Development of Life Cycle Water Footprints for Gas-Fired Power Generation Technologies

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Abstract

The key objective of this paper is to develop a benchmark for water demand coefficients of the complete life cycle of natural gas-fired power generation. Water demand coefficients include water consumption and water withdrawals for various stages of natural gas production as well as for power generation from it. Pathways were structured based on the unit operations of the types of natural gas sources, power generation technologies, and cooling systems. Eighteen generic pathways were developed to comparatively study the impacts of different unit operations on water demand. The lowest life cycle water consumption coefficient of 0.12 L/kWh is for the pathway of conventional gas with combined cycle technology, and dry cooling. The highest life cycle consumption coefficient of 2.57 L/kWh is for a pathway of shale gas utilization through steam cycle technology and cooling tower systems. The water consumption coefficient for the complete life cycle of cogeneration technology is in the range 0.07 - 0.39 L/kWh and for withdrawals ranged 0.10 - 14.73 L/kWh.

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1. **Introduction**

It is expected that natural gas production and demand will increase due to the diversity of its applications, well-established technologies of extraction and conversion, cost competiveness, and attractiveness to environmentalists as a cleaner fuel than other fossil fuels such as coal and oil on combustion. The water footprints for power generation from natural gas can be evaluated through the life cycle assessment (LCA) which is considered as a useful tool in the research community to conduct comparative analysis of the environmental impacts [1]. The province of Alberta is one of the largest natural gas producers in North America and dominates about 70% of the total production in Canada. Other unconventional gas resources in Alberta are coal-bed methane (CBM) which is representing 8% of the total production and about 0.1% from shale gas [2]. Shale gas is one of the unconventional sources that have started to contribute significantly to the production of natural gas. The annual natural gas production in Canada is expected to reach 0.21 trillion cubic meters (tcm) by 2025, and 40% of this production will be from unconventional gas [3]. Researchers, policy makers, and the public have raised concerns about the extraction of this unconventional gas and its environmental impact on water [4-6].. Water use for electricity generation has been a key issue as some power plants have been forced to shut down or have reduced generation due to the water shortage [7,8].

The generation of power through natural gas is expected to increase because of its availability and its ability to compete with other fossil fuels and renewable sources of energy. It has been expected that by 2035 natural gas will overcome coal as the most used source for electricity generation in the world. [9]. Natural gas is also used for cooking, space heating, transportation, hydrogen production, and petrochemical industries, where it is converted to heat or used as a feedstock.

The unit operations associated with natural gas are those related to primary fuel extraction and processing. The impact on the water demand varies according to the natural gas source and the technologies used for processing and transportation. The type of technology and cooling system used for power generation from natural gas are essential unit operations in determining the amount of water required. Electricity can be generated from natural gas without the use of steam through single cycle while combined cycle (NGCC), the steam cycle, and cogeneration necessitate the use of water for steam make-up and cooling [10-12].

Most studies carried out in the water-energy nexus consider only the power generation stage [13-15] without taking into account the fuel cycle, some recognize only water consumption without considering intensive water withdrawals for power generation stage [16-18], and comprehensive studies, including fuel life cycle water demand through detailed pathways, are scarce. Other than that, the broad effects of boundaries, technologies, and power plant's performance on the variability of water demand coefficients have not been captured through sensitivity analysis in earlier studies [19].

There has been study on life cycle water demand on power generation from coal [20]. Grubert et. al.[21] addressed natural gas and coal power generation through complete life cycle for specific geographical boundary (Texas) and for specific technology (NGCC).

One of the motivations to estimate water demand for the first stage of primary fuel extraction is due to the fact that the geographical location of natural gas resources is not controlled by humans, unlike the locations of power plants, which of necessity have to be located near a water source.

The aim of this paper is to develop a life cycle water demand benchmark for power generation from natural gas. The key objectives of this study are:

- To develop and estimate the life cycle water demand for gas-fired power generation including plants with advanced conversion technologies.
- To provide a comparative assessment of the water demand of eighteen different pathways in the conversion of natural gas to power. Pathways were structured to cover the full life cycle based on the unit operations of the gas source, power generation technology, and cooling system used.
- To assess the impacts on the complete life cycle water demand coefficients from using minimum, maximum, and average coefficients of the different unit operations.

2. Methodology

Water demand coefficients were developed to include water consumption and water withdrawals . Water consumption term is defined by USGS [22] to include part of the water withdrawals that is not returned back to the source. This part can be consumed through evaporation (for example from the cooling system of a thermal power plant), transpiration, or direct consumption by a product. Water withdrawal is defined as the total amount of water that diverted from a source.

Water demand coefficients are defined as the amount of water consumed and water withdrawn per unit power generation over life cycle and related as follows:

$$\textbf{Water withdrawals} = \textbf{Water consumption + Returned water} \qquad \textbf{(1)}$$

Natural gas is consumed either in power generation pathways or for heat and other applications. Effects on water demand due to conversion to heat and applications of natural gas other than power generation are not covered in this study, except in the case of cogeneration technology which is covered in a separate section 4.4. Each pathway of electricity generation from natural gas consists of a number of unit operations. This includes unit operations for production of natural gas, its processing, transportation and utilization of power production. Upstream pathways are divided according to the type of natural gas source. Power generation pathways are branched according to the unit operations that affect the water footprints significantly.

In this study, data were developed, gathered from the literature and harmonized at the assumed conversion efficiency for each technology. In the base case, average values for the data are used to represent water demand coefficients for the various upstream and downstream unit operations involved in power generation from natural gas. These developed water demand coefficients for each unit operations are used to estimate the complete life cycle water demand coefficient of gas-fired power generation. Only fresh water was considered in this study. A comprehensive sensitivity analysis is carried out in order to study the uncertainty of using average values in the base case on the complete life cycle water demand coefficients. The average data are taken as the most likely in Monte Carlo simulations model with the consideration for the minimum and maximum values. Annual water consumption and water withdrawals were calculated for each pathway for a 1000 MW gas-fired power plant with assumed capacity factor 80% (7000 hour/year). The unit operations and system boundary considered for this study are shown in Figure 1.

2.1 Selection of gas-fired power generation pathways

Gas-fired power generation pathways are branched according to the technology and cooling system used. Technologies used to generate power from natural gas are single cycle, steam cycle, and NGCC. In this study four types of cooling systems are investigated including once-through cooling, cooling tower, cooling pond, and dry cooling [20].

2.1.1 Single cycle

Gas-fired power plants with single cycle work on the principle of the Brayton cycle by burning a mixture of pressurized air and fuel in a chamber. The exhaust gases are expanded into the turbine, which spins to generate electricity and drive the compressor

[10]. When the gas turbine reaches a high temperature, it needs to be cooled to improve the conversion efficiency. Wet compression, the injection of water into the compressor inlet, is one of the technologies used to improve the performance of gas turbine power plants [23]. Other technologies used to improve performance are evaporative cooling, fogging, mechanical cooling, absorption chillers, and thermal energy storage [23-26].

2.1.2 Steam cycle

Gas-fired power plants can use steam as the working fluid, and the simplest, most practical plant using steam is based on the Rankine cycle. In this cycle, the boiler is fired by natural gas to generate steam that is supplied to the turbine to spin and generate electricity at a low conversion efficiency in the range of 33% to 35% [11]. The steam, after expanding in the turbine, is passed to the condenser and pumped back as water to the boiler [27]. The condensation of steam into water necessitates wet or dry cooling systems.

