

Synthesis on the Economics of Nuclear Energy

Study for the European Commission, DG Energy

Final Report

November 27, 2013

William D. D'haeseleer

Professor at the University of Leuven (KU Leuven), Belgium

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List of Abbreviations, Acronyms & Symbols

ABWR	Advanced Boiling Water Reactor
ASN	Autorité de Sûreté Nucléaire
BEC	Bare Erected Cost (part of the OCC)
BEPA	Bureau of European Policy Advisors
BWR	Boiling Water Reactor
CBA	Cost-Benefit Analysis
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDF	Core Damage Frequency
CEZ	Czech electricity Company
CH	<i>“Confoederatio Helvetica”</i> ; ISO abbreviation for Switzerland
CHP	Combined Heat & Power
CPI	Consumer Price Index
CRF	Capital Recovery Factor
D&P	Du and Parsons
DALY	Disability-Adjusted Life Years (note that it is a <i>loss</i> of Life Years, equal to YOLL + YLD; this is an “effective” loss of healthy life expectancy)
DK	Denmark
EdF	Electricité de France
EEA	European Economic Area
EGE	European Group on Ethics (in Science and New Technologies)
EPC	Engineering, Procurement & Construction
EPCC	Engineering, Procurement & Construction Cost = BEC + EPC contractor services
EPCCI	European Power Capital Cost Index (from IHS CERA)
EPR	European Pressurized Reactor
Esc1	Escalation option 1
Esc2	Escalation option 2
Esc3	Escalation option 3
EUR	European Utility Requirements
EUR	the Euro currency
FAO	Food and Agriculture Organization (of the United Nations)
FOAK ₁	First of a Kind of the first sort, i.e., the very first unit of a particular reactor type
FOAK ₂	First of a Kind, of the second sort, i.e., the first unit of a particular type in a particular country
GDA	General Design Assessment
GdF	Gaz de France
GDP	Gross Domestic Product
G€	Giga Euro, being 10 ⁹ EUR, or thus 1 billion EUR.
GER	Germany
GHG	Greenhouse Gas
GRS	Gesellschaft für Anlagen- und Reaktorsicherheit
HDR	Hot Dry Rock
ICRP	International Commission on Radiological Protection
IDC	Interest during Construction
IPA	Impact-Pathway Analysis
IRR	Internal Rate of Return

IRSN	Institut de Radioprotection et de Sûreté Nucléaire
kW	kilo-Watt
LCOE	Levelized Cost of Electricity
LE	Life Expectancy
LERF	Large Early Release Frequency
LHS	Left Hand Side
LLE	Loss of Life Expectancy
LTO	Long-Term Operation
MCDA	Multi-Criteria Decision Analysis
M€	Mega Euro, or Million Euro, being 10^6 EUR.
MER	Market Exchange Rate
MIT	Massachusetts Institute of Technology
MMD	Mott MacDonald
MOX	Mixed Oxide
MWh	Mega Watt-hour
NA	North America
NOAK	N_{th} of a Kind
NOAK (5+)	N_{th} of a Kind – after 5 units and more
NOAK (10+)	N_{th} of a Kind – after 10 units and more
NPP	Nuclear Power Plant
NRC	Nuclear Regulatory Commission (USA)
OC	Owners Cost
OCC	Overnight Construction Cost, <i>synonym of</i> TOC and TOCC
OEM	Original Equipment Manufacturer
OCGT	Open Cycle Gas Turbine
ORC	Overnight Refurbishment Cost
PCCI	Power Capital Cost Index (from IHS CERA)
PPA	Power Purchase Agreement
PPI	Producer Price Index
PPP	Purchasing Power Parity exchange rate
PRA	Probabilistic Risk Analysis / Assessment
PSA	Probabilistic Safety Assessment
PV	Photo Voltaic (mc-Si = multi crystalline Si / a-Si = amorphous Si)
PWC	PricewaterhouseCoopers
PWR	Pressurized Water Reactor
REPUOX	Reprocessed Uranium Oxide
RES	Renewable Energy Sources
RHS	Right Hand Side
SNF	Spent Nuclear Fuel
SNG	Synthetic Natural Gas
SOFC	Solid Oxide Fuel Cell
SSDI	Simplified Supply and Demand Index
SWU	Separative Work Unit
TASC	Total As-spent Capital (expressed in mixed or nominal currency) = TOC + IDC incorporating escalation (inflation and real cost escalation beyond the usual inflation)
TIC	Total Investment Cost
TMI	Three Mile Island
TOC	Total Overnight Cost= TPC + OC , also sometimes called ‘Total Overnight Capital’, ‘Total Overnight Construction Cost’, ‘Total Overnight Capital Cost’ or ‘Overnight Construction Cost’; all these designations are effectively <i>synonyms of</i> OCC

TOCC	‘Total Overnight Construction Cost’, ‘Total Overnight Capital Cost’ same as OCC
TPC	Total Plant Cost = EPCC + Contingencies
TVO	Teollisuuden Voima Oyj (Finland)
UCS	Union of Concerned Scientists
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UN-OCHA	United Nations - Office for the Coordination of Humanitarian Affairs
UNSCEAR	United Nations Scientific Committee on the Effects of Atomic Radiation
USD	the USA currency (dollar)
US NRC	US Nuclear Regulatory Commission
VGB	“Vereinigung der Großkesselbesitzer e.V.”, historic abbreviation of the Technical Association for Electricity and Heat Generation. This association issues the journal VGB Powertech.
VOLY	Value Of a Life Year
VPF	Value of a Prevented Fatality (=VSL)
VSL	Value of a Statistical Life (= VPF)
VVER	Vodo-Vodyanoi Energeticheskoy Reactor
WACC	Weighted Average Cost of Capital
WHO	World Health Organization
WNA	World Nuclear Association
WTP	Willingness To Pay
YLD	Years Lost due to Disability
YLL	Years of Life Lost (as used by WHO; is identical to YOLL)
YOLL	Years Of Life Lost (as used by ExternE; is identical to YLL)

Executive Summary

ES 1. Scope and Methodology

Scope

The aim of this report is to establish a comprehensive picture of the cost estimations in the nuclear sector, on the basis of available contemporary information in the open literature, so as to establish a coherent background for the discussions on the cost of nuclear-generated electricity. This would provide guidance for an objective context for electricity generation investments.

The cost estimates comprise investment costs for new-build Generation-III plants, major refurbishment investment costs for long-term operation of existing plants, normal operational expenses and fuel-cycle costs (including waste management and final disposal) and decommissioning. Particular attention is devoted to the historic investment-cost evolution (mostly cost escalation) and possible future improvements in moving from a “First of a Kind” to routine construction, from analyzing learning/serial/fleet effects.

In addition, “external costs” are analyzed and an attempt is made to estimate their order of magnitude. Externalities due to routine operation but also of accidents are considered. Regarding nuclear accidents, reflections on the liability issue and alleged hidden subsidies are offered. Finally, system-integration effects of future electricity systems (consisting of nuclear plants, dispatchable fossil plants, and renewable sources) are estimated.

Methodology

The work is based on literature research, whereby the goal is to establish cost estimations for the EU, but relevant figures from other parts of the world are used on a comparative basis, or as input if the numbers are sensibly transposable.

During the whole project phase, the European Nuclear Energy Forum (ENEF) has served as a Steering Committee, commenting on the approach taken and the results obtained, and supervising the activities.

For the thorniest issue, being the future investments costs, a crucial two-step approach in a two tier structure has been additionally utilized. An exhaustive ‘scan’ of the available numbers in the ‘respectable’ open literature has been made, culminating in 137 cost figures from 28 sources (ranging from a variety of sources, some rather neutral, others tending to be critical of nuclear investment, and still others being hopeful about future cost reductions). Deliberately, no information was asked from market players (reactor vendors, electricity generators) since such a-priori surveys are often unsuccessful. Based on the numbers from the literature, a proposed estimate was “constructed” by the author. In a next phase, the market players were then confronted with that estimate with the aim to provoke a reaction from those “connoisseurs”. As a second layer, and in an attempt to have the report reviewed as to the methodological basics, definitions and assumptions, the preliminary report was reviewed by four knowledgeable energy-economics academics. After this double consultation, and commensurate with the a-priori established methodology, the numbers were slightly revised and more “Europeanized”.

As said, this investment part and the other cost elements have been found in the open literature. Clearly, the numbers and estimates are subject to the conditions and assumptions of those literature sources. The author has tried to “situate” the approaches and results from the literature and has provided the sources, so as to allow the reader to check out these references for further study.

It must be stressed at the outset that there is no unique cost figure fitting all situations. Cost figures depend on a variety of circumstances (many of which are discussed in the report). Our goal is to provide an **order of magnitude**, usually expressing a range, with a reasonable window of uncertainty.

ES 2. Messages in Brief

On the basis of a thorough analysis of the published literature on the cost of nuclear power, one can state the points to remember in a few bullet points:

1. Nuclear new build is highly capital intensive and currently not cheap, but it may be anticipated that the capital cost will come down in the future (in particular compared to ongoing new build construction in the EU, depending on return of experience and learning effects, 'fleet effects', standardization, strict construction schedules, competition in the supply chain,...). Analysis of past cost escalation and opportunities for learning and 'fleet effects', suggests that negative learning is not necessarily an 'intrinsic property' of nuclear-reactor construction. Nevertheless, it is up to the nuclear sector itself to demonstrate on the ground that cost-effective construction is possible.
2. Long Term Operation (LTO) is an interesting intermediate cost-effective route if safety standards can be guaranteed.
3. The back-end fuel-cycle costs are low; the full fuel-cycle is quite cheap.
4. External costs of nuclear are small, including accidents (and much smaller than the external costs of fossil-fuel generation).
5. Systems costs of nuclear plants are small, comparable to dispatchable fossil-fired plants, and according to two independent recent calculations (subject to given modeling assumptions), much lower than systems costs of intermittent non-dispatchable renewables.

Ref: NEA/OECD, "Nuclear Energy and Renewables - System Effects in Low-Carbon Electricity Systems" [NEA, 2012a]

If supported politically at national level and authorized by the national Nuclear Regulatory Authorities (the first being related to public acceptance, and the second subject to adequate safety characteristics), upgrades for long-term operation of existing nuclear plants may continue to provide a very competitive low-carbon, secure, stable and reliable source of electricity for the next decades. Nuclear new build may come along, inter alia to replace existing plants at time of shutdown (brownfield), to be part of national energy mix on the longer run. This will be much dependent on the investment decisions which will be linked to the *effective control of the construction costs*.

All other costs beyond extensive upgrades of existing plants and construction of new build, be it O&M, fuel-cycle costs, waste and decommissioning, liability costs, systems costs, and other external costs are marginal and position nuclear generation economically favorably versus other generation sources, certainly if all externalities of other generation sources as well would be internalized.

ES 3. Summarizing Numbers

All concluding ***orders of magnitude*** of the chapters to come are summarized. The reader can easily make the total calculation. The focus is on the levelized cost of electricity (LCOE) of nuclear electricity generation; the LCOE of other generation means is out of the scope of this report, but can be found in illustrative figures further in the report. The reader certainly knows those orders of magnitude. For the *external costs* and the *system costs*, we are obliged to quote numbers for the other generation means so as to be able to put the values for nuclear in perspective.

The orders of magnitude arrived at are the result of sifting through and analyzing a considerable amount of the published literature. The final numbers are based on a common sense “engineering judgment” to be able to appreciate the situation.

But, behind that engineering judgment, there is a substantial amount of interpretation, nuances, assumptions, boundary conditions, etc. It is on purpose that those “ifs-and-buts” are not repeated here in this summary. If interested, the reader should make the effort to read through the report and properly absorb those “qualifying conditions”.

A.- New Build Nuclear Reactors – Levelized Electricity Cost (LCOE)

→ Overnight Construction Cost (OCC):

For **NOAK₂ (5+)** on a **brownfield**: 3,060...**3,400**...3,910 €₂₀₁₂/kW

For **FOAK₂ twin** unit on **brownfield**: 3,128...**3,910**...5,083 €₂₀₁₂/kW

For **FOAK₂ single** unit on **brownfield**: 3,400...**4,250**...5,525 €₂₀₁₂/kW

→ Fuel-Cycle Cost-Part of LCOE:

Full fuel-cycle cost ~ 6 €₂₀₁₂ /MWh_e (± 0.75 €₂₀₁₂ /MWh_e)

→ Operation & Maintenance (O&M):

Generic order of magnitude O&M cost ~ 10 €₂₀₁₂ /MWh_e (± 3.5 €₂₀₁₂ /MWh_e)

→→ LCOE New Build (rounded numbers):

NOAK (5+) brownfield generic single/twin

3,060 €	(ref – 10%)	→ LCOE(5%)= 41€ ₂₀₁₂ /MWh	&	LCOE(10%)= 69€ ₂₀₁₂ /MWh
3,400 €	(ref)	→ LCOE(5%)= 43€₂₀₁₂/MWh	&	LCOE(10%)= 75€₂₀₁₂/MWh
3,910 €	(ref + 15%)	→ LCOE(5%)= 48€ ₂₀₁₂ /MWh	&	LCOE(10%)= 84€ ₂₀₁₂ /MWh

FOAK₂ brownfield twin

3,128 €	(ref – 20%)	→ LCOE(5%)= 41€ ₂₀₁₂ /MWh	&	LCOE(10%)= 70€ ₂₀₁₂ /MWh
3,910 €	(ref)	→ LCOE(5%)= 48€₂₀₁₂/MWh	&	LCOE(10%)= 84€₂₀₁₂/MWh
5,083 €	(ref + 30%)	→ LCOE(5%)= 57€ ₂₀₁₂ /MWh	&	LCOE(10%)= 104€ ₂₀₁₂ /MWh

FOAK₂ brownfield single

3,400 €	(ref – 20%)	→ LCOE(5%)= 43€ ₂₀₁₂ /MWh	&	LCOE(10%)= 75€ ₂₀₁₂ /MWh
4,250 €	(ref)	→ LCOE(5%)= 50€₂₀₁₂/MWh	&	LCOE(10%)= 89€₂₀₁₂/MWh
5,525 €	(ref + 30%)	→ LCOE(5%)= 61€ ₂₀₁₂ /MWh	&	LCOE(10%)= 111€ ₂₀₁₂ /MWh

For each of these LCOE numbers, there is an additional uncertainty of the fuel-cycle cost (± 3.5 €₂₀₁₂ / MWh) and the O&M cost (± 0.75 €₂₀₁₂ / MWh). If we simply combine the uncertainties and round them off, then the above numbers each have an extra **uncertainty of ± 4 €₂₀₁₂ / MWh**.

B.- Long Term Operation Refurbishment – Levelized Electricity Cost (LCOE)

→ Overnight Refurbishment Cost (ORC):

Specific ORC ~ 400 – 850 €₂₀₁₂/kW

→ Fuel-Cycle Cost-Part of LCOE:

Full fuel-cycle cost ~ 6 €₂₀₁₂ /MWh_e (± 0.75 €₂₀₁₂ /MWh_e)

→ Operation & Maintenance (O&M):

Generic order of magnitude O&M cost ~ 10 €₂₀₁₂ /MWh_e (± 3.5 €₂₀₁₂ /MWh_e)

→→ LCOE LTO (rounded numbers):

ORC = 400 € (ref – 33%) → LCOE_{LTO}(5%)= 21€₂₀₁₂/MWh & LCOE_{LTO}(10%)= 23€₂₀₁₂/MWh

ORC = 600 € (ref) → LCOE_{LTO}(5%)= 23€₂₀₁₂/MWh & LCOE_{LTO}(10%)= 26€₂₀₁₂/MWh

ORC = 850 € (ref + 42%) → LCOE_{LTO}(5%)= 26€₂₀₁₂/MWh & LCOE_{LTO}(10%)= 30€₂₀₁₂/MWh

For each of these LCOE numbers, there is an additional uncertainty of the fuel-cycle cost (± 3.5 €₂₀₁₂ / MWh) and the O&M cost (± 0.75 €₂₀₁₂ / MWh). If we simply combine the uncertainties and round them off, then the above numbers each have an extra **uncertainty of ± 4 €₂₀₁₂ / MWh**.

C.- External Costs

C.1 Without Accidents

External costs for nuclear-generated electricity → 1 – 4 €₂₀₁₂/MWh

Compare with other means (cfr [IER, 2013] – Fig 7.8 this report)

Coal ~ 40 €₂₀₁₂/MWh

Gas ~ 20 €₂₀₁₂/MWh

PV ~ 10 €₂₀₁₂/MWh

Wind ~ 2 €₂₀₁₂/MWh

C.2 Nuclear Accidents

Order of magnitude of external cost due to nuclear accidents is ~ 0.3 ... 1 ... 3 €/MWh.

D.- System Costs¹

System costs are considered in two steps:

1. grid-level system costs
2. overall system costs (encompassing 1., but also variable and fixed savings or increases due to displacement of generation from conventional units)

D.1 Grid-Level System Cost

For penetrations of 10% & 30% for each technology

Includes: Back-up (adequacy); Balancing Cost; Grid Connection; Grid Reinforcement and Extension

Does not include: merit-order effects nor fuel savings

Nuclear: ~ 2 – 3 \$₂₀₁₁/MWh

Coal: ~ 1 \$₂₀₁₁/MWh

Gas: ~ 0.5 \$₂₀₁₁/MWh

Wind onshore: ~ 20 – 30 \$₂₀₁₁/MWh

Wind offshore: ~ 30 – 40 \$₂₀₁₁/MWh

PV: ~ 35 – 55 \$₂₀₁₁/MWh

¹ Ref: Nuclear Energy Agency, “Nuclear Energy and Renewables - System Effects in Low-Carbon Electricity Systems” [NEA, 2012a]

D.2 Overall System cost

Two *independent* computations for the German electricity system are shown (permitting validation of obtained results) – other cases are discussed in the main text. Both are published in [NEA, 2012a].

i. Results from Excel-based model for Germany (by NEA/OECD economists)

Total cost of electricity generation in Germany in \$₂₀₁₁/MWh. The situation without renewables (“Reference” for comparison) and with renewables at penetration levels of 10% and 30% of annual electricity generation/consumption are compared. The total costs and the cost increases are shown in the table. In this table, the mix of dispatchable generation plants is the same as in the “Reference”.

Total cost of electricity supply (USD/MWh)								
		Reference	10% penetration level			30% penetration level		
		Conv. mix	Wind onshore	Wind offshore	Solar	Wind onshore	Wind offshore	Solar
Germany	Total cost of electricity supply	80.7	86.6	91.3	101.2	105.5	116.9	156.2
	Increase in plant-level cost	-	3.9	7.8	16.9	11.6	23.3	50.6
	Grid-level system costs	-	1.9	2.8	3.6	13.2	12.9	24.9
	Cost increase	-	5.8	10.6	20.4	24.8	36.2	75.4

ii. Comprehensive in-depth modeling for Germany, using two integrated computer codes (by IER)

Total cost of electricity generation in Germany in €₂₀₀₇/MWh. Four renewables penetration levels are considered (15%, 35%, 50% and 80%, in terms of TWh/a) for three cases of nuclear installed capacities: 20.7 GW – before Fukushima, and two extreme cases, the double (41.7 GW) and 0. The conventional dispatchable generation mix is adjusted conforming to renewables penetration.

Installed capacities of nuclear power plants/share of renewables	(EUR/MWh)		
	0 GW	20.7 GW	41.4 GW
15%	95	84	71
35%	120	109	101
50%	132	122	119
80%	174	171	174 ^a

a) Variation RES-80%_NUCL-41(21LE) with one half of the nuclear power plant portfolio being entirely depreciated but retrofitted: EUR 169/kWh.

Main Report

Chapter 0

Objectives of the Study

0.1 Objective & Methodology

0.1.1 Observation

The existing and readily available open literature on the cost of nuclear-generated electricity is very confusing. There exists an enormous variety of cost estimates because of:

- a lack of clear definitions (overnight cost, total cost, real or nominal currency);
- often erroneous conversions from nominal to real currency (with regard to the concept of “escalation” where double counting is not unusual);
- sometimes
 - pessimistic extrapolations based on historic precedents (e.g., USA) or raw-materials & equipment index rises over period 2005-2008;
 - optimistic projections of learning effects;
- purely illustrative numbers, or numbers for sensitivity analyses, appearing in the literature, that are sometimes taken as hard figures which continue to be quoted and “live their own life”;
- the fact that very few peer refereed papers in scientific journals seem to exist; mostly (non-reviewed) reports are available on the internet; sometimes it concerns tendentious reports, that look more like pamphlets, opinions, testimonials from opinion makers or campaigners. Such questionable documents as to their “objectivity” appear on all sides of the spectrum, both pro and contra nuclear (or vice versa).

This work sifts through a considerable body of the existing (and available) literature on the subject matter and tries to understand the reasoning of the different documents. It aims at gathering the useful important information. Nonsensical or illogical statements (not to mention obvious errors or mistakes) and/or results are ignored.

This work tries and “pledges” to come up with a neutral and realistic estimate for the full cost of nuclear electricity generation. The fact that often so-called “engineering judgment” has been necessary in interpreting the results could perhaps lead to criticism because of the interpretation given by the author of this report. However, to neutralize that sort of criticism, the author will explain as much as possible the reasons for certain choices, but more importantly, the methodology behind this work is supposed to guarantee a legitimate and representative estimate of the cost. Indeed, a wide range of numbers and arguments is taken from the literature, as diverse as it may be. From these numbers, an appropriate average or median is obtained.

As mentioned further below, as an important step in our approach, these results are then presented to different actors, who, from experience and basic engineering/costing knowledge, should be able to give

feedback on the estimates presented.² After reflection on the arguments, a final generic estimate is then presented and explained by the author. It is important to notice that our methodology does not inquire a priori information from reactor vendors, electricity generators or other connoisseurs, but it confronts them with the results from the literature to “provoke” a reaction. This “reactive” approach is expected to be more successful than a priori information requests by means of survey sheets or the like, given also that explanations were requested if certain numbers presented by the author are questioned.

0.1.2 The Aim is to Obtain the Right Order of Magnitude; Not a Single Unique Figure

Because of the many varying influencing factors, unknowns and uncertainties, it clearly does not make much sense to search for a unique number of “the” cost of nuclear electricity. It seems obvious that one should try to identify the *ranges* of the cost, with a reasonable estimate of the degree of uncertainty/accuracy.

This viewpoint is well explained by the Engineering Company Black & Veatch [NREL, 2012], where we take the liberty of displaying Box 1 of that work verbatim:³

Text Box 1: “*Why Estimates Are Not Single Points*”

In a recent utility solicitation for (engineering, procurement and construction) EPC and power purchase agreement (PPA) bids for the same wind project at a specific site, the bids varied by 60%. More typically, when bidders propose on the exact scope at the same location for the same client, their bids vary by on the order of 10% or more. Why does this variability occur and what does it mean? Different bidders make different assumptions, they often obtain bids from multiple equipment suppliers, different construction contractors, they have different overheads, different profit requirements and they have better or worse capabilities to estimate and perform the work. These factors can all show up as a range of bids to accomplish the same scope for the same client in the same location.

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Some overlap can be seen in the categories above, which is another contributor to variability - different estimators prepare estimates using different formats and methodologies.

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Given all these sources of variability, contractors normally speak in terms of cost ranges and not specific values. Modelers, on the other hand, often find it easier to deal with single point estimates. While modelers often conveniently think of one price, competition can result in many price/cost options. It is not possible to estimate costs with as much precision as many think it is possible to do; further, the idea of a national average cost that can be applied universally is actually problematic. One can calculate a historical national average cost for anything, but predicting a future national average cost with some certainty for a developing technology and geographically diverse markets that are evolving is far from straightforward.

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Because cost estimates reflect these sources of variability, they are best thought of as ranges that reflect the variability as well as other uncertainties. When the cost estimate ranges for two technologies overlap, either technology could be the most cost effective solution for any given specific owner and site. Of course, capital costs may not reflect the entire value proposition of a technology, and other cost components, like O&M or fuel costs with their own sources of variability and uncertainty, might be necessary to include in a cost analysis.

To cope with the uncertainties, and guided by the literature, the author will distil some reasonable ranges of accuracy/uncertainty. Those are explained towards the end of Chapter 2.

² Actors agreed upon with the Steering Committee (European Nuclear Energy Forum (ENEF) Sub-Working Group on “Opportunities” / Competitiveness”)

³ Abbreviations are explained in the front of the report under the Section “List of Abbreviations, Acronyms & Symbols”

0.1.3 Overall Methodology of this Study

In line with the aim expressed in the ‘Scope of the study’, this study tries “to establish an exhaustive picture of the costs estimations in the nuclear sector”. It was a *first objective* of the author to perform a comprehensive picture of the cost of nuclear power generation, taking as a starting point the open scientific-technical literature. The literature study is used to understand the different numbers published, especially as it comes to the boundary conditions and hypotheses/assumptions. As a result of the evaluation, a first comparative analysis can be made, leading, with the appropriate interpretation, to a “first documented estimate” of the cost of nuclear electricity generation.

But more importantly, and this is a *second objective* of the author, the outcome of the literature-documented “estimate” has served as a means to find ‘updated’ or ‘validated’ representative cost numbers. This adds an extra added value over a “mere literature study”. To do so, a so-called “*reactive*” or “*stimulative*” approach has been utilized. Said differently, a *well-targeted consultation* phase directed towards industrial actors has been included.

A selected group of industrial actors, which are supposed to possess the best information on the costing numbers, were therefore asked to react to numbers given by the author, and to specify their degree of (dis)agreement.

The consultation phase with the industrial actors has concentrated on the investment cost, being the dominant and most often controversial cost element. The consultation was done based on the “Intermediate Report”, the contents of which is effectively reflected by the first few chapters of this Final Report (up to Section 3.2.1). The confrontation of our original estimate for the Overnight Construction Cost with the industrial reaction is presented in Section 3.2.2.

As explained in detail further in this document, the numbers (for capital cost) found in the literature will be converted to monetary values of €₂₀₁₂, not only based on available usual inflation numbers (through, e.g., the Consumer Price Index), but the numbers will be escalated via the power-capital-cost index as e.g., provided by IHS CERA (which exist for North America and for Europe). This escalation exercise requires careful consideration, as demonstrated further in this study.

As expected from a comprehensive study, we will make a systematic study of the different *components* that make up the *levelized cost of electricity* (LCOE), expressed in €/kWh or €/MWh. Except for taxes that try to mimic part of the external costs⁴, and contributions that need to be paid by the nuclear operators into certain national funds for nuclear-waste management & disposal, and for decommissioning, funds that are commonly supervised by the authorities, the LCOE is usually limited to the economically *private cost*. When the *external costs* are added, then a number for *social cost* can be obtained. This study will make a clear difference between the two considerations.

Concerning the types of costs, it is important to distinguish between the actors that bear the costs. Since the final outcome of the study concentrates on the European Union, this study will focus its considerations in a

⁴ A typical example for fossil-fired plants would be the price of CO₂ allowances under the Emission Trading Scheme (ETS).

liberalized-market context.⁵ To recall, in a regulated market, a full cost-plus philosophy reigns, and the electricity prices (for the commodity) are directly related to the cost of generation, whereby levies for waste management and decommissioning can be transferred directly to the final consumer. In contrast, in properly functioning (i.e., “ideal”) liberalized markets, the wholesale electricity price of a well-interconnected region (with little cross-border congestion) is set by the marginal generation unit in the overall system. As a consequence, the cost seen by the generating company⁶ (here, the operator of the nuclear plant) is not carried through to the electricity commodity price.⁷ Contributions to funds for waste management and decommissioning are to be provided by the nuclear operator, and are part of the cost seen by the operator, but they cannot be transferred to the final consumer. These fund contributions mean therefore a reduction of the operator’s profit.

0.1.4 Quality Assurance & Control Process

To guarantee a continued quality-assurance process for this cost of nuclear report, regular meetings with the Sub-Working Group on “Opportunities” / Competitiveness” of the *European Nuclear Energy Forum* (ENEF), acting as the Steering Committee for this study, have taken place.⁸ In those meetings, the author has presented his findings, and the draft preliminary report and the draft final report were made available to the participants to the meetings.

