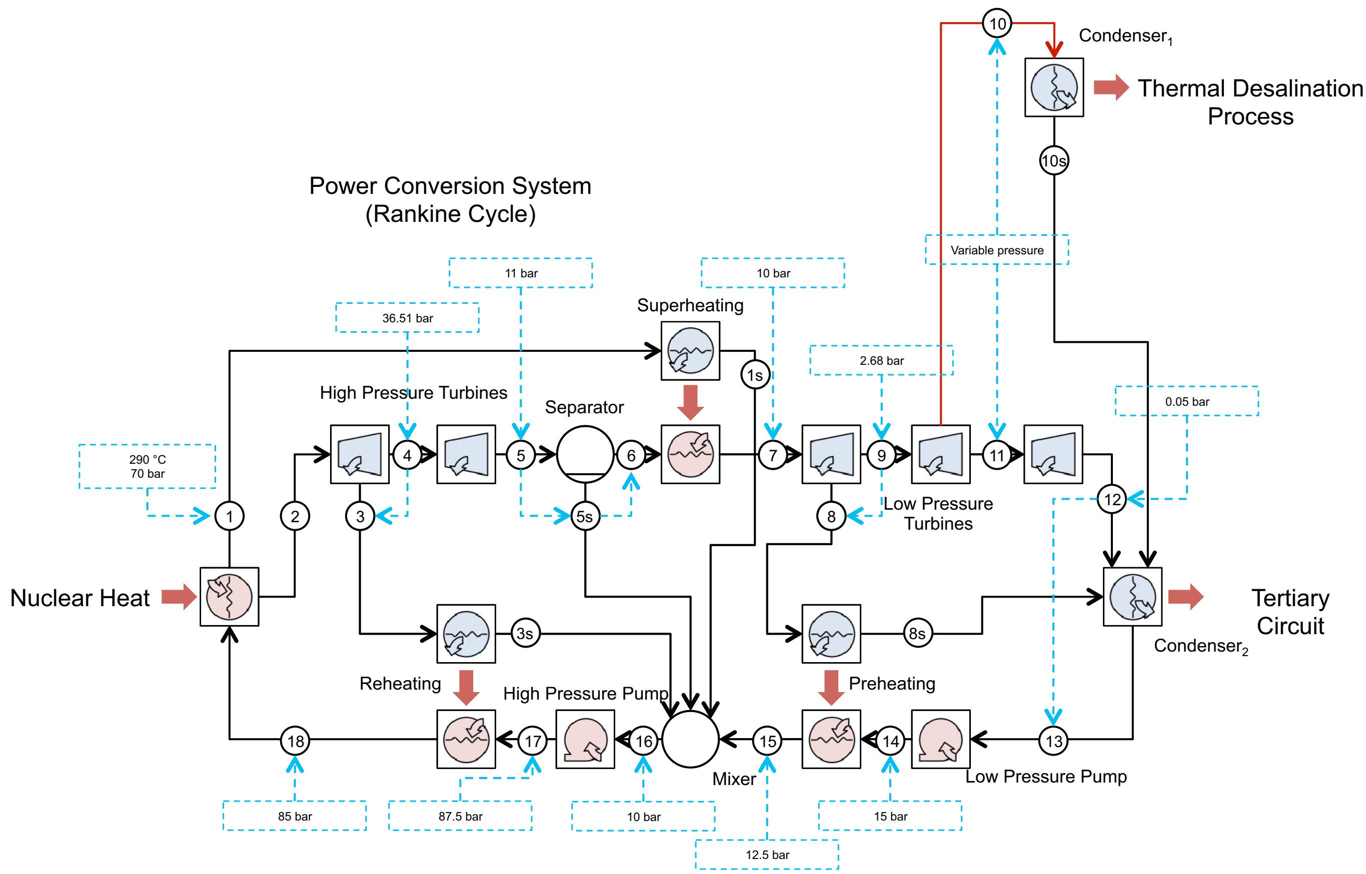

Fig. 2. Power conversion system architecture.

Table 1. Assumed pressure distribution.

Steam generator outlet	70 bar
High pressure turbine 1 inlet	
High pressure turbine 2 inlet	36.5091 bar
High pressure turbine 2 outlet	11 bar
Separator inlet, outlets	
Low pressure turbine 1 inlet	10 bar
Low pressure turbine 2 inlet	2.685 bar
Low pressure turbine 3 inlet	(variable)
Condenser$_1$	
Condenser$_2$	0.05 bar
Low pressure pump outlet	15 bar
Preheater outlet	12.5 bar
Mixer outlet	11 bar
High pressure pump outlet	87.5 bar
Reheater outlet	85 bar

The model calculates the characteristics of the 23 points of the flowsheet – temperature, pressure, steam quality,[5] enthalpy, exergy and flowrate – the power of the major components of the PCS, as well as the amounts of electricity (W_{Elec}) and process heat (Q_{Pro}) cogenerated by the system.

Model inputs include:
- an assumed pressure distribution within the PCS (Tab. 1);
- SG outlet temperature (290 °C) and thermal power output (Q_{SG});
- the temperature at the steam extraction point (T_{SteamEx});
- the fraction of steam (normally expending through LPT_3) diverted to the external process (y).

The calculation of the Rankine cycle is performed sequentially, component by component, applying the mass and energy balance equations (Eqs. (1) and (2)[6]) to different control volumes.

$$\sum_{\mathrm{in}} \dot{m} = \sum_{\mathrm{out}} \dot{m}, \tag{1}$$

$$\sum_{\mathrm{in}} \dot{Q} + \dot{W} + \dot{m} \times \left(\bar{h} + \frac{v^2}{2} + g \times z\right) = \sum_{\mathrm{out}} \dot{Q} + \dot{W} + \dot{m} \times \left(\bar{h} + \frac{v^2}{2} + g \times z\right), \tag{2}$$

$\dot{m}$, mass flowrate (kg/s); $\dot{Q}$, thermal power (W); $\dot{W}$, mechanical power (W); $\bar{h}$, specific enthalpy (J/kg); $v^2/2$, specific kinetic energy (J/kg); $g \times z$, specific potential energy (J/kg); $g \times z$, specific potential energy (J/kg).

[5] Mass of vapor to total mass in a saturated liquid–vapor mixture. Values lower than 0 or higher than 1 indicate that the fluid is either subcooled (−100) or superheated (200).

[6] In practice, the "kinetic + potential energies" term of equation (2) is neglected, leading to a simpler formulation of the energy conservation principle.

Table 2. SPP (PWR 2748 $MW_{th} \rightarrow$ 1000 MW_e): thermodynamic points.

Point	T (°C)	P (bar)	X (%)	H (kJ kg^{-1})	E (kJ kg^{-1} K^{-1})	F (kg s^{-1})
1	290	70	200	2793.98	1048.97	139.405
2	290	70	200	2793.98	1048.97	1385.06
3	245	36.5091	93.2741	2685.23	931.684	245.05
4	245	36.5091	93.2741	2685.23	931.684	1140.01
5	184.07	11	85.9332	2499.41	729.341	1140.01
6	184.07	11	100	2780.67	827.192	979.649
7	275	10	200	2997.9	902.283	979.649
8	145.081	2.685	200	2753.21	633.359	180.999
9	145.081	2.685	200	2753.21	633.359	798.65
10	80	0.474147	93.8269	2500.54	351.599	0
11	80	0.474147	93.8269	2500.54	351.599	798.65
12	32.8755	0.05	86.5162	2234.05	49.7124	798.65
13	32.8755	0.05	0	137.765	−4.22995	979.649
14	32.9654	15	−100	139.492	−2.72166	979.649
15	130.081	12.5	−100	547.394	60.0595	979.649
16	170.264	10	−100	720.471	110.977	1524.47
17	171.56	87.5	−100	730.378	120.02	1524.47
18	230	85	−100	991.385	216.545	1524.47
1s	285.83	70	0	1267.44	336.615	139.405
3s	245	36.5091	0	1061.49	242.266	245.05
5s	184.07	11	0	781.198	131.569	160.363
8s	129.782	2.685	0	545.456	58.7786	180.999
10s	80	0.474147	0	334.949	14.3207	0

The state of the fluid at the outlet of steam turbines and water pumps is determined applying an isentropic efficiency (88% for turbines and 87% for pumps):

$$\varepsilon_{\text{turbine}} = \frac{\overline{h}_{\text{in}} - \overline{h}_{\text{out}}}{\overline{h}_{\text{in}} - \overline{h}_{\text{out}}(\overline{s}_{\text{out}} = \overline{s}_{\text{in}})}, \tag{3}$$

$$\varepsilon_{\text{pump}} = \frac{\overline{h}_{\text{out}}(\overline{s}_{\text{out}} = \overline{s}_{\text{in}}) - \overline{h}_{\text{in}}}{\overline{h}_{\text{out}} - \overline{h}_{\text{in}}}, \tag{4}$$

ε, isentropic efficiency; $\overline{h}_{\text{in}}$, specific enthalpy at inlet (J/kg); $\overline{s}_{\text{in}}$, specific entropy at inlet (J/kg/K); $\overline{h}_{\text{out}}$, specific enthalpy at outlet (J/kg); $\overline{s}_{\text{out}}$, specific entropy at outlet (J/kg/K); $\overline{h}_{\text{out}}(\overline{s}_{\text{out}} = \overline{s}_{\text{in}})$, specific enthalpy at outlet for a constant-entropy transformation.