2.1.3 Combined cycle (NGCC)

The efficiency of the single gas turbine can be improved significantly by incorporating the principles of the Rankine cycle [11]. The exhaust gases from the gas turbine are supplied to the heat recovery steam generator, which is a combination of the Brayton and Rankine cycles [28]. This combination of high and low temperature cycles in the gas and steam turbines, respectively, make this technology one of the most effective in energy conversion [25]. Water is required both for the cooling systems used during the steam cycle and to improve performance in the gas turbine.

2.2 Selection of natural gas upstream pathways

The upstream unit operations for the extraction of natural gas considered in this study includes processes and delivery. Processes have stages of exploration, drilling (drilling mud and casing), fracturing (stimulation), water produced (production), and well abandonment [29,30]. Delivery unit operations include gas transportation, through pipelines, storage, and distribution. Each stage in the system boundary has its own impact on the water footprints of the complete life cycle. The selection of upstream pathways for water footprints depends mainly on the type of natural gas resource, since the unit operation and equipment used may differ according to the type of natural gas. In this study, upstream pathways are initiated from resource types and include conventional, CBM, and shale gas. Other types of natural gas resources such as deep, tight, geo-pressurized, and Methane hydrates [31] are not considered in this study due to the limited data available for water footprints in these pathways.

The conversion efficiency (η) and higher heating value (HHV) in (kJ/m^3) are used to estimate the water demand coefficients (WDC) (includes water consumption and water withdrawals in L/kWh) for the upstream stage with respect to the unit of power to be generated:

$$\mathbf{WDC = 3600 * COE / (HHV * \eta)} \qquad \textbf{(2)}$$

In equation (2): 1 kWh = 3600 kJ is used for conversion and COE is the upstream water demand coefficient (water consumption and water withdrawals) in litres of water per cubic meter of gas (L/ m^3).

3. Assumptions and input data

Table 1 shows the assumptions taken in this study for higher heating value (HHV) of natural gas and conversion efficiencies for different technologies of gas-fired power plants. Table 2 shows the minimum, maximum, and average water demand coefficients for the upstream stage and the assumptions of Table 1 are used to convert the average coefficients from L/m^3 to L/kWh using equation (2) for the analysis of the base case. The water consumption coefficient for gas upstream pathways is assumed to be equal to the water withdrawals coefficient [19], which indicates that no water is returned to the source after being diverted. The minimum water demand coefficients for the upstream stage are all assumed with no fresh water is consumed/ withdrawn and the required amount is fully satisfied from the produced water.

The conversion efficiency of a natural gas combined cycle (NGCC) power plant (η_{cc}) is assumed to be 60%, for single cycle (η_{sc}) 40%, and for steam cycle (η_{st}) 33%. The assumed conversion efficiencies are related and should satisfy the following governing equation [40]:

$$\eta_{cc} = \eta_{sc} + \eta_{st} - \eta_{sc} * \eta_{st} \tag{3}$$

With these conversion efficiencies, a gas turbine would generate two-thirds and a steam turbine would generate the remaining one-third of the total generated by an NGCC power plant [41]. Input data for the power generation stage as shown in Table 3 were gathered from literature and harmonized at the assumed conversion efficiency values. Table 4 gives the maximum and minimum ranges as well as the considered average values for water-demand coefficients of the power generation stage. Water is not required for dry cooling, and many studies have assumed that the total water demand is about one-tenth that of wet re-circulating systems and used for other plant operations such as boiler make-up, system maintenance, and cleaning [46-48]. The same assumption is followed in this study for the dry cooling and taken as 10%.

4. Results and discussion

4.1 Water demand for the upstream stage

Equation (2), Table 1, and Table 2 were used to obtain the water demand coefficients for natural gas upstream processes as shown in Figure 2. The water footprint of this stage is determined mainly by the gas source and the performance of the power generation technology. The source affect the water demand through the unit operations, and the technology impact the water demand through the amount of gas used to generate a specific unit of power. A considerable amount of water is required for hydraulic fracturing in the case of shale gas [17, 29], and a huge amount of water is produced during the extraction of coal-bed methane (CBM) [29, 49]. The amount of fresh water required during the upstream stage does not depend only on the amount of water produced, but on the portion of that water re-injected, which has to be of a certain quality [50]. The more efficient power generation technology would consume less energy to produce a specific unit of power and consequently would use less natural gas and water. Pathways from the same power generation technology and using conventional gas or CBM have nearly the same water demand coefficient.

4.2 Water demand for the power generation stage

Figure 3 shows the water consumption and water withdrawals coefficients for the second stage of the power generation life cycle based on the average data shown in Table 4. The effect of the minimum and maximum values would be studied in the sensitivity analysis section. Besides the power generation technology, the most determining water demand factor in this stage is the cooling system type. Dry cooling systems have very low water demand coefficients. Single-cycle power plants have low water demand coefficients in this stage because no condenser or steam is used. The conversion efficiency of the power generation technology in this second stage determines the level of water demand. The conversion efficiency of the power plant is important, and it affects the two stages of the life cycle (natural gas upstream stage and power generation stage).

4.3 Water demand coefficients for the complete life cycle

Two stages of fuel extraction and power generation from natural gas, as detailed in Figures 2 and 3, are combined in Table 5 to give the water demand coefficients over the complete life cycle (because of the closeness of values for the natural gas and CBM are presented together in one line in Table 5). These combined coefficients represent benchmarks for generic water demand coefficients associated with the type of natural gas source, power generation technology, and cooling system.

The lowest water demand coefficients (0.12 L/kWh for consumption and 0.15 L/kWh for withdrawals) are achieved through the pathway that uses conventional gas or CBM to generate power through NGCC technology and dry cooling. These lowest coefficients are achieved due to the low water requirement for conventional gas, CBM, and dry cooling, along with the highest conversion efficiency of NGCC technology. The highest water consumption coefficient (2.57 L/kWh) is seen in the pathway that uses shale gas with a steam cycle and cooling tower. Ninety per cent of this full life cycle-based coefficient is from the power generation stage and 10% from the gas upstream stage. Improving this technology's conversion efficiency is a solution to the intensive consumption of water in this pathway. A further improvement in NGCC technology efficiency would decrease the same highest water consumption coefficient by 70% to 0.77 L/kWh, and even this last coefficient could be improved 74% further to reach 0.20 L/kWh through dry cooling, so the total reduction in water consumption over the complete life cycle would be 92% (from 2.57 L/kWh to 0.20 L/kWh).

The once-through cooling system has the greatest impact on the water withdrawals coefficient, and, when considering the complete life cycle, all pathways using once-through cooling have more than 99% of water withdrawn during the power generation stage. On average and for the complete life cycle of all pathways that use once-through cooling systems, 1% of the water withdrawn is consumed. Based on all 18 developed pathways, water consumed for the power generation stage averaged 76% of the total life cycle consumption and the remaining 24% was consumed during the upstream fuel extraction stage. For water withdrawal, 86% is the average for the power generation stage and 14% for the upstream fuel extraction stage. The range of annual water consumption for a 1000 MW gas-fired power plants is 833 – 18,014 million liters (220 – 4,762 million U.S. gallons) and water withdrawals 1,064 – 969,804 million liters (281 – 256,358 million U.S. gallons).