As a further quality-control measure, two sorts of independent reviews have taken place. The Intermediate Report was reviewed by a group of Academic reviewers, on the one hand, and a set of industrial representatives, on the other.

Academic Reviewers:

- Professor William Nuttall – Open University, UK
- Professor John Parsons – MIT, USA
- Professor Jan-Horst Keppler – Univ Dauphine Paris, FR
- Professor François Lévêque – Mines Paris Tech, FR

Industrial Actors: About 15 industrial actors were contacted, 9 actors have reacted. Those who have replied are:

- Reactor vendors: Areva, Westinghouse, Rosatom
- Nuclear-electricity generators: EdF, GdF-Suez, TVO, CEZ
- Nuclear-knowledgeable industry organization: WNA, VGB / Eurelectric

⁵ Please note that this statement relates to the *final outcome* of the study which concentrates on costs and not on prices. Clearly, the author makes use of information on generation costs in regulated markets (as is the case in about still half of the states in the USA) to document his analysis of the variety of costs.

⁶ It is recommended to avoid the usage of the word “utility” in a liberalized unbundled electricity market as the EU. There are four important levels of actors: Generating Companies (GenCo’s), Transmission System Operators (TSO’s), Distribution System Operators (DSO’s) and Suppliers. GenCo’s and Suppliers are fully liberalized, whereby the profit is determined by the market price minus their costs. The natural monopolies TSO’s and DSO’s are regulated, with a transparent cost-plus tariff determination supervised by the Regulators.

⁷ In markets with massive amounts of zero-marginal cost renewables (like wind and PV, already now in Germany), it already occurs from time to time that wholesale prices may be zero or even negative.

⁸ Meetings with the Steering Committee have taken place on: January 14, March 26, June 21, September 18 and November 8 2013.

Chapter 1

Context & Setting the Scene

— The Different Cost Elements of Nuclear Generated Electricity —

Contents of Chapter 1

- 1.1 Concept of Cost
- 1.2 Cost Elements Nuclear Generation
- 1.3 Type of Investor
- 1.4 Levelized Cost Of Electricity (LCOE)

Important Notice

This chapter 1 “*Context & Setting the Scene*” is to be considered as an introductory chapter that tries to explain certain concepts in an illustrative or indicative manner, whereby often examples from the literature are used.

It is important to recognize that the numbers in this introductory chapter, be it overnight costs for the construction of power plants (expressed in EUR/kW or USD/kW), or the cost of electricity from nuclear, coal- or gas-fired plants (expressed in EUR/MWh or USD/MWh), only have an illustrative character, often meant to express rough relative relationships for showing orders of magnitude. These numbers must not be interpreted as “correct” absolute values as they are often somewhat dated, or expressed in nominal currency etc. *None of these figures should be considered as actual and exact numbers expressing “this or such part of the nuclear cost of electricity”.*

Our own numbers for a cost estimate of nuclear generated electricity (all included) will be developed in later chapters, with the final outcome being presented in Chapters 6 and 10. It will be those numbers that we present as legitimate representative numbers of the cost of nuclear electricity generation.

1.1 Concept of Cost⁹

Cost is a difficult concept, as there is a whole variety of different sorts of costs, each meaningful and applicable in a certain context. It is important to distinguish between bookkeeping cost, opportunity cost, average cost, marginal cost, sunk cost, investment cost, operational cost, decommissioning cost, resource cost, private cost, social cost, external cost, fuel cost, fuel-cycle cost, variable and operational O&M costs, refurbishment costs,...etc etc. The following examples illustrate the fact that caution is needed, and that appropriate definitions, hypotheses and boundary conditions are of uttermost importance for the interpretation of the cost results.

According to the earlier presented excerpt from Black & Veatch [NREL, 2012], cost bids for the same wind project at a specific site differed by 60%. MIT changed its generic estimate for overnight construction cost of a new nuclear plant from 2,000 USD in 2003 [MIT, 2003] to 4,000 USD in 2009 [MIT, 2009]. Lévêque mentions two different numbers for the cost of current-day French nuclear electricity (from existing plants), as being 32 EUR/MWh or 49 EUR/MWh, emerging from a discussion/dispute between the two main French actors EdF and GdF-Suez [Lévêque, 2013a].

A first, almost trivial requirement is that one should always identify the year of the currency quoted, or mention whether the quotation is in nominal or real currency, and what the reference year is in case of the latter.

As a second important element in the discussion on nuclear costs, one must recognize the difference between the cost of existing plants as seen today (only marginal cost and fixed O&M costs, since the investment cost is a sunk cost) and a new plant (whereby the investment cost must be taken into account). In addition, a cost is only really meaningful when it is compared to the alternatives. Practically speaking, it means that the cost of nuclear electricity should be compared to the cost of other generation means, like coal, gas and renewables.... Theoretically speaking, economic cost is reflected by the *opportunity cost* which is the value of the best alternative good or service foregone, or still differently, a measure of what has been given up when we make a decision. [Samuelson & Nordhaus, 2010][Lévêque, 2013a] However, since the cost of other generation means requires a study of its own, and because that is beyond the scope of the present study, we will concentrate on what could be called an '*engineering-economics cost*' or a "*cost-accounting*" approach, being roughly equal to a bookkeeping way of looking at the cost.

To have a full grasp of the cost for nuclear electricity generation, one must obtain the *social cost*; being equal to the sum of private and external cost. [Field, 2002]

In short:

Social Cost = Private Cost + External Cost

- Private costs:¹⁰ costs that show up in the profit-and-loss statement [of the firm] at the end of the year
- External costs: or externalities, "are costs that arise when the social or economic activities of one group of persons have an impact on another group and when that impact is not fully accounted, or compensated, for by the first group" [CEU, 2003]

⁹ Many works on nuclear cost make similar points, but it is important to re-iterate these points at the beginning of this report. A nice introductory sketch has recently been given by [Lévêque, 2013a]. The work by Du & Parsons [Du, 2009] is also recommended; it will be used explicitly further in this chapter.

¹⁰ This is somewhat simplified and maybe misleading, since we will consider the "Levelized Cost of Electricity" without considering taxes. Use of the concept "resource cost" would perhaps be more appropriate.

Cost is somewhat intangible: it varies in time, it is geographically different (e.g., the OECD versus the non-OECD countries), it furthermore depends on the viewpoint of the investor because the opportunity cost may be different —a private versus a public investor, versus a (private) concession holder in a regulated market.

This last point relates also to the expected rate of return on investment and the interest rates obtainable for debt financing. These issues will be clarified further in this report. In addition, the viewpoint is important as to taxes and/or subsidies. For a private actor, these are costs & revenues, whereas for a public actor (and actually for society), taxes and subsidies are transfers.

The fact that investors expect a return on investment (whereby this investment competes with other possible investment choices) and that interest is to be paid on loans, means that money has a *time value*, usually expressed by a *discount rate*.¹¹ The discount rate, usually considered as the opportunity cost of capital, will be explained below, together with the concept of “Weighted Average Cost of Capital” (WACC).

Illustrative Example to Compute the Full Investment Cost

As will be shown later, the investment cost for a new nuclear power plant is by far the most important factor in the cost of nuclear electricity. To set the stage and to clarify already some aspects in an illustrative manner, we take the liberty here to reproduce a very clarifying example by Du & Parsons [Du, 2009].¹² (It is difficult to better explain these issues; so it makes more sense to give full credit to Du & Parsons, rather than trying to paraphrase their example.)

The example, quoted here literally, stresses, a.o., the importance of interest during construction (IDC), which deals with the following elements:

- The importance of the length of the construction period;
- Investment schedule during construction (sinusoidal);
- Discount rate (or WACC);¹³
- Inflation;
- Reference time for Overnight Construction Cost – defined at the time electricity generation begins.

¹¹ Corporate-financing (or engineering-economics) terminology distinguishes between the (annual) discount rate r and the discount factor $d = 1/(1+r)$ or $d_N = 1/(1+r)^N$. This last one, d_N , is sometimes referred to as the discounting factor to distinguish it from d .

¹² Permission to take this example “verbatim” has been received implicitly through the review by J. Parsons.

¹³ It is understood from the context and from MIT (2003) and MIT (2009) that the nominal discount rate equals 11.5%, so that, with an inflation of 3% per year, the real discount rate equals $(1.115/1.03) - 1 = 0.0825$, or thus 8.25% per year.

In order to clarify the problem and to help explain certain steps that are necessary in order to make differently quoted estimates comparable, we have constructed the illustrative example shown in Table [D&P]. The illustration provides cost data on the construction of a hypothetical power plant, and lays out a few standard, but very different methods for quoting these same costs. The illustration gives a measure of how large a disparity one can expect for the different methods, even when the underlying plant and cost data are the same.

For the hypothetical nuclear plant, construction is to occur over a five year period running from 2009 through 2013, so that the plant is ready to begin production at the end of 2013 and the start of 2014. The future owner and operator of the plant orders it from a vendor who will construct the reactor and power generation unit under an EPC contract. Lines [3] and [4] show how the cost is typically quoted by the vendor. The vendor's total EPC overnight cost quoted in 2007 dollars is \$3,333/kW. Assuming that the nuclear plant's capacity is 1,000 MW, this translates into \$3.333 billion. These figures represent the cost of the relevant parts and services were those services to be provided immediately once the EPC contract negotiations are completed, i.e., overnight. In fact, these parts and services will be delivered according to a construction schedule which is shown in Line [3]. 10% of these parts and services will be provided in 2009, 25% in 2010, 31% in 2011, and so on. Line [4] shows the corresponding dollar figures apportioned across these years, but still quoted in 2007 dollars.

Lines [5-11] show how the cost for the same plant is typically quoted by a regulated utility as it submits filings seeking approval for the plant. Line [5] is the vendor's cost but these figures have been adjusted for inflation so that each year's figure reflects the expected nominal expenditure. Line [6] shows the owner's costs, i.e., costs that the utility will have to cover out of its own pocket, in addition to the vendor EPC costs. The figures shown in line [6] are 20% of the figures shown in line [5]. A 20% figure is a reasonable assumption absent specific information for a given plant. Line [7] shows the cost of transmission system upgrades which are scheduled in concert with the construction of the new generation capacity. There is no standard ratio for this item, as it depends significantly on the specific situation within each transmission territory including the regulatory rules in operation, so the figures shown are simply given. Line [8] shows the total of lines [5], [6] and [7]. This total cost, which is exclusive of financing costs, is \$4,706. The regulated utility will be allowed to recover this total cost through customer charges. It will also be allowed to recover capital costs or financial charges. These are calculated in line [9], assuming an effective capital charge of 11.5%. Line [10] shows the total costs as expended, inclusive of this capital charge. Line [11] cumulates this total cost, which is a step in calculating the allowed annual capital charge. By the end of 2013, when the plant is complete and ready to start producing power, this total cost, inclusive of capital charges, is \$5,837/kW. This is 75% more than the vendor's EPC overnight cost of \$3,333/kW, although the difference between the estimates is purely a question of the method of quotation, i.e., of what is in and what is out and how the dollar expenditures are denominated, whether in 2007 dollars or dollars as expended.

We have boxed a number of the figures shown in the table: line [4F], line [8F], line [10F] and line [14F]. The first three figures reflect the quotation methods most often encountered in published reports. Line [4F] is the total EPC overnight cost quoted in 2007 dollars, and it is the lowest of all the figures. Lines [8F] and [10F] are two alternative figures often reported in utility filings. Both are total costs, inclusive of owner's costs and of transmission costs. The former excludes financing costs and the latter includes them.

Line [14F] represents the standard basis for quoting comparable costs across different plants as described in the MIT (2003) Future of Nuclear Power study. It reflects the "busbar" cost, including only transmission costs related to connecting the plant to the grid, and excluding the cost of expanding the overall transmission network to handle the growing power needs which are independent of the specific plant generating the power. Therefore it excludes the cost from line [7] in our illustration. It is inclusive of owner's costs – line [6] in our illustration. Therefore, we take line [5] + [6] = [12]. Unfortunately, it makes little sense to add up the different annual expenditures in line [12] since these are denominated in dollars of different years, incorporating different amounts of inflation. Therefore, the industry convention is to quote the total expenditures as an "overnight cost" using a single year as the baseline. Lines [14] and [15] show this overnight cost quoted in \$2007 figures, when the plant is being contemplated, and in \$2013 figures, when the plant is scheduled to be completed and ready to start producing power. The terminology and calculations shown in lines [12]-[15] are those used in the MIT (2003) Future of Nuclear Power study Appendix 5, Table A-5.A.2, although the costs have been adjusted upward.

In the hypothetical example shown in Table [D&P], our overnight cost figure is 20% more than the overnight cost reflecting only vendor EPC costs, 15% less than the utility's total cost as reported in regulatory filings, exclusive of financing charges, and 31% less than the utility's total cost as reported in regulatory filings, inclusive of financing charges. These results help benchmark reported figures that do not provide a complete breakdown of all elements, but which do describe the quotation method. With this analysis of methodology in hand, we are ready to turn to an analysis of new information about the costs of constructing a nuclear power plant.

Table [D&P]: Alternative Cost Quotation Methods for Nuclear Power Plants Illustrated with a Hypothetical Example

		[A]	[B]	[C]	[D]	[E]	[F]
[1]	Project Period (relative to start)	-4	-3	-2	-1	0	
[2]	Year	2009	2010	2011	2012	2013	Total
[3]	Construction Schedule as a Fraction of EPC Cost, \$2007	10%	25%	31%	25%	10%	100%
[4]	Vendor EPC Overnight Cost, \$2007	318	833	1,030	833	318	3,333
[5]	Vendor EPC Cost, Nominal Dollars as Expended @ 3% Inflation	337	911	1,160	966	380	3,753
[6]	Owner's Costs, Nominal Dollars as Expended	67	182	232	193	76	751
[7]	Transmission System Upgrades, Nominal Dollars as Expended				145	57	202
[8]	Total Cost, excl. Capital Recovery Charge, Nominal Dollars as Expended	405	1,093	1,391	1,304	513	4,706
[9]	Capital Recovery Charge @ 11.5%		47	178	358	549	1,131
[10]	Total Cost, incl. Capital Recovery Charge	405	1,139	1,569	1,662	1,062	5,837
[11]	Total Cost, incl. Capital Recovery Charge, Cumulative	405	1,544	3,113	4,775	5,837	
[12]	Total Outlay, Nominal Dollars as Expended	405	1,093	1,391	1,159	456	4,504
[13]	Total Cost (incl. capital charge), \$2013	626	1,515	1,730	1,292	456	5,619
[14]	Overnight Cost, \$2007	382	1,000	1,236	1,000	382	4,000
[15]	Overnight Cost, \$2013	456	1,194	1,476	1,194	456	4,776

Notes:

All figures in \$/kW.

Example assumes a total EPC overnight cost of \$3,333, an inflation rate of 3%, a 20% factor for owner's cost and an allowed capital recovery charge of 11.5%.

Columns [A]-[E]

[3] Rate of expenditures is given.

[4] = \$3,333*[3].

[5] = [4]*(1.03)^[(2)-(2007)]

[6] = 20%*[5]

[7] Transmission expenditures are given.

[8] = [5]+[6]+[7].

[9] [9B]=[11A]*11.5%, and so on.

[10] = [8]+[9]

[11] [11B]=[11A]+[8B]+[9B].

[12] = [5]+[6]

[13] = [12]*(1.115)^(2013-[2])

[14] = [12]*(1.03)^(2007-[2])

[15] = [12]*(1.03)^(2013-[2])

Inputs:

Vendor EPC Overnight Cost, \$2007	3,333
Inflation	3%
Owner's cost fraction	20%
Allowed capital recovery charge	11.5%

IDC = \$5619 – \$4776 = \$843 (expressed in \$2013)

*** End of Excerpt from [Du, 2009] ***

The importance of the **interest** to be paid **during construction** is furthermore well illustrated in Table 1.1 below, taken from [Davis, 2011].

Table 1.1: Illustration of interest during construction (IDC) (Table 2 from [Davis, 2011])

Financing Costs as a Fraction of Total Construction Costs			
	Construction Period		
	One Year	Five Years	Ten Years
5% Cost of Capital	2%	12%	22%
10% Cost of Capital	4%	22%	40%
15% Cost of Capital	6%	30%	54%

This table is to be well understood. It presents the orders of magnitude (based on appropriate assumptions).¹⁴ The Cost of Capital (being the discount rate r) is assumed to be *real*, i.e., inflation is already “neutralized”.¹⁵ As an example, a 5-year construction period and a 10% cost-of-capital rate, leads to a relative IDC fraction of 22% of the total construction cost.

Du & Parson in the example above, took the *nominal* discount rate equal to 11.5% with an annual inflation of 3%. The *real* discount rate is therefore 8.25%. Table [D&P] shows that the fractions of IDC to be kept in mind are dependent on the reference taken:

IDC = 15% of the ‘total cost’ (both) expressed in USD₂₀₁₃ (i.e., 843/5619=0.15)

IDC = 17.7% of the ‘overnight construction cost’ (both) expressed in USD₂₀₁₃ (i.e., 843/4776=0.177)

IDC = 19.4% of the ‘total construction cost as expended’ during construction in nominal/mixed USD, *including capital charges* (i.e., 1131/5837=0.194)

IDC = 24% of the ‘construction cost as expended’ during construction in nominal/mixed USD, but *without capital charges* (i.e., 1131/4706=0.24).

The past record of construction periods in some countries has been rather “disappointing”, as shown in Figure 1.1 below, taken from [IEA, 2006]. Long periods at high discount rates make investment costs extra hard to bear, a point that is made in Table 1.1.

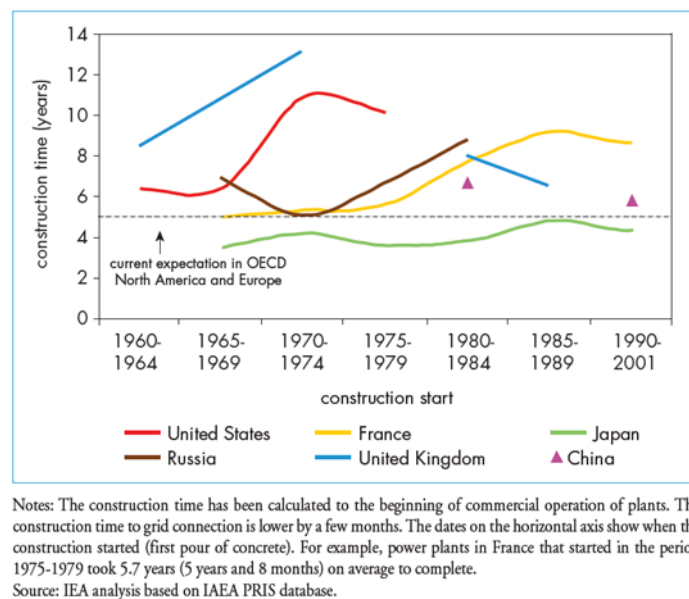


Figure 1.1: Construction time of existing nuclear power plants (Fig. 13.12 from [IEA, 2006])

Figure 1.1 shows that it is not impossible to keep the construction period to values between 4 and 6 years. Japan has set the example with all its plants, shown in Figure 1.1, constructed in a time period shorter than 5 years. The Republic of South Korea (with presently 23 reactors operational and 4 reactors under

¹⁴ Davis uses a constant monthly expenditure and financing charges accrue monthly at the cost of capital.

¹⁵ For an inflation rate equal to $x\% = 0.0x$, the real discount rate is computed as follows: $r^{\text{real}} = [(1 + r^{\text{nom}})/(1 + 0.0x)] - 1$. See later for details.

construction), has also a record of short construction periods.¹⁶ Keeping the construction period to something like 5-6 years, is one of the major challenges for future success of the nuclear sector.

1.2 Cost Elements of Nuclear Generation

The cost elements constituting a “full” cost of electricity (i.e., USD or EUR per MWh) for nuclear power plants can be delineated as follows.

a. Private costs¹⁷

- i. Investment cost
- ii. Decommissioning cost
- iii. Operation & Maintenance (O&M cost)
- iv. Fuel-cycle (including the back-end) cost

The order of magnitude of the importance of each of the elements mentioned can be seen in Figure 1.2 [DTI, 2007]. The nuclear-related (yellow) columns are of interest for our purposes. It should be stressed again that these numbers are just for illustration and should not be taken as exact values today (2013). In this chapter, we are just after approximate relative ranges.

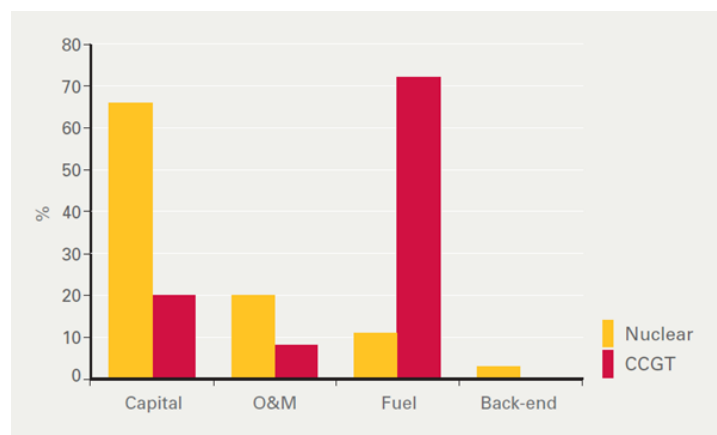


Figure 1.2: Cost profile of nuclear and gas-fired generation (Fig. 4.1 from [DTI 2007])

For this DTI example,

Capital	~ 65%
O&M	~ 21%
Fuel	~ 11%
Back-end	~ 3%.

Two somewhat older, but still instructive figures, were published in [IEA, 2006]; see Figure 1.3.

¹⁶ See e.g., the IEAE website <http://www.iaea.org/pris/CountryStatistics/CountryDetails.aspx?current=KR>

¹⁷ Or perhaps “resource cost” as mentioned in an earlier footnote.

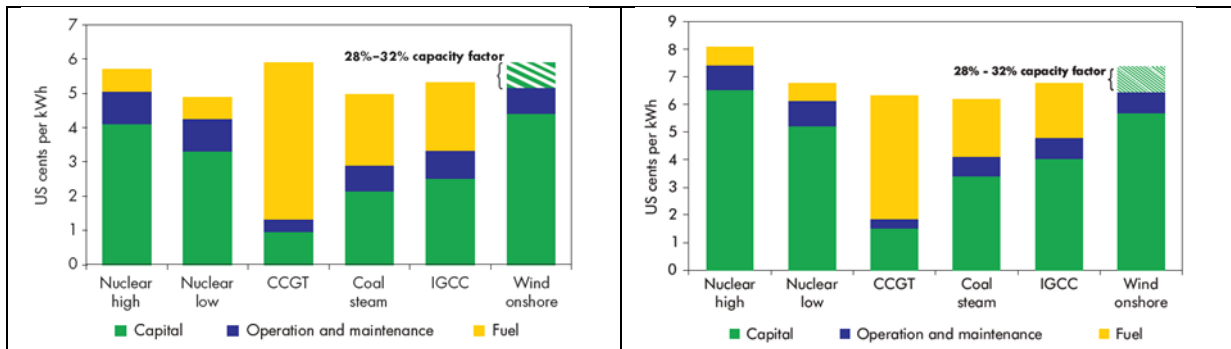


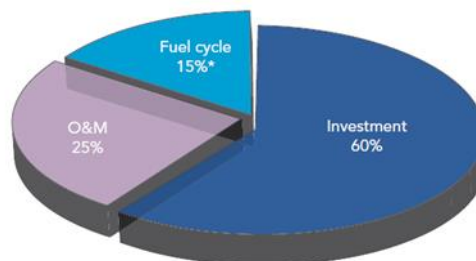
Figure 1.3: Electricity generating costs in the low discount rate case (left) and the high discount rate case (right) (Figs 13.7 and 13.8 from [IEA, 2006])

In this case, the relative proportions for nuclear-generated electricity are:

- Nuclear fuel cycle: ~ btwn 7-14% (back-end cost 25% of fuel-cycle cost, included here)
- O&M: ~ btwn 10-20%
- Capital Cost: ~ roughly 65-85% (the balance of the fuel cycle and O&M).

The absolute values of the nuclear-fuel cycle and O&M remain roughly constant, but their relative ranges change because of the changes in capital cost.

Finally, we present a pie chart from the NEA Nuclear Energy Outlook 2008. The proportions are shown in Figure 1.4.



* The cost of natural uranium typically represents only 5%.
Source: NEA and IEA (2005).

Figure 1.4: Cost structure of nuclear electricity generation (Fig. 6.1 from [NEA 2008])

Conclusion on the breakdown of the private costs:

The actual distribution between the three elements depends on all kinds of variables, but the *capital investment* cost is clearly dominant. The degree of dominance depends on many parameters of which the most important ones are overnight construction cost, discount rate, construction time, and the load factor. For the contribution of O&M, it is important to identify whether major refurbishments are assumed and/or included or not. Likewise, for the fuel cycle, it is important to know what fraction is assumed for the downstream or back-end part.

- Capital is clearly dominant: ~ **60-85%**
- O&M ~ **10-25%**
- Fuel Cycle ~ **7-15%**

b. External Costs

As mentioned before, external costs “are costs that arise when the social or economic activities of one group of persons have an impact on another group and when that impact is not fully accounted, or compensated, for by the first group” [CEU, 2003]

Here, some of the externalities are just mentioned; they will be discussed below in chapters 7-9.

When discussing external costs in the nuclear area it is important to recognize that a considerable fraction of the costs linked to the harmful nature of radioactive substances has already been internalized, and should thus no longer be considered as an externality. Typical examples are levies that have been and are being charged both for radioactive-waste management and final disposal, and for decommissioning, for the purpose of feeding long-term funds.¹⁸

We just list here a few remaining externalities (where depending on the situation they may still be part of the externalities; in other cases they should be deleted from the list).

- i. Radioactive emissions
- ii. Long-term waste disposal (sometimes part of fuel cycle; often already internalized)
- iii. Accidents – liability
- iv. Proliferation
- v. Avoided CO₂ emissions – a positive externality? (The small amount of embedded CO₂ is to be considered, in principle)
- vi. System effects
 1. Negative compared to gas & coal: ‘less well’ dispatchable (load following)
 2. Positive with respect to wind and sun since nuclear *is* reasonably well dispatchable nevertheless, and the need for large rotating inertia.

1.3 Type of Investor

As strange as it may sound, the cost of nuclear-generated electricity depends on the type of investor. The reason is the way the project is financed and the cost of capital.

In general, financing for a project occurs on a split basis, with part of it coming from ‘equity’ (i.e., the shareholders) and part of it through borrowing, referred to as ‘debt’ (i.e., by creditors). Each of those financing channels has its cost, with r_{equity} and r_{debt} being the nominal costs for equity and debt (i.e., interest rates), respectively.

Public investors (say governments or state-owned institutions) have access to cheap capital when borrowing money. The interest rates on government bonds are usually relatively low compared to interest charged for financial loans taken up by private actors. For that reason, the financing of public projects is basically done through the issue of bonds, and this for 100%. In the electricity generation business in Europe, this public-

¹⁸ Clearly, these funds should be sufficiently large to cover all costs for this argument to hold. Conversely, in some countries, authorities have imposed taxes on nuclear-generation activities, which are “given” amounts (often per MWh), which cannot directly be traced back to numerically evaluated results for external costs. When considering the internalization of externalities or alleged subsidies etc., these elements should be taken into account.

investor situation may apply to the largely state-owned companies such as Electricité de France (EdF) and Vattenfall (Sweden).

Private investors take a fraction of both financing channels, often of the order of 40/60, 50/50 or 60/40, depending on the interest rates. When they operate *in a regulated market* (which is no longer the case in the EU, but is still the case in about half the states in the USA) there is relatively little risk and the interest rates are 'moderate' (first, the cost of debt is 'reasonable' because of the low risk; and second, regulators assure that the return on equity also remains 'reasonable' to protect customers from too high electricity rates and private equity holders accept lower returns because there is little risk in a regulated market).