The following assumptions were also made:

- Steam admitted to different heat exchangers is assumed to leave all its latent heat to the fluid flowing on the secondary side of the exchanger.
- A fixed pinch point temperature difference of 15 °C was systematically applied to determine the outlet fluid temperature on the secondary side.
- Energy losses[7] are not taken into account (the calculated "net" power and heat outputs are actually "gross" power and heat outputs).

[7] Thermal losses at heat exchangers. Mechanical losses at pumps, turbines and generators. Electrical power consumption, internal to the power plant and the external process.

Table 3. SPP (PWR 2748 $MW_{th} \rightarrow$ 1000 MW_e): mechanical and thermal powers.

Component	Power (MW)
Steam generators	2747.99
High pressure turbine 1	−150.624
High pressure turbine 2	−211.837
Low pressure turbine 1	−239.709
Low pressure turbine 2	−201.796
Low pressure turbine 3	−212.827
Condenser_1 (Process)	0
Condenser_2 (Tertiary circuit)	−1747.99
Low pressure pump	1.69183
High pressure pump	15.102
Sum	-1.14×10^{-13}
Net power output	−1000
Power conversion efficiency (%)	36.3902

2.3 Energetic performance of the PCS

Tables 2 and 3 show the characteristics of a 2748 MW_{th} single-purpose plant (SPP) generating 1000 MW_e of electricity.

The contribution of steam turbines to SPP's electricity output is shown in Figure 3. LPT_3 delivers 213 MW_e of mechanical power, which represents 21% of the total electricity output.

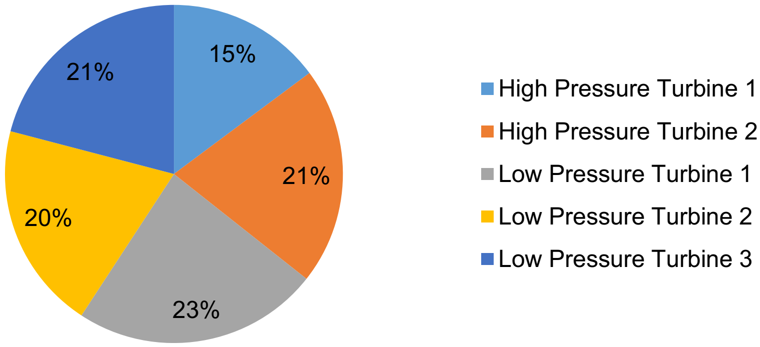

Fig. 3. Contribution of steam turbines to SPP's electricity output.

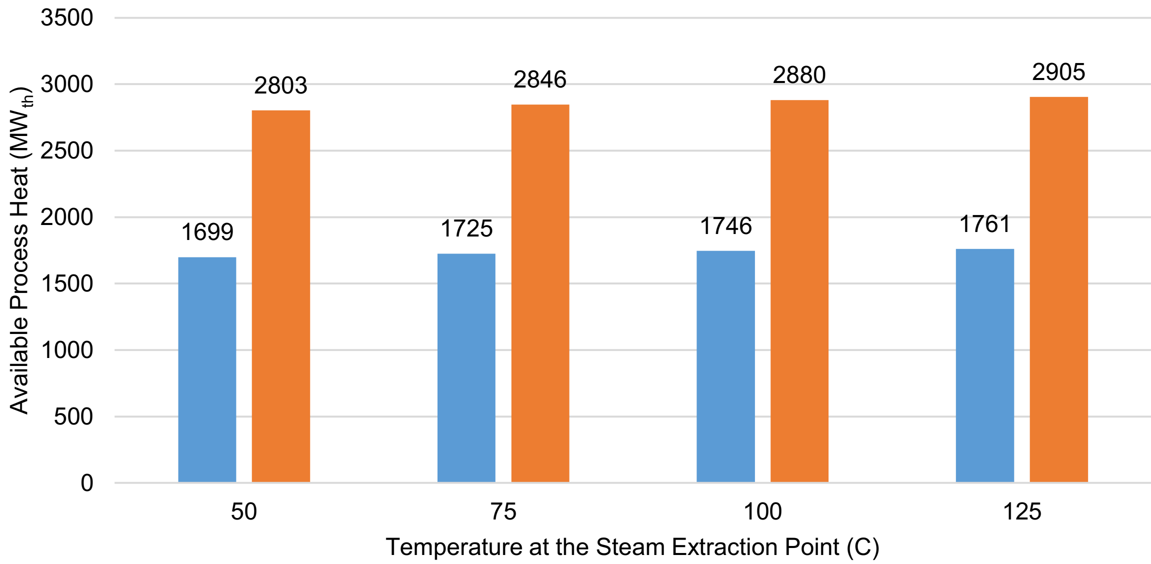

Fig. 4. Available heat for the external process vs. temperature at the steam extraction point. Blue bar: PWR 1000 MWe (2748 MWth); orange bar: PWR 1650 MWe (4534 MWth).

If *all* the steam normally flowing towards this turbine is redirected to the external process ($T_{\mathrm{SteamEx}} = 80\,°\mathrm{C}$), the plant would generate 787 $\mathrm{MW_e}$ of electricity and 1730 $\mathrm{MW_{th}}$ of process heat. The reactor's process heat generation capacity depends, in fact, on the core power, and on the temperature at the steam extraction point, as shown in Figure 4.

Now, if only a portion of this steam – exactly 57.8% – is diverted, the plant would produce 877 $\mathrm{MW_e}$ of electricity and 1000 $\mathrm{MW_{th}}$ of heat. The characteristics of configuration – we will call it $\mathrm{DPP_1}$ (dual-purpose plant) – are listed in Tables 4 and 5.

The differences between SPP and $\mathrm{DPP_1}$ are highlighted (underlined) in Tables 2–5. The two Rankine cycles have identical characteristics except for points 10–12. In $\mathrm{DPP_1}$, turbine $\mathrm{LPT_3}$ is partly bypassed – the exergy of the rerouted steam is later "destructed" in $\mathrm{Condenser_1}$ – resulting in a 123 $\mathrm{MW_e}$ decrease in power generation compared to SPP.

The number of $\mathrm{MW_e}$ of electricity production lost for each $\mathrm{MW_{th}}$ supplied to the external process (123 $\mathrm{kW_e}$ per $\mathrm{MW_{th}}$ in the case of $\mathrm{DPP_1}$) is a traditional measure of the energetic cost of process heat. This measure will be referred to as the "W-cost of heat" or WCH:

$$\mathrm{WCH} = \left[\frac{\Delta \dot{W}_{\mathrm{Elec}}}{\dot{Q}_{\mathrm{Pro}}}\right]_{\dot{Q}_{\mathrm{SG}}=\mathrm{Constant}}. \tag{5}$$

This "loss" in electricity production can be avoided by increasing the thermal power of the core. To keep the electricity generation capacity at 1000 $\mathrm{MW_e}$ – and the heat production level at 1000 $\mathrm{MW_{th}}$ – SG have to deliver an additional 338 $\mathrm{MW_{th}}$. The portion of diverted steam has also to be adjusted (51.5%). This configuration – we will call it $\mathrm{DPP_2}$ (Tabs. 6 and 7) – not only offers higher power conversion efficiency (32.40%) compared to $\mathrm{DPP_1}$ (31.91%), but also results in lower heat cost, as we will see in Section 2.