4.4 The effect of cogeneration technology on the water footprints

Cogeneration or combined heat and power (CHP) refers to the simultaneous production of electricity and thermal power from one source of energy [12]. This thermal power can be used for heating or cooling in different sectors such industrial, commercial, or residential. The combined efficiency of the cogeneration power plant is higher than the efficiency of a single application for an electricity generation plant. Adding cogeneration to an existing electricity generation power plant can improve conversion efficiency from 45% to 80% [12, 51]. The major fuel used for cogeneration in the U.S. is natural gas [52], and district heating, of great concern to researchers, is one of the promising applications of cogeneration in which space heating and electricity generation are combined [52-54]. Cogeneration based on NGCC technology is considered in this study to be a significant improvement on plant performance. Cogeneration pathways are extrapolated from the related NGCC pathways with the conversion efficiency (η_{cg}) extended to 75%. The increase in the conversion efficiency of cogeneration technology is assumed to be from the steam cycle portion [20], with its constant, single cycle performance at η_{sc}=40%. Table 6 shows the resulted ranges of water demand coefficients for cogeneration pathways during the power generation stage and Table 7 detailed the disaggregated water demand for the complete life cycle of cogeneration.

Based on the complete life cycle, the minimum water demand coefficients (0.07 L/kWh for consumption and 0.10 for withdrawals) for cogeneration pathways is achieved when conventional gas is utilized with dry cooling technology and the maximum consumption is with shale gas and cooling pond (0.39 L/kWh for consumption and 0.69 for withdrawals).

During the upstream stage of the gas production life cycle, a pathway through a CBM source using steam cycle would have a very close water demand coefficient (0.10 L/kWh in Figure 2) to a different pathway through a shale gas source using cogeneration (0.11 L/kWh in Table 7). Although the two pathways have different gas sources, the cogeneration technology would compensate for the extra water used during the fuel extraction stage.

5. Sensitivity analysis

The average values of water demand coefficients assumed for the base case are taken as input with the associated minimum and maximum ranges in a model using Monte Carlo simulations to study the uncertainty of the obtained results. Triangle distribution is used through ModelRisk software [55] and the inputs for upstream stage are based on Table 2 data and for the power generation stage are based on Table 4 data. Inputs for cogeneration are based on Table 6.

5.1 Upstream stage

Figure 4 shows the distribution of the probability percentiles for the water demand coefficients during the upstream stage. The considered average values for natural gas (0.357 L/m^3), for CBM (0.361 L/m^3), and for shale gas (0.888 L/m^3) have probability percentiles of 72%, 73%, and 58%, respectively. The low probability for shale gas is due to the wide variability in the gathered data and also because of the technology being in the stage of early stage development. The average values considered in the base case for natural gas and CBM during the upstream stage are more reliable and the range between minimum and maximum is narrower than the shale gas case.

5.2 Power generation stage

Distribution of water consumption coefficients during the power generation stage is shown in Figure 5 for pathways involved dry cooling, Figure 6 for pathways through NGCC, cogeneration, and single cycle. Figure 7 for steam cycle technology pathways. The lowest probability for the most likely value (0.09 L/kWh) is 9% for the consumption coefficient of single cycle. This most likely value has been taken closer to the minimum value (0.00 L/kWh) compared to the maximum (1.06 L/kWh) which is derived from Meldrum et al. [19] and led to this low probability. The most likely water consumption coefficient of cogeneration with once through cooling (0.19 L/kWh) has been calculated from the gathered data and resulted in the highest probability percentile of 83%.

Table 8 shows the distribution of water withdrawals coefficients during the power generation stage at probability 10%, 90%, and the probability percentile of the most likely value (average) taken at the base case. The lowest probability 27% is obtained for the steam cycle with cooling tower. Water withdrawals coefficient for single cycle has a probability of 28% and its probability is affected as in the consumption coefficient by the very high maximum value (1.34 L/kWh). The base case water withdrawals coefficient for cogeneration with dry cooling has the highest certainty with probability 75%.

6. Conclusions

The conversion efficiency of a gas-fired power plant has a significant effect on water demand. The conversion efficiency affects both upstream gas extraction and power generation. The higher water demand from specific types of gas sources can be compensated for with efficient power generation technology. The cooling system used is also essential in determining the level of water required. Dry cooling could improve water demand performance, though there are uncertainties related to economic feasibility and overall conversion efficiency. Water demand is higher during power generation from natural gas than during the fuel extraction stage. Water withdrawals coefficients during power generation for gas-fired power plants using once-through cooling systems are higher than for plants using other cooling systems. With once-through cooling systems, a smaller percentage of withdrawn water is consumed. The water consumption coefficient for the complete life cycle of gas-fired power generation pathways ranged between 0.12 to 2.57 L/kWh, the corresponding water withdrawals ranged between 0.15 to 3.13 L/kWh for closed loop cooling systems, and 40.95 to 138.54 L/kWh for once-through cooling systems.

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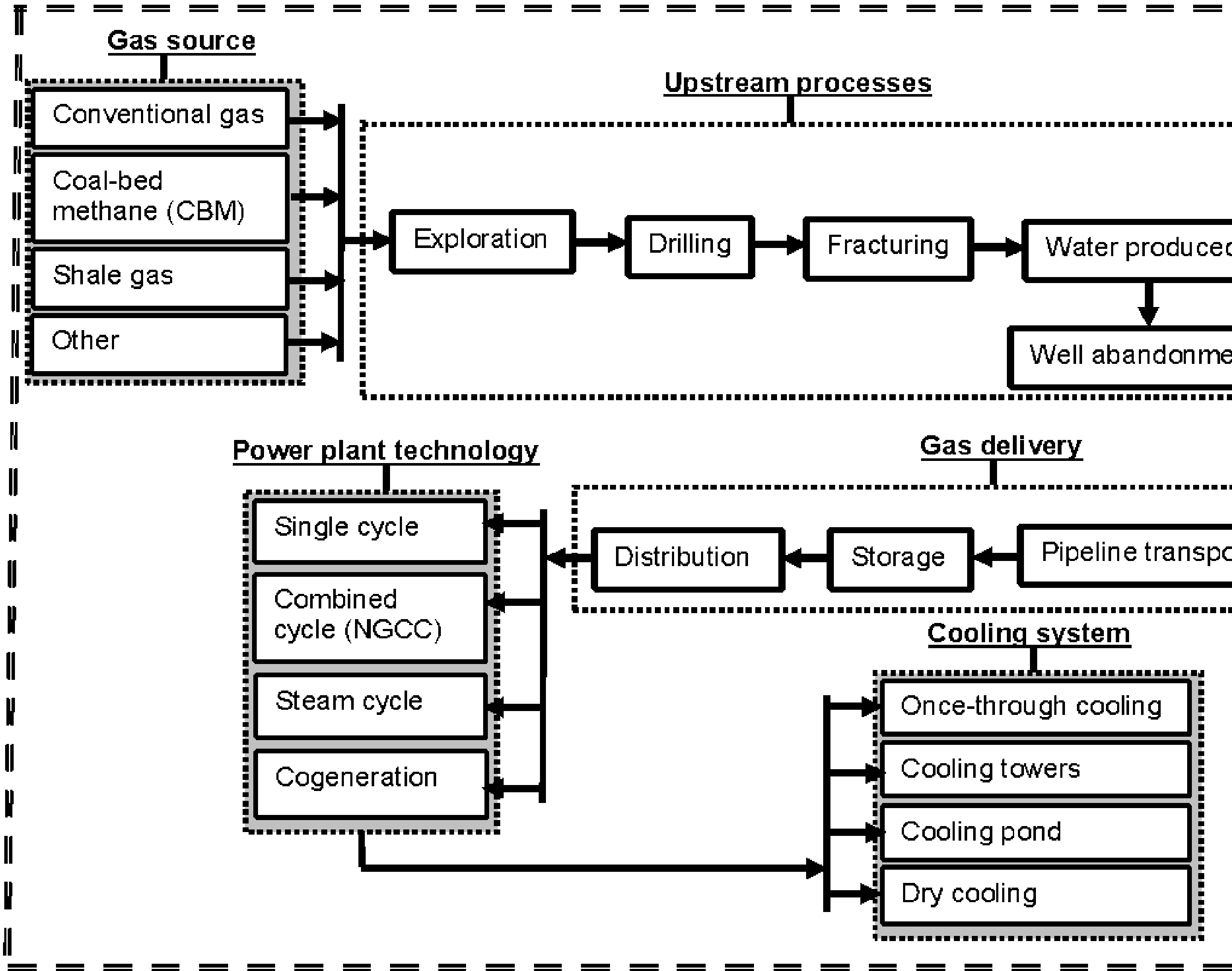