Private investors in liberalized markets operate in an uncertain environment, and their interest rates are the highest, depending on the rating of the company and the type of project. For nuclear construction, a premium of up to 3%-pts for the overall cost of capital is not unusual (MIT (2003)).

The Finish example with large customers acting as co-investors is an intermediate case that lowers the cost of capital for the investors. This financing model deserves further study, as it seems to be unique due to Finish circumstances.

Clearly, there is sometimes overlap between the different types of investors as shown by the illustrative picture on the Role of Government by [Kee, 2012], depicted in Figure 1.5.

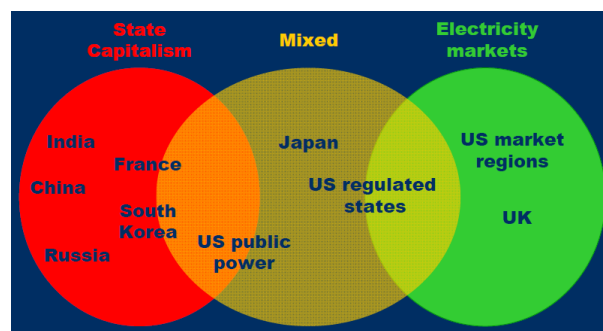


Figure 1.5: The role of government versus private investors (from [Kee, 2012])

In summary and in addition to what has been mentioned above, the following aspects differ, depending on the nature of the investor (private versus public):

- Project is to be profitable (private company) or beneficial for society (public investor);
- Both actors can apply a different discount rate;
- Taxes & subsidies are considered differently;
- External costs (with a special 'long-term' discount rate).

1.4 Levelized Cost of Electricity (LCOE)

The Levelized Cost of Electricity is defined as the long-term breakeven price an investor should receive to cover all his costs (including an acceptable return on investment as expressed by the equity part of the discount rate).

In the end, it is the aim of this study to compute a “*levelized cost of electricity*” (**LCOE**). Although this concept has certain usefulness, it has also certain drawbacks as a single number, in that it depends on many parameters. The inputs clearly are the overnight capital cost of construction, the fixed and variable operation & maintenance (O&M) costs, and the fuel-cycle costs, but important influencing parameters are the load factor (or capacity factor), the duration of construction, the costs of financing, reflected by the discount rate. In any case, a variation of these parameters must be considered. As a particular element for a capital intensive technology like a nuclear power plant (NPP), the load factor is of utmost importance: the “classical paradigm” of base load with load factors of ~ 90% may no longer be applicable in some future European electric-system contexts, with massive amounts of intermittent renewables with zero marginal cost (especially wind and PV-solar), whereby NPPs will have to participate in load following with load factors of only ~ 50-70%. Likewise, the discount rate is of major importance. As an example, [DGEC, 2008] gives an illuminating table showing a range of a factor 2.5 for the LCOE: for a discount rate of 8% and 8760h/a as the basis for a reference LCOE of 100%, the minimum practical case with a discount rate of 5% and 8000h/a gives as result 82% of the reference LCOE, whereas a discount rate of 11% and 5000h/a leads to a relative LCOE of 204%. Similar sensitivity graphs are shown in [NEA/IEA, 2010]. When the LCOE is evaluated, the dependence on the parameters mentioned is obligatory information; some of these factors are more important than others.

In the following, as part of setting the scene, we illustrate the impact of a few elements for contextual purposes:

- Large geographical/ regional variety;
- Inputs of LCOE (Capex, Opex, Fuel Cycle)
- Influencing parameters: capacity factor, discount rate, construction period (IDC)
- Unimportant parameter: lifetime beyond 40y;
- Decommissioning is actually negligible.

Figure 1.6 illustrates the geographic variety of the LCOE. This figure is taken from [ECN, 2010], in turn using the numerical information of [NEA/IEA, 2010].

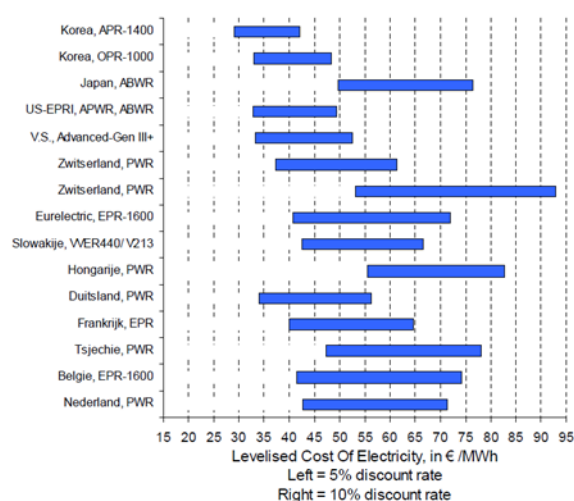


Figure 1.6: LCOE for new power plants in OECD countries, to be operational between 2015 and 2020 (Fig. 5.6 from [ECN, 2010])

The geographical disparity is also well illustrated in Figure 1.7, taken from [NEA/IEA, 2010].

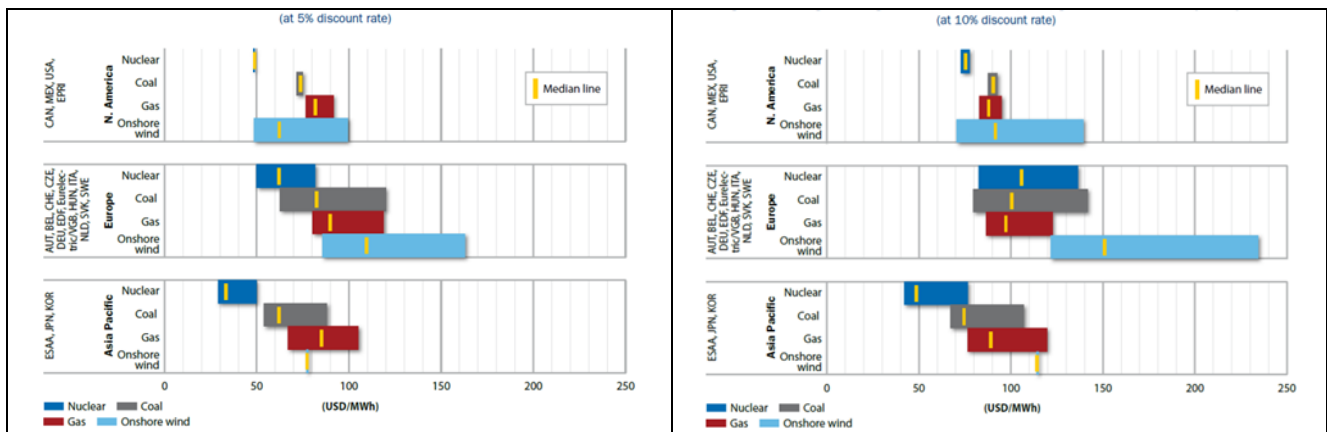


Figure 1.7: Regional ranges of LCOE for nuclear, gas coal and onshore wind power plants for 5% (left) and 10% (right) discount rate (Figs. ES.1 and ES2 from [NEA/IEA, 2010])

As will also become clear later in this report, various cost estimates since about 2000 not only have a broad range but they have also varied considerably over time. See Figure 1.8. This will be explained later; for now it suffices to illustrate the differences reported so as to stress the point that cost estimates are to be looked at as *orders of magnitude* and not as single numbers “carved in stone”.¹⁹ All dollars are expressed in \$ of 2007.

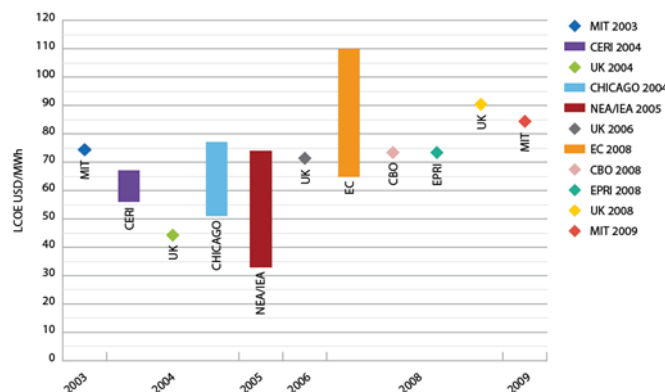


Figure 1.8: Time variations of LCOE for nuclear, as reported in different studies - \$ of 2007 (Fig. 11.1 from [NEA/IEA, 2010])

The sensitivity with respect to some cost components, such as overnight construction cost, construction period, operational life time, load factor and discount rate, is well summarized in Figure 1.9, taken from [ICEPT, 2012]. The absolute numbers are not relevant at this level of our discussion; the relative differences are important. Clearly, some parameters are less important than others.

¹⁹ It is interesting to note though that the MIT figure in 2009 takes an overnight construction cost that is roughly the double of that in 2003 (4000\$/kW versus 2208 \$/kW), but the LCOE has merely increased by 13.5% from 74\$/MWh to 84 \$/MWh. The reason for this discrepancy is to be found in a different methodology for discounting and is explained in footnote of the Du & Parsons paper [Du, 2009]. In summary, the LCOE in the MIT (2003) report was actually too large; the methodology used in MIT (2009) is more appropriate. See also [Osouf, 2007].

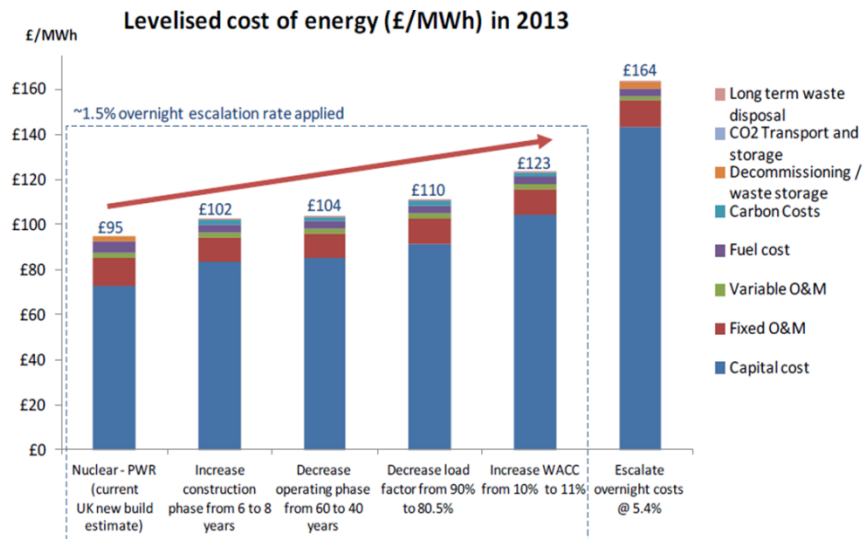


Figure 1.9: Sensitivity of the nuclear LCOE with respect to different parameters (Fig. 10 from [ICEPT, 2012])²⁰

Notice that especially the change of the lifetime from 60 to 40 years makes very little difference (being a consequence of the discounting). The first and the last vertical bars give the appropriate breakdown of the different cost components.²¹ They show that “decommissioning/waste storage” does show up as part of the cost, but is of minor importance. (Decommissioning is not really important because of the discounting – at least for a discount rate >5%/a.) Long-term waste disposal is not visible on the scale of the graph, probably also a consequence of the discounting.

To wrap up our illustrative discussion on the different components of the LCOE, we refer to Figures 1.10 and 1.11.

Figure 1.10 shows the LCOE, expressed on GBP₂₀₁₀/MWh as computed by the engineering consulting firm Parsons Brinckerhoff (after performing a review of the work by the consultancy firm Mott MacDonald) in 2011. [PB, 2011].

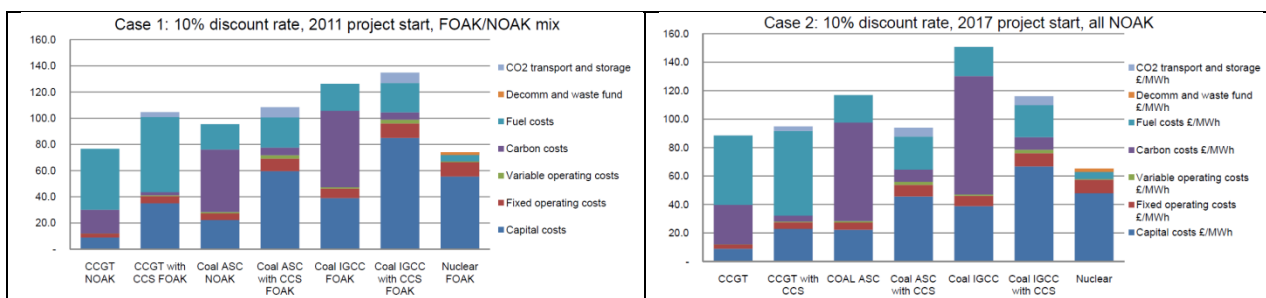


Figure 1.10: Comparison of the LCOE (expressed in GBP₂₀₁₀/MWh) for several “conventional” generation means and the breakdown in its components - (from Parsons Brinckerhoff, [PB, 2011])

²⁰ [ICEPT, 2012] applies a cost escalation of nuclear construction above the estimates originally made. The escalation rate assumed for the “reference” case for comparison in Figure 1.9 seems to be 1.5%/a during a total period of 5.5 y (pre-construction) and 7.5 y (construction). Its so-called “Baseline”, however, assumes an annual escalation of 5.4% of the overnight construction cost. From the context of [ICEPT, 2012] it should be assumed that the escalation rates are real rates (i.e., above the usual inflation of the economy as measured by the CPI).

²¹ The intermediate bars do not seem to portray the correct color distribution for the components. The carbon-cost reference is mysterious.

Because of its relevance for the “strike price” in the context of the “Contracts for Difference”, as agreed by the UK Government and a group of investors led by EdF, in 21 October 2013,²² we present the latest “official” numbers for LCOE computation in the UK, dated from July 2013, in Figure 1.11. The currency is GBP of 2012. [DECC, 2013]²³

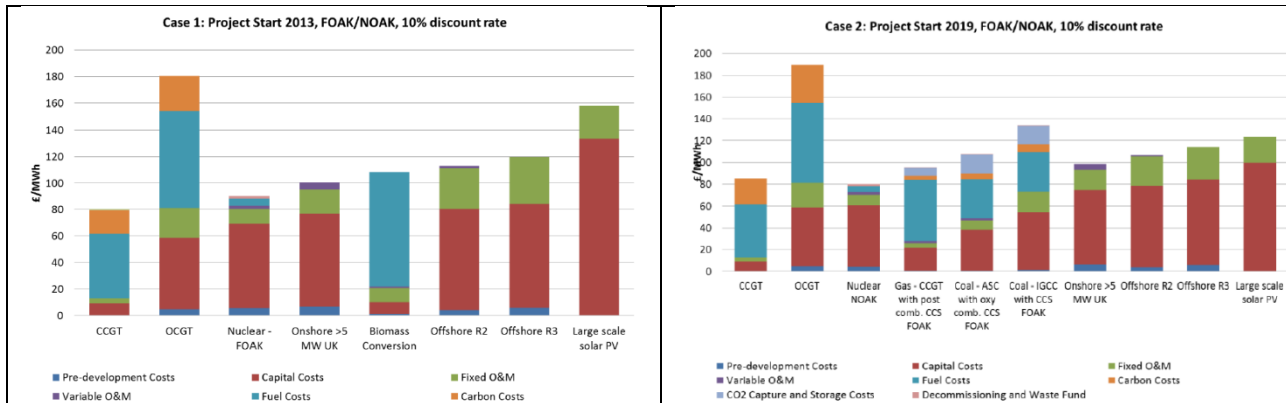


Figure 1.11: Comparison of the LCOE (expressed in GBP₂₀₁₂/MWh) for several “conventional” generation means and the breakdown in its components - (from the UK Department of Energy & Climate Change, [DECC, 2013])

Figures 1.10 and 1.11 confirm the breakdown for nuclear-generated electricity of the two outside bars of Figure 1.9, and they show that the costs are distributed as follows:

- mostly capital cost;
- O&M & fuel costs are smaller (relative importance depends on the cost of capital – being the discount rate, the construction period and the load factor);
- waste management and decommissioning-related costs are of minor importance;
- but the final word on the competitiveness of nuclear-generated electricity depends on the cost components of other generation means, in particular:
 - the capital cost of nuclear and the load factor compared to that of the competition;
 - fuel costs of the competing generation means (especially for natural gas in the EU) and the CO₂ cost (especially for coal).

The above illustrative “analysis”, which in all cases has shown the dominance of capital costs, motivated the approach to concentrate the first part of the study and its intermediate report on the capital costs of nuclear power plants, and to provoke a reaction of the industrial actors on these very important capex-related input elements.

²² <https://www.gov.uk/government/news/initial-agreement-reached-on-new-nuclear-power-station-at-hinkley> and <http://newsroom.edfenergy.com/News-Releases/Agreement-reached-on-commercial-terms-for-the-planned-Hinkley-Point-C-nuclear-power-station-82.aspx>

²³ Which are in turn based on the updated reports by Parsons Brinckerhoff of April and June 2013 [PB, 2013a] and [PB, 2013b]

Chapter 2

Definitions, Conventions, Boundary Conditions, Hypotheses; Important Issues

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 - 2.3.3 Owners’s Costs
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 - 2.7.4 Summary on contingency, cost levels and accuracy

2.1 PWR - BWR Generic Estimate

This study concentrates on the most likely nuclear “Generation III” projects in Europe. We focus on (light) water cooled reactors. Neither heavy water cooled CANDU reactors, nor gas or liquid-metal cooled reactors are considered. In our economic analysis, we do not make a distinction between pressurized and boiling water reactors (PWR and BWR, respectively); but we consider a generic type of reactor (although it is known that the capital cost of a BWR is typically somewhat less than that of a PWR, while the O&M costs for a BWR are higher).

The considered reactors must satisfy the European Utility Requirements (EUR).²⁴ So, typically the following reactors are considered:

- EPR – “*European Pressurized Reactor*”
- AP1000 – “*Advanced Pressurized Reactor*”
- ABWR – “*Advanced Boiling Water Reactor*”
- VVER – “*Vodo-Vodyanoi Energetichesky Reactor*”,

as well as related reactors. The South Korean OPR and APR reactors are not considered, since they have no EUR accreditation at the time of writing.

In this study, we no longer consider so-called FOAK₁ reactors, by which we mean the very “First of a Kind” of a reactor ever built. However, we do discuss what we call FOAK₂ reactors, which are the first reactors of a certain kind within a particular country. NOAK reactors are also considered, being the N-th of a type.

2.2 Fuel Cycle: Upstream /Downstream – Decommissioning

From our illustrative discussion of Section 1.2 we recall that the *fuel-cycle* cost amounts to about ~ 7-15% of the total levelized cost of electricity (LCOE). It is indeed often customary to combine the cost of the **entire fuel cycle**, which consist of two parts: an upstream part (i.e., fuel preparation all the way up to the fuel assemblies), and a downstream part (thus waste management – simple conditioning or full reprocessing and final disposal of the spent fuel or the waste after reprocessing). The upstream and downstream parts are also often referred to as the front-end and back-end parts, respectively.

The cost ratio of downstream versus upstream may differ from country to country and depends on the different approaches considered, such as reprocessing versus immediate spent nuclear fuel (SNF) disposal. So far, mostly assumptions have been suggested in the literature. For example, [IEA, 2006] assumes an upstream/downstream ratio of 3/1 such that the downstream part accounts for 25% of the fuel-cycle cost. In Belgium, a ratio of 1/1 is assumed, so that each part accounts for 50% [CE2030, 2007]. In the UK, it seems customary to present the fuel-upstream part separately from the back-end part. Following the information of Figure 1.2, the fuel cost is ~ 11% and the back-end (or downstream) cost ~ 3% of the LCOE, being a ratio 11/3 such that the downstream part is ~ 20% of the fuel-cycle cost. In the USA, one customary takes the statutory fee of 1 \$/MWh (or 1 mill/kWh) for the disposal of the spent fuel.

²⁴ See <http://www.europeanutilityrequirements.org>

A recently published NEA/OECD report on “*The Economics of the Back-End of the Nuclear Fuel Cycle*” has considered some generic, but well-defined, fuel-cycle scenarios, thereby clarifying the relative contributions of the front-end and back-end parts. [NEA, 2013] The full fuel cycle will be discussed below in Chapter 5, but here, it suffices to state that we will consider two scenarios:

- 1) “once through” or direct spent nuclear fuel (SNF) disposal, and
- 2) reprocessing with a single recycling cycle, after which all waste and spent fuel is disposed of.

Multiple reprocessing and recycling by means of fast reactors or accelerator driven systems are not considered in this report.²⁵

The exact amount set aside for **decommissioning** when considering investments in new nuclear power plants is of limited importance, as long as the order of magnitude is right. This is a consequence of the discounting, which makes that the present value to be set aside upfront for decommissioning is “almost negligible”.²⁶

In this report, we take the same approach as [NEA/IEA, 2010], which takes the **decommissioning** cost (at the time of decommissioning) equal to **15% of the overnight construction cost**.²⁷ This is also in line with the recommendation by [Lallement, 2004].

2.3 Investment Cost – Definition

2.3.1 Capital Cost Components – Recommended Delineation

There is no uniformity in the literature concerning the breakdown of cost components for the capital cost or capital expenses (Capex). However, we recommend the delineation used by [NEA/IEA, 2010],²⁸ as this also seems to be the most widely used one. The recommended breakdown is as follows:²⁹

(Total) Investment Cost (TIC)

Includes:

Overnight Construction Cost (OCC) and
Interest During Construction (IDC) —often also loosely referred to as “financing cost”

The **Overnight Construction Cost (OCC)**, in turn,

Includes:

Owner’s Cost (OC) —mostly Preconstruction,
Engineering, Procurement & Construction Cost (EPCC) and
Contingency Provision

The OCC is the cost as if the full expenditure were spent ‘overnight’, thus at one instance. It therefore explicitly excludes the interest during construction (IDC).

²⁵ Multiple recycling is considered in [NEA, 2013]

²⁶ According to standard engineering-economics formulae, the present worth P is obtained from a future worth F , N years into the future, as follows:

$P = F(1+r)^{-N}$. Here r is the discount rate in real terms, and $(1+r)^{-N}$ is the discount(ing) factor. As an example, suppose an overnight construction cost of 5 G€₂₀₁₂ at this moment. For decommissioning, one would need 15% of that amount at the time of decommissioning (say after $N = 60$ years), still in real terms, i.e., 750 M€₂₀₁₂. For $r=5\%$, the discount(ing) factor is 18.7, resulting in a present worth $P = 40$ M€₂₀₁₂ “to be set aside now”; for $r=10\%$, the discount(ing) factor is 304.5, resulting in a present worth of merely $P = 2.5$ M€₂₀₁₂.

²⁷ As a further illustration, for the median case of [NEA/IEA, 2010], a decommissioning fund of 15% of the overnight construction cost amounts to a fraction of only 0.2% of the total LCOE for a discount rate of 5%, and to a mere 0.015% of the total LCOE for a discount rate of 10%.

²⁸ [NEA/IEA, 2010]; see legend of Table 3.7-a; page 59.

²⁹ All terms will be explained in due course further in the report.

[NETL, 2011] uses a ‘similar’ breakdown of costs, thereby introducing some new terminology, but still fully compatible with our proposed delineation. This is shown in Figure 2.1.

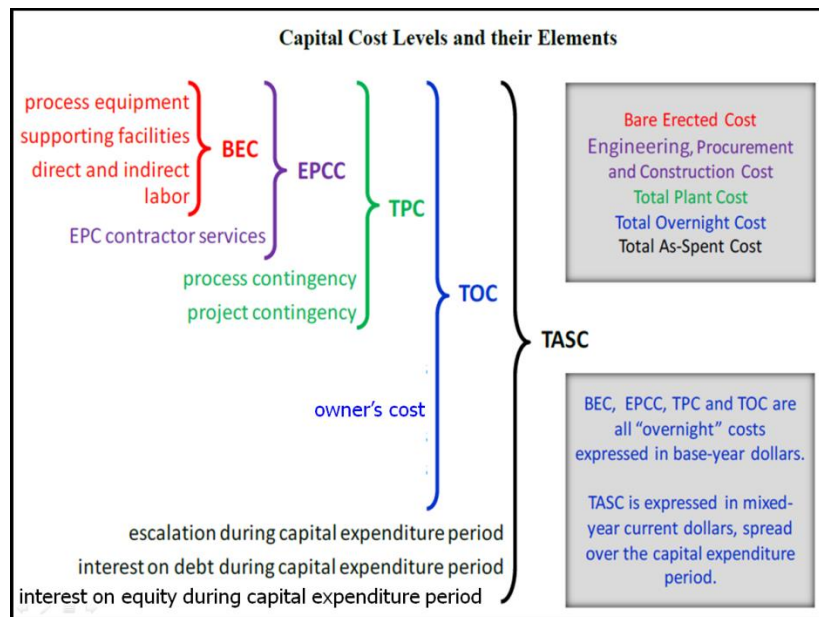


Figure 2.1: Cost components of capital expenditure (from [Ref: NETL, 2011] -slightly adapted by the author)

The abbreviations of Figure 2.1 are explained as follows by [NETL, 2012]:

The **Bare Erected Cost (BEC)** comprises the cost of process equipment, on-site facilities and infrastructure that support the plant (e.g., shops, offices, labs, road), and the direct and indirect labor required for its construction and/or installation. The cost of EPC services and contingencies are not included in BEC. BEC is an overnight cost expressed in base-year dollars.

The **Engineering, Procurement and Construction Cost (EPCC)** comprises the BEC plus the cost of services provided by the engineering, procurement and construction (EPC) contractor. EPC services include: detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs. EPCC is an overnight cost expressed in base-year dollars.

The **Total Plant Cost (TPC)** comprises the EPCC plus project and process contingencies. TPC is an overnight cost expressed in base-year dollars.

The **Total Overnight Capital (TOC)** comprises the TPC plus all other overnight costs, including owner's costs. TOC is an "overnight" cost, expressed in base-year dollars and as such does not include escalation during construction or interest during construction. TOC is an overnight cost expressed in base-year dollars.

The **Total As-Spent Capital (TASC)** is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction. Accordingly, TASC is expressed in mixed, current-year dollars over the capital expenditure period.

Note:

To this excerpt of [NETL, 2011], it is necessary to clarify:

- “capital expenditure period” is usually equal to the construction period;
 - “escalation” is an increase in the capital cost of a facility (as constructed) above the first-estimated costs and beyond the usual inflation (as expressed by a GDP Deflator, the CPI or perhaps the PPI)
 - “Total Overnight Capital” = TPC + OC
= “Total Overnight Cost”
= “Total Overnight Construction Cost”
= “Total Overnight Capital Cost”
- All synonyms of
OCC

Furthermore, **BEC**, **EPCC**, **TPC**, **TOC** are all *overnight costs*, expressed in the currency of a base year. Note, however, that

- For [NETL, 2011], the base year is the first year of capital expenditure (i.e., the first year construction);
- For Du & Parsons [Du, 2009] & MIT[2003, 2009], the base year is the first year of operation (or roughly the last year of construction).

TASC is expressed in mixed, current-year currency, spread over the entire construction period.

Sometimes the “short-cut” denomination “Construction Cost” is utilized for *EPCC + Owner’s Cost*, thus without Contingency & IDC [NEA/IEA, 2010].³⁰

The **Owner’s Cost** and **Contingency** are explained further in this chapter.

Figure 2.2, taken from [ILAR, 2012], gives an indicative idea of the relative orders of magnitude of each of the overnight-cost components for an advanced PWR.