The number of $\mathrm{MW_{th}}$ added to core power, per $\mathrm{MW_{th}}$ supplied to the external process (338 $\mathrm{kW_{th}}$ per $\mathrm{MW_{th}}$ in the case of $\mathrm{DPP_2}$) provides an alternative measure of the energetic cost of steam – we will call it the "Q-cost of heat" or QCH:

$$\mathrm{QCH} = \left[\frac{\Delta \dot{Q}_{\mathrm{SG}}}{\dot{Q}_{\mathrm{Pro}}}\right]_{\dot{W}_{\mathrm{Elec}}=\mathrm{Constant}}, \tag{6}$$

Table 4. DPP_1 (PWR 2748 $MW_{th} \rightarrow 877$ $MW_e + 1000$ MW_{th} at 80 °C): thermodynamic points.

Point	T (°C)	P (bar)	X (%)	H (kJ kg^{-1})	E (kJ kg^{-1} K^{-1})	F (kg s^{-1})
1	290	70	200	2793.98	1048.97	139.405
2	290	70	200	2793.98	1048.97	1385.06
3	245	36.5091	93.2741	2685.23	931.684	245.05
4	245	36.5091	93.2741	2685.23	931.684	1140.01
5	184.07	11	85.9332	2499.41	729.341	1140.01
6	184.07	11	100	2780.67	827.192	979.649
7	275	10	200	2997.9	902.283	979.649
8	145.081	2.685	200	2753.21	633.359	180.999
9	145.081	2.685	200	2753.21	633.359	798.65
10	80	0.474147	93.8269	2500.54	351.599	461.769
11	80	0.474147	93.8269	2500.54	351.599	336.881
12	32.8755	0.05	86.5162	2234.05	49.7124	336.881
13	32.8755	0.05	0	137.765	−4.22995	979.649
14	32.9654	15	−100	139.492	−2.72166	979.649
15	130.081	12.5	−100	547.394	60.0595	979.649
16	170.264	10	−100	720.471	110.977	1524.47
17	171.56	87.5	−100	730.378	120.02	1524.47
18	230	85	−100	991.385	216.545	1524.47
1s	285.83	70	0	1267.44	336.615	139.405
3s	245	36.5091	0	1061.49	242.266	245.05
5s	184.07	11	0	781.198	131.569	160.363
8s	129.782	2.685	0	545.456	58.7786	180.999
10s	80	0.474147	0	334.949	14.3207	461.769

QCH is simply obtained dividing WCH by SPP's power conversion efficiency.

The increase in core power considered in this study is purely conceptual.[8] Adopting QCH as a measure of the energetic cost of steam makes it possible, in fact, to take into account the advantages cogeneration offers.

Figure 5 shows how WCS and QCH vary with T_{SteamEx}. At 75 °C, each $MW_{th}h$ of thermal power supplied to the process costs 111 kW_eh of electricity. At 100 °C, the cost increases to 169 $kW_eh\,MW_{th}h^{-1}$ (×1.5), and at 125 °C it reaches 223 $kW_eh\,MW_{th}h^{-1}$ (×2).

The energetic cost of heat depends, actually, on the enthalpy at the steam extraction point, which is a function of the level of temperature required by the external process (Eq. (7)).

$$\mathrm{WCH}(T_{\mathrm{SteamEx}}) = \frac{\overline{h}_{\mathrm{SteamEx}}(T_{\mathrm{SteamEx}}) - \overline{h}_{\mathrm{LPT_{3,outlet}}}}{\overline{h}_{\mathrm{SteamEx}}(T_{\mathrm{SteamEx}}) - \overline{h}_{\mathrm{Consenser_{1,outlet}}}}. \quad (7)$$

Table 5. DPP_1 (PWR 2748 $MW_{th} \rightarrow 877$ $MW_e + 1000$ MW_{th} at 80 °C): mechanical and thermal powers.

Component	Power (MW)
Steam generators	2747.99
High pressure turbine 1	−150.624
High pressure turbine 2	−211.837
Low pressure turbine 1	−239.709
Low pressure turbine 2	−201.796
Low pressure turbine 3	−89.7732
$Condenser_1$ (Process)	−1000
$Condenser_2$ (Tertiary circuit)	−871.044
Low pressure pump	1.69183
High pressure pump	15.102
Sum	1.25×10^{-13}
Net power output	−876.946
Power conversion efficiency (%)	31.9123

3 Economic cost of heat

3.1 Single-purpose plant

To evaluate the cost of electricity relative a single-purpose plant, we first calculate the minimal annual cash in – generated from the sale of electricity – required to have a positive NPV.NPV refers here to the net present value of future free cash flows:
– annual expenses related to, construction, purchase of nuclear fuel, operation and maintenance (O&M), and decommissioning, on one hand;
– annual revenue generated from the sale of electricity, on the other hand.

[8] Increasing the fission power of the core is not always technologically feasible, especially for plants that are already "big".

Table 6. DPP_2 (PWR 3086 $MW_{th} \rightarrow 1000$ $MW_e + 1000$ MW_{th} at 80 °C): thermodynamic points.

Point	T (°C)	P (bar)	X (%)	H (kJ kg^{-1})	E (kJ kg^{-1} K^{-1})	F (kg s^{-1})
1	290	70	200	2793.98	1048.97	156.56
2	290	70	200	2793.98	1048.97	1555.5
3	245	36.5091	93.2741	2685.23	931.684	275.204
4	245	36.5091	93.2741	2685.23	931.684	1280.29
5	184.07	11	85.9332	2499.41	729.341	1280.29
6	184.07	11	100	2780.67	827.192	1100.2
7	275	10	200	2997.9	902.283	1100.2
8	145.081	2.685	200	2753.21	633.359	203.272
9	145.081	2.685	200	2753.21	633.359	896.926
10	80	0.474147	93.8269	2500.54	351.599	461.769
11	80	0.474147	93.8269	2500.54	351.599	435.158
12	32.8755	0.05	86.5162	2234.05	49.7124	435.158
13	32.8755	0.05	0	137.765	−4.22995	1100.2
14	32.9654	15	−100	139.492	−2.72166	1100.2
15	130.081	12.5	−100	547.394	60.0595	1100.2
16	170.264	10	−100	720.471	110.977	1712.06
17	171.56	87.5	−100	730.378	120.02	1712.06
18	230	85	−100	991.385	216.545	1712.06
1s	285.83	70	0	1267.44	336.615	156.56
3s	245	36.5091	0	1061.49	242.266	275.204
5s	184.07	11	0	781.198	131.569	180.097
8s	129.782	2.685	0	545.456	58.7786	203.272
10s	80	0.474147	0	334.949	14.3207	461.769

Table 7. DPP_2 (PWR 3086 $MW_{th} \rightarrow 1000$ $MW_e + 1000$ MW_{th} at 80 °C): mechanical and thermal powers.

Component	Power (MW)
Steam generators	3086.14
High pressure turbine 1	−169.159
High pressure turbine 2	−237.905
Low pressure turbine 1	−269.206
Low pressure turbine 2	−226.627
Low pressure turbine 3	−115.962
$Condenser_1$ (Process)	−1000
$Condenser_2$ (Tertiary circuit)	−1086.14
Low pressure pump	1.90001
High pressure pump	16.9604
Sum	1.31×10^{-12}
Net power output	−1000
Power conversion efficiency (%)	32.4029

The minimal annual cash in (ci) is related to cash outflows by equation (8):

$$-\,\mathrm{co}_{\mathrm{cst}} \times \mathrm{npv}(1\$, \mathrm{cst}) + (\mathrm{ci} - \mathrm{co}_{\mathrm{opr}}) \times \mathrm{npv}(1\$, \mathrm{opr}) - \mathrm{co}_{\mathrm{dcm}} \times \mathrm{npv}(1\$, \mathrm{dcm}) = 0, \tag{8}$$

$\mathrm{co}_{\mathrm{cst}}$, annual cash out, construction period, ($); npv (1$, cst), NPV of a fixed expense of 1$ per year, spent during the construction period, ($); ci, annual revenue generated from the sale of electricity, ($); $\mathrm{co}_{\mathrm{opr}}$, annual expenses related to fuel and O&M, economic lifetime of the plant, ($); npv (1$, opr), NPV of a fixed expense of 1$ per year, spent over the economic lifetime of the plant; $\mathrm{co}_{\mathrm{dcm}}$, annual cash out, decommissioning period, ($); npv (1$, dcm), NPV of a fixed expense of 1$ per year, spent during the decommissioning period.