Figure 1: System boundary and unit operations for gas-fired power generation

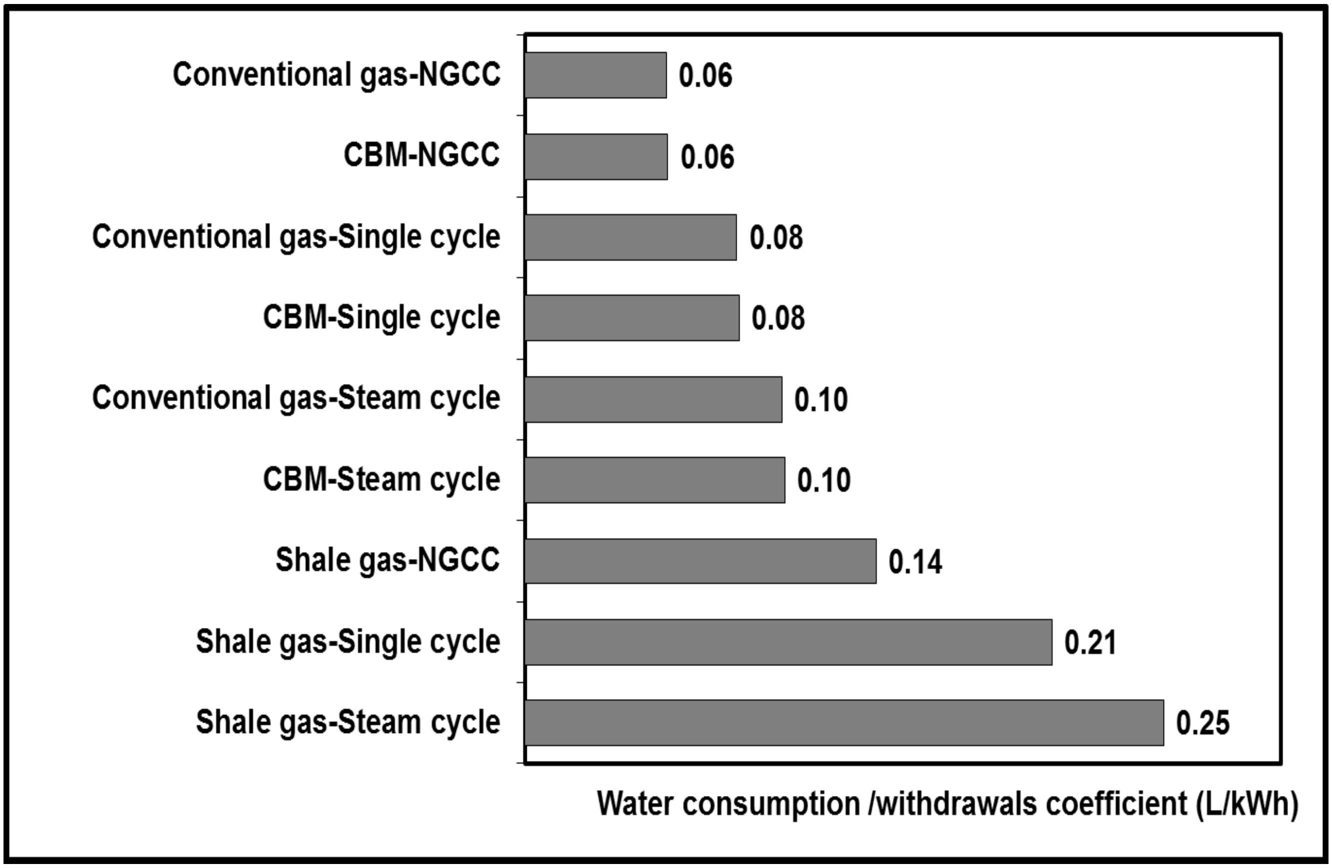

Figure 2: Water demand coefficients for the upstream stage of natural gas extraction

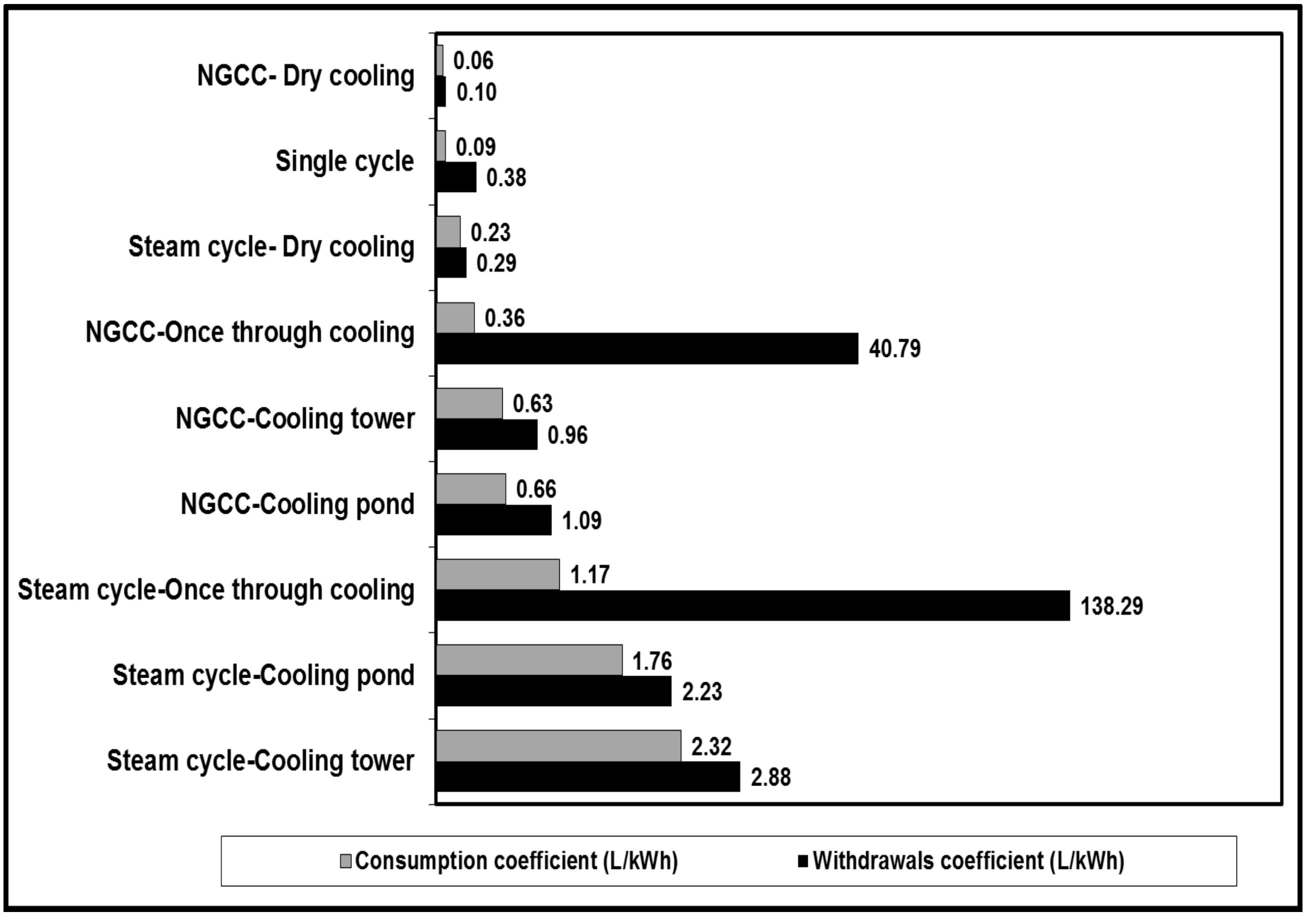

Figure 3: Water demand coefficients for the stage of power generation from natural gas