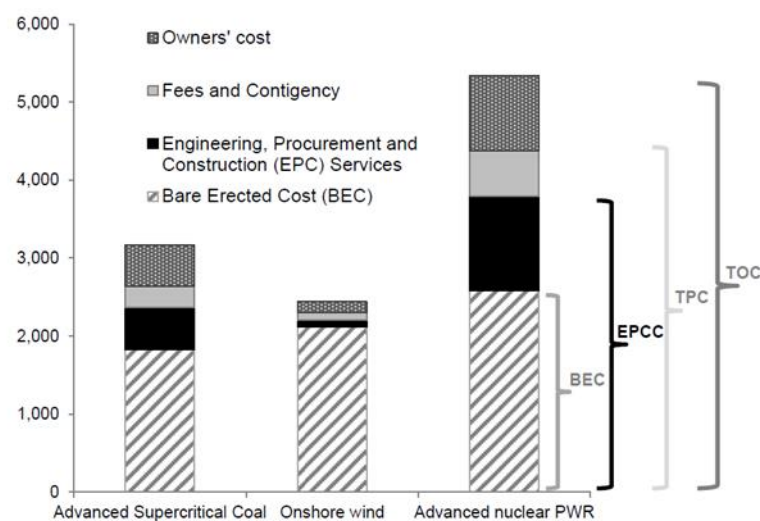


Figure 2.2: Breakdown of capital-cost estimate of some technologies (in 2010\$/kW)(from [ILAR, 2012])

³⁰ [NEA/IEA, 2010] p 103 under Table 5.2

This reference [ILAR, 2012] takes the EPC services to be about $\sim 30\%$ of EPCC, or $\sim 45\%$ of the BEC. In [NETL, 2011] one talks about EPC Services being only $\sim 10\%$ of the BEC but one should realize that the numbers quoted in [NETL, 2011] are for (conventional) thermal plants. For nuclear projects the engineering service part is much higher (strict qualification, quality, organizational issues).

Finally, on the cost-component breakdown, it should be noted that [NEA/IEA, 2005] considers decommissioning as part of the OCC. This is not our approach here (nor is it that of [NEA/IEA, 2010]). Decommissioning will be listed as a separate item to be added later to the capital cost to compute its contribution to the LCOE, after having been properly discounted.

2.3.2 Direct & Indirect Costs

Often also a distinction between so-called “direct costs” and “indirect costs” is made. This was amongst others done in [NEA/IEA, 2005]. The breakdown is as follows:

Direct Costs:

- Site preparation
- Civil work
- Material, equipment and manpower

Indirect Costs:

- Design, engineering & supervision
- Provisional equipment & operation
- Worksite administrative expenses

To a large extent, the *direct costs* agree with the BEC plus the direct-cost part of the owner’s cost (OC). The indirect costs very often refer to “services” such as administration, supervision, etc.

The following specific breakdown direct/indirect (including the usual reference codes in the USA) is available in [UChicago, 2004]. See Table 2.1.

Table 2.1: Breakdown of nuclear plant construction cost in direct & indirect cost elements (from [UChicago, 2004])

Direct Costs	21	Structures & improvements
	22	Reactor plant equipment
	23	Turbine plant equipment
	24	Electric plant equipment
	25	Miscellaneous plant equipment
	26	Main conditioning heat rejection system
Indirect Costs	91	Construction <i>services</i>
	92	Engineering & home office <i>services</i>
	93	Field supervision & field office <i>services</i>

2.3.3 Owners Costs (OC)

Several “definitions” of the Owners Cost (OC) exist. In the end, it all depends on which costs are borne by the owner outside the EPC contract. However, regarding the extent of the works beyond the plant’s transformer, some ambiguity exists. We mention a few definitions:

[Larsson, 2012] p 38:

identifies the ‘preconstruction costs’ with the *owner’s cost*, thereby effectively referring to e.g., land cost, site works, switch yards, licenses, etc.

The US EIA website (<http://www.eia.gov/forecasts/capitalcost>) specifies:

«Owners costs: development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system»³¹

Following [NEA/IEA, 2005], the owner’s cost is assumed to be composed of:

- General administration
- Pre-operation
- R&D (plant specific)
- Spare parts
- Site selection, acquisition, licensing & public relations
- Taxes (local/regional, plant specific)

According to [NETL, 2011], the following elements are part of the owner’s cost:

- the cost of securing financing, including fees and closing costs, but not including interest during construction
- preliminary feasibility studies, including so-called a Front-End Engineering Design study
- legal fees; permitting costs
- owner’s engineering (staff paid by the owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors)
- owner’s contingency (sometimes called “management reserve”, these are funds to cover costs relating to delayed start up, fluctuations in equipment costs, ...).

Note that according to the definition by [NETL, 2011], the owner’s contingency is considered not to be part of the project contingency.

Also, not considered part of the owner’s costs by [NETL, 2011] are the transmission interconnections beyond the plant busbar, nor so-called unusual site improvements. As a simplifying rule, [NETL, 2011] suggests that cost estimates should be limited to within the plant boundary, defined by the “fence line”.³²

The engineering company Black & Veatch states about owner’s cost [NREL, 2012] (Text Box 1):

³¹ Underlining by the author of this report.

³² Underlining by the author of this report.

Owners will also have specific needs and their costs will vary for a cost category referred to as Owner's costs. The Electric Power Research Institute (EPRI) standard owner's costs include 1) paid-up royalty allowance, 2) preproduction costs, 3) inventory capital and 4) land costs. However, this total construction cost or total capital requirement by EPRI does not include many of the other owner's costs that a contractor like Black & Veatch would include in project cost comparisons. These additional elements include the following:

- **Spare parts and plant equipment** includes materials, supplies and parts, machine shop equipment, rolling stock, plant furnishings and supplies.
- **Utility interconnections** include natural gas service, gas system upgrades, electrical transmission, substation/switchyard, wastewater and supply water or wells and railroad.
- **Project development** includes fuel-related project management and engineering, site selection, preliminary engineering, land and rezoning, rights of way for pipelines, laydown yard, access roads, demolition, environmental permitting and offsets, public relations, community development, site development legal assistance, man-camp, heliport, barge unloading facility, airstrip and diesel fuel storage.
- **Owner's project management** includes bid document preparation, owner's project management, engineering due diligence and owner's site construction management.
- **Taxes/ins/advisory fees/legal** includes sales/use and property tax, market and environmental consultants and rating agencies, owner's legal expenses, PPA, interconnect agreements, contract-procurement and construction, property transfer/title/escrow and construction all risk insurance.
- **Financing** includes financial advisor, market analyst and engineer, loan administration and commitment fees and debt service reserve fund.
- **Plant startup/construction support** includes owner's site mobilization, operation and maintenance (O&M) staff training and pre-commercial operation, start-up, initial test fluids, initial inventory of chemical and reagents, major consumables and cost of fuel not covered recovered in power sales.

Some overlap can be seen in the categories above, which is another contributor to variability - different estimators prepare estimates using different formats and methodologies.

Given the broad definition and the wide range covered in some instances, most authoritative references seem to converge on an estimate that reads as follows:

Owners cost:

~ 15-20% of the EPCC [MIT, 2003, 2009][Du, 2009][Rothwell, 2010]³³ ; or,

~ 15-20% of the TPC [NETL, 2012]; or,

~ 15-20% of the OCC [UChicago, 2011]³⁴

2.3.4 Interest During Construction (IDC) – Financing

The interest during construction, or “financing cost” as it is also often referred to, is the interest paid during construction, not only on the debt part, but also to provide an acceptable rate of return to equity investors.

The illustrative example by Du & Parsons [Du, 2009], already presented in Section 1.1, explains the computation in detail. See also [MIT, 2003].

³³ Actually EPCC is called 'Base Overnight Construction Cost' by [Rothwell, 2010]

³⁴ Note that [UChicago, 2004] used only ~ 5% for the owner's cost; a “mistake” the authors have corrected in the 2011 version.

In formula form, an expression for IDC can be obtained as follows [CEU, 2008]³⁵:

$$IDC = OCC \times (IDC)_{fract}$$

with

$$(IDC)_{fract} = \sum_{k=1}^{CT} W_k (1+r)^{CT-(k-1)} - 1$$

where:

OCC = the Overnight Construction Cost

$(IDC)_{fract}$ = the additional fraction of the OCC due to interest during construction

CT = is the construction time

W_k = the fraction of the total capital expended in year k

r = the discount rate³⁶

Note that the discount rate r is expressed in decimal form as $0.0r$ for $r\%$.

When actually computing the IDC one must assure that W_k and r are both expressed in either nominal or real terms. This is especially important if tax deductions on interest paid on debt is considered, since these deductions are usually performed in nominal currency.

The order of magnitude of the IDC was already illustrated in Table 1.1 from [Davis, 2011] and our considerations underneath that table.

A different example is given by [Rothwell, 2012] in Figure 2.3. In this illustration, IDC is about 20% of the OCC.

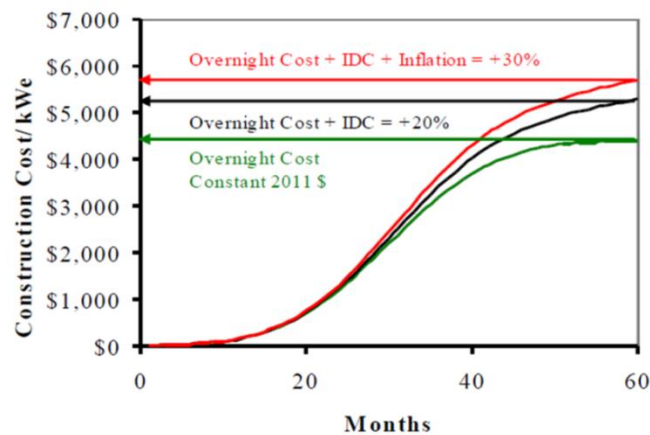


Figure 2.3: Illustration of the expenditure during the construction period of 5 years and the impact of IDC and inflation. The inflation is taken here as $2\%/a \rightarrow (1.02)^{**5}=1.10$ or 10% extra. No further escalation beyond “normal CPI-inflation” is assumed.

(From [Rothwell, 2012])

³⁵ The formulae have been adapted by the author of this report to bring them in line with the definitions used in this report.

³⁶ In [CEU, 2008], r is called the interest rate.

2.4 Levelized Cost of Electricity (LCOE) – Computational Guidelines

2.4.1 New Build

The levelized cost of electricity (LCOE) is *the equivalent stable price needed over the lifetime of the plant to break even the full costs for the investor*. The approach is based on a discounted cash flow model and thus the LCOE is a fictitious stable price needed to make the net present value of the sum of all costs (including return on equity) and all revenues over the entire operational life time of the plant equal to zero.

An explicit expression for the computation of the LCOE is given by [NEA/IEA 2010]:³⁷

Using the following definitions and concepts:

$Electricity_t$:	The amount of electricity produced in year “t”;
$P_{Electricity}$:	The constant price of electricity;
$(1+r)^{-t}$:	The discount factor for year “t”;
$Investment_t$:	Investment costs in year “t”;
$O\&M_t$:	Operations and maintenance costs in year “t”;
$Fuel_t$:	Fuel costs in year “t”;
$Carbon_t$:	Carbon costs in year “t”;
$Decommissioning_t$:	Decommissioning cost in year “t”.

For nuclear power, the so-called carbon costs $Carbon_t$ can be set to zero.

One can state that the sum of the revenues must equal the sum of all costs, as follows:

$$\sum_t (Electricity_t * P_{Electricity} * (1+r)^{-t}) = \sum_t ((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t) * (1+r)^{-t}) \quad (1).$$

From (1) follows that

$$P_{Electricity} = \frac{\sum_t ((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t) * (1+r)^{-t})}{\sum_t (Electricity_t * (1+r)^{-t})} \quad (2),$$

which is, of course, equivalent to

$$LCOE = P_{Electricity} = \frac{\sum_t ((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t) * (1+r)^{-t})}{\sum_t (Electricity_t * (1+r)^{-t})} \quad (2)'.$$

It should be noted that the costs usually take place in a different time period: investments ($Investment_t$) take place during the construction period, whereas $O\&M_t$ and $Fuel_t$ costs occur during the operational life time of the plant and $Decommissioning_t$ takes place after the plant has stopped operating, whereby most expenses only start about 10 or 20 years after the shutdown. Revenues only occur during operation.

If $t=0$ is chosen at the start of operation, then construction years are negative. See e.g., Du & Parsons [Du, 2009]. Through the discounting factor $(1+r)^{-t}$, the expression then automatically “generates” the interest during construction (IDC) ‘expenditures’.

³⁷ These expressions are an excerpt of [NEA/IEA, 2010], p 34.

The investment-cost elements needed for the LCOE formula are:

$Investment_t$ = The part of the Overnight Construction Cost (EPCC, Owners & Contingency) that is expended in year t

Important factors influencing this expression are: the *discount rate* r , the *load factor* (which determines the amount of electricity produced per year, i.e., $Electricity_t [MWh/a] = Installed Capacity [MW] * Load Factor of year t [-] * 8760h/a$), and the *construction period* (being the period over which the summation index runs negatively).

Because of the discounting, it should be noted that the Operational Life Time of the plant (the upper index in the summation of revenues and O&M and Fuel costs) is relatively unimportant beyond, say 40 years. See also Figure 1.9 above. Likewise, because of the discounting, decommissioning costs are basically negligible when discounted back to the beginning of operation.

For completeness, we mention that [CEU, 2008] uses a somewhat different expression, making use of the annuities and the capital recovery factor CRF. The cost of electricity reads:

$$(LCOE)_{CEU} = \frac{SOCC \cdot \sum_{k=1}^{CT} W_k (1+r)^{CT-(k-1)} \cdot CRF}{8760 \cdot LF} + \frac{FOM}{8760 \cdot LF} + VOM + FC$$

where:

$(LCOE)_{CEU}$ = the levelized cost of electricity in €/MWh

$SOCC$ = the Specific Overnight Construction Cost in €/MW (also referred to as Specific Capital Investment, SCI)

CT = is the construction time

W_k = the fraction of the total capital expended in year k

r = the discount rate

CRF = the capital recovery factor = $\frac{r(1+r)^N}{(1+r)^N - 1}$

N = the operational life time of the facility

LF = the annual load factor of the facility

FOM = the annualized fixed operating cost during the facility life time in €/MWh

VOM = the annualized variable operating cost during the facility life time in €/MWh

FC = the annualized fuel cost during the facility life time in €/MWh

As already stated above,

$$(IDC)_{fract} = \sum_{k=1}^{CT} W_k (1+r)^{CT-(k-1)} - 1$$

And thus the summation over k is the additional fraction of the OCC due to interest during construction, plus one.

Under the appropriate conditions, such as $Electricity_t = constant$, and

$SOCC = \sum_t (Investment_t / Installed Capacity)$, both expressions can be shown to be identical.

Equivalent explicit expressions are given in [UChicago, 2004]³⁸, [Rothwell, 2012], and [Osouf, 2007].

Sometimes the concept of LCOE is criticized since prices fluctuate in liberalized markets. See e.g., Figure 2.4 for an illustrative example [Kee, 2012].

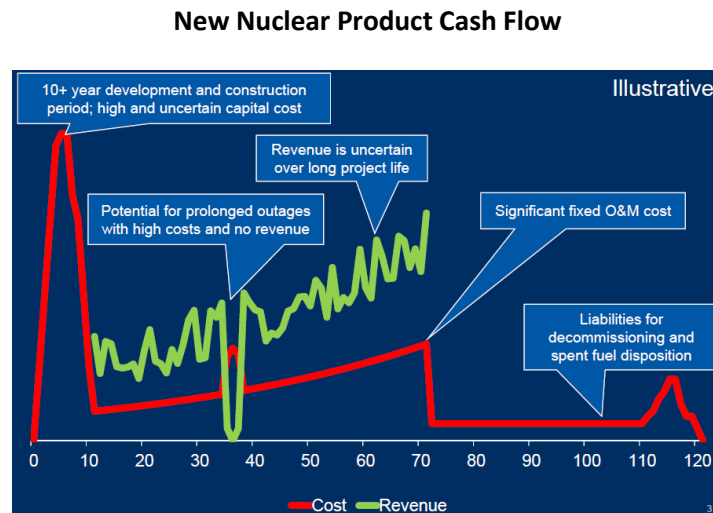


Figure 2.4: An example of the cash flow during the overall life of a nuclear project. (From [Kee, 2012])

Even [NEA/IEA, 2010] writes the following statement:

“LCOE is closer to the real cost of investment in electricity production in regulated monopoly electricity markets with loan guarantees and regulated prices rather than to the real costs of investments in competitive markets”

Also, the French Cour des Comptes [CdC, 2012] has made similar remarks.

The author believes that, although these remarks are thoughtful considerations, it must be recognized that the LCOE is defined as an equivalent (hypothetical) price for breakeven (which of course may differ from the real prices!). If one really insists, then one could qualify that the LCOE computation finds the average annual

³⁸ Caution is needed with the expressions [UChicago, 2004] since the expressions on p 1-4,5 seem to be ‘mysterious’, while the expressions in § 2.6 Appendix, p 2-16 to 19, seem to be OK.

price, by integrating the actual price over the full year. Having said that, however, the LCOE concept is a good metric as long as the value of the *commodity ‘electricity’* (expressed in MWh) is the subject matter of interest. According to Joskow, caution *is* needed when comparing the cost of nuclear plants with non-dispatchable units, because both have a different market value. [Joskow, 2011] In a first instance, this basically means that the LCOE concept must be ‘supplemented’ with system-integration-cost considerations (whereby cost elements other than those related to merely the production of the commodity —such as availability of reserve or back-up capacity to be provided by dispatchable units— must be reflected upon). Identification and evaluation of the system-integration aspects of nuclear and intermittent sources is discussed in Chapter 9 of this report.

2.4.2 LCOE Computations after Major Refurbishments for Long-Term Operation (LTO)

When major investments take place to prolong the operational life of a power plant, a new LCOE that characterizes the extended operational period can be computed following similar logic as for new build, but with an appropriately adapted expression. We borrow the expression from [NEA, 2012c], “The Economics of Long-Term Operation of Nuclear Power Plants” (p55):

Calculation of $LCOE_{EO}$ after refurbishment and lifetime extension

The formula for $LCOE_{EO}$ corresponding to the period of extended operation reads:

$$LCOE_{EO} = \frac{\sum_{t=t_R}^{t_{EO}} \left(\text{Refurbishment}_t + O\&M_t^{EO} + \text{Fuel}_t^{EO} + \text{Decommissioning}_t^{EO} \right) (1+r)^t}{\sum_{t=1}^{t_{EO}} \left(\frac{\text{Electricity}_t^{EO}}{(1+r)^t} \right)}$$

where:

t_R :	Refurbishment duration
t_{EO} :	Duration of extended operation
$\text{Electricity}_t^{EO}$:	The amount of electricity produced in year “t”, after refurbishment
r :	Annual discount rate
Refurbishment_t :	Refurbishment cost in year “t”
$O\&M_t^{EO}$:	Operations and maintenance cost after refurbishment, in year “t”
Fuel_t^{EO} :	Fuel cost after refurbishment, in year “t”
$\text{Decommissioning}_t^{EO}$:	Decommissioning cost associated with refurbishment in year “t”

2.5 Exchange Rates

An additional uncertainty factor when comparing cost estimates in different parts of the world is the exchange rate to be used. Of course when real goods or services are actually bought from a different country, then the market exchange rate (MER) at the date of contract signature applies. The principle for immediate transactions is clear, but the issue becomes less tangible when comparing cost estimates that refer to different time periods, because MERs are known to have fluctuated considerably over time. Figure 2.5 shows the recent history of three major currency ratios USD/EUR, JPY/EUR and GBP/EUR.

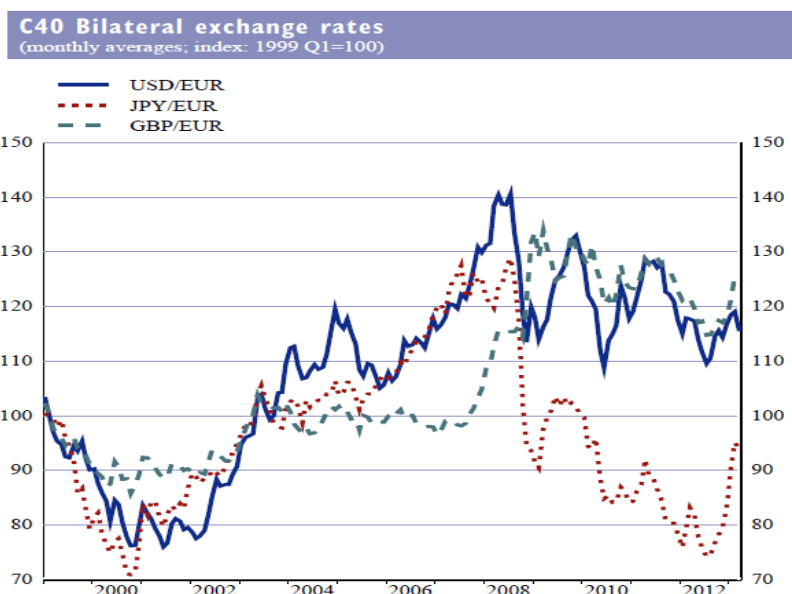


Figure 2.5: Relative Market Exchange values of US dollar, Japanese Yen and British Pound versus the Euro, from 1999 till April 2013. The beginning of 1999 has index 100. [From ECB, 2013]]

The MER of the Japanese Yen is not important for our purposes, since we do not directly convert the costs of Japanese projects to Euros in our study.³⁹ Ample information on nuclear costs estimates is available in the US and the UK, which is useful for “designing” our estimate. Figure 2.5 shows, however, that exchange rates can change considerably. For completeness, we present the full set of conversion values that can be used in Table 2.2.

Table 2.2 Market Exchange rates applicable for conversion from USD and GBP to EUR. (From ECB⁴⁰)

1999	0.938	1 USD equals	0.938 EUR	1999	1.518	1 GBP equals	1.518 EUR
2000	1.083			2000	1.641		
2001	1.117			2001	1.608		
2002	1.058			2002	1.59		
2003	0.884			2003	1.445		
2004	0.804			2004	1.473		
2005	0.804			2005	1.462		
2006	0.796			2006	1.467		
2007	0.73			2007	1.461		
2008	0.68			2008	1.256		
2009	0.717			2009	1.122		
2010	0.754			2010	1.166		
2011	0.718			2011	1.152		
2012	0.778	1 USD equals	0.778 EUR	2012	1.233	1 GBP equals	1.233 EUR

³⁹ We use Japanese information only indirectly, e.g., from Du & Parsons [Du, 2009]. The Japanese cost estimates have first been converted to USD, and we have taken the US figures as input. Note that Du & Parsons use the Power Purchasing Parity (PPP) rates for converting Japanese and Korean numbers to dollars. For conversion of European values, MER are used.

⁴⁰ Obtainable from

http://sdw.ecb.europa.eu/browseSelection.do?DATASET=0&sf1=4&FREQ=A&sf3=4&node=2018794&SERIES_KEY=120.EXR.A.USD.EUR.SP00.A and likewise with USD replaced by GBP.

As will be explained later, we have utilized a strict “methodological” convention (which to some extent is disputable, but nevertheless consistent) to first escalate estimates of the US and the UK to current 2012 values and only then the currency is converted to Euros. The values explicitly used in our study are:

1.47 $\$/\epsilon_{2008}$ ⁴¹

0.81 $\text{GBP}/\epsilon_{2012}$

1.28 $\$/\epsilon_{2012}$

2.6 Inflation – Escalation

2.6.1 Inflation and Escalation

2.6.1.1 Different Sorts of Escalation

The issue of escalation is a tricky one, especially because – again – there is much confusion in the literature. We will try to be consistent and will consider three sorts of “escalation”.

Escalation # 1, referred to as ‘Esc1’:

This type of escalation is nothing else than the *usual inflation*, and allows ‘simple’ conversion of nominal currency of one year into that of another year.

The inflation is usually measured by concepts such as the GDP deflator, the Consumer Price Index (CPI) or, for wholesale goods, the Producer Price Index (PPI). See e.g., [Samuelson & Nordhaus, 2010]

Escalation # 2, referred to as ‘Esc2’:

The second type of escalation is a price escalation whereby we focus on the actual price evolution (expressed in currency of that day) of *one particular* sort of goods, in our context especially process equipment, electricity generation power plants, etc.

In the past, Esc2 has been considerably higher than Esc1, and this for all kinds of reasons. This will be explained in some detail below.

In this study Esc2 is utilized to adjust estimates for power plants from one instant to another, based on the escalation that has actually occurred over the period defined by those instances.

At this stage it is important to *caution against double counting*. Indeed, if one uses cost escalation figures of, say power plants, from year x to year y, then this escalation is —as a rule— expressed in *nominal* currency. Applying in addition a GDP deflator or CPI to convert from $\epsilon_{\text{year } x}$ to $\epsilon_{\text{year } y}$ would be double counting, as the plant equipment is characterized by its own “inflation”, independent of the price of cookies, bread, milk, TVs, etc. In some (rare) cases, Esc2 figures are shown whereby it is *explicitly* stated that the escalation is in *real* terms, thereby assuming that an extra “usual inflation” conversion of the currency by the CPI deflator or the CPI is necessary.

⁴¹ The reason for using the conversion ratio of 2008 is that all values of [NEA/IEA, 2012] (including European ones) are expressed in USD. The conversion factor used in [NEA/IEA, 2012] is 0.68 USD/EUR and $1/0.68=1.47$.

Escalation # 3, referred to as ‘Esc3’:

The third kind of escalation found in the literature is an anticipation towards the future by extrapolating historical figures, assuming a continuing and similar escalation during construction. This is e.g., done by [Cooper, 2009, 2010, 2011], [Severance, 2009], [Harding, 2008], [ICEPT, 2012].

The idea behind this sort of escalation is to look at historic cost *estimates* or actual construction costs *in the early ‘70s* and to compare them to the *actual cost of construction especially for the later units*. For the USA and France, there is a considerable amount of historical data available, and there are the recent data for the EPR construction in Finland (Olkiluoto) and France (Flamanville).

This type of ‘extrapolatory’ practice is dangerous as there is no justification for the extrapolation. There is no reason why the past should repeat itself. Indeed, lessons *are* learnt from the past, project organization is streamlined, but also unexpected events during construction do happen. Therefore, we have opted for a different and more legitimate approach.

Rather than using a fictitious escalation (such as Esc3), we will rather stress that our estimates have *uncertainties*, such that actually a *range* rather than a single figure is presented. Our approach, to be explained in one of the sections below, takes into account different circumstances such as “first of a kind” (FOAK) construction versus “N-th of a kind” (NOAK), learning and fleet effects etc.

2.6.1.2 Escalation of Power Plant Costs

a. The facts

IHS CERA provides most useful cost-escalation indices for the actual construction of power plants. According to Pauschert [ESMAP, 2009]⁴²: «...the IHS/CERA Power Plant Cost Index (PCCI), which reflects the market price of actually building power plants in North America.»⁴³

IHS CERA gives the following description of its Power Capital Cost Index, **PCCI**:

«The IHS CERA PCCI tracks the costs of equipment, facilities, materials and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of more than 30 power generation construction projects throughout North America. It is similar to the consumer price index (CPI) in that it provides a clear, transparent benchmark tool for tracking and forecasting a complex and dynamic environment. The IHS CERA PCCI can be tracked on the IHS Index Web Site at www.ihsindexes.com.»

Figure 2.6 presents the latest⁴⁴ PCCI index (for North America) and the EPCCI index (for Europe).

⁴² [ESMAP, 2009] p7

⁴³ Emphasis by Pauschert

⁴⁴ It is interesting to note that in December 2012 the IHS CERA website already included an estimate towards the third quarter of 2013. In February 2013, this estimate towards the future has been deleted, probably because of uncertain projections for 2013.