NPV terms of equation (8) are estimated based on a fixed discount rate (r) applicable for the three periods[9]:

$$\mathrm{npv}(1\$, \mathrm{period}) = \sum_{Y=Y_{\mathrm{beginning,period}}}^{Y_{\mathrm{end,period}}} (1+r)^{-Y}. \tag{9}$$

Equation (8) assumes fixed values of future inflows and outflows over the three key phases of the lifetime of the plant: construction (cst), operation (opr) and decommissioning (dcm).

[9] Traditionally, the rate used in discounted cash flow analysis is adjusted for risk, period by period. This is not the case for this exercise.

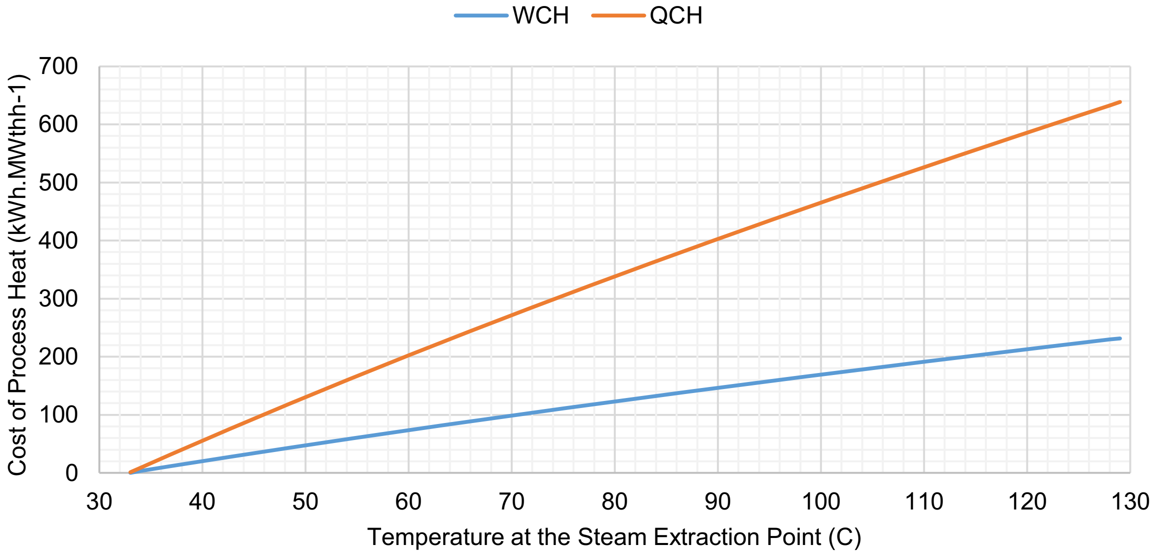

Fig. 5. WCH and QCH vs. temperature at the steam extraction point.

Annual expenses[10] (construction, fuel, O&M and decommissioning) are evaluated on the basis of specific costs:
- The specific cost of construction[11]: in $ per (installed) kW_e.
- The specific cost of fuel: in $ per (produced) MW_eh.
- The specific cost of O&M: in $ per (produced) MW_eh.
- The specific cost of decommissioning: in $ per (installed) kW_e.

Once minimal annual cash in (ci) is evaluated, the cost of electricity is deduced by dividing ci by the annual electricity production volume[12] ($P_{\mathrm{Elec,1Y}}$):

$$c_{\mathrm{kW_eh}} = \frac{\mathrm{ci}}{P_{\mathrm{Elec},1Y}}, \tag{10}$$

$c_{\mathrm{kW_eh}}$, cost of electricity; $P_{\mathrm{Elec},1Y}$, annual electricity production volume (kW_eh). ($ per kW_eh).

A numerical example of electricity cost calculation for a 1000 MW_e PWR is provided in Table 8. The results show good agreement with the evaluation reported in OECD' 2010 Projected Costs of Generating Electricity [9].

Table 8. SPP (PWR 2748 $MW_{th} \rightarrow$ 1000 MW_e): electricity cost.

Reference core thermal power (MW_{th})	2748
Reference electric power generation capacity (MW_e)	1000
Specific construction cost ($ per installed kW_e (electric power))	4101.51[a]
Specific fuel cost ($ per produced MW_eh (electric power))	9.33[a]
Specific O&M cost ($ per produced MW_eh (electric power))	14.74[a]
Specific decommissioning cost ($ per installed kW_e (electric power))	820.30[b]
Length of the construction period (years)	7[a]
Economic lifetime of the plant (years)	60[a]
Average availability of the plant (%)	85[a]
Length of the decommissioning period (years)	5
Discount rate (%)	5
Cost of electricity (10^{-2} $ per kW_eh)	5.816
Percentage allocated to construction (%)	58.15%
Percentage allocated to fuel (%)	16.04%
Percentage allocated to O&M (%)	25.34%
Percentage allocated to decommissioning (%)	0.46%

[a] Values suggested in the OECD' 2010 Projected Costs of Generating Electricity [9, p. 103].
[b] 20% of the specific construction cost.

3.2 Dual-purpose plant

The traditional method (Method 1) for evaluating the cost of process heat consists in multiplying the cost of electricity, as calculated for SPP, by the expected decrease in electricity production.

Consider the 1000 MW_e PWR example of Table 8. According to the thermodynamic model described in the previous section, the reactor can produce up to 1730 MW_{th} of process heat at 80 °C. Each $MW_{th}h$ supplied to the external process at this temperature will cause the reactor's net power output to decrease by 123 kW_eh (W-cost of heat). With a cost of electricity of 5.82 cents per kW_eh, the cost of heat would be equal to 7.15 $ per $MW_{th}h$ (0.715 cents per $kW_{th}h$).

An alternative method of evaluating the cost of heat (Method 2) consists of considering a modified reactor design (DPP_2, cf. Tabs. 6 and 7) offering higher core power output compared to SPP. Such plant would generate the

[10] All expenses are considered "overnight", i.e. interest free. Inflation (fuel cost escalation in particular) is not taken into account.
[11] Owner's, construction and contingency costs.
[12] The annual electricity production volume is evaluated from the reference electric power generation capacity assuming a constant average availability of the plant.

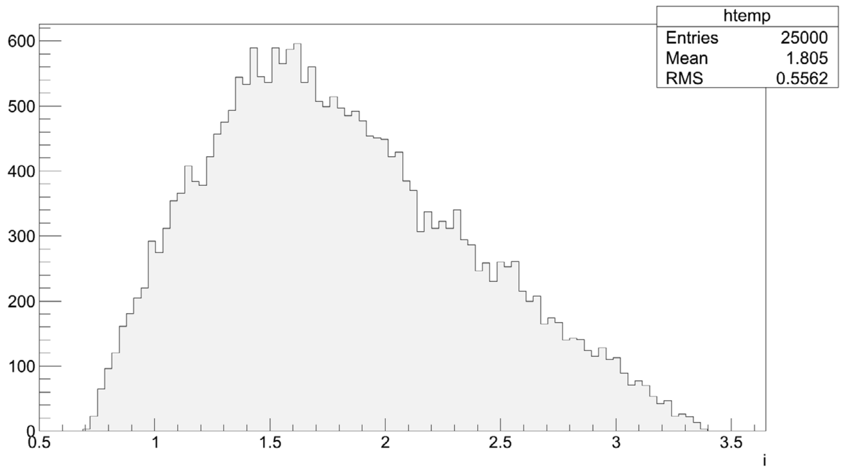

Fig. 6. Number of entries (vertical axis) for which i equals a certain value (horizontal axis).

same amount of electricity as SPP (1000 $\mathrm{MW_e}$) while meeting the demand of the external process in terms of thermal power (1000 $\mathrm{MW_{th}}$ at 80 °C).

At 80 °C, the Q-cost of heat is equal to 338 $\mathrm{kWh_{th}}$ per $\mathrm{MW_{th}}$. This means that, in order to produce 1000 $\mathrm{MW_{th}}$ of process heat at 80 °C, without affecting the electric power generation capacity, the core power has to be raised from 2748 to 3086 $\mathrm{MW_{th}}$ (+12.3%).

The effect of increasing core power on construction costs can be estimated based on the formula:

$$\frac{\mathrm{cost_{DPP}}}{\mathrm{cost_{SPP}}} = 0.75 + 0.25 \times \left(\frac{\dot{Q}_{\mathrm{Core,DPP}}}{\dot{Q}_{\mathrm{Core,SPP}}}\right)^{0.6}. \tag{11}$$

Equation (11) assumes that:

- Nuclear Island represents roughly $x = 25\%$ of the costs.
- The cost relative to Nuclear Island:
  - Depends on core power exclusively.
  - Can be scaled-up applying a capital scaling function[13] with a scaling exponent equal to $n = 0.6$.[14]
- The remaining 75% of the costs depend solely on the plant power generation capacity (which is the same for both SPP and DPP).