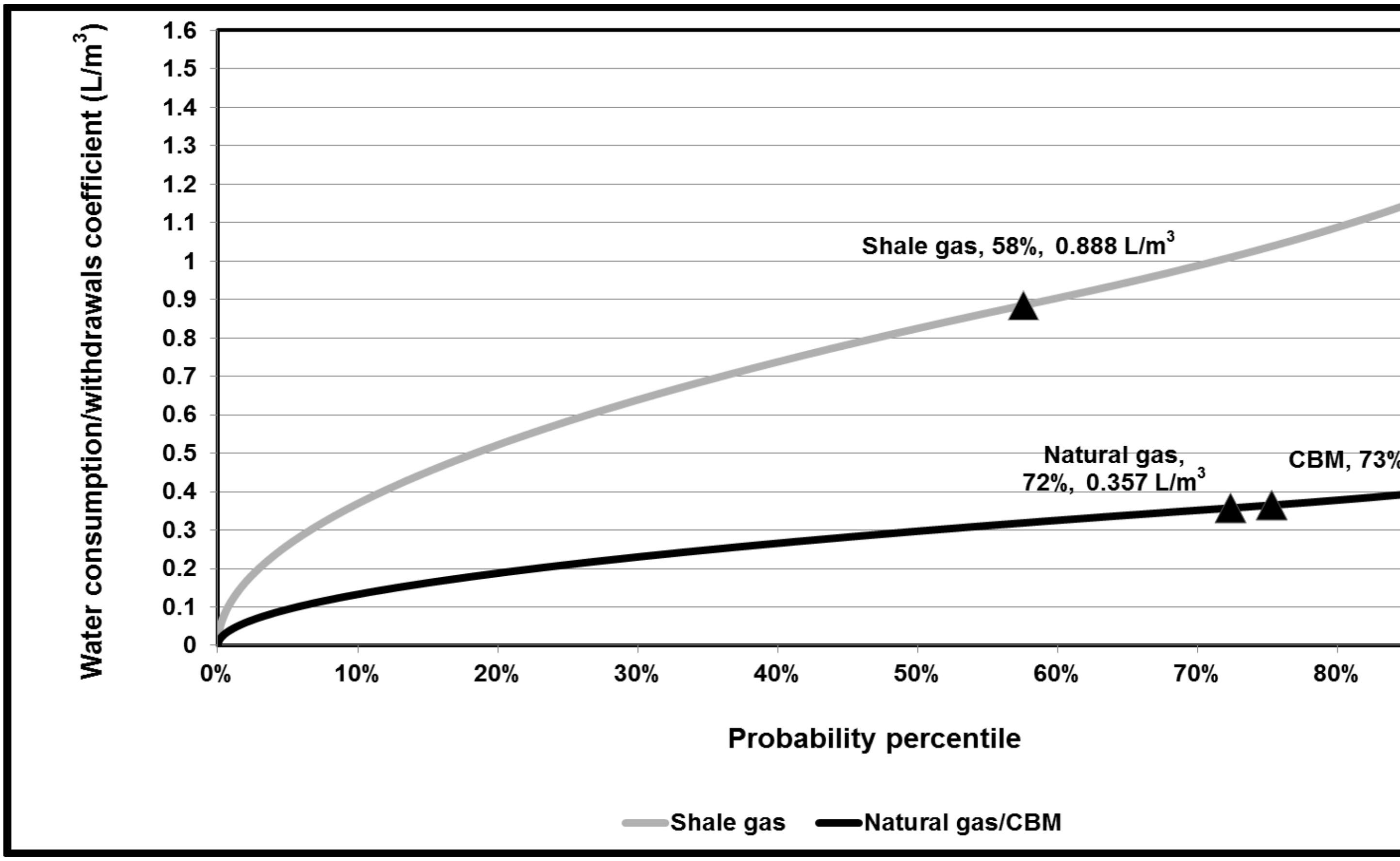

Figure 4: Distribution of water demand coefficients for natural gas upstream stage