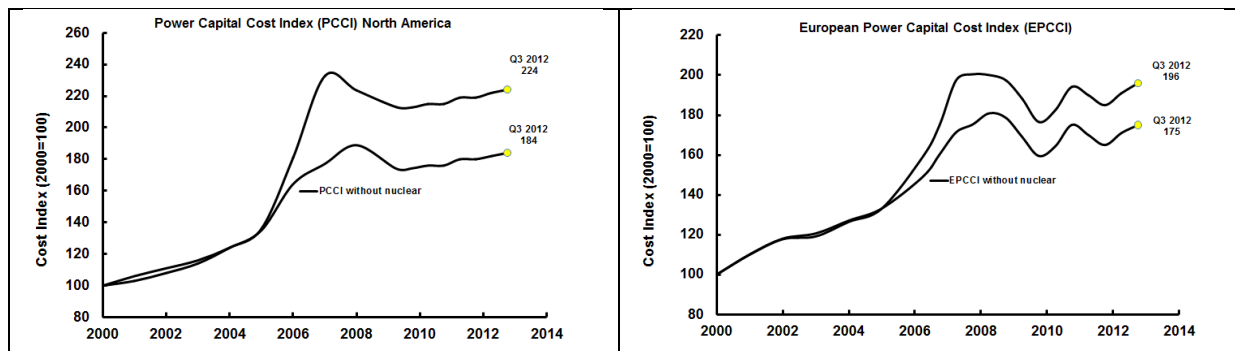


Figure 2.6: PCCI and EPCCI indices from 2000 till the third quarter of 2012 (From www.ihsindexes.com/)

In Figure 2.6, the top solid curves are the full (E)PCCI with nuclear plants included; the lower curves are without nuclear plants.

As is shown in Figure 2.7, the cost increase of power plants in the period 2000-2005 was well beyond the usual inflation (measured by the GDP deflator, the CPI or PPI). In the period from 2005-2007 the market seems to have overheated with perhaps an over-reaction, after which, since the arrival of the economic crisis, a “drop” occurred in 2008, to saturate then to a much milder increasing level between 2008-2012/13.

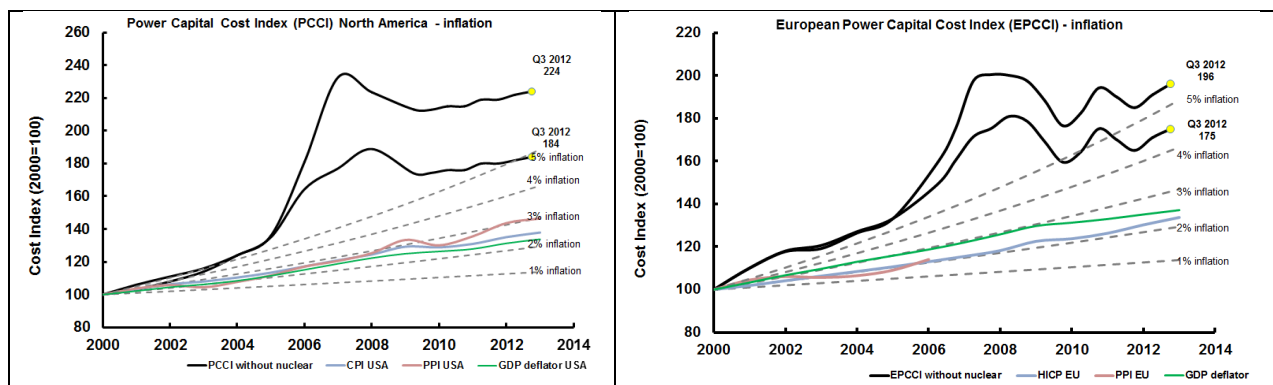


Figure 2.7: Comparison of the PCCI and EPCCI with the usual inflation parameters CPI, PPI or GDP deflator.

The top solid curve in each panel includes nuclear plants; the lower curve is without nuclear plants.

(Base curves from www.ihsindexes.com/) (K. Van den Bergh's help in 'completing' these graphs is greatly appreciated.)

The PCCI curve including nuclear must still be an estimate, likely based on actual bids or quotations or on a clever combination of equipment & projection/anticipation of actual construction. Indeed, during the time span of the graphs, no actual NPP has been built in the US (first concrete was poured in the 1-st trim of 2013). For the EPCCI, a similar remark applies since only two plants (EPRs – Finland and France) are under construction in Europe. One must hope that the degree of professionalism of the IHS CERA estimators is sufficient to arrive at trustworthy nuclear-related indices.

Comparisons with different types of indices have been made by others. [Larsson, 2012] compared several indices, as shown in Figure 2.8.

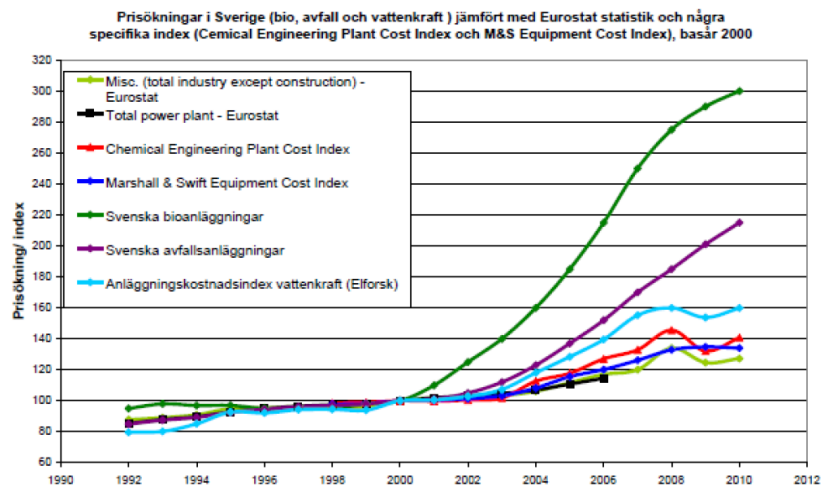
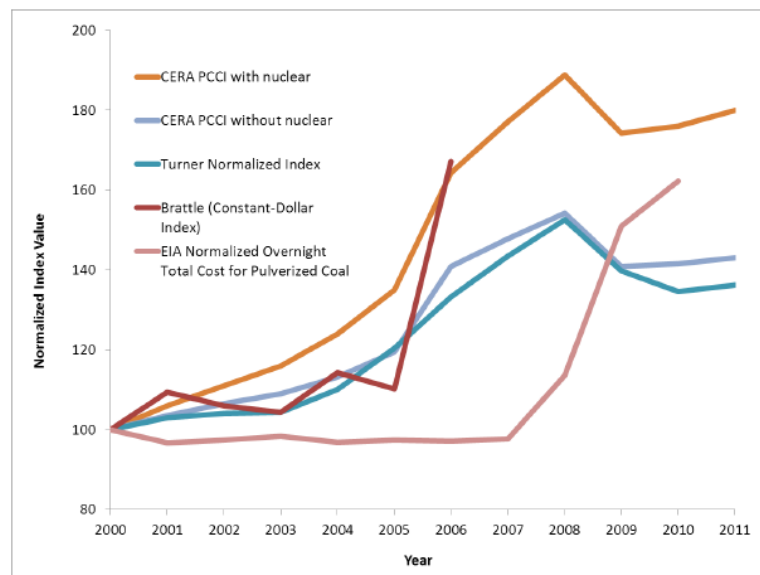


Figure 9. International capital cost indexes and Swedish price increases (Elforsk, 2011b). Svenska bioanläggningar = Swedish biomass power plants, Svenska avfallsanläggningar = Swedish waste power plants, Anläggningskostnadsindex vattenkraft = cost index for hydropower plants. The price increases for biomass and waste power plants can be explained by a significant steel price increase and a large increase in demand.

Figure 2.8: Comparison of several capital-cost indices. (From [Larsson, 2012], Figure 9)

The Union of Concerned Scientists (UCS) in the US has likewise compared several indices in which also the IHS CERA indices are incorporated. [UCS, 2011] It should be noted that the indices in Figure 2.9 are expressed in real terms. To convert to a particular nominal currency, a GDP deflator correction from the year 2000 must be utilized.



Source: EIA 2010, 2009c; IHS CERA 2011; Turner 2011; Chupka and Basheda 2007.

Note: We used a GDP deflator to express all indices in constant dollars.

Figure 2.9: Escalation in the Cost of Constructing Power Plants, 2000-2011; this is a constant-dollar index; year 2000=100. (From USC, 2011)

The comparison with the *Turner* and the *Brattle* indices is a useful exercise. The graph representing the EIA cost estimate for coal-fired plants is less relevant as it will be shown later in this report that the EIA estimates for nuclear plants were likewise seriously underestimated up to about 2009.

Pauschert [ESMAP, 2011] has performed a cost-increase analysis for a (non-nuclear) thermal pulverized coal-fired plant.

- He estimated the cost using EPRI's "PCCost program" and escalated the cost from 2005 to 2008 by «using the 25 different historical escalation rates that include equipment, material and labor.»⁴⁵ The result was a three-year total plant cost increase of 11%.
- In addition, Pauschert states that «another source of power plant cost increase is the "Marshall and Swift" (M&S) index. This index indicates an increase of 16% in the composite equipment costs of steam power plants from 2005 to 2008.»⁴⁶
- Next, he compared both the EPRI PCCost and the M&S results with the IHS-CERA Power Capital Cost Index (PCCI). The IHS-CERA PCCI for non-nuclear plants shows an increase by about 27% from 2005 to 2008. Hence, the price of actually building a plant is about 11%-pts higher than the M&S index would indicate, and 16%-pts higher than suggested by the EPRI-based PCCost program. Hence, the "analytic" equipment cost-breakdown indices (PCCost and M&S) underestimate the real purchasing price of a plant by 11 to 16 %-pts.

Pauschert's conclusion reads: «The North American Market is being influenced by the global power sector, including expansive construction in the Middle East and Asia, many infrastructure projects worldwide, and concurrent expansion of power plant construction in the United States. As a result of all this activity, lead times for engineered equipment have increased by up to 50% in the last 6-12 months, impacting prices for some "big ticket" items in a way that is not being captured by [expected equipment] escalation alone.»⁴⁷ «The latest increases reflect the worldwide market demand and the corresponding prices currently charged by manufacturers and suppliers. In this sense, the difference can be termed a "market demand charge"»⁴⁸

The author of this report would like to add that for nuclear plants, because of competition with classical-equipment manufacturing, the limited availability of manufacturing capability for special nuclear-grade equipment (such as forging of nuclear-reactor vessels and steam generators), the demand for highly skilled labor, both blue-collar employees and technicians/engineers, and the anticipated specific nuclear-related country-specific demands by nuclear regulators, the nuclear cost-escalation index has been even much larger. The nuclear capital-cost issue will be further explored below.

b. Attempts to Explain the Escalation

Several authors have tried to explain the cost escalation since 2000 by a breakdown in different cost categories. As shown below, this is not unequivocal. Especially confusing is the impact of labor versus resources/raw materials.

We illustrate this with some observations from the literature.

Figure 2.10 shows the four IHS CERA power-plant curves up to 2011 (left panel) while the right panel compares the North American plant index with an index for Metal and Metal Products. [ILAR 2012].

⁴⁵ Verbatim from [ESMAP, 2011]

⁴⁶ Verbatim from [ESMAP, 2011]

⁴⁷ [expected equipment] was added by the author (WDH)

⁴⁸ Verbatim from [ESMAP, 2011]

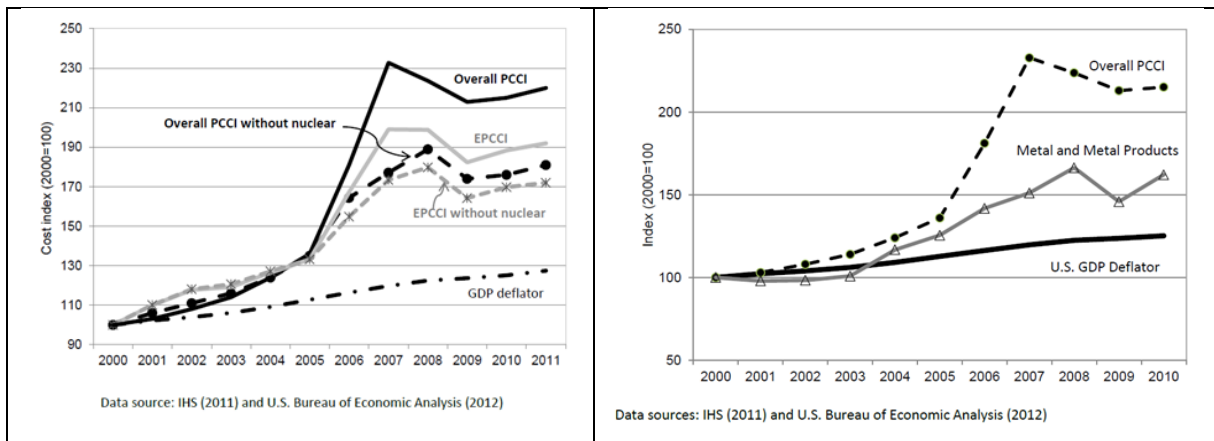


Figure 2.10: IHS CERA power-plant indices and a comparison of the NA plant index with a US index for Metal and Metal Products. (From [ILAR, 2012], figures 1 (left) and 8 (right))

Disentanglement in cost components in table form also gives some insight. Table 2.3 is taken from [EIA, 2010] for a 'base plant' PWR AP1000 (twin unit), NOAK.

Table 2.3: Cost-component breakdown for a typical PWR AP1000 twin unit (from[EIA, 2010])

Capital Cost Category		
Civil Structural Material & Installation	14.5 % of TOCC	20.4% of EPCC
Mechanical Equipment Supply and Installation	28.3% of TOCC	39.8% of EPCC
Electrical / I&C Supply and Installation	5.3% of TOCC	7.6% of EPCC
Project Indirects (engineering, distributable costs, scaffolding, construction management and start-up)	22.8% of TOCC	32% of EPCC
EPCC (Engr, Procure & Constr Cost)	71.1% of TOCC	100 % of EPCC
Contingency & Fee	10.9% of TOCC	
TPC (Total Plant Cost)	82% of TOCC	
Owner's Cost	18% of TOCC	
TOCC (Total Overnight Construction Cost) or TOC (Total Overnight Capital)	100%	

[UChicago, 2004] (adapted by the author) gives the relative cost breakdown for an ABWR Mature Design in Table 2.4. This breakdown uses the same delineation as the one presented in Table 2.1

Table 2.4: Cost-component breakdown for an ABWR Mature Design (from [UChicago, 2004])

% of EPCC	Account		(1) Factory Equipment Cost	(2) Site Labor Cost	(3) Site Material Cost	Total	Total approx
Direct Costs	21	Structures & improvements	1.8	9.0	5.3	16.1	
	22	Reactor plant equipment	20	3	1	24	
	23	Turbine plant equipment	14.8	2	0.6	17.4	
	24	Electric plant equipment	3	1.5	0.7	5.2	
	25	Miscellaneous plant equipment	1.8	1.5	0.5	3.8	
	26	Main conditioning heat rejection system	2.6	1.2	0.2	4	
		Total Direct Cost	44.0	18.2	8.3	70.5	~ 70
Indirect Costs	91	Construction services	4.1	5.9	5.3	15.3	
	92	Engineering & home office services	7.6	-	-	7.6	
	93	Field supervision & field office services	5.1	0.7	0.7	6.5	
		Total Indirect Costs	16.7	6.6	6.1	29.4	~ 30
		Total EPCC = Dir + Indir	60.7	24.8	14.4	99.9	
		Total approx	~ 60	~ 25	~ 15		100

As announced above, especially on the issue of cost of raw materials versus labor cost, there seems to be disagreement/confusion. We have tried to discern some logic by emphasizing the difference between the direct and indirect costs (i.e., mostly services).

The University of Chicago update 2011 report [UChicago, 2011] presents⁴⁹ the following for the *Process Capital Cost breakdown of a generic ABWR*:⁵⁰

Materials ~ 71-74% versus labor ~ 26-29%

In addition, Figure 2.11 gives the distribution of *direct*⁵¹ costs for a generic ABWR (still from [UChicago, 2011] (following EPRI 2009).

⁴⁹ Page 45 of [UChicago, 2012]; breakdown in Table E-1 taken from EPRI, 2009

⁵⁰ Emphasis added by the author (WDH)

⁵¹ 'Guessed' and emphasis added by the author (WDH)

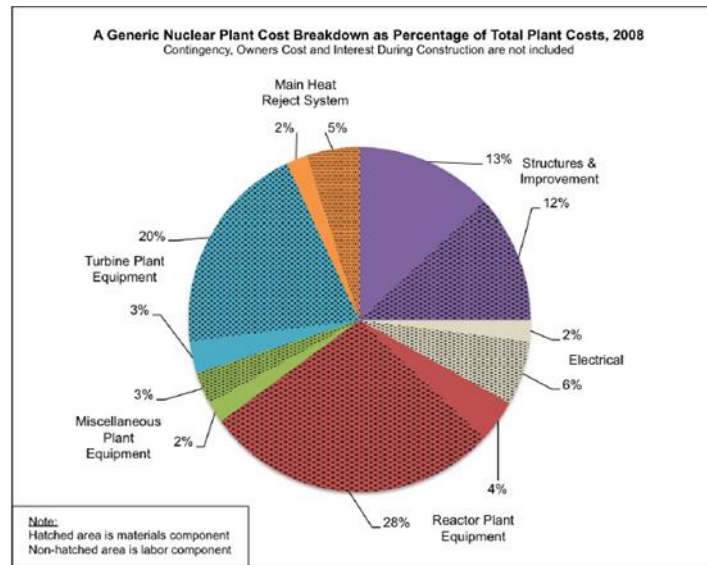


Figure 2.11: Breakdown of Nuclear Power Plant Costs by Major Components (from [UChicago, 2011] in turn taken from EPRI)

The breakdown shown in Figure 2.11 adds up to:

Materials cost 74% versus labor cost 26%

So, if Figure 2.11 is interpreted as representing only the direct cost component, then it seems to be consistent with the earlier claim and Table 2.4.

Finally, we present an *illustrative* breakdown by Black & Veatch [NREL, 2012], which gives a totally different impression showing the relative minor importance of equipment cost and the dominance of labor. See Figure 2.12. Black & Veatch add explicitly to the figure:

“The total plant labor and installation⁵² is included in the Yard/Cooling/Installation cost element.

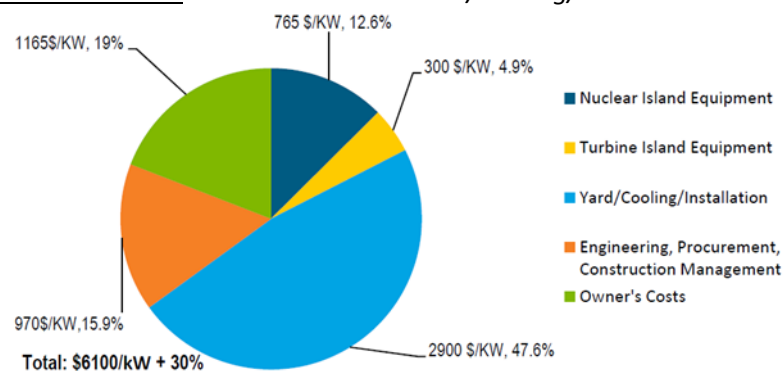


Figure 2.12: Capital cost breakdown for a nuclear power plant (from [NREL, 2012] Figure 1)
The power plant is assumed to be a single unit with no provision for future additions.
Switchyard, interconnection and interest during construction are not included.

⁵² Emphasis added by the author (WDH)

At first sight, the Black & Veatch pie chart would seem to be in disagreement with [UChicago, 2011] since Figure 2.12 clearly shows that labor makes up substantially more than half of the costs. However, it actually turns out that the [UChicago, 2011] report (relying on EPRI) first gives a wrong impression as it is only after careful rereading that the reader realizes that it actually mostly focusses on the process-related capital cost, which is roughly equivalent to the direct cost.

The dominance of labor costs is clarified by the following excerpts.

Rong & Victor state [ILAR, 2012, p 19]:

«...for [a] nuclear power plant, the [Bare Erected Cost] BER accounts for less than half of the total [overnight construction cost] and EPC services could be as high as one quarter of the total, reflecting that a significant share of the capex for nuclear is labor.»

Further, Rong & Victor (following Mott MacDonald 2011) write [ILAR, 2012, p 23]:

«... Mott MacDonald's study, for example, indicates that for low carbon technologies the basic raw materials even at the peak of the market typically account for less than 5% of the capital cost.»

More specifically, in the beginning of its 2011 report on UK low-carbon generation technologies, [MMD, 2011, p 2-2] states that *«Raw material costs [for nuclear] are typically [...] about 4-5% of total capex. Energy consumed in construction and component fabrication is of similar magnitude. Invariably, the largest component of the capex is the cost of labour either on-site or embodied within first tier components (and third party services). Even for a nuclear station, two thirds of the capex is accounted for by labor, supervision and project management services.»*

Rong & Victor continue [ILAR, 2012, p 38]:

«... three other factors also play major roles in determining capital costs: the price of commodities (e.g., steel), labor, and a country's business and regulatory context. [...] The price of commodity markets, though widely believed to be important, only plays a minimal role in the overall costs. For mature technologies, labor costs are usually the single largest contributor to total cost. In a nuclear plant built in a typical western country, labor is 90% of the capital cost.⁵³ Along with labor costs, regulatory contexts probably largely explain the large differences across countries.»

As this statement is largely based on [MMD, 2011] it is instructive to learn what is behind that statement. Actually [MMD, 2011] makes the point that, depending on the level/layer/tier of the components, equipment & systems considered (e.g., steelplate, ingots, bare copper or aluminum wire; versus forged vessels, pumps, motors; versus primary reactor cooling system, etc), the degree of labor considered can vary substantially. In the limit, in principle everything can almost be reduced to labor. It is therefore important to be careful when considering the cost of the labor component of the construction of nuclear plant.

⁵³ Underlined by author (WDH)

MMD then continues [MMD, 2011, p 3-66]: «From an engineering point of view nuclear should not be that much more difficult than a coal station. There is a different “black-box” in the system, however the equipment costs for this are typically a small share of the total capex – as low as 10% in some cases. However, the primary difference between coal and nuclear is the level of certification required across almost all stages of assembly and construction. Coupled with this is the much lower tolerances accepted by certification authorities compared with conventional power plant. This in turn means there is a special requirement for skilled workers and certainly having a work force that is conscious of compliance. This is one of the reasons for the extremely high share of on-site labour and supervision in nuclear plants...»

In conclusion, we do recognize that labor costs are a major part of the nuclear-plant cost, especially because of the need for high-skilled labor (both technicians and engineers) and the substantial part for (organization, licensing, quality-related) services.

It seems to be non-trivial to pinpoint the real breakdown of the cost components and to identify the responsible culprit for the cost escalation seen. As will be seen in the next section, an analysis of the French historic construction case sheds some further light on escalations, without being fully conclusive.

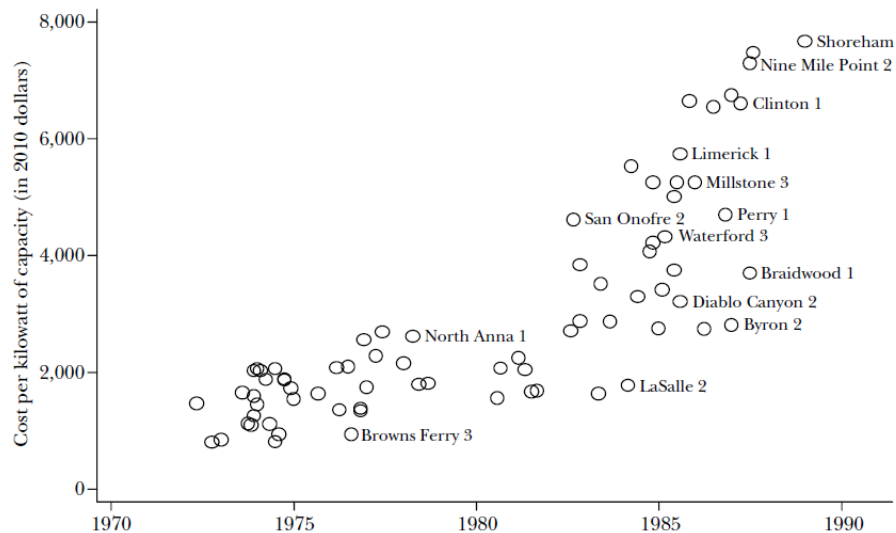
As to the recent cost escalations of the *estimates* (from 2000 to 2012), part is due to the very rough conceptual estimates in an early stage of the designs/projects. The accompanying accuracies and uncertainties are discussed below.

From a pragmatic point of view, we shall accept the IHS CERA (E)PPCI curves as being a trustworthy reflection of the recent cost escalations. In a further analysis, discussed below, we shall try to reconstruct the nuclear-only curve and then take a practical viewpoint with a window of accuracy, reflecting some of the uncertainties.

2.6.2 Historic Escalation of the Cost of NPPs

2.6.2.1 In the USA

The history of actual construction costs of nuclear power plants in the USA is not a good example of making progress by doing. There seems to have been little learning, or as stated by some, rather a negative learning effect. Figure 2.13 shows data that are representative for similar ones found in the literature.



Source: U.S. DOE (1986), table 4.

Notes: Figure 3 plots “overnight” construction costs for selected U.S. nuclear power plants from the U.S. Department of Energy (1986). The figure includes *predicted* costs from the same source for a handful of reactors that were under construction but not yet in operation in 1986.

Fig 2.13: Construction Cost for U.S. Nuclear Reactors by Year of Completion (From [Davis, 2012])

This is not the place to discuss the reasons behind this escalation, since it has been done by others. See e.g., [Kessides, 2012], [Cantor & Hewlett, 1988], [Koomey, 2007], [Cooper, 2009, 2010, 2011], [ICEPT, 2012], [Severance, 2009], [Harding, 2008], [Lévêque, 2013], [Cohen, 1983 & 1990].

Suffice it to say that there is no broad agreement as to the actual reasons for the cost escalation. Some claim that it is a problem inherent in nuclear-plant construction and that learning is a fiction; others state that it is related to the financial circumstances of those years (high interest rates), the increasing regulatory requirements, poor construction management etc. Clearly, there are objective reasons for the escalation and they should be studied and understood, and the nuclear sector should draw lessons from the past. It is obvious that in the late '60s and early '70s the nuclear plant safety regulation was tightened (to improve the safety of the plants), something that began before the accident of TMI in 1979, but which was certainly amplified further after the accident. [Cohen, 1983 & 1990] speaks about “regulatory ratcheting”. As a result, the complexity of the plants made construction more expensive, and redesigns and adaptations had to take place during construction. As construction periods tended to become much longer and this in a time of high interest rates during the late '70s and 80s, as shown by Figure 2.14, then it is understood that the IDC became one of the killing factors in the cost of NPPs.

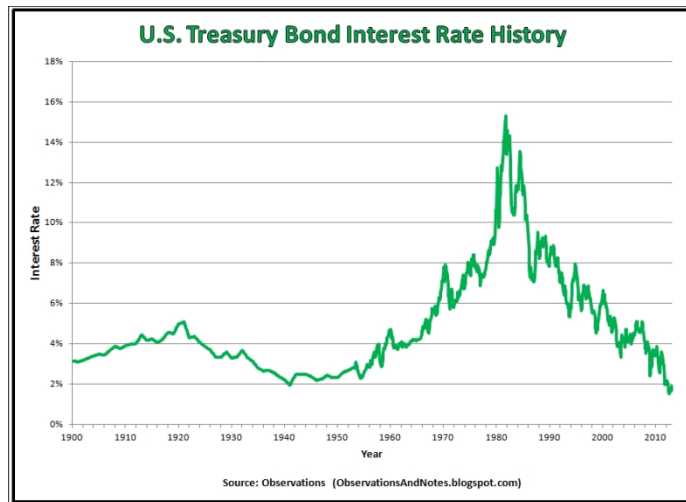


Figure 2.14: History of the U.S. Treasury Bond Interest Rate⁵⁴

[Escobar, 2012]⁵⁵ summarizes the US effort nicely, using some information of [Cantor & Hewlett, 1988], whereby we take the liberty of reproducing his slide as Figure 2.15.