The Single-Purpose 1000 $\mathrm{MW_e}$ PWR example of Table 8 costs 4.102 billion \$ to construct. Adding 338 $\mathrm{MW_{th}}$ to core power would increase this cost by $i = 1.8\%$. If x and n – which are rather uncertain – are uniformly distributed, in [15–35] (%) for x, and in [0.4–0.8] for n, i would have the distribution[15] shown in Figure 6 (mean value for cost increase: 1.8%, standard deviation: 0.56%). A cost increase of 3.5% appears to be an upper limit.

[13] Capital cost scaling functions are often used to account for economies of scale (as the nuclear island gets larger in size, it gets progressively cheaper to add additional capacity). Examples from the power generation industry are provided in [14].

[14] When n is unknown, a value of 0.6 is generally assumed (rule of six-tenths).

[15] Figure 6 was obtained after (Latin Hypercube) sampling of two inputs, carried out using CEA's open source software URANIE [15].

Increasing core power has also an impact on fuel costs. A simple way to take it into account is to apply a correction factor (f) to SPP's specific fuel cost (Eq. (12)). Although SPP and $\mathrm{DPP_2}$ have the same power generation capacity, the annual electricity production volume can differ between the two plants depending on the availability of $\mathrm{DPP_2}$ vs. SPP. If we assume a 1% decrease in availability for $\mathrm{DPP_2}$ compared to SPP (84% for $\mathrm{DPP_2}$ vs. 85% for SPP), the increase in fuel costs would be equal to 12.31%.

$$f = \frac{P_{\mathrm{Elec},1Y,\mathrm{SPP}}}{P_{\mathrm{Elec},1Y,\mathrm{DPP}}} \times \frac{P_{\mathrm{Core},1Y,\mathrm{DPP}}}{P_{\mathrm{Core},1Y,\mathrm{SPP}}}, \tag{12}$$

$P_{\mathrm{Elec},1\,Y,\mathrm{SPP}}$, annual electricity production volume, SPP ($\mathrm{kW_eh}$); $P_{\mathrm{Elec},1\,Y,\mathrm{DPP}}$, annual electricity production volume, DPP ($\mathrm{kW_eh}$); $P_{\mathrm{Core},1\,Y,\mathrm{SPP}}$, annual production volume, thermal power, SG, SPP ($\mathrm{kW_{th}h}$); $P_{\mathrm{Core},1\,Y,\mathrm{DPP}}$, annual production volume, thermal power, SG, DPP ($\mathrm{kW_{th}h}$).

The rise in O&M expenses is expected to be less sensitive to the increase in core power compared to fuel costs. The correction factor (f'), applicable to SPP's specific O&M cost, is assumed to be the following:

$$f' = \frac{1+f}{2}. \tag{13}$$

Table 9 provides a preliminary economic evaluation of $\mathrm{DPP_2}$ vs. SPP. The cost of heat reported in this table is calculated following the steps listed below:

- The – minimal annual cash in required to have a positive NPV – ($\mathrm{ci_{DPP}}$) is calculated for $\mathrm{DPP_2}$.
- We assume that all electricity generated by $\mathrm{DPP_2}$ is sold at 5.82 cents per $\mathrm{kW_eh}$ – i.e. the cost of electricity as produced by SPP ($c_{\mathrm{kWeh,SPP}}$).
- We use the difference between, the – minimal annual cash in required to have a positive NPV – and, the – annual revenue generated from the sale of electricity – as a basis for evaluating the cost of heat (Eq. (14)).

$$c_{\mathrm{kW_{th}h,DPP}} = \frac{\mathrm{ci_{DPP}} - c_{\mathrm{kW_eh,SPP}} \times P_{\mathrm{Elec},1Y,\mathrm{DPP}}}{P_{\mathrm{Heat},1Y,\mathrm{DPP}}}. \tag{14}$$

Table 9. DPP_2 (PWR 3086 $MW_{th} \rightarrow$ 1000 MW_e + 1000 MW_{th} at 80 °C): electricity and heat costs.

	SPP	DPP_2
Reference core thermal power (MW_{th})	2748	3086 (+12.3%)
Reference electric power generation capacity (MW_e)	1000	1000
Reference process heat generation capacity (MW_{th} at 80 °C)	–	1000
Specific construction cost ($ per installed kW_e (electric power))	4101.51	4175.451 (+1.8%)
Specific fuel cost ($ per produced MW_eh (electric power))	9.33	10.478 (+12.31%)
Specific O&M cost ($ per produced MW_eh (electric power))	14.74	15.647 (+6.15%)
Specific decommissioning cost ($ per installed kW_e (electric power))	820.30	835.090 (+1.8%)
Length of the construction period (years)	7	7
Economic lifetime of the plant (years)	60	60
Average availability of the plant (%)	85	84 (−1 point)
Length of the decommissioning period (years)	5	5
Discount rate (%)	5	5
Minimal annual cash in required to have a positive NPV (million $)	433.378	450.979 (+17.601)
Cost of electricity (10^{-2} $ per kW_eh)	5.816	
Cost of heat (10^{-2} $ per $kW_{th}h$ at 80 °C)	–	0.308
Cost of heat (DPP) to cost of electricity (SPP)		5.30%

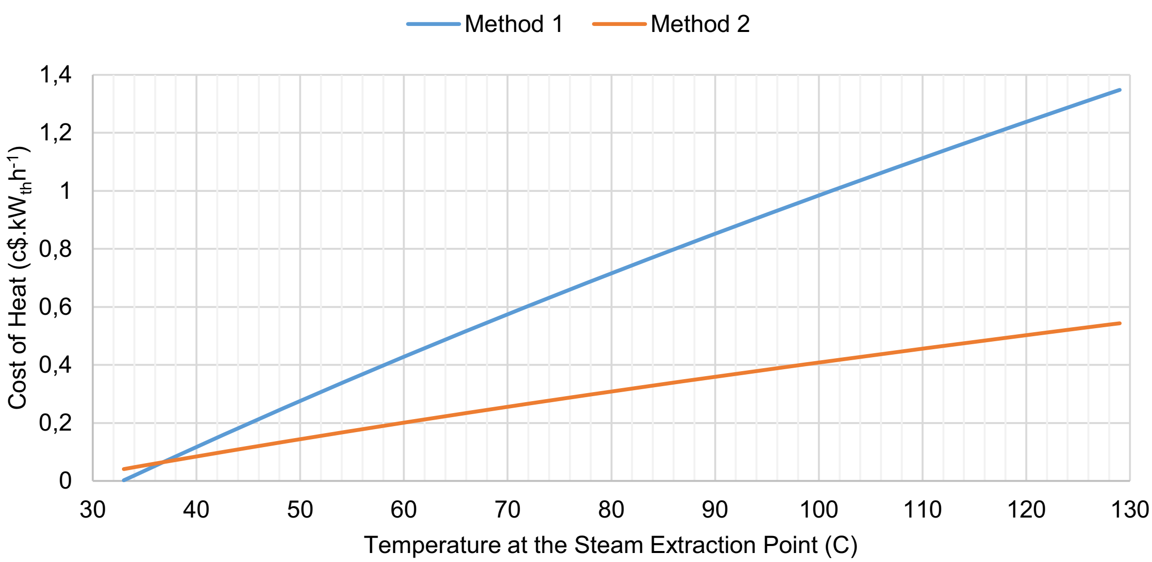

Fig. 7. Cost of heat vs. temperature at the steam extraction point.

The cost of heat, as calculated by this method (Method 2), is equal to 0.308 cent per $kW_{th}h$ (80 °C), which represents 5.30% of the cost of electricity produced by SPP. This cost is 57% percent lower than the cost calculated by Method 1. Figure 7 shows how the cost varies with the level of temperature required by the external process.

At 75 °C, each $kW_{th}h$ of thermal power supplied to the process costs 0.282 c$. At 100 °C, the cost rises to 0.408 c$ $kW_{th}h^{-1}$ (×1.45), and at 125 °C it reaches 0.525 c$ $kW_{th}h^{-1}$ (×1.86). These costs, estimated based on Method 2, represent 4.9–9.0% of the cost of electricity, depending on the steam extraction temperature (Fig. 8).

The ratio – cost of heat to cost of electricity – will be referred to as the E-cost of heat (ECH). ECH is subject to the size effect (Fig. 9). It is also sensitive to availability of the cogeneration plant, as shown in Figure 10.