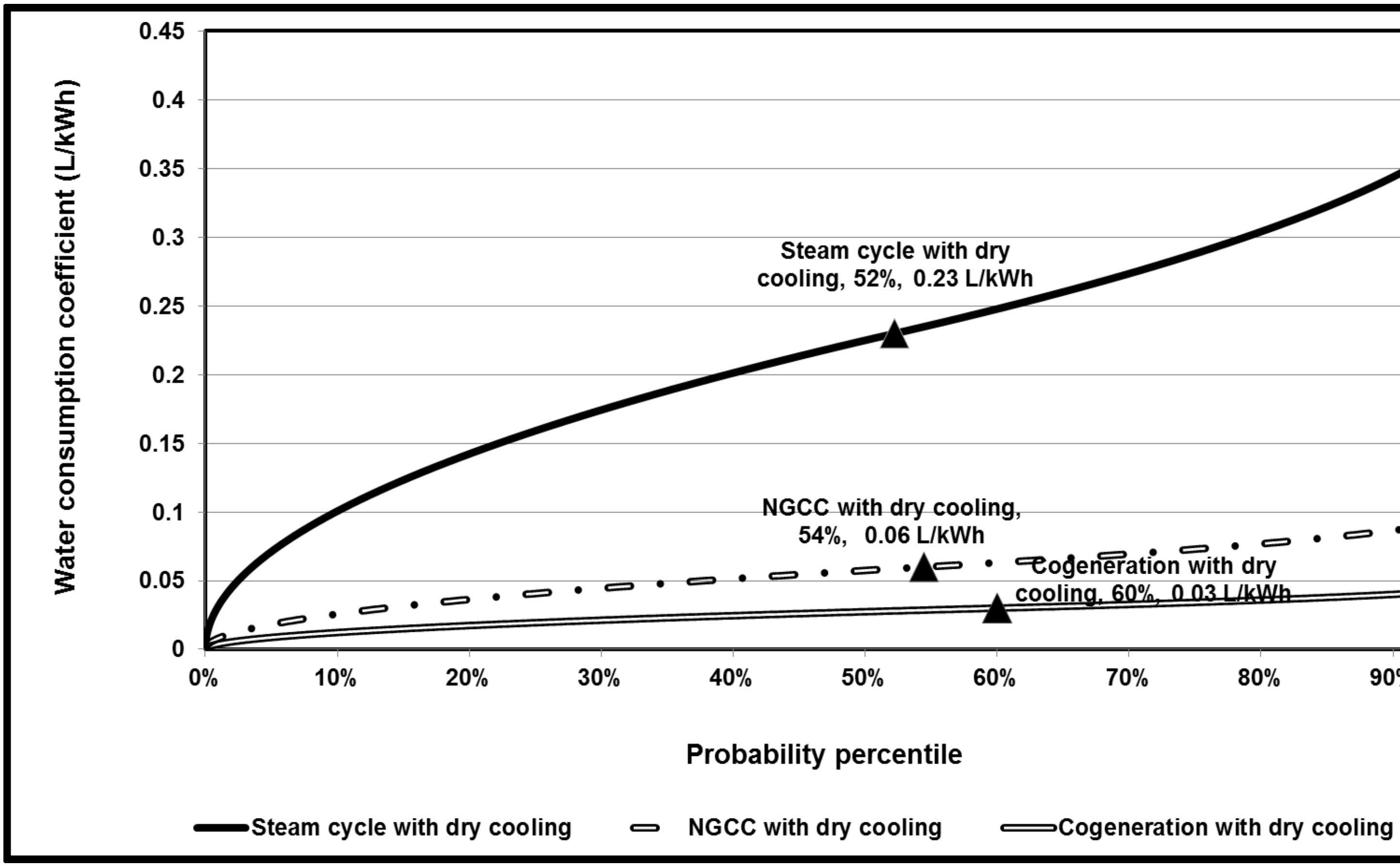

Figure 5: Distribution of water consumption coefficients for pathways with dry cooling during the power generation stage

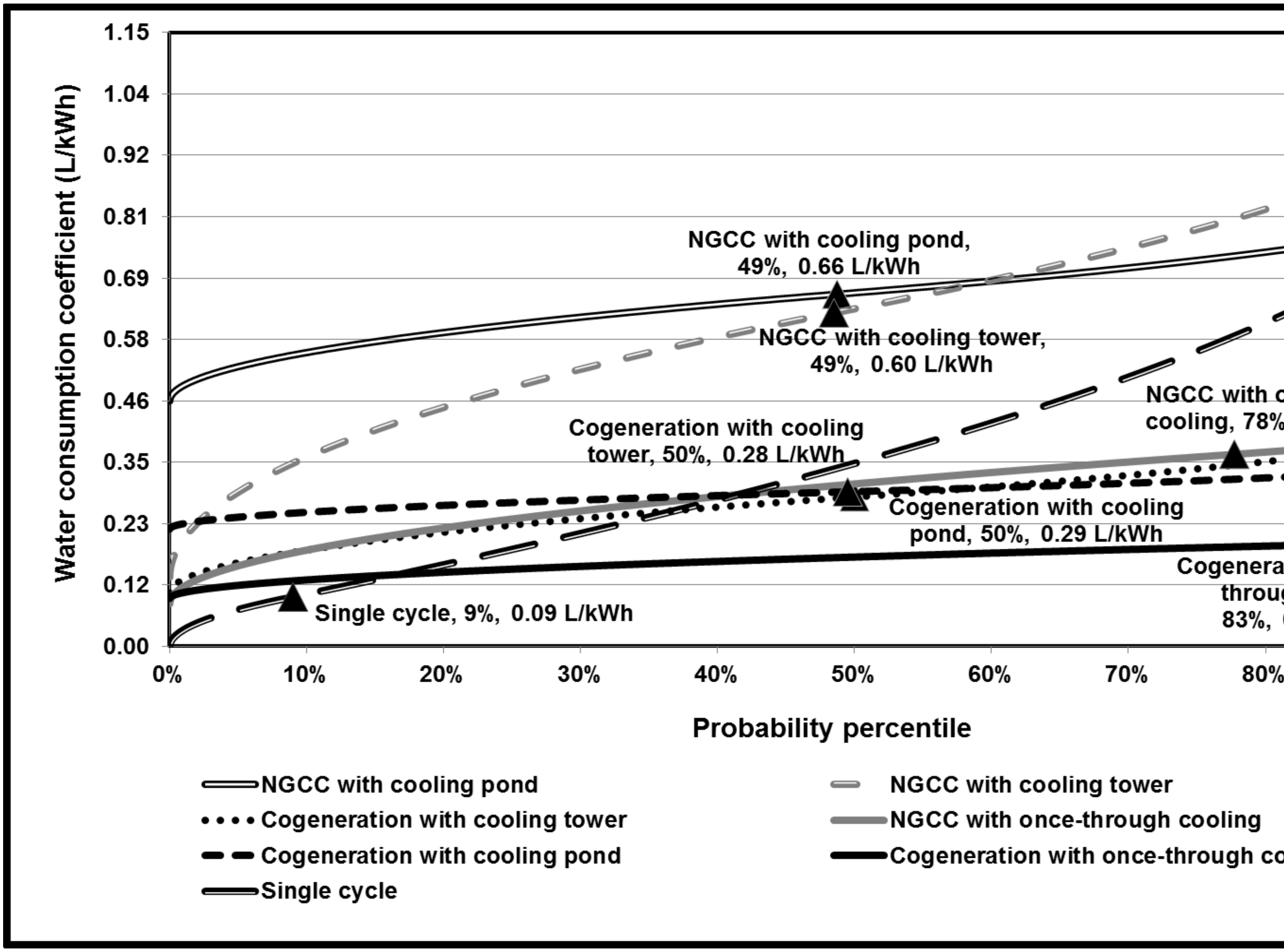

Figure 6: Distribution of water consumption coefficients for pathways through NGCC, cogeneration, and single cycle during the power generation stage