Effect	Komanoff (1981)	Zimmerman (1982)	Cantor & Hewlett (1988)	McCabe (1996)	Cooper(2010)
Scale	-0.2%	+0.17%	+0.13% offsetting by leadtime effect	-0.22% but no significant	+0.94% offsetting by leadtime effect
Learning	-7.0% by doubling the experience	-11.8% first unit -4% second unit	-42% first unit -18% second unit Only for utilities	-9% by 1 unit of builders experience added	0.9% by 1% increase in builders experience
Regulatory	+15.4% +24%	+14% trend	+10% time trend	Not included	+0.179% NRC Rules +0.096% ΔNRC Rules

- Scale: Once the endogeneity of lead-time is taken into account, the scale effect is offset
- Regulation: Safety regulation instability has been a key driver for the cost escalation
- Learning: There is no consensus. The learning effects were significant only when the utilities have built their own plants

Figure 2.15: Cost escalation drivers in the U.S. case. (From [Escobar, 2012] but Toulouse 2013.)

⁵⁴ Obtained from: <http://observationsandnotes.blogspot.be/2010/11/100-years-of-bond-interest-rate-history.html>

⁵⁵ See the accompanying presentation of January 2013 in Toulouse

2.6.2.2 The French Case (Grubler versus Escobar-Lévêque)

An interesting case on the escalation of construction costs in France has surfaced recently. [Grubler, 2009, 2010], [Escobar, 2012] The negative conclusions on the French case as obtained by [Grubler, 2009, 2010] have been widely amplified by many actors such as [Cooper, 2010], [Kessides, 2012], [Davis, 2012], [Schröder, 2013], [Komanov, 2010], which is regrettable because, according to [Escobar, 2012], the conclusions are based on allegedly “erroneous” input data.

The issue arises because [Grubler, 2009, 2010] has taken his cost data for French nuclear reactors from the report by Charpin-Dessus-Pellat [CDP, 2000] and its accompanying document by Girard-Marignac-Tassart [GMT, 2000]. According to [Escobar, 2012], however, these data are not quite “correct” because *«Grubler made his cost assessment using estimations based on an annual investment report of Electricité de France (EDF) from 1972 to 1998.»* It is only at the beginning of 2012 that supposedly more reliable data on the cost of the French nuclear program has become available with the publication of the detailed study by the ‘Cour des Comptes’⁵⁶ [CdC, 2012].

The well-publicized data by [Grubler, 2010] are shown in Figure 2.16.

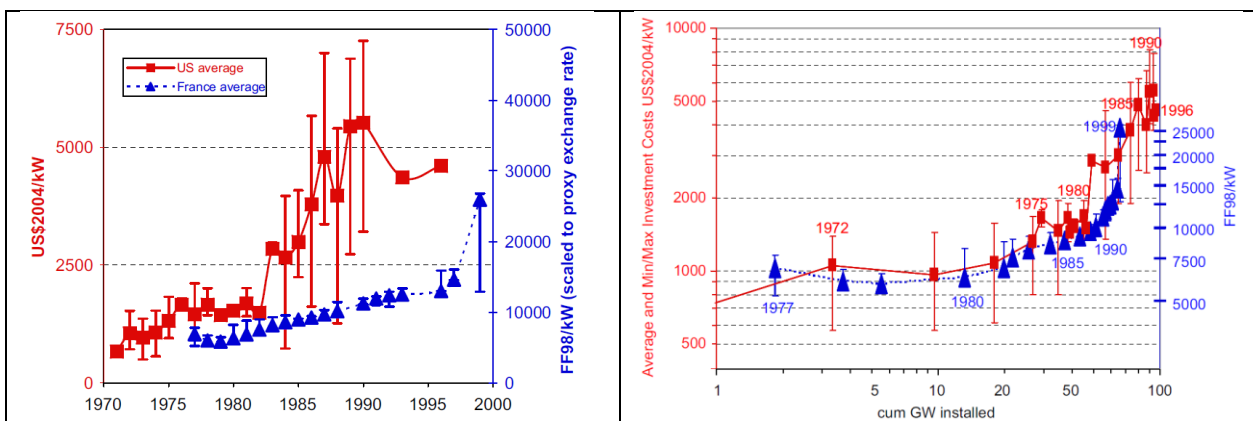


Figure 2.16: Comparison of the cost escalation of the construction cost of French reactors with USA reactors (From [Grubler, 2010])

In their paper, Escobar Rangel and Lévêque ([Escobar, 2012]) have replotted the Grubler data and have compared them with the data from the [CdC, 2012]. These data are presented in Figures 2.17 and 2.18, respectively.

All data have been converted to EUR of 2010, and are expressed in M€/MW. Note that the ordinate axes have different scales.

As observed by [Escobar, 2012], [Grubler, 2010] found that the construction costs for the post 1990 installed reactors were 3.5 times more than the cost for the units installed in 1974, and this *«despite the favorable institutional setting (i.e. centralized decision making, high degree of standardization and regulatory stability)»*.

⁵⁶ Sometimes translated as the French “Court of Audit” or “Court of Accounts”.

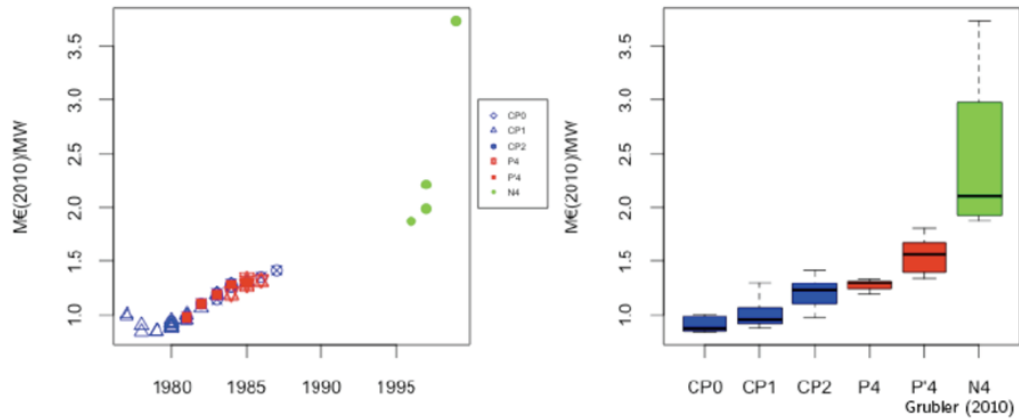


Figure 2.17: Data of the construction cost of the French nuclear reactors according to [Grubler, 2010], but plotted by [Escobar, 2012]

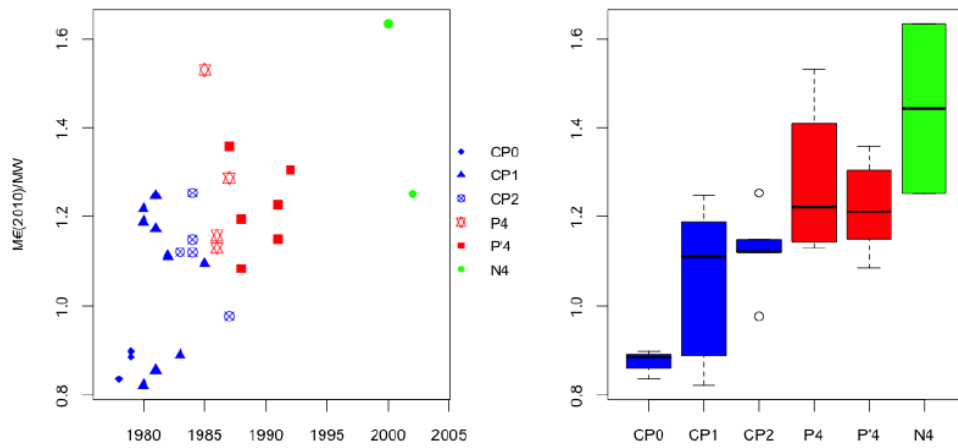


Figure 2.18: Data of the construction cost of the French nuclear reactors according to [CdC, 2012], assembled by [Escobar, 2012]

Figure 2.19 shows the actual comparison of both data sets, as made by [Escobar, 2012]. According to [Escobar, 2012], the [Grubler, 2010] data suggest an escalation of 9% per year (the red fit in Figure 2.19 right panel), whereas the more supposedly correct escalation equals 3.8% per year (the blue fit).

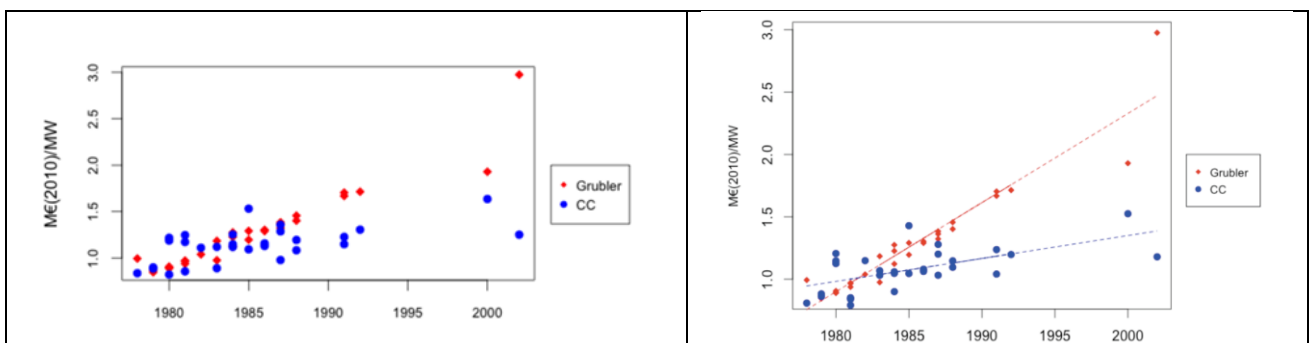


Figure 2.19: Comparison of the data for the construction cost of the French nuclear reactors by [Grubler, 2010] and [CdC, 2012] according to [Escobar, 2012]

To understand the remaining analysis made by [Escobar, 2012], it is important to give some specifics on the data provided by the [CdC, 2012]. We take the liberty to follow the summary provided by [Escobar, 2012], displayed here as Figure 2.20.

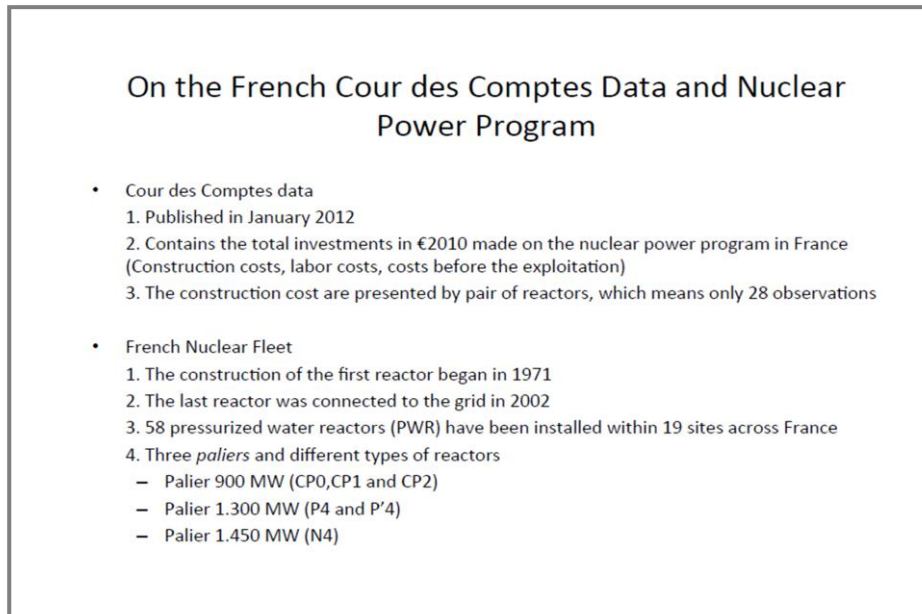


Figure 2.20: Summary of the specifics of the data provided by the [CdC, 2012] by [Escobar, 2012], but Toulouse 2013.

It is important to recognize the three stages or levels of French nuclear reactors, best referred to as the three “*paliers*”. See also the different colors in Figures 2.17 and 2.18. In each of these “*paliers*”, there are furthermore different types (CP0, CP1, CP2; P4, P'4; and N4) as indicated also in Figures 2.17 and 2.18.

In a careful econometric analysis, Escobar Rangel and Lévêque ([Escobar, 2012]) explore the relationships of the [CdC, 2012] data. They investigated the impact of the following “possibly explanatory variables”:

- C_i : Construction cost for the pair of units i in €2010 per MW
- Cap_i : Installed capacity in MW
- $LTime_i$: Construction leadtime in months
- $EXPI_i$: Number of completed reactors at the time of the construction of plant i
- $EXPP_i$: Number of completed reactors within the same palier at the time of the construction of plant i
- $EXPT_i$: Number of completed reactors within the same type at the time of the construction of plant i
- UCL_i : Lifetime average Unplanned Capability Loss Factor for unit i
- $US7_i$: Lifetime average Unplanned Automatic Scram for unit i

They confirmed (not unexpectedly, since also reported in other sources of the literature concerning nuclear construction costs) that there is a problem of *multicollinearity*, in particular the high correlation between installed capacity, industry experience and lead times⁵⁷. To overcome the problem, they resorted to a “principal component analysis”. The authors of [Escobar, 2012], Escobar Rangel and Lévêque, make the

⁵⁷ Lead time is to be considered as synonym of “construction time” or “construction period”

following observations *based on their analysis*, which at the same time confirms observations already made by others, but they add new interesting insights.⁵⁸

- There is really no scale effect. Increasing the size of the reactors did not lead to lower specific (i.e., per kW installed) costs. So far, larger reactors have been known to be more complex, meaning longer lead times and greater risk of cost overruns.
- Cumulated experience of the industry did not induce a reduction in costs. This is often seen as a consequence of an alleged intrinsic characteristic of nuclear reactor construction: lumpy investments and site-specific. However, there is a positive learning effect for the construction within the set of 'similar' reactors (size and type). This observation pleads for standardization of future nuclear reactors.
- The correlation between capacity, lead time and cumulative experience can be explained as follows. It signals what can be called the “big-size syndrome”. As nuclear power industry (vendors and utilities) gained experience, bigger reactors were made and this technology scaling up is associated with greater complexity which ended up in longer lead-times. (See also [Cooper, 2009].)
- Constructing similar reactors (in size or type) has allowed improvements in terms of safety.
- The latest reactors are indeed more expensive, but they have embodied safety improvements.

In conclusion, they state that the cost escalation in France was largely due to the scaling-up strategy. In addition, this scaling up (and the French drive to “frenchify” their reactors)⁵⁹ is associated with longer lead times and increased complexity, leading in turn to an increased cost per kW installed. With the benefit of hindsight, based on the French experience, they recommend the following (not surprising) strategy: the number of different technologies should be limited, standardization should be high on the wish list together with more off-site (i.e., within the factory) modular construction, so as to obtain learning effects that lead to lower construction costs and better performance in operation and safety performance.

2.6.3 Learning Effects / Fleet Effect

Knowing the not very rosy track record of nuclear construction in the US and (to a minor extent) in France, and noting that we have seen a significant cost escalation of power-plant costs since 2000 (cfr the IHS CERA indices), we must now tackle the issue of **what kind of credible estimate for the future construction costs can be made.**

2.6.3.1 Starting all over again?

Recent experience does not seem to be encouraging. The first reactors of both EPR and AP1000 built or projected in Europe and the USA have been plagued by cost overruns as summarized by [Escobar, 2012] in Figure 2.21.⁶⁰

⁵⁸ This summary relies heavily on the summarizing presentation accompanying [Escobar, 2012]

⁵⁹ This was the French industrial policy to be freed from the license-agreement of the Westinghouse PWR designs. See also [Grubler, 2010].

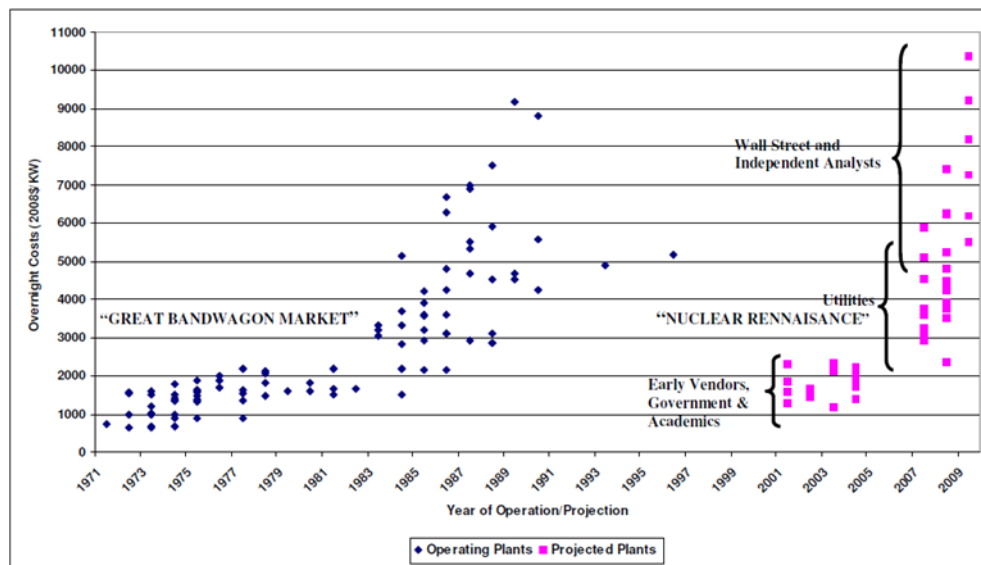
⁶⁰ This summary relies heavily on the summarizing presentation accompanying [Escobar, 2012]

Starting again

- EPR
 1. Olkiluoto-3 in Finland
 - Initial cost prevision in 2003 €3 billion (€_{2010} 2.100/kW)
 - Cost revision in 2010 €5.7 billion (€_{2010} 3.500/kW)
 2. Flamanville in France
 - Initial cost prevision in 2005 €3.3 billion (€_{2010} 2.200/kW)
 - Cost revision in 2011 €6 billion (€_{2010} 3.650/kW)
 - Cost revision in 2012 €8.5 billion (€_{2010} 5.100/kW)
 - AP1000
 1. MIT studies
 - In 2003 the estimated base case overnight cost was $\text{US\$}_{2010}$ 2.400/ kW
 - In 2009 the range of overnight costs was $\text{US\$}_{2010}$ 3.650/kW to $\text{US\$}_{2010}$ 5.100/kW
 - 2 The University of Chicago
 - Updated their 2004 forecast in 2010: for the AP1000 overnight costs has increased from $\text{US\$}_{2010}$ 1950/kW to $\text{US\$}_{2010}$ 4.210 kW
- New generation reactors have been initially expected to be cheaper than the last variant built (e.g., EPR v. N4) whereas their revised costs based on applications to regulator (AP 1000) or on-going constructions (EPR) are much higher than the most expensive type of reactor ever built in the past

Figure 2.21: Illustration of the recent cost increase estimates for European and USA new build. (From [Escobar, 2012], but Toulouse 2013)⁶¹

The plot prepared by [Cooper, 2009] also suggests a similar danger of repeated history. See Figure 2.22.



Sources: Koomey and Hultman, 2007, Data Appendix; University of Chicago 2004, p. S-2, p. S-8; University of Chicago estimate, MIT, 2003, p. 42; Tennessee Valley Authority, 2005, p. I-7; Klein, p. 14; Keystone Center, 2007, p. 42; Kaplan, 2008 Appendix B for utility estimates, p. 39; Harding, 2007, p. 71; Lovins and Shiekh, 2008b, p. 2; Congressional Budget Office, 2008, p. 13; Lazard, 2008, Lazard, p. 2; Moody's, 2008, p. 15; Standard and Poor, 2008, p. 11; Severance, 2009, pp. 35-36; Schlüssel and Biewald, 2008, p. 2; Energy Information Administration, 2009, p. 89; Harding, 2009. PPL, 2009; Deutch, et al., 2009, p. 6. See Bibliography for full citations.

Figure 2.22: Overnight cost of completed nuclear reactors compared to projected costs of future reactors. (From [Cooper, 2009])

Apparently, these figures suggest that very little learning takes place with nuclear construction, quite the contrary. However, to qualify the above information of Figure 2.22, and to avoid that misleading pictures are spread too much, it must be pointed out that many of the data of so-called "Wall Street and Independent Analyst" mentioned in Figure 2.22 are questionable. Indeed, one of the so-called estimates is from [Moody's,

⁶¹ A later cost figure (December 2012) estimates the total cost for Olkiluoto at 8.5 billion €. This is similar to the estimated cost of Flamanville.
Ref: http://en.wikipedia.org/wiki/Olkiluoto_Nuclear_Power_Plant

2008], even though it is explicitly stated by Moody's that «*This [] estimate is for illustrative purposes only and does not represent a \$/kW capacity figure.*»⁶² Nevertheless, the figure of \$6,259/kW is used by Cooper and many authors. Also Figure 2.22 includes high estimates appearing in “analyses” by Harding [2008] and Severance [2009], which utilize an extrapolation of the construction-cost *during the future construction period itself* similarly to what occurred in the period 2005-2007, a dubious and questionable practice; being little more than a mere “guestimate”. Furthermore, Figure 2.22 incorporates the cost figures used in a “simple” sensitivity analysis made by Harding [2008]⁶³, which are by no means meant to be representative figures – i.e., they are mere variations to perform a sensitivity. Note that many of these so-called results are presented in presentations or web-based reports that are not peer reviewed as would be normal practice in the scientific literature.

Before discussion learning effects, we remark that the types of cost projections such as that in Figure 2.22 do not mention the successful construction record in Japan and South Korea. On the other hand, it must likewise be said that many of the early estimates by vendors and utilities were also unjustifiably biased towards the low end.

2.6.3.2 Positive or Negative Learning in Nuclear Construction?

As is already clear from what has been discussed above, the issue of learning in nuclear-plant construction is not obvious. An attempt to identify the weak points and to give recommendations for the “Reduction of Capital Costs of Nuclear Power Plants” has been made in [NEA, 2000]. However, some of the suggestions made there, such as increase of installed capacity, may not lead to a decrease in cost, as is obvious from careful empirical research. It is instructive, in that regard to recall the analysis by [Escobar, 2012], discussed above.

As already shown in Figure 2.15, the issue of learning for nuclear-reactor construction is not clear. Another interesting picture is taken from [ECN, 2010], in turn borrowed from [Neij, 2008]; see Figure 2.23.

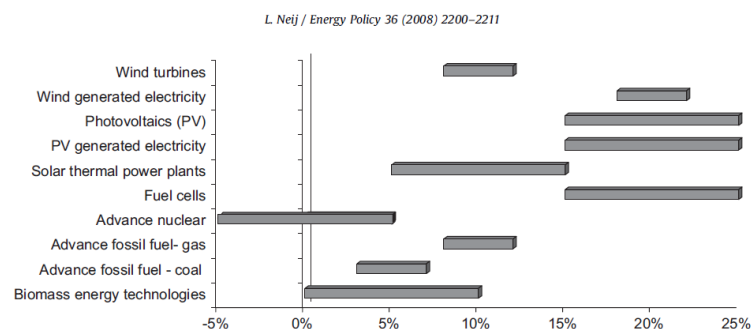


Figure 2.23: Learning rates suggested for new energy technologies (up to 2050). The bars in the figure indicate the learning rate including a sensitivity range of $\pm 2\%$ pt or $\pm 5\%$ pt. The learning rate indicates the cost reduction for each doubling of cumulative installed power (kW). (From [ECN, 2012], in turn taken from [Neij, 2008])

Neij confirms the indecisiveness on nuclear learning. She assumes a learning rate of 0% with an uncertainty band of 5%-pts on either side.

⁶² Underlining added by the author (WDH)

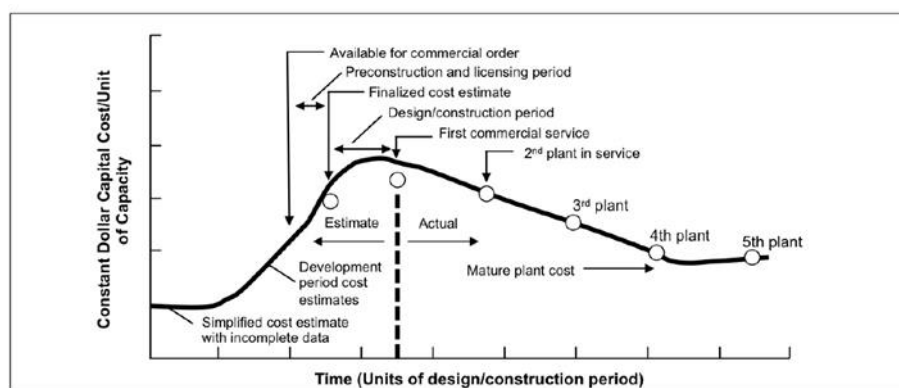
⁶³ It concerns a sensitivity table by Harding for 0%, 4%, 8%, 14% real escalation estimates. Nowhere in his documents does he mention the table and does he explain their applicability.

To say something meaningful on the cost of new nuclear reactors, it is important to distinguish between some particular cases, especially regarding a first or N-th of a kind construction of a particular type of reactor.

It seems convenient to define two types of FOAK (First of a Kind):

- A first type of FOAK (call it **FOAK₁**) is the very first plant of a particular type that is built, regardless of where it is built (e.g., the EPR in Finland, AP1000 in China).
- A second category of FOAK (i.e., **FOAK₂**) is a first plant of a certain type in a particular country. So, the EPR in Flamanville (FR) is not a FOAK₁ but a FOAK₂.
- In addition, one should recognize that plants are expected to be more expensive in those countries that have not built any nuclear reactor for a few decades, or which have no nuclear background whatsoever.
- Also, it makes a difference whether plants are built on a greenfield or whether an existing nuclear site (called a brownfield) is available. Furthermore, it makes a difference whether only one single unit is built, or whether twin units are built, or whether the units are part of a fleet of, say 8 identical plants to be built in series.
- For an N-th of a kind plant (NOAK), it makes sense to consider “routine construction” as of the 5-th or 6-th reactor of the same type in the same country (where the same nuclear licensing regulatory process exists). This will be denoted by NOAK₂ (5+) or NOAK₂ (6+).

Some interesting information on the initial struggling and “almost natural” increases in the cost estimates before construction of the first unit is offered by [EPRI, 2011]; see Figure 2.24.



Source: EPRI Program on Technology Innovation: Integrated Generation Technology Options, June 2011.

Figure 2.24: Capital Cost Learning Curve (From [EPRI, 2012])

[Kee, 2012] has interpreted this information a bit further for nuclear reactors in Figure 2.25.

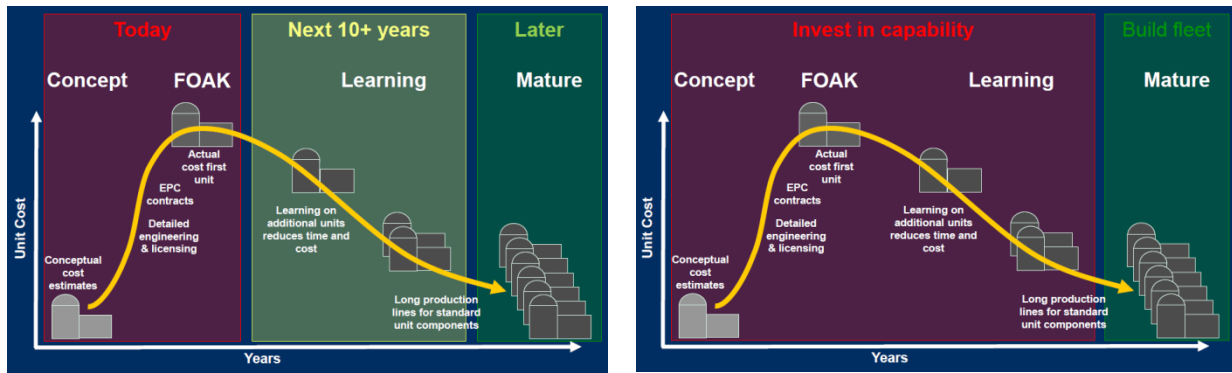


Figure 2.25: Capital Cost Learning Curve and the Route towards Fleet Building (From [Kee, 2012])

[Kee, 2012] portrays the route towards fleet building and identifies the following benefits to a fleet approach in Figure 2.26.