Method 2 provides an alternative approach to converting MW_{th} to MW_e, considering the benefits of cogeneration – it allocates CAPEX and OPEX to the two byproducts – but also, the constraints introduced by the integrated system – higher expenses, extended construction period, lower availability, etc.

In the next section, we will use this method to compare two nuclear-powered integrated water and power plants, based on either, multi-effect distillation, or, seawater RO.

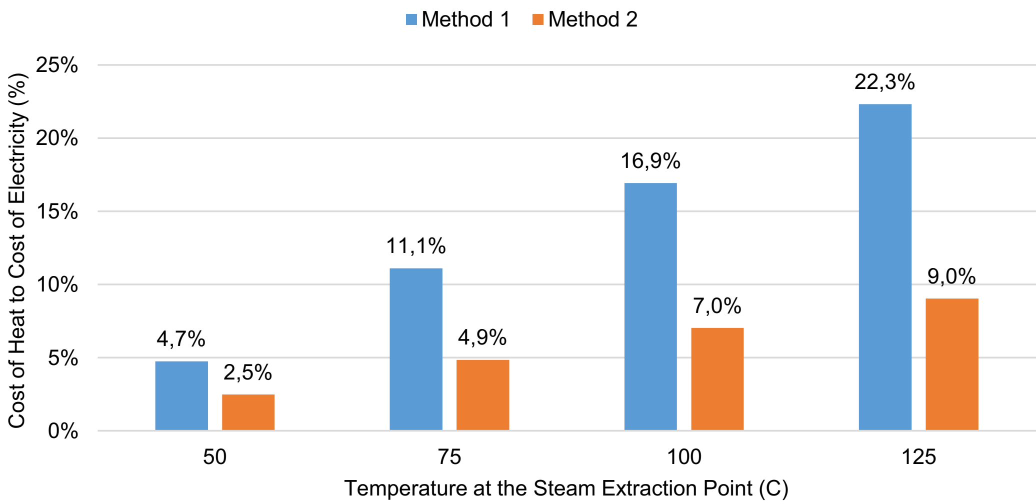

Fig. 8. Cost of heat to cost of electricity vs. temperature at the steam extraction point.

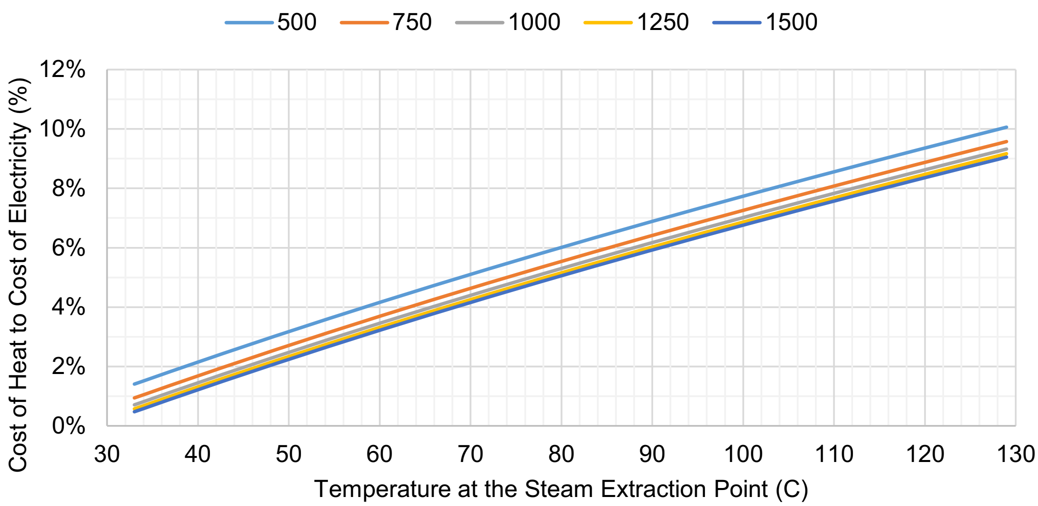

Fig. 9. Cost of heat to cost of electricity vs. temperature at the steam extraction point (Method 2) for different values of process thermal power (MW_{th}).

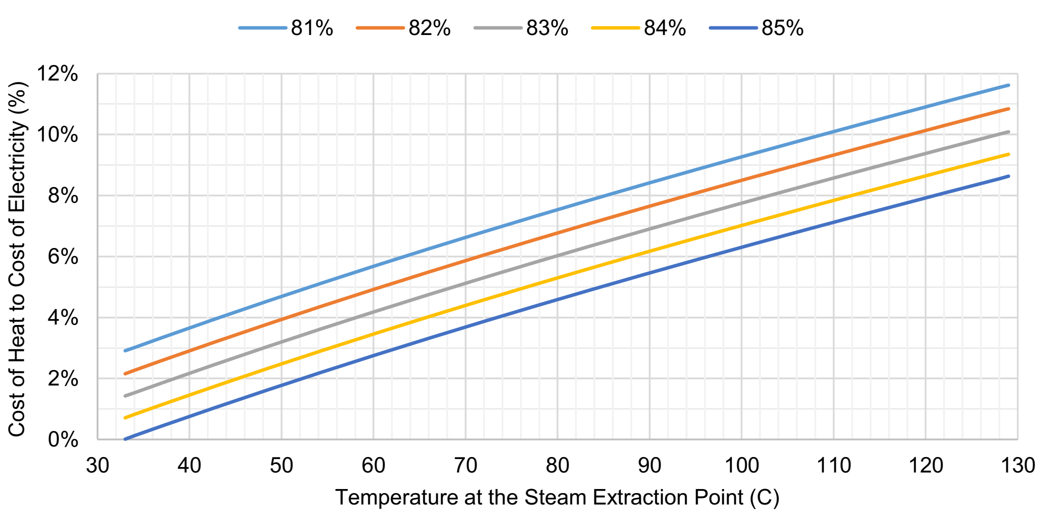

Fig. 10. Cost of heat to cost of electricity vs. temperature at the steam extraction point (Method 2) for different values of (DPP_2) availability.

4 Impact on the cost of desalination

4.1 MED process performance model

The MED process performance model aims at evaluating its specific thermal power consumption, in $kW_{th}h\,m^{-3}$ for fresh water produced by the plant. Based on the simplified approach already implemented in the DEEP Code [16], the model follows the three steps described below:

– First, the number of MED stages is determined (Eq. (15)) based on:
  - The temperatures at the first stage (top brine temperature) and the final condenser.
  - The average temperature drop between stages.

$$N_{\text{Stages}} = \text{int}\left(\frac{T_{\max} - T_{\min}}{\Delta T_{\text{Stages}}}\right), \tag{15}$$

N_{Stages}, number of stages; int (function), round down real numbers to the nearest integer; $T_{\max}$, top brine temperature, (°C); $T_{\min}$, temperature at the final condenser, (°C); ΔT_{Stages}, average temperature drop between stages, (°C).

Table 10. Example of MED process performance calculation (1).

Top brine temperature (°C)	70
Temperature at the final condenser (°C)	33
Average temperature drop between stages (°C)	2
Number of stages (–)	18
GOR to number of stages	0.8
GOR (–)	14.4
Pinch point temperature difference, first effect (°C)	5
Steam supply temperature (°C)	75
Specific heat consumption ($kWh_{th}\,m^{-3}$)	44.76

– The gain output ratio (GOR) (kilograms of fresh water produced per kilogram of steam supplied to the process) is then estimated based on an average effect efficiency of 0.8:

$$\text{GOR} = 0.8 \times \text{NS}. \tag{16}$$

– The specific power consumption ($kW_{th}h\ m^{-3}$) is finally deduced:

$$\text{SHC} = \frac{L}{3.6 \times \text{GOR}}, \tag{17}$$

L, latent heat at steam supply temperature, ($kJ\,kg^{-1}$).

A numerical example of MED process performance calculation is provided in Table 10.

The specific thermal power consumption evaluated by this model is sensitive to both, the temperature difference between MED effects, and, the stage average efficiency, as illustrated by Figures 11 and 12 .

4.2 MED equivalent specific electric power consumption

The calculations, reported in this paragraph, are based on the following assumptions:

– MED model inputs are basically those listed in Table 10. Only the top brine – and steam supply – temperatures vary.

– A (pinch point temperature) difference of 5 °C between MED's steam supply temperature and the temperature at the steam extraction point (T_{SteamEx}, power conversion system).