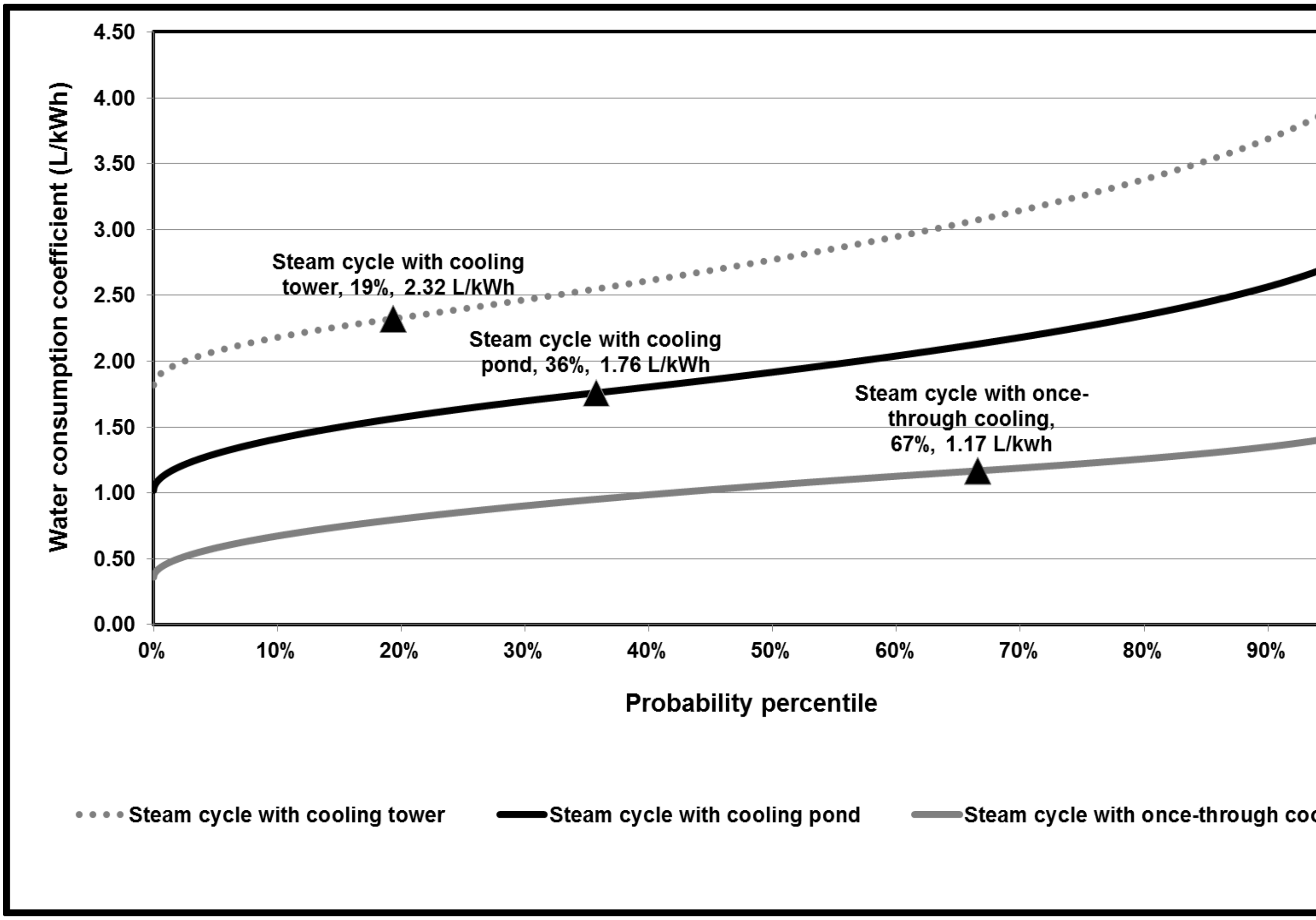

Figure 7: Distribution of water consumption coefficients for pathways through steam cycle during the power generation stage

Table 1: Assumptions for natural gas and power plant characteristics

Items	Values	Comments/Sources
Higher heating value (HHV) of natural gas	38,230 kJ/ m^3	Typical average heat content of natural gas delivered to consumers in the U.S. based on the period 2003-2011 [32]
Conversion efficiency of a single cycle power plant at HHV (η_{sc})	40%	Assumed based on literature [17,33,34]
Conversion efficiency of an NGCC power plant at HHV (η_{cc})	60%	Assumed based on literature [34-37]
Conversion efficiency of a steam power plant at HHV (η_{st})	33%	Assumed based on literature [17,33,38]
Conversion efficiency of a cogeneration power plant at HHV (η_{cg})	75%	Assumed based on literature [12,19,33,38]

Table 2: Ranges for water-demand coefficients of natural gas upstream pathways

Pathway	Conventional gas (L/m^3)			Shale gas (L/m^3)			Coal bed methane (CBM) (L/m^3)			Comm
	Min.	Average	Max.	Min.	Average	Max.	Min.	Average	Max.	
Exploration	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	Assur literat 29]
Drilling	0.000	0.045	0.068	0.000	0.045	0.068	0.000	0.045	0.068	Assur literat
Extraction	0.000	0.003	0.01	0.000	0.534	1.048	0.000	0.007	0.01	Assur literat 29, 39 fractu this st
Processing	0.000	0.194	0.278	0.000	0.194	0.278	0.000	0.194	0.278	Assur literat 29] ar is the types
Transport	0.000	0.115	0.139	0.000	0.115	0.139	0.000	0.115	0.139	Assur literat 29] ar the sa differe sourc
Total	**0.000**	**0.357**	**0.495**	**0.000**	**0.888**	**1.533**	**0.000**	**0.361**	**0.495**	These used analys upstre

Table 3: Input data for water-demand coefficients during the power generation stage of gas-fired power plants

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments/Sources
Single cycle	0.04	0.04	Mentioned as “other use” to include water f cooling, equipment washing, emission trea U.S. DOE [42]. The withdrawals coefficient equal to the consumption coefficient.
	0.16	1.34	Median taken from Meldrum et al. [19], with L/kWh for consumption, and harmonized a
	0.14	0.14	Derived from Clark et al. [17] and harmoniz

			withdrawals coefficient is assumed to be ec consumption coefficient.
	0.00	0.00	Mentioned as zero [43] or not specified in s 16, 39] and assumed to be zero in this stuc
	0.09	0.38	Average value used for the analysis in this cycle.
Steam cycle with once-through cooling	1.14	75.76	For U.S. thermal power plants based on ΔT Goldstein and Smith [14]).
	1.14	189.39	For U.S. thermal power plants based on ΔT Goldstein and Smith [14]).
	1.57	157.35	Theoretical withdrawals coefficient calculat ΔT=20 °F [20] and consumption coefficient of the withdrawals (from Goldstein and Sm
	1.10	136.36	Median taken from Meldrum et al. [19] with 0.72 – 1.55 L/kWh.
	0.91	132.58	Median taken from Macknick et al. [13] with 0.36 – 1.10 L/kWh and withdrawals range 3 L/kWh.
	1.17	138.29	Average value used for the analysis in this cycle using once-through cooling systems.
Steam cycle with closed-loop using cooling tower	1.82	1.89	Based on cooling water demand for the U.S concentration =10 (from Goldstein and Sm
	1.82	2.27	Based on cooling water demand for the U.S concentration = 5 (from Goldstein and Smi
	1.85	2.11	Typical evaporation from cooling systems f calculated theoretically for a 1000 MW pow =33% and ΔT=18 °F [44]. Withdrawals coe theoretically at a recycling turns =7[20].
	2.28	2.61	Typical evaporation from cooling systems f calculated theoretically for a 1000 MW pow =33% and ΔT=18 °F [44]. Withdrawals coe theoretically at a recycling turns =7[20].
	2.41	3.01	Theoretical coefficients calculated at a = 80 =33%, and C =5 [20].
	2.41	2.68	Theoretical coefficients calculated from equ 80%, WT=80°F, η_{st} =33%, and C =10 [20].
	2.77	4.55	Median taken from Meldrum et al. [19] with 2.12 – 4.17 L/kWh.
	2.13	2.43	Average used by [17] for analysis and harn Withdrawals coefficient calculated theoretic turns =7[20].
	3.13	4.56	Median taken from Macknick et al. [13] with 2.51 – 4.43 L/kWh and withdrawals range 3
	2.58	2.69	Estimated coefficients for Texas, U.S. [45].
	2.32	2.88	Average value used for the analysis in this

			cycle using cooling tower systems.
Steam cycle with closed-loop using cooling pond	1.02	1.14	Based on cooling water demand for the U.S concentration =10 (from Goldstein and Sm
	1.89	2.27	Based on cooling water demand for the U.S concentration = 5 (from Goldstein and Smit
	1.02	1.71	Median for consumption coefficient taken fr withdrawals coefficient calculated as avera and Smith [14]).
	3.09	3.81	Calculated as stated by Gleick [16]: 30% h corresponding wet cooling towers.
	1.76	2.23	Average value used for the analysis in this cycle using cooling pond systems.
NGCC with once-through cooling	0.44	43.27	Based on the assumption that two-thirds of is from gas turbines and one-third from ste
	0.38	28.41	For U.S. thermal power plants based on ΔT Goldstein and Smith [14]).
	0.38	75.76	For U.S. thermal power plants based on ΔT Goldstein and Smith [14]).
	0.22	15.71	Median value from Meldrum et al. [19] and =60%[20].
	0.36	40.79	Average value used for the analysis in this cycle using once-through cooling systems.
NGCC with closed-loop using cooling tower	0.85	1.23	Based on the assumption that two-thirds of is from gas turbines and one-third from ste
	0.41	0.64	Median value from Meldrum et al. [19] with 0.13 – 0.57 L/kWh, withdrawals range 0.47 harmonized at η_{cc} =60%[20].
	0.24		Derived from Clark et al. [17] and harmoniz
	0.78	0.97	Median taken from Macknick et al. [13] with 0.49 – 1.14 L/kWh.
	0.87	0.98	Estimated coefficients for Texas, U.S. [45].
	0.63	0.96	Average value used for the analysis in this cycle using cooling tower systems.
NGCC with closed loop using cooling pond	0.65	1.00	Based on the assumption that two-thirds of is from gas turbines and one-third from ste
	0.46		Median taken from Meldrum et al. [19] and =60%[20].
	0.87	1.17	Calculated as stated by Gleick [16]: 30% h corresponding wet cooling towers.
	0.66	1.09	Average value used for the analysis in this using cooling pond systems.