Organization & Management	Multiple Identical Units	Learning Curve Effects	Volume Orders	Mobilize Teams	Industry & Employment
A single organization with a unified approach and economies of scale to accomplish: <ul style="list-style-type: none"> • Training • Purchasing • Management • Engineering • Regulatory affairs 	<ul style="list-style-type: none"> • Training • Simulator • Operators and management • Refueling outage skills & equipment • New procedures & equipment modifications • Shared spare parts, special tools, and strategic spares 	Learning from: <ul style="list-style-type: none"> • People involved in construction and operation of multiple units • Modification of the design or the construction approach and schedule • Documenting and sharing lessons learned • Vendors build in learning for later bids 	Volume orders may allow upstream component suppliers to invest in longer production lines due to bulk procurement Volume orders may bring discounts from NPP vendors that reflect <i>expected</i> learning curve benefits and upstream component savings	Sequencing of construction is key Teams move from one project to the next without interruption (also may allow simultaneous work on multiple units) Teams could work on similar tasks for many units, allowing significant commitment to hiring & training	French nuclear industrial development is model Investment in new production facilities Over time, such local suppliers should be able to use their experience (and their own learning curve benefits) to become competitive suppliers in the export market

Figure 2.26: Benefits to Fleet Building (From [Kee, 2010])

These observations are broadly in line with Escobar & L  v  que’s conclusions (expressed in question format) after studying the cost escalation of the French units [Escobar, 2012], although Escobar & L  v  que (quite legitimately) also stress the important point of the regulatory framework. See Figure 2.27.

Means to achieve reduction of nuclear power plant capital costs

- Scale effects: Can the increase in the size of the plant lead to a reduction in the construction costs per MW installed?
- Modularization: Can the building of more components in factories and less on site reduce construction time and cost?
- Standardization and cumulative experience: Can capital cost reductions be achieved in standardizing plant designs and constructing similar plants in large series?
- Regulation: Can the regulatory framework reduce the risk of cost overruns while providing adequate safety levels?
- Procurement and competition: Can improved competition and procurement contracts result in significant cost reductions?

Figure 2.27: Crucial questions raised for cost reduction of nuclear-plant construction. (From [Escobar, 2012], but Toulouse 2013)

It is instructive to quote an important industrial player, Engineering Consultant Mott MacDonald, involved in the analyses in the UK [MMD, 2011].

«On the basis of the learning rates observed in the literature and a modest rate of projected doublings in deployed capacity (based on a[n] aggregate category of nuclear) the outlook for cost reductions is projected to be modest. However, this picture embodies the assumption that the nuclear industry will continue to be dogged by a regulatory process [which] is subject to change during the construction process, requires design modifications and has limited continuity in contracts and OEMs.⁶⁴»

«Our view is that this is overly pessimistic. The central case for the engineering based assessment builds in considerable cost reductions even by 2020. The UK's GDA (Generic Design Assessment) process has narrowed the field of competitors, but it does promise the potential of reducing the need for ongoing changes through the construction process. Post 2020, the scope of cost reductions increases as the UK should have access to more reactor models and vendors.»

MMD considers that there is a current market mark-up (due to market congestion or distortions) of over 20%, which should be eliminated by 2020. For further cost reductions up to 30%-35% for NOAK-type of plants, it will *«require that the construction process in the future moves away from current substantial requirement for on-site labour, through better logistics control and/or increased reliance on offsite modular assembly.»*

«Some commentators, such as Professor Steve Thomas⁶⁵ in University of Greenwich, argue that the past experience suggests actual costs will rise in real terms. MML believes that this is entirely possible, however, a combination of the GDA process, greater focus on project logistics and increased international competition in

⁶⁴ OEM: Original Equipment Manufacturer

⁶⁵ Steven Thomas is author of the critical report "The Economics of Nuclear Power: An Update", Heinrich Böll Foundation/Stiftung, March 2010. [Thomas, 2010]

nuclear equipment markets, points to a turnaround on past trends and significant real reductions over the next decades as being a more plausible outcome.»

Finally, we note the recent study on fleet effects by PricewaterhouseCoopers of November 2012⁶⁶ [PWC, 2012]. PWC has investigated the fleet effect for building new NPP in the UK for a building scheme as explained in Figure 2.28, but whereby it is understood that *pairs* of reactors are built on the same site.

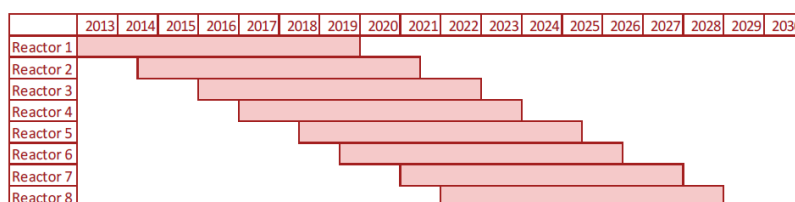


Figure 2.28: Illustration of a fleet approach to nuclear new build. (From [PWC, 2012], figure 5.)

The cost savings results are explained in Figure 2.29. Taking the first pair of reactors at a cost of 100%, then the next pair would be 11% cheaper. The next steps towards the third pair and the fourth pair would each time lead to a further cost saving of about 4%.

All in all, the cost saving of the fourth pair compared to the first pair would be about 18%.

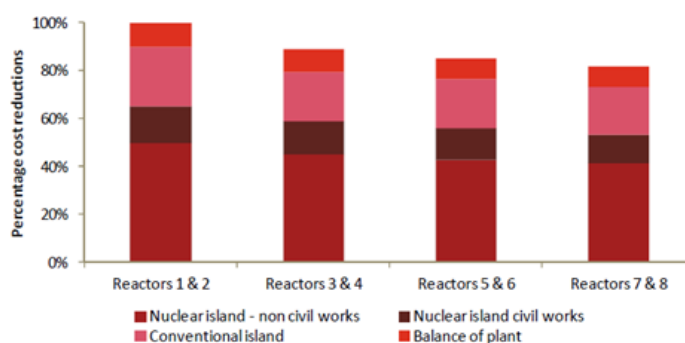


Figure 2.29: Expected cost savings during design and build phase with a fleet approach.(From [PWC, 2012], figure 8.)

It is furthermore reported by [PWC, 2012] that «In 2011 Parsons Brinckerhoff's study for DECC⁶⁷ estimated a saving of 15% for the total capital costs of a nuclear power station with multiple reactors, as construction moves from FOAK to NOAK in the UK, which is comparable to the savings in Figure [2.29]»⁶⁸

The above quote by PWC has been cross checked and confirmed by the author of this report. The results of comparable and simultaneous studies in the UK by Mott MacDonald [MMD, 2010 and 2011], are somewhat

⁶⁶ PWC, "The fleet effect: The economic benefits of adopting a fleet approach to nuclear new build in the UK"

⁶⁷ See [PB, 2011]

⁶⁸ Comment from the author (WDH): the FOAK assumed in the PB study for the UK (which is what we call FOAK₂) assumes a site of 3300 MWe, with either 2 EPRs or 3 AP1000 reactors.

more optimistic for long term NPP construction, signaling a NOAK/FOAK₂ reduction of about 25%. MMD mentions a market premium of about 700 GBP/kW due to market imperfections for the FOAK₂.

[KEE, 2010], already mentioned above related to Figures 2.25 and 2.26, states: «... some data show that the 5-th or 6-th unit[s] of a kind are 40% less expensive than the first unit...». Note that [Kee, 2012] does not distinguish between, what we refer to as, FOAK₁ or FOAK₂ types.

Reality will tell... , but the above discussion illustrates that negative learning is not necessarily an “intrinsic property” of nuclear-reactor construction. Nevertheless, it is up to the nuclear sector itself to demonstrate on the ground that cost-effective construction is possible.

2.6.4 Pragmatic Approach on Cost Escalation – Own Analysis

For *future* possible cost escalations (above the estimates or original contract value), we reject the idea of extrapolation since the slopes of growth have been too different over the last 12 years to make any sense as a basis for extrapolation. (See the IHS CERA PPCI curves –repeated below in Figure 2.30). As explained below, we will hedge ourselves by assuming a reasonable window of *uncertainty*.

To deal with the cost escalation of *past* estimates since 2000, we have opted for a pragmatic, simplifying, but justified approach.

On that past cost escalation, we have attempted to reconstruct the cost-evolution curve for nuclear plants only. As will be recalled, the lower black solid (E)PPCI curve in Figure 2.30 represents the capital-cost curve without nuclear plants. The top black curve includes nuclear plants. Clearly then, there must be a curve representing only nuclear construction cost.

Based on circulating CERA documents for North America (NA) up to the end of the year 2008, we have been able to figure out the course of the *nuclear-only* curve. This is shown by the *red curve*⁶⁹ in Figure 2.30. From 2009 on, the red curve is estimated by the author, such that the sum of the red curve (nuclear alone) and the bottom curve (w/o nuclear) equal the middle curve (everything, including nuclear) by assuming a certain proportion, derived from the pre-2009 curve.

The European red curve is fully estimated by the author, such that the sum matches, and based on proportionality similar to NA.

⁶⁹ The help of Kenneth Van den Bergh in making these plots is greatly acknowledged.

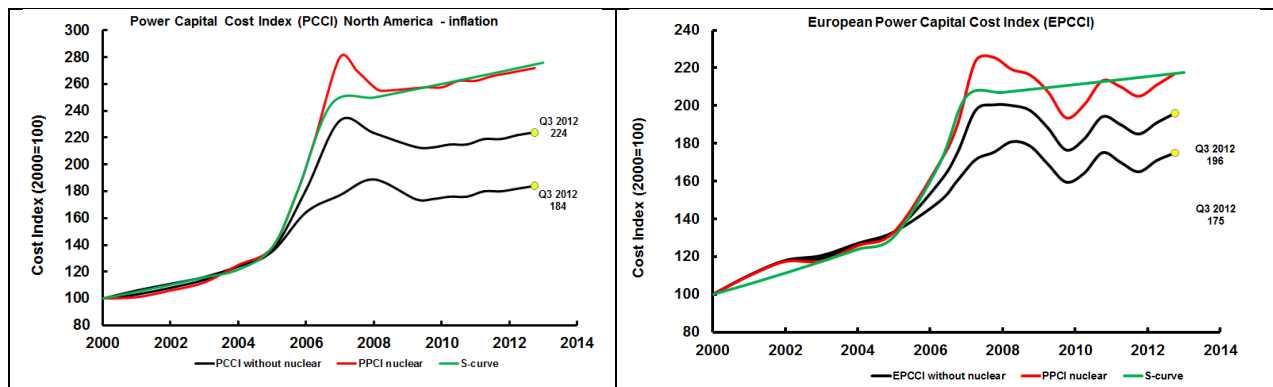


Figure 2.30: Attempts to discern the nuclear-only IHS CERA (E)PCCI curves, and further approximations.
(K. Van den Bergh's help in 'completing' these graphs is greatly appreciated.)

When data in the red peak period (2006-2007) are of concern, then it is necessary to take into account that there was overheating of the market at that time, which resulted in some kind of an overshoot. However, if a longer-term perspective is taken, and when one concentrates on an order of magnitude, then the fluctuations (as also seen in the European PCCI) can be averaged out. This is shown by the green curve.

In summary, for the past cost escalations, we assume the following rough behavior as shown by the green curves; see Table 2.5.

Table 2.5: Approximate escalation factor for nuclear-only construction in the past (2000-2013)

North America (NA)	Annual percentage growth		Europe (EUR)	Annual percentage growth
2000-2005	~ 5%/a		2000-2005	~ 5.5%/a
2005-2007	~ 26%/a		2005-2007	~ 25%/a
2007-2013	~ 2%/a		2007-2013	~ 1%/a

In conclusion, we consider that:

- the escalation during the early years two-thousand (2000-2005) are a “natural” phenomenon, being a consequence of early “premature” and merely “conceptual” estimates. Those cost increases are not “unexpected”.
- the escalation during the period 2005-2007/8 is a consequence of an overheated market, similar to what occurred in other markets (natural resources etc), aggravated by the peculiar nuclear-plant construction situation.
- The escalation since 2007/8 up to 2013 is very small, even smaller than the usual inflation, largely due to the economic downturn.
- The future escalation is difficult to predict, but may be in between the ~ 1-2%/a observed now and the ~ 5%/a in the early 2000s (or higher still). However, for NPPs, the actual cost will also depend on serial effects depending on standardization, fleet effects etc.
- It is therefore advisable not to assume further cost-escalations beyond the usual inflation, but to include possible capital-cost changes by assuming a “realistic” *margin of uncertainty* in our final result.

2.7 Costs of “This Study’s Cost” Expressed in EUR 2012

It is a basic convention/agreement that our “final results” will be expressed in EUR 2012. All other EUR, USD or GBP values leading up to that “final result” will be escalated to 2012, either by using the common inflation measures such as GDP deflator, CPI or PPI, or, for the case of power-plant construction, by using the IHS CERA cost-escalation indices (E)PPCI. It should be stressed again that one must be careful to avoid double counting.

The USD and GBP values of 2012 are then converted using the MER given in Section 2.5.

2.8 Discount Rates / WACC Definition

To perform a proper ‘discounted cash flow’ analysis, it is necessary to utilize an appropriate *discount rate*. This is not the place here to give a full treatment on how this discount rate should be determined as other documents exist that explain the relevant issues. We mention [NEA/IEA, 2010] (chapter 8), [MIT, 2003] (Appendix to Chapter 5), [Osouf, 2007] and [Lévêque, 2013a], and for more theoretical considerations [Brealey & Myers, 1996], amongst others.

Here, we only give some general but useful statements and some warnings on the proper use of the discount rate.

The discount rate may be different for the short term and the long term. By ‘short term’ here, we refer to “overseeable” project duration, of the order of 40 to 60 years for a nuclear plant. The ‘longer term’ mainly refers to the internalization of externalities such as long term waste disposal and decommissioning costs (for the period after plant shut down).

First we concentrate on the ‘short term’.

Generally speaking, the discount rate is the *opportunity cost of capital*. It depends on the type of investor (public versus private) and on the type of market (liberalized versus regulated). In a sense, it depends on how a project is financed, i.e., what combination of debt financing (thus via a loan) and equity financing (from the shareholders) is considered and what is the interest rate to be paid for the loan and what is the expected rate of return for the investors.

A basic concept to determine a discount rate is the *Weighted Average Cost of Capital* (WACC). It is defined as:

$$WACC = r_{debt} \left(\frac{D}{V} \right) (1 - t_c) + r_{equity} \left(\frac{E}{V} \right)$$

with

r_{debt} = interest rate on debt

r_{equity} = expected rate of return rate for share holders

V = total Volume of capital to be covered

D = amount of Debt

E = amount of Equity

t_c = corporate tax rate

$V = D + E$

The WACC as defined above is a *nominal* rate. Typical ratios for debt/equity financing for nuclear private projects are 50/50 or 40/60 or vice versa.

Often, depending on the point of view (and not subtracting tax deductions on debt interest), an effective (gross) nominal discount rate is defined as:

$$(r_{eff})^{nom} = r_{debt} \left(\frac{D}{V} \right) + r_{equity} \left(\frac{E}{V} \right)$$

As an example,⁷⁰ [MIT, 2003] utilized $(r_{eff})^{nom}=11.5\%$ or a WACC of 10% (using a corporate tax rate of 37%), based on values $r_{debt}=8\%$, $r_{equity}=15\%$ and a 50/50 debt/equity ratio.⁷¹

[MIT, 2003] further explains: «*Equity holders invest funds during construction and receive profits net of taxes and debt obligations during plant operation. Net profits over the life of the project are such that the internal rate of return (IRR) of equity holders' cash flows equals the required nominal return; 15% in the nuclear base case...*»

The French study [DGEMP-DIDEME, 2003] has taken a discount rate of 11%/a for private investors.⁷²

Furthermore, when one is interested in the *real* discount rate, hence taking out inflation, then the appropriate relationship reads [Brealey & Myers, 1996]:

$$(r_{eff})^{real} = \frac{1 + (r_{eff})^{nom}}{1 + i} - 1$$

with

i = inflation rate.

Assuming an inflation rate of $i=3\%/a$, the real (gross) discount rate in [MIT, 2003] reduces to $(r_{eff})^{real} = 8.25\%$.

As a general rule, it is important to distinguish between:

real versus *nominal* (related to inflation)

net versus *gross* (after and before tax, respectively).

The [MIT, 2003] values are typical for private investors (at least in a USA context). Because of 'uncertainties' for nuclear plants in liberalized markets, a discount-rate penalty or mark up of about 3%-pts applies. In regulated markets, lower discount rates may be assumed.

Furthermore, if public investors decide on the construction of a new plant, then ("if so desired") all of the financing could be done through debt financing, at interest rates defined by government bond rates, of the order of $\sim 3-4\%/a$.

⁷⁰ This is merely an illustration, not a recommendation on the chosen values.

⁷¹ In a discussion blog, Severance claims that MIT utilized an effective WACC of 16.1%/a. This claim is mysterious to J.E. Parsons, one of the authors of the MIT reports - private communication, May 11, 2013. On the blog discussion related to Severance's work, see <http://thinkprogress.org/climate/2009/01/05/202859/study-cost-risks-new-nuclear-power-plants/#comment-26274>.

⁷² D. Beutier, private communication 22.01.2013

Figure 2.31 shows the evolution of the US government bond rates over the last 30 years.⁷³ The left panel spans the period Jan 01 1980 – early May 2013; the right panel ranges from Jan 01 2005 – early May 2013, confirming the order of magnitude of the interest rate. Figure 2.31 also shows that currently (2013 or so), public financing would be relatively cheap.

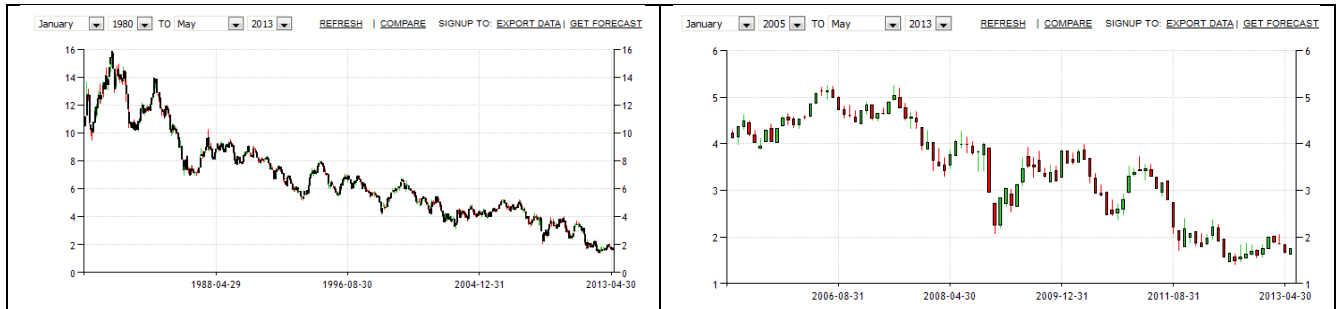


Figure 2.31: Evolution of USA government bond rates from Jan 01 1980 – early May 2013 (L) and from Jan 01 2005 – early May 2013 (R).

The previously mentioned study [DGEMP-DIDEME, 2003] takes 3%/a as discount rate for a public investor.⁷⁴

Coming back to the ‘longer-term’ discount rate, to deal with e.g., final disposal of waste, we refer to [Lévêque, 2013a] for an interesting discussion,⁷⁵ based on a nice economic analysis, going back to Ramsey (1928). Lévêque summarizes his findings as follows:⁷⁶

- Ch. Gollier (2002)
 - $T < 30a$, $r=5\%$ and $T > 31a$, $r = 2\%$
- Oxera, UK (2002)
 - $T < 30a$, $r=3.5\%$ $75a > T > 31a$, $r = 3\%$ $125a > T > 76a$, $r = 2.5\%$... and $T > 300a$, $r=1\%$
- Lebéque, FR (2005) – for all public investments
 - $T < 30a$, $r=4\%$...continuously... $T=100a$, $r = 3\%$
...continuously... $T=200a$, $r = 2\%$

In his PhD thesis, [Laes, 2006], also addresses the issue of long-term discount rates, mentioning that environmentalists favor a long-term discount rate of 0% or even a negative one, while he confirms the point of view of economists that “correct” discount rates are positive. [Laes, 2006] refers to Pearce et al. (2003)⁷⁷ and Rabl (1996)⁷⁸ to document his statements and quotes ‘conventional social discount rates’ (3-8%) up to a certain time, determined by the average duration of long-term commercial loans (~ 30 years is proposed by Rabl), followed by a reduced rate for intergenerational effects, equal to the long-term growth rate of the economy (~ 1-2% as proposed by Rabl). According to [Laes, 2006], Pearce et al. (2003) argue that “discount rates to be used by governments in investment and policy appraisal should decline over time, up to a low value of about 1%”.

⁷³ <http://www.tradingeconomics.com/united-states/government-bond-yield>

⁷⁴ D. Beutier, private communication 22.01.2013

⁷⁵ Lévêque also discusses “conflict” between N. Stern & W. Nordhaus on “The Economics of Climate Change”

⁷⁶ For references, see [Lévêque, 2013]

⁷⁷ For reference, see [Laes, 2006]

⁷⁸ For reference, see [Laes, 2006]

First it must be remarked that long-term issues are in the sphere of public discount rates. Perhaps the time limit T above is too short for typical industrial projects during operation. The long-term rates seem to apply more after plant closure, and counting from then on. The application of long-term discount rates will be briefly reconsidered in the chapter on long-term waste disposal and external costs.

2.9 Discount Rates Used in Study: 5% and 10% in Real Terms

To simplify matters and to have more “universal applicability” of our own computed results for an LCOE, we shall take the approach used by [NEA/IEA, 2010] and ***apply two real discount rates of 5%/a and 10%/a.***

For “other” effects (e.g., system effects and external effects), we must rely on analyses and computations performed by others in the literature, and there we need to utilize discount rates chosen by those authors. Those discount rates will be clearly mentioned in the respective parts of the text.

2.10 No Taxes or Subsidies Considered

Although certainly not unimportant for private investors, we shall **not consider taxes explicitly** (i.e., no deductions on interest paid for debt financing and no asset depreciation). This means that we do not distinguish between net and gross discount rates.

2.11 Lifetime 60 Years for New Build

In agreement with the European Utility Requirements (EUR), we assume that the operational lifetime of a newly built nuclear plant is 60 years.

2.12 First Fuel Load Not Considered in Investment Cost (~ 3% of OCC)

In some discussions in the literature (see e.g., [Rothwell, 2012]), it is assumed that the first fuel load is part of the overnight capital cost. The order of magnitude of the first fuel load seems to be of the order of 3%. [INL, 2004] Because most references do not mention this first fuel load, and since it is only ~ 3% of the overall OCC, thereby “disappearing” in the margin of uncertainty, **we do not consider the first fuel load as part of the capital cost. It is just fuel during operation.**

2.13 Lifetime Availability Factor 85%

In our generic computations of the LCOE, we will use an **average life-time load factor of 85%**, which is representative of nuclear base load plants, as shown in Figure 2.32. For some countries this may be higher or lower. In addition, in the future it is possible that some plants may have to participate in load following. This correction, which is due to “systems effects” will be considered in a later chapter.

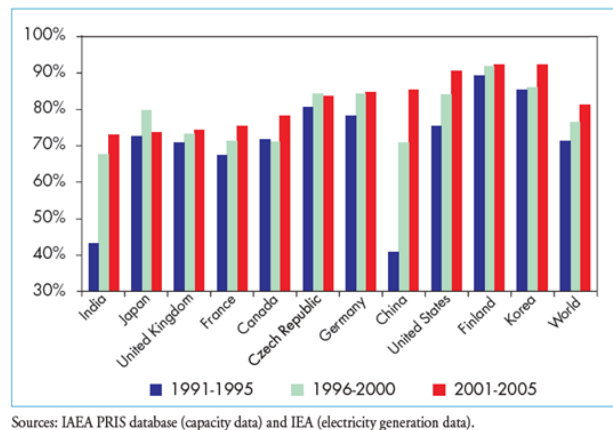


Figure 2.32: Five-year averages of load factors for selected countries. From [IEA, 2006]

2.14 Uncertainties and Accuracy of Estimate

2.14.1 Level of Accuracy of the Cost Estimate

Rather than “guessing” the future escalation of the construction cost of nuclear reactors during actual construction, we have previously announced that we will opt to “dress” our estimate with an “error bar” or “level of uncertainty” to characterize the degree of accuracy.

We therefore rely on the “Accuracy of Cost Estimate” classifications, as reported in [NETL 2011] and [PB, 2011], being the levels of estimate accuracy depending on the degree of detail of engineering work performed of a project.

According to AACE (Association for the Advancement of Cost Engineering International), Recommended Practice 18R-97, one has (see Figure 2.33):

ESTIMATE CLASS	Primary Characteristic	Secondary Characteristic			
	LEVEL OF PROJECT DEFINITION Expressed as % of complete definition	END USAGE Typical purpose of estimate	METHODOLOGY Typical estimating method	EXPECTED ACCURACY RANGE Typical variation in low and high ranges [a]	PREPARATION EFFORT Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range marked. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

Figure 2.33: Accuracy of Cost Estimate (From [PB, 2011], Appendix F)

During a conceptual study, [PB, 2011] estimates that Class 5 applies, with a degree of accuracy which is at best - 20% to + 30%, although for new technologies, the accuracy might be -50% to +100%.

[NETL, 2011] claims that its studies have an expected accuracy level of Class 4, in the range of -15% to +30%. It specifies further what degree of engineering is expected to be completed in class 4:

- Plant capacity, block schematics, indicated layout, process flow diagrams for main process
- Systems, and preliminary engineered process and utility
- Equipment lists

Because at this stage there are no FOAK₁ plants anymore to be considered⁷⁹ meaning that at least one or a few unit(s) has/ve been built somewhere (AP1000 or EPR, a.o.) we should therefore only be concerned with FOAK₂ projects and NOAK plants.

For a nuclear PWR, [MMD, 2011] estimates that its cost estimates have a “subjective” 95% confidence level of about -15% to +20%.

For our purposes, in our estimate for the construction cost of a generic plant of at least FOAK₂, we do realize that detailed designs exist, whereby a certain degree of “return on experience” applies, which would narrow down the uncertainty to class 1 to 2. However, for nuclear projects, it is important to recognize the possibility of uncertainties like regulatory hurdles, unanticipated cost escalations for materials, equipment and skilled

⁷⁹ More accurately, our study here excludes FOAK₁ type plants for cost-estimate purposes

labor which may be very country dependent. Although part of that uncertainty is usually incorporated in the provision for contingency, we feel that the accuracy level must be downgraded towards a “higher class”.

For **FOAK₂**, we suggest that our generic estimate fits in a category somewhere between the optimistic accuracy limit of class 5 and the pessimistic accuracy limit of class 3, being an **accuracy of -20% to +30%**.

For **NOAK₂**, starting with N=5 and higher (i.e., NOAK₂ (5+)), the generic estimate is assumed to be between classes 3 and 1, with an **accuracy of -10% to + 15%** (being actually equal to the pessimistic accuracy limit of class 1 and almost equal to the optimistic limit of class 3).

2.14.2 Contingency

[NETL, 2011] describes Capital Cost Contingencies as follows:⁸⁰

«Process and project contingencies are included in estimates to account for unknown costs that are omitted or unforeseen due to a lack of complete project definition and engineering. Contingencies are added because experience has shown that such costs are likely and expected, to be incurred even though they cannot be explicitly determined at the time the estimate is prepared.»

In the nuclear area, process contingency may occur because of special wishes by regulatory bodies. They may vary between 0 and 10%.

Project contingency for AACE class 4 or 5 projects, may range from 15% to 30% of the EPCC and process contingencies.[NETL, 2011].

Provisions for contingency are “explained” by Black & Veatch [NREL, 2012] – in Text Box 1:

Another form of variability that exists in estimates concerns the use of different classes of estimate and associated types of contingency. There are industry guidelines for different classes of estimate that provide levels of contingency to be applied for the particular class. A final estimate suitable for bidding would have lots of detail identified and would include a 5 to 10% project contingency. A complete process design might have less detail defined and include a 10 to 15% contingency. The lowest level of conceptual estimate might be based on a total plant performance estimate with some site-specific conditions and it might include a 20 to 30% contingency. Contingency is meant to cover both items not estimated and errors in the estimate as well as variability dealing with site-specific differences.