– Conversion of MED specific power thermal consumption to an electric equivalent is performed based on either:
  - the W-cost of heat (cf. Sect. 2.3) (Method 1), or,
  - the – cost of heat to cost of electricity – ratio (ECH) as calculated by Method 2 (cf. Sect. 3.2).

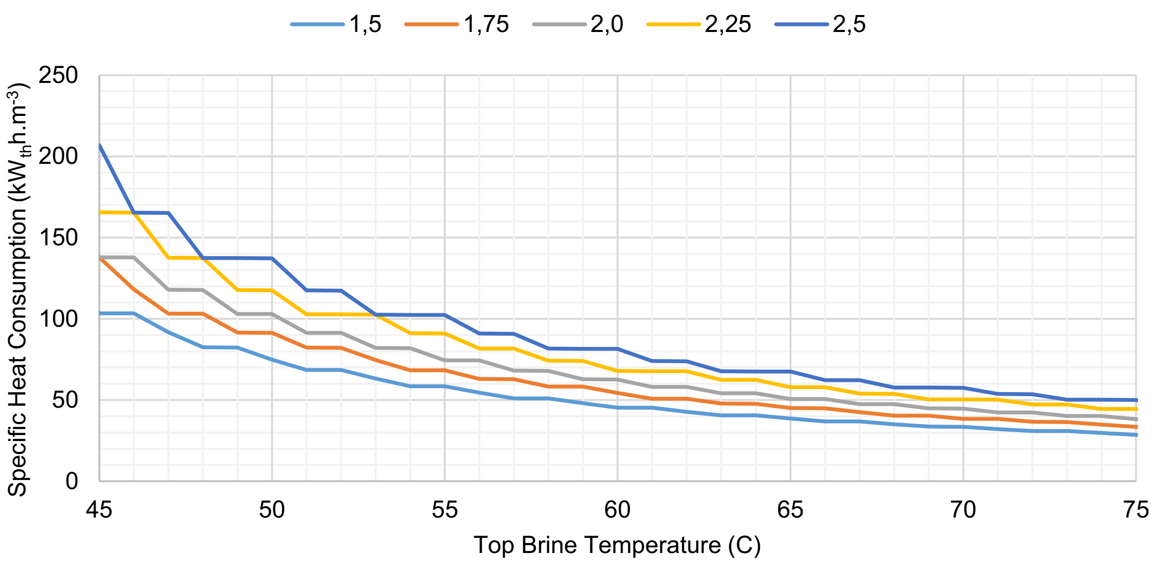

Fig. 11. MED specific thermal power consumption vs. top brine temperature. 1.5, 1.75, 2.0, 2.25, 2.5: average temperature drop between stages (°C).

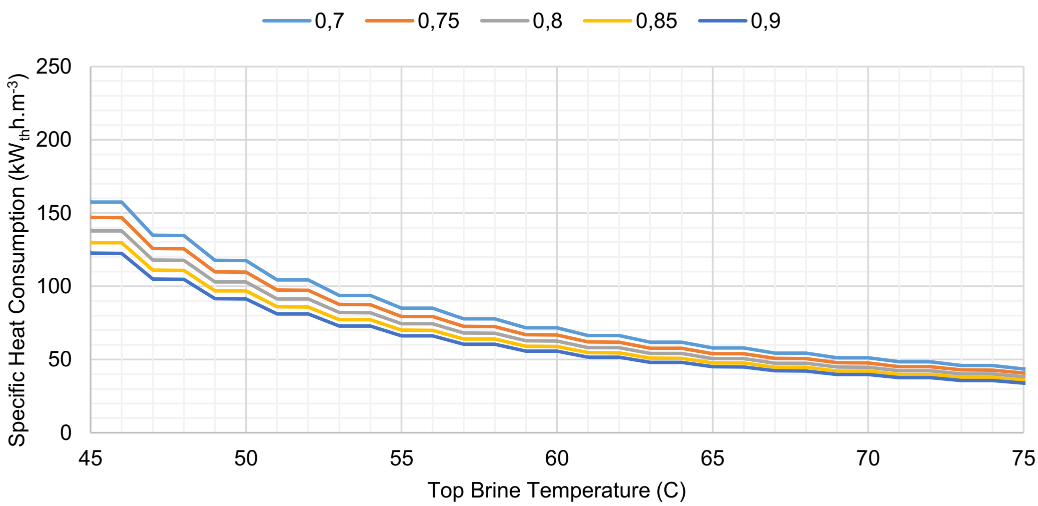

Fig. 12. MED specific thermal power consumption vs. top brine temperature. 0.7, 0.75, 0.8, 0.85, 0.9: GOR to number of stages.

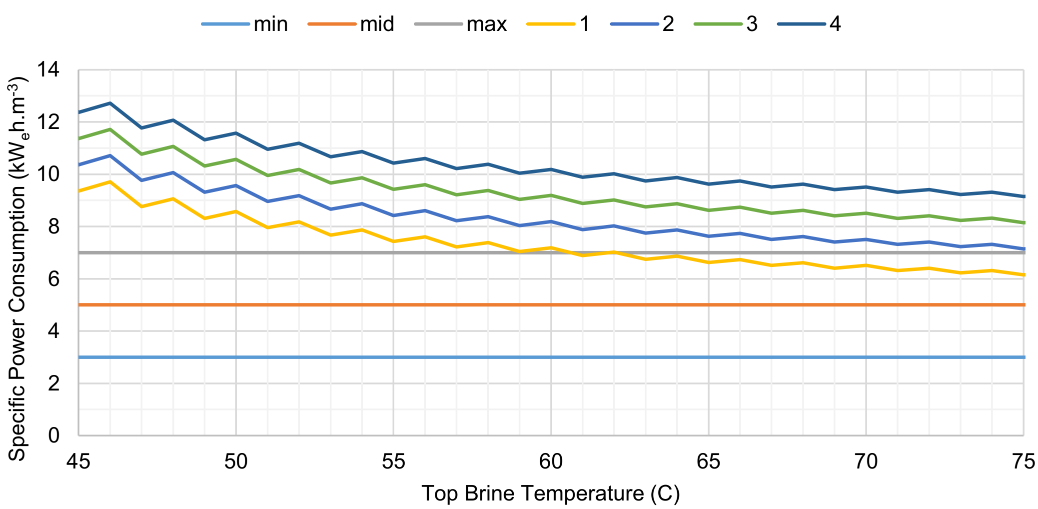

Fig. 13. MED energy cost vs. top brine temperature. Based on Method 1. 1, 2, 3, 4: MED specific electric consumption equal to 1, 2, 3 and 4 $kW_e\,m^{-3}$ respectively. min, mid, and max: minimal, medium and maximal specific electric consumption of the SWRO process as reported in literature.

Figure 13 shows how MED's equivalent electric power consumption[16] varies with the top brine temperature (TBT). Conversion from W_{th} to W_e is based, in this case, on the W-cost of heat (WCH).

The power required to produce a cubic meter of fresh water, as calculated by Method 1, is higher for MED than for SWRO, except for processes operating at a TBT higher than 60, with a specific electric consumption lower than 1 $kW_e\,m^{-3}$, for which the equivalent electric power consumption is in the range 6–7 $kW_e\,m^{-3}$.

If the – cost of heat to cost of electricity – ratio (ECH), as calculated by Method 2, is used as a basis for converting W_{th} to W_e, MED's efficiency, in terms of energy utilization, is globally improved, as illustrated by Figure 14.

[16] Electric equivalent of the thermal power supplied by the nuclear reactor, plus, electric power consumption internal to the process.

Figure 14 shows that, for specific consumptions in the range [1–4] $kW_e\,m^{-3}$, MED's equivalent electric power consumption varies between 3 and 6 $kW_e\,m^{-3}$, matching the range of the RO specific electric consumption as reported in literature.

MED's equivalent electric power consumption can be further reduced by, raising the TBT,[17] decreasing the average temperature drop between MED stages,[18] or, increasing MED effects' efficiency[19] (GOR to number of stages), as illustrated by the example provided in Table 11.

[17] Raising the TBT exposes the plant to severe corrosion and scaling problems. In recent years, many of these problems have been solved thanks to improvements in materials and anti-scalants.

[18] Reducing the temperature difference requires larger heat transfer surfaces.

[19] Effect efficiency can be improved by reducing thermal losses.