Table 4: Ranges of water demand coefficients for the power generation stage[a]

Pathway	**Consumption coefficient (L/kWh)**			**Withdrawals coefficient (L/kWh)**		
	Min.	Average	Max.	Min.	Average	Max.
Single cycle	0.00	0.09	1.06	0.00	0.38	1.34
Steam cycle with once-through cooling	0.36	1.17	1.57	37.88	138.29	227.27
Steam cycle with cooling tower	1.82	2.32	4.43	1.89	2.88	5.53
Steam cycle with cooling pond	1.02	1.76	3.09	1.14	2.23	3.81
Steam cycle with dry cooling	0.00	0.23	0.44	0.00	0.29	0.55
NGCC with once-through cooling	0.08[b]	0.36	0.44	15.71	40.79	75.76
NGCC with cooling tower	0.13	0.63	1.14	0.47	0.96	1.52
NGCC with cooling pond	0.46	0.66	0.87	1.00	1.09	1.17
NGCC with dry cooling	0.00	0.06	0.11	0.00	0.10	0.15

[a]Ranges are based and abstracted from Table 3.
[b]Taken from Macknick et al. [13]
All minimum coefficients for dry cooling pathways are assumed with 0.00 L/kWh

Table 5: Water demand for the complete life cycle of gas-fired power plant pathways

No.	Pathway	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumptio for a 1000 M plant (million L/yea
1	Conventional gas/CBM-Single cycle	0.17	0.46	1,218
2	Shale gas-Single cycle	0.30	0.59	2,093
3	Conventional gas/CBM-Steam cycle-Once-through cooling	1.27	138.39	8,903
4	Conventional gas/CBM-Steam cycle-Cooling tower	2.42	2.98	16,953
5	Conventional gas/CBM-Steam cycle-Cooling pond	1.86	2.33	13,033
6	Conventional gas/CBM-Steam cycle-Dry cooling	0.33	0.39	2,337
7	Shale gas-Steam cycle-Once-through cooling	1.42	138.54	9,964
8	Shale gas-Steam cycle-Cooling tower	2.57	3.13	18,014
9	Shale gas-Steam cycle-Cooling pond	2.01	2.48	14,094
10	Shale gas-Steam cycle-Dry cooling	0.49	0.54	3,398
11	Conventional gas/CBM-NGCC-Once-through cooling	0.42	40.85	2,912
12	Conventional gas/CBM-NGCC-Cooling tower	0.69	1.02	4,802
13	Conventional gas/CBM-NGCC-Cooling pond	0.72	1.15	5,012
14	Conventional gas/CBM-NGCC-Dry cooling	0.12	0.15	833
15	Shale gas-NGCC-Once-through cooling	0.50	40.93	3,496
16	Shale gas-NGCC-Cooling tower	0.77	1.10	5,386

17	Shale gas-NGCC-Cooling pond	0.80	1.23	5,596
18	Shale gas-NGCC-Dry cooling	0.20	0.24	1,417

Table 6: Ranges of water demand coefficients for cogeneration pathways during the power generation stage**

Pathway	Consumption coefficient (L/kWh)			Withdrawals coefficient (L/kWh)		
	Min.	Average	Max.	Min.	Average	Max.
Cogeneration with once-through cooling	0.09	0.19	0.21	5.78	14.62	26.94
Cogeneration with cooling tower	0.1	0.28	0.46	0.41	0.58	0.78
Cogeneration with cooling pond	0.22	0.29	0.36	0.60	0.63	0.66
Cogeneration with dry cooling	0.00	0.03	0.05	0.00	0.06	0.08

** Ranges are extrapolated from NGCC pathways in Table 4.

Table 7: Disaggregated water demand for the cogeneration pathways

No.	Pathway	Upstream stage	Power generation stage		Comp
		Consumption/ withdrawals coefficients (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consu coef (L/
1	Conventional gas/CBM-Cogeneration-Once-through cooling	0.04	0.19	14.62	0
2	Conventional gas/CBM-Cogeneration-Cooling tower	0.04	0.28	0.58	0
3	Conventional gas/CBM-Cogeneration-Cooling pond	0.04	0.27	0.63	0
4	Conventional gas/CBM-Cogeneration-Dry cooling	0.04	0.03	0.06	0
5	Shale gas-Cogeneration-Once-through cooling	0.11	0.19	14.62	0
6	Shale gas-Cogeneration-Cooling tower	0.11	0.28	0.58	0
7	Shale gas-Cogeneration-Cooling pond	0.11	0.27	0.63	0
8	Shale gas-Cogeneration-Dry cooling	0.11	0.03	0.06	0

Table 8: Distribution of water withdrawals coefficients during the power generation stage

Pathway	Water withdrawals coefficient (L/kWh) at probability 10%	Water withdrawals coefficient (L/kWh) at probability 90%	Probability percentile of the most likely water withdrawals coefficient (%)
Single cycle	0.23	0.98	28
Steam cycle with once-through cooling	81.44	186.10	53
Steam cycle with cooling tower	2.49	4.55	27
Steam cycle with cooling pond	1.68	3.16	41
Steam cycle with dry cooling	0.13	0.43	53
NGCC with once-through cooling	28.02	61.20	42
NGCC with cooling tower	0.70	1.28	46
NGCC with cooling pond	1.04	1.13	53
NGCC with dry cooling	0.04	0.12	67
Cogeneration with once-through cooling	10.10	21.81	42
Cogeneration with cooling tower	0.49	0.69	46
Cogeneration with cooling pond	0.61	0.65	50
Cogeneration with dry cooling	0.02	0.07	75

Table 9: Nomenclature

CBM	coal-bed methane
CHP	combined heat and power
COE	water consumption/withdrawals coefficient in litres of water per m^3 of natural gas for upstream pathways
DOE	Department of Energy
EIA	the U.S. Energy Information Administration
HHV	higher heating value
kJ	kilojoule, unit of energy equal to 1,000 Joule
LCA	life cycle assessment
L/kWh	litres of water per kWh of electricity generated
L/year	litres of water per year of operation
m^3	cubic metre, a unit of volume in the metric system, equal to a volume of a cube with edges one metre
NGCC	natural gas combined cycle
tcm	trillion cubic meters, equal to 10^{12} metres
U.S.	United States of America
WDC	water consumption/withdrawals coefficient in litres of water per kWh generated in upstream pathways
η	conversion efficiency of the power plant from fuel heat content up to the electricity generated
η_{cc}	total conversion efficiency of a NGCC power plant
η_{cg}	conversion efficiency of a cogeneration gas-fired power plant
η_{pst}	the conversion efficiency of the portion of power generated by steam cycle in an NGCC power plant
η_{sc}	conversion efficiency of a single cycle gas-fired power plant

η_{st}	conversion efficiency of a steam cycle gas-fired power plant