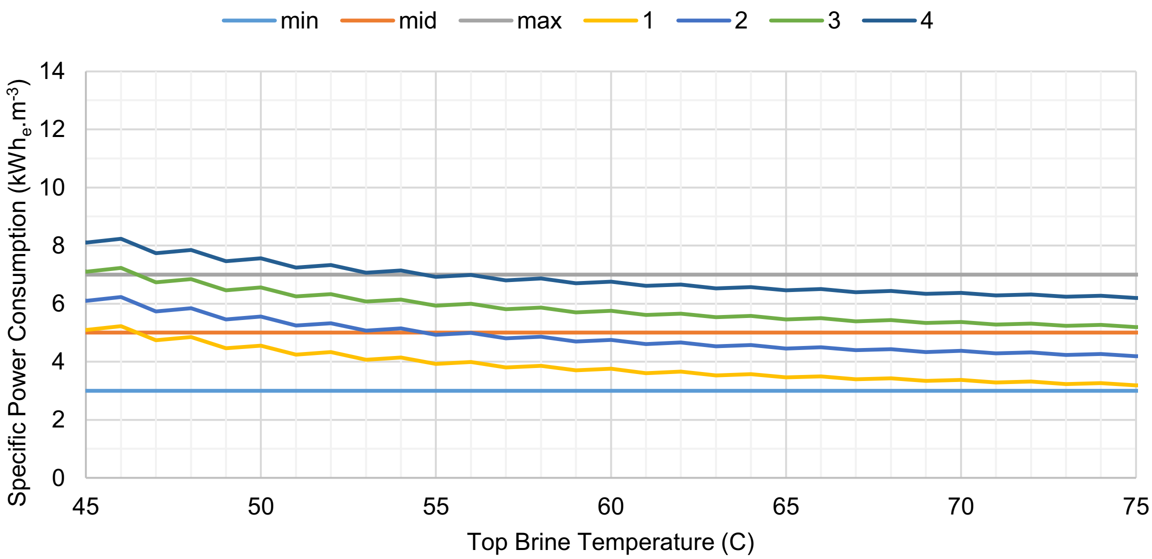

Fig. 14. MED energy cost vs. top brine temperature. Based on Method 2. 1, 2, 3, 4: MED specific electric consumption equal to 1, 2, 3 and 4 $kW_e\,m^{-3}$ respectively. min, mid, and max: minimal, medium and maximal specific electric consumption of the SWRO process as reported in literature.

Table 11. Example of MED process performance calculation (2).

Top brine temperature (°C)	75
Temperature at the final condenser (°C)	33
Average temperature drop between stages (°C)	1.85
Number of stages (–)	22
GOR to number of stages	0.85
GOR (–)	18.7[a]
Pinch point temperature difference, first effect (°C)	5
Steam supply temperature (°C)	80
Specific heat consumption ($kWh_{th}\,m^{-3}$)	34.285
Equivalent electric power consumption ($kW_e\,m^{-3}$) – Basis: 1 $kW_e\,m^{-3}$	2.97
Equivalent electric power consumption ($kW_e\,m^{-3}$) – Basis: 2 $kW_e\,m^{-3}$	3.97
Equivalent electric power consumption ($kW_e\,m^{-3}$) – Basis: 3 $kW_e\,m^{-3}$	4.97
Equivalent electric power consumption ($kW_e\,m^{-3}$) – Basis: 4 $kW_e\,m^{-3}$	5.97

[a] MED manufacturers claim a GOR of 10–16 in working units and up to 30 in designed prototypes [2].

5 Conclusion

Process heat has an energetic and an economic cost that affects the cost of desalination. The exploratory study, described in this paper, attempted to evaluate these costs based on simplified models.

The power conversion system model provided a basis for assessing the "W-cost of heat" (WCH) – number of kW_e of "missed electricity production" per MW_{th} of process power – and the "Q-cost of heat" (QCH) – number of kW_{th} of additional core power (required to keep a constant level of electricity production) per MW_{th}.

The economic model helped evaluate the "E-cost of heat" (ECH), defined as the ratio – cost of heat to cost of electricity – taking into account cogeneration's benefits and constraints.

The three costs – WCH, QCH, and ECH – depend primarily on the level of temperature required by the process. ECH also depends on the economic model's inputs.

This work confirms two conclusions from an earlier study by Rognoni et al. [8]:

– Evaluating the heat cost on the basis of WCH (and the cost of electricity generated by a single-purpose power plant) leads to higher energy costs for MED compared to SWRO.

– A rigorous techno-economic approach, duly considering the benefits of cogeneration, results in lower heat costs, and comparable equivalent electric power consumptions between MED and SWRO.

Energy is an important contributor to the cost of desalted water – a contributor among many others: construction, O&M, chemicals, insurance, labor . . . –. Evaluating the cost of desalted water should take into account *all* the expenses related to the project, including the investments needed to construct (or extend) water transfer and supply networks (IWPPs are generally located far from urban and industrial areas).

Water desalination plants produce huge amounts of reject brine. This brine can be turned into salt [17] or used to convert CO_2 into useful and reusable products such as sodium bicarbonate [18]. These processes – still under development – can potentially improve the economics of seawater desalination while minimizing the impact of brine discharge on the environment.

To identify the most appropriate reactor-process combination for a given site, case-specific evaluations have to be performed, considering the precise characteristics of the power generation system, the reactor to process heat transfer loop, the seawater desalination unit, and the water transport system. Other important factors have also to be considered such as the final use of the product, the quality of the feed, the – intake, pretreatment, post-treatment and brine reject – structures, and the variability of the demand for power and water.

Abbreviations

CAPEX	capital expenditures
DEEP	desalination economic evaluation program (Software)
DPP	dual-purpose plant
ECH	E-cost of heat
ED	electrodialysis
GOR	gain output ratio
HPT	high pressure turbine
IAEA	international atomic energy agency
ICV	interconnected control volumes (software)
IWPP	integrated water and power plant
LPT	low pressure turbine
MED	multi-effect evaporation
MSF	multi-stage flash
NPV	net present value
O&M	operation and maintenance
OPEX	operating expenditures
PCS	power conversion system
PWR	pressurized water reactor
QCH	Q-cost of heat
RO	reverse osmosis
SG	steam generator
SPP	single-purpose plant
SteamEx	steam extraction point
SWRO	seawater reverse osmosis
TBT	top brine temperature
WCH	W-cost of heat

Appendix

Cost of heat vs. temperature at the extraction point.

T	WCH	QCH	ECH	T	WCH	QCH	ECH
33	0	1	7	81	125	345	54
34	3	9	8	82	128	351	55
35	6	17	9	83	130	358	56
36	9	25	10	84	133	364	57
37	12	32	11	85	135	371	57
38	15	40	12	86	137	377	58
39	17	48	14	87	140	384	59
40	20	56	15	88	142	390	60
41	23	63	16	89	144	396	61
42	26	71	17	90	147	403	62
43	28	78	18	91	149	409	63
44	31	86	19	92	151	415	63
45	34	93	20	93	153	422	64
46	37	101	21	94	156	428	65
47	39	108	22	95	158	434	66
48	42	116	23	96	160	440	67
49	45	123	24	97	162	447	68
50	47	131	25	98	165	453	68
51	50	138	26	99	167	459	69
52	53	145	27	100	169	465	70
53	55	152	28	101	171	471	71
54	58	160	29	102	174	478	72
55	61	167	30	103	176	484	73
56	63	174	31	104	178	490	73
57	66	181	32	105	180	496	74
58	68	188	33	106	183	502	75
59	71	195	34	107	185	508	76
60	74	202	35	108	187	514	77
61	76	209	36	109	189	520	78
62	79	216	36	110	191	526	78
63	81	223	37	111	193	532	79
64	84	230	38	112	196	538	80
65	86	237	39	113	198	544	81
66	89	244	40	114	200	550	82
67	91	251	41	115	202	556	82
68	94	258	42	116	204	562	83
69	96	265	43	117	206	568	84
70	99	271	44	118	208	574	85
71	101	278	45	119	211	580	85
72	104	285	46	120	213	586	86
73	106	292	47	121	215	592	87
74	109	298	48	122	217	598	88
75	111	305	49	123	219	603	89
76	113	312	49	124	221	609	89
77	116	318	50	125	223	615	90
78	118	325	51	126	225	621	91
79	121	332	52	127	227	627	92
80	123	338	53	128	230	633	92

T, temperature at the extraction point (°C); WCH, W-cost of heat (kW_e of "missed electricity production" per MW_{th} supplied to the process); QCH, Q-cost of heat (kW_{th} of additional core thermal power per MW_{th} supplied to the process); ECH, E-cost of heat (kW_e of electricity per MW_{th} supplied to the process).

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