Especially the last sentence summarizes the aspects quite well.

For generic nuclear plants which are already routinely commercial (of the type NOAK₂ category) we estimate that a **provision for contingencies** between 10-20% is reasonable. For simplicity, **we assume an average of ~ 15%**.

We recall that in this report we do not consider FOAK₁-type plants, but we must certainly include FOAK₂ plants. It is possible that e.g., the 10-th EPR or AP1000 ever would be the first NPP built in Italy. Also, if Italy would order two more EPR's five years later, that should be much easier.

⁸⁰ [NETL, 2011] p 4

The following numbers for NPPs would be reasonable:

- FOAK₁ contingency 30-50% (but not very relevant to our report);
- FOAK₂ contingency 15-30% (depending on the country; the low end would be if it concerns the 10-th plant ever of that type, the high end as long as no more than e.g., 5 units of that type have been built);
- NOAK₂: Other plants: 10-15% seems reasonable.

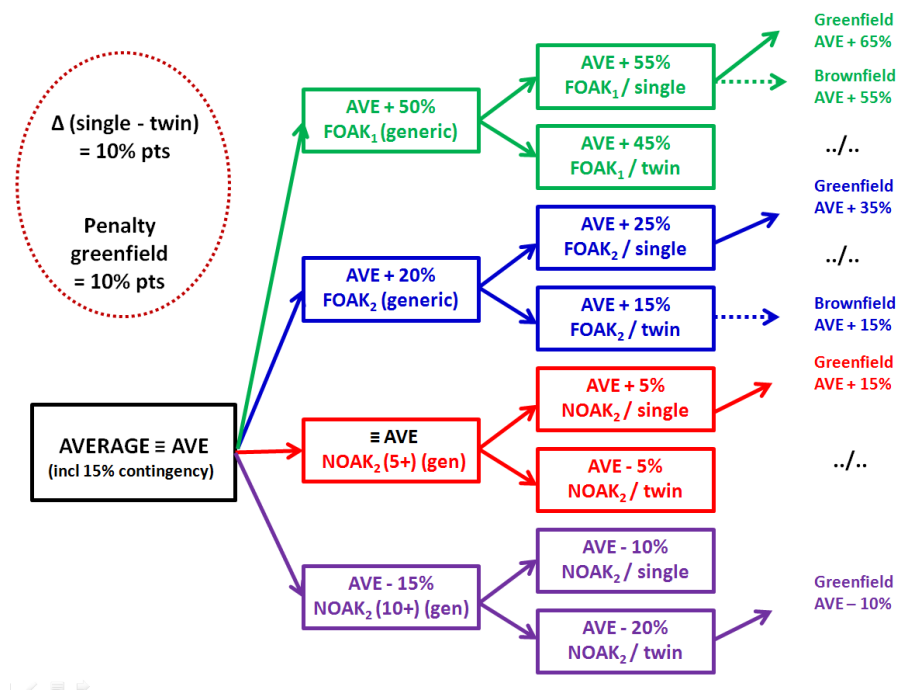
Assuming a generic contingency of 15% for “NOAK₂ (5+)”, the *penalties* for FOAK₂ as defined in Section 2.14.3.

2.14.3 Proposed Overnight Capital Cost Levels

We consider some simple rules which by and large should give the right orders of magnitude.

We start from the average of the estimates for the OCC collected from our literature scan: AVE = average (mean, median); to a large extent based on generic reactors, often being part of a twin.

By definition, **AVE is for “NOAK₂ (5+)”** (in the same country as of unit 5+ of same type; single unit). The following schematic, in Figure 2.34, illustrates our proposed range of cost estimates.



Legend on next page

Legend

Penalty or advantage Δ | single - twin | = 10% pts

Generic numbers based on 'brownfield'

Penalty for 'greenfield' | = 10% pts

FOAK₁ = very 'first of a kind' of a particular plant type ever, regardless of country

FOAK₂ = 'first of a kind' of a particular plant type, in a particular country

NOAK₂ (5+) = N-th unit of a kind of a particular plant type, as of the 5-th unit

NOAK₂ (10+) = N-th unit of a kind of a particular plant type, as of the 10-th unit

Figure 2.34: Proposed cost level schematic for different situations (own proposal)

Note: "gen" is abbreviation of "generic"

2.14.4 Summary on Contingency, Cost Levels and Accuracy

- **Overall generic contingency (all kinds of reactor types) = 15%**
- **Generic average estimate applies to a NOAK₂(5+) reactor, single on a brownfield –expressed in constant EUR 2012**
 - **For FOAK₂ reactor: a generic penalty of +20%**
 - **For twin units, a bonus/advantage of 10%pts per unit**
 - **For greenfield construction: a penalty of 10%pts**
- **Overall accuracy on final result is**
 - **For FOAK₂: -20% to + 30%**
 - **For NOAK₂ (5+): -10% to + 15%.**

Chapter 3

Investment Cost of New NPPs

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3.1.3 Variation in Time of “Recent” Cost Estimates

3.2 Capital Cost Estimate of this Study

3.2.1 Pre-Consultation Estimate

3.2.2 Consultation of Academics and Nuclear Market Actors

3.2.3 Overnight Cost New Build – Post-Consultation Wrap-Up

In this Chapter, we present our findings from an extensive search through the literature, for the **Overnight Construction Cost (OCC)**. We first recall that there exists an enormous variety of estimates, some more credible than others. To set the tone, some illustrations are given.

3.1 Variation of Estimates – Illustrations

3.1.1 Geographic Variation

The [NEA/IEA, 2010] results are obtained from a survey-sheet poll in the respective countries. [UChicago, 2011] has plotted the data graphically as reproduced in Figure 3.1. Clearly, there is an enormous geographical variation in the estimates.

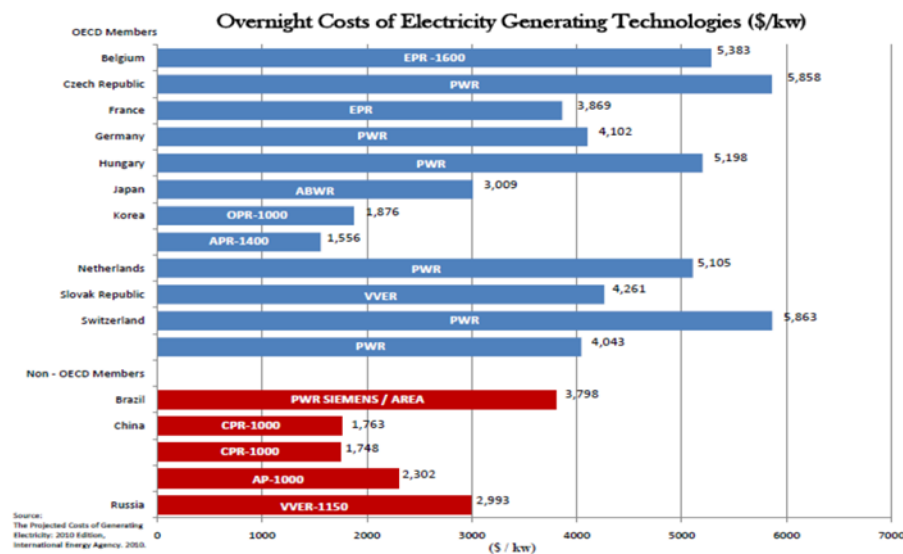


Figure 3.1: Overnight Cost of Electricity Generation Technologies. From [UChicago, 2011], data taken from [NEA/IEA, 2010]
Expressed in \$ of 2008 – USA is not included. Average w/o S. Korea: 4,669 \$/kW ; Ave w/ S. Korea: 4,177 \$/kW

[Rothwell, 2012] points out that many estimates exist and that in the “ideal” case (in the USA) a normal distribution of estimates can be conjectured; see Figure 3.2. It is obvious that other distributions, influenced by local circumstances, are plausible.

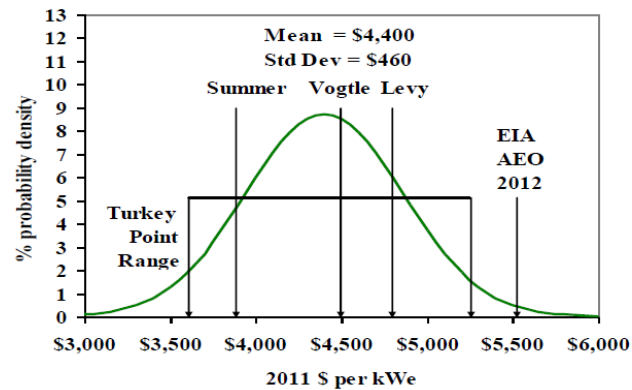


Figure 3.2: Illustration of the expected variability of estimates of OCC for new nuclear power plants. (From [Rothwell, 2012])

3.1.2 Discrepancy Cost Estimations and Actual Construction Costs

We have already discussed the issue of difference between the cost *estimates before* construction and the *actual cost after* construction. Figure 3.3 makes that point again.

Average Estimated and Realized Investment Costs of Nuclear Power Plants by Year of Construction Start, 1966-1977 (\$2005 per kW)			
Year of construction start	Number of plants	Initial estimate	Realised costs
1966-1967	11	530	1 109
1968-1969	26	643	1 062
1970-1971	12	719	1 407
1972-1973	7	1057	1 891
1974-1975	14	1095	2 346
1976-1977	5	1413	2 132

Note: Original data expressed in \$1982.

Source: EIA/US DOE (1986).

Figure 3.3: Discrepancy between the estimated cost and the actual cost after construction of NPPs in the USA. (From [IEA, 2006])

3.1.3 Variation in Time of “Recent” Cost Estimates

Finally, it is instructive to learn how cost *estimates* for the overnight cost of NPPs have changed over the years. Two illustrations make the point. See Figures 3.4 and 3.5.

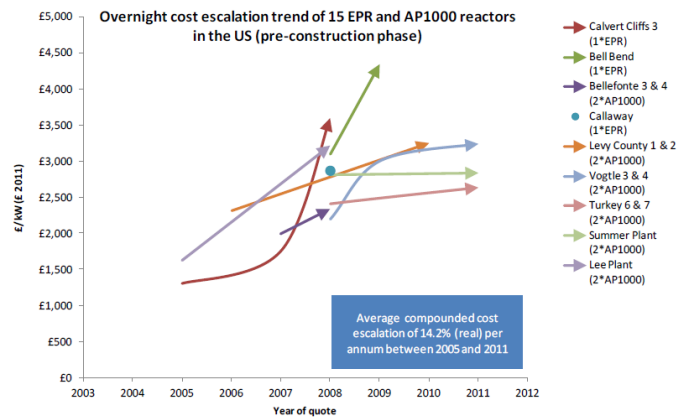


Figure 3: Overnight cost escalations in the pre-construction phase of US reactors between 2005 and 2011 (EPR and AP1000 reactor types only). All costs are expressed in 2011 values using the US CPI to index historic costs. For the Bell Bend and Callaway plants, where pure overnight cost estimates were not available, we have reduced quoted construction cost estimates by 23% (the average reduction that was experienced from other US plants in this analysis). Data sources are diverse and of varying credibility and content, so emphases should be placed on overall trends in the data, rather than on individual project-level estimates. Source: Authors own analysis from a range of sources outlined in Appendix 1.

Figure 3.4: Illustration of the cost escalation of the estimates since 2005. (From [ICEPT, 2012])

Figure 3.5 illustrates the strange estimates of the US Energy Information Administration (EIA) in the years up to 2009.

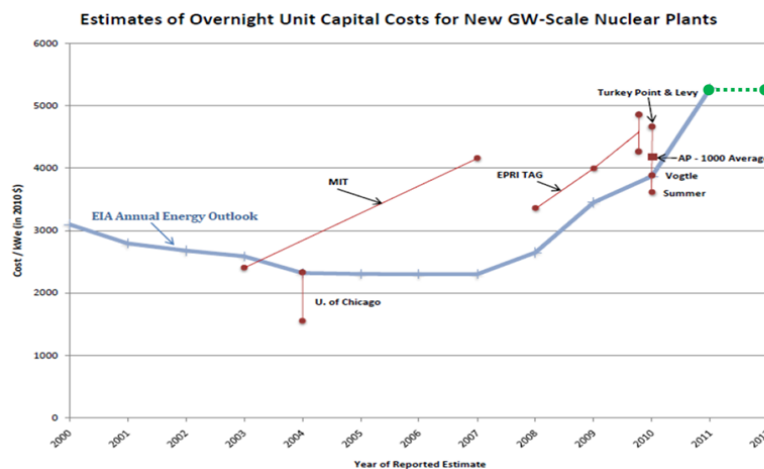


Figure 3.5: Changes over Time in Overnight Unit Capital Cost Estimates. (From [UChicago, 2011])⁸¹

As is obvious from comparing this figure with the IHS CERA PCCI, the early EIA estimates up to 2009 were completely “off the mark”. As of 2010, the estimates seem reasonable. The estimates for 2011 through 2013 have been reported to be the same.

⁸¹ As a remark on the latest MIT estimate, we signal that the values of [MIT, 2009] are expressed in \$2007, but that the study was reported in 2009.

3.2 Capital Cost Estimate of This Study

3.2.1 Pre-Consultation Estimate

Altogether, estimates from 28 sources (some neutral, some favorable to nuclear, some critical to nuclear) were considered. Some of these sources only present one single number, others a few numbers, while e.g., [NEA/IEA, 2010] and [Du, 2009] give more than a dozen estimates. We have carefully analyzed the data, insofar as this was possible given that many references give very little detail on what is included. From the comprehensive works, we have (in a first instance) accepted the various estimates as well as the summarizing estimate. Simple variations related to mere sensitivity analyses have not been retained and care was taken to avoid double counting when the same data were reported from cross referencing. Whenever data referred to the same plant and the same year of estimate, but where the author has utilized a particular methodology for cost escalation up to a later date, the data were retained. Anticipated cost escalation *during later construction* by extrapolation from the past was not retained. Future escalations are supposed to be incorporated in *the level of accuracy/uncertainty*. Also, several documents in the literature use numbers which are too old to be considered seriously.

To illustrate that such literature search is not obvious, we mention that [Cooper, 2009] criticizes the results of the [MIT, 2009] update as being too optimistic, whereas [Rothwell, 2010] criticizes that same [MIT, 2009] update result as being too pessimistic...

It must be recalled that in the end, it only makes sense to obtain a **range** or an **order of magnitude**. That is what our methodology aims at.

Our proposed estimate starts from an **‘average’ estimate** assigned to a **generic case**. Next, that estimate is adjusted for differences:

- brownfield / greenfield,
- single / twin,
- FOAK / NOAK / Fleet,

thereby assuming reasonable range of **provision for contingencies**. Through adjustments for brownfield/greenfield, single/twin, and FOAK/NOAK/Fleet, these provisions for contingencies are implicitly enlarged.

Our estimates are characterized by a reasonable **range for uncertainty/accuracy**, as explained in Section 2.14.

We stress again that our obtained **‘average’ estimate** for an **order of magnitude** is **NOT** based on a representative sample of data on which sophisticated statistical or econometric analyses should/can be performed! The data points used are merely a scan of “reasonable”, published, results with varying degree of quality, detail, specification, circumstances,..., whereby, as said above, some strange outliers or obvious “wet-finger” approaches are rejected.

But, the key point of our methodology is to present this proposed ‘average’ estimate to the so-called connoisseurs from the nuclear-related industry; i.e., our estimate only serves to **trigger/provoke reaction from nuclear-market ‘experts’!**

All in all, we have retained 137 data points for the **Overnight Construction Cost** from the 28 sources listed below.

NEA/IAE 2010	(17 data points)
Du & Parsons 2009	(18 data points)
U Chicago Update 2011	(7 data points)
CEU COMM 2008	(3 data points)
Rothwell June 2010	(5 data points)
EPRI Update June 2011	(2 data points)
LUT 2012	(2 data points)
Lazard 2008-11-12	(2 data points)
IEA Stuttgart 2010	(1 data points)
ECN 2010	(3 data points)
ICEPT 2012	(15 data points)
Parsons Brinckerhoff 2011	(6 data points)
Mott MacDonald 2010 and 2011	(5 + 6 data points)
Black & Veatch 2012	(3 data points)
USC 2010 & 2011	(1 + 12 data points)
Calif En Comm (CEC) 2010	(1 data points)
BERR 2012	(2 data points)
CBO 2008	(1 data points)
Harding 2008	(4 data points)
EIA AEO 2013	(1 data points)
Keystone 2007	(1 data points)
Severance 2009	(1 data points)
Cooper 2009 (-10-11)	(14 data points)
CRS (Kaplan) 2008	(1 data points)
Lévêque 2013	(2 data points)
VGB 2012	(1 data points)

Estimate for Overnight Construction Cost (OCC)

The OCC is expressed in $EUR_{2012}/kW_{installed}$

The collection of 137 data points (all obtained from the mentioned references) are presented in three different ways:

- a scatter plot in Figure 3.6
- a histogram in Figure 3.7
- a box plot in Figure 3.8

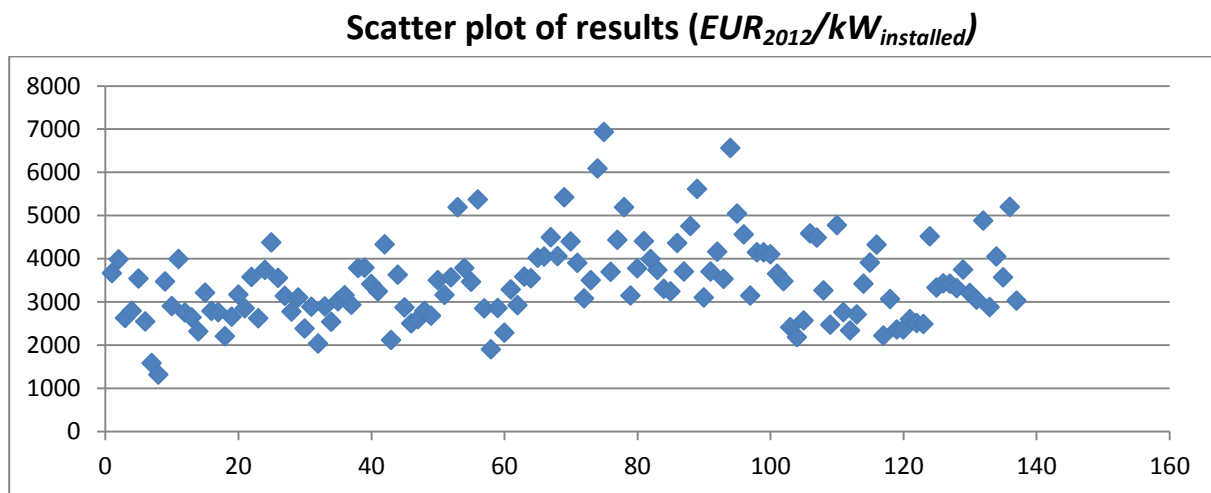


Figure 3.6: Scatter plot for the 137 data points for the overnight construction cost (OCC) from a disparate set of references (mostly PWRs, but also a few BWRs, and so-called “generic” plants)

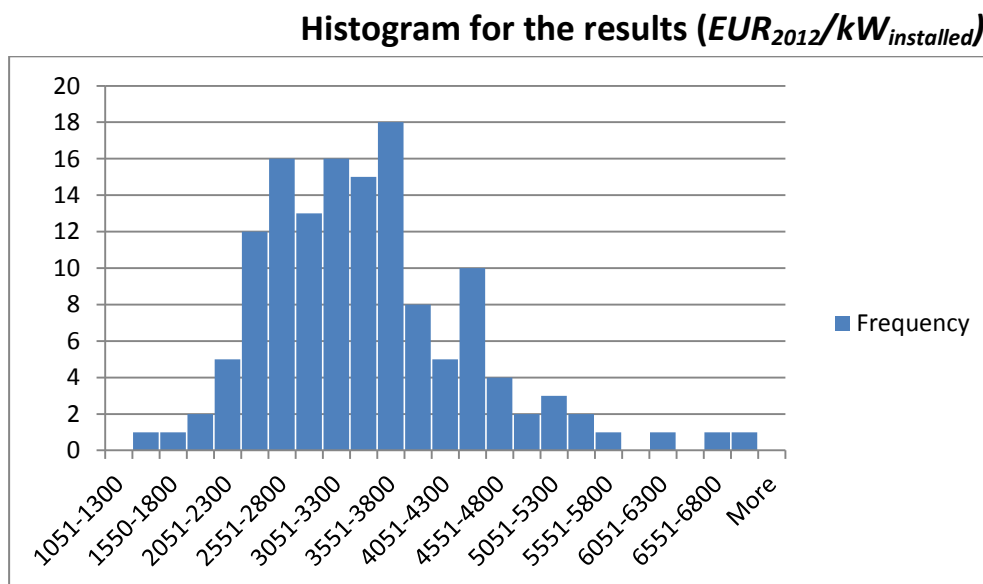
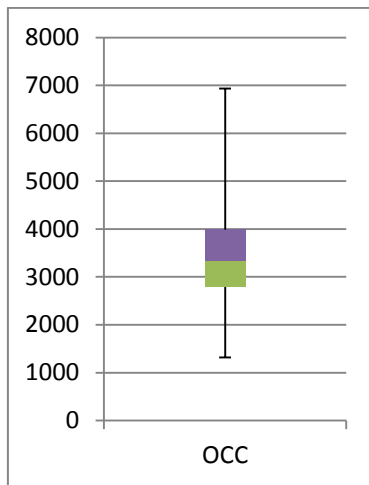


Figure 3.7: Histogram for the 137 data points for the overnight construction cost (OCC) from a disparate set of references (mostly PWRs, but also a few BWRs, and so-called “generic” plants). The intervals of the bins are 250 EUR_{2012} wide.

Box plot for the results ($EUR_{2012}/kW_{installed}$)



The following parameters apply:

Minimum	= 1316 EUR_{12}/kW
Median	= 3320 EUR_{12}/kW
Maximum	= 6934 EUR_{12}/kW

Figure 3.8: Box plot for the 137 data points. The box-plot parameters are listed to the right of the figure

In summary, the results for our ‘estimate’ of the Overnight Construction Cost (OCC), are:

Median = 3320 EUR_{12}/kW

Mean⁸² = 3447.5 EUR_{12}/kW

Define “**AVERAGE**” as $(MEAN + MEDIAN)/2 = 3383.7 \rightarrow$ roughly **3400 EUR_{12}/kW**

The estimate for a NOAK₂(5+) generic case, is therefore:

= about **3400 EUR_{2012}/kW** for **NOAK₂ (5+)** with uncertainty **-10 to + 15%**
on a brownfield, a as a generic estimate (single/twin)

More concretely, the estimates are as follows:

Distinguishing between twin/single (still for NOAK₂(5+)) leads to:

= about **3230 EUR_{2012}/kW** for **NOAK₂ (5+)** with uncertainty **-10 to + 15%**
on a brownfield, for a twin unit

= about **3570 EUR_{2012}/kW** for **NOAK₂ (5+)** with uncertainty **-10 to + 15%**
on a brownfield, for a single unit

⁸² The “mean” is the arithmetic average of all 137 data points.

For a first of a kind in a particular country (FOAK₂), we obtain:

= about **3910 EUR₂₀₁₂/kW** for FOAK₂ with uncertainty -20 to + 30%

on a brownfield, for a twin unit

= about **4250 EUR₂₀₁₂/kW** for FOAK₂ with uncertainty -20 to + 30%

on a brownfield, for a single unit

3.2.2 Consultation of Academics and Nuclear Market Actors

As mentioned under the Scope/Objectives, a two-track review process was undertaken, the first being an academic peer-review exercise to guarantee “quality control” of the intermediate report, and an industrial review to trigger/provoke reactions on the overall set up of the study but especially on the “proposed” overnight construction cost.

To recall, the academic Reviewers are: William Nuttall – Open University, UK, John Parsons – MIT, USA, Jan-Horst Keppler – Univ Dauphine Paris, FR, François Lévêque –Mines Paris Tech, FR.

The industrial actors who have replied to our request are: Areva, Westinghouse, Rosatom (reactor vendors), EdF, GdF-Suez, TVO, CEZ (nuclear-electricity generators), and WNA, VGB / Eurelectric (nuclear-knowledgeable industry organizations)

In general, the feedback was positive, with praise for the scope, the wide breath of definitions, hypotheses and boundary condition, and delineations of cost factors. There were no fundamental disagreements or issues; only (minor) requests for further clarification on goal of “average estimate” (statistics), exact definition of external costs, were ventilated. One reviewer thought the issue of escalation was a bit overdone,...

Nobody from industry ‘disagreed’ with the value of the “proposed estimate”; it is considered to be generally in right ballpark. However, it was requested to better stress that there are *differences* in reality depending on the reactor type, geographical differences, regulatory influence,...etc. From a methodological viewpoint, it was suggested not to include the average & median of the [NEA/IEA, 2010] study nor the average of the [MIT, 2009] study, as it actually amounts to double counting.⁸³

Explicit reactions by industry can be summarized as follows:

- ‘Utility’ / Electricity Generator (anonymous):
 - *«the orders of magnitude are coherent with what we see in projects we are developing» ... [But]... «we make a clear distinction between a European and a world average»*
 - **3,750 €/kW** Europe
 - **2,350 €/kW** world average

⁸³ Following this refereeing remark, the numbers were recomputed, resulting in slightly different results, that do not, however, influence the bottom line of our approach. The Median would then be 3,372; the Mean would then be 3,461; with Average value equal to 3,416, which is de-facto equal to our proposed rounded value of **3,400 €₂₀₁₂/kW** that we presented to the industrial actors.

- Comments Reactor Vendors on the proposed estimate:
 - Westinghouse:
 - **4,200 €/kW** Europe (range between 3,600 to 4,900 €/kW) for *twin* units
 - **5,040 €/kW** Europe for *single* units (factor 1.2)
 - Rosatom:
 - The «OCC realized in Russia is in the range between **2,575 and 3,526 €₂₀₁₂/kW**»
 - Areva:
 - «The resulting “Average”, used as a generic case, is not far from sources like the IEA WEO which is broadly recogni[z]ed – OCC Europe **4,000 \$/kW**»
 - «Results coming from the methodology of this study are also in line with today’s ongoing nuclear projects. E.g., the cost of the EPR in Flamanville as publically quoted by EdF is ... **4,900 to 5,150 €/kW**, close to your result of **5,270 €/kW** for FOAK₁ single unit on Brownfield»
- Comment by the author of this report: Actually, the EPR in Flamanville is a FOAK₂ single unit on brownfield, so that our estimate for such case is actually 4,250 €/kW with an uncertainty -20% to +30%. This means that the range spans 3,400 to 5,525 €/kW.

It is instructive to explain the methodology on “Evaluation Criteria”, used by Westinghouse which stresses the differences between practical projects in a particular location and with a particular reactor type, and generic estimates.⁸⁴

The 14 evaluation criteria used by Westinghouse are those listed in Figure 3.9.

Evaluation Criteria

Licenseability	Supply Chain Localization
Codes and Standards	Supply Chain Resilience
Design Completion	Equipment and Material Requirements and Cost (Safety)
Design Complexity	Equipment and Material Requirements and Cost (Other)
Constructability	Vertical Integration
Labor Quantity and Productivity	Quality Assurance
Logistics	I&C Performance Monitoring

Figure 3.9. Evaluation criteria used by Westinghouse to determine a cost range for new-build reactors

Each of these “Evaluation Criteria” is given a weight, depending on the location and the reactor technology. In a second step, the weighted criteria are then scored, again based on geographical/regional location or range of the project and the maturity of the technology.

⁸⁴ Provided by F. Naredo, Westinghouse; mail exchange August 13, 2013.

The intent is to capture a quantitative measurement of the extent to which a single factor could influence the overnight cost of the project. This potential project-impact value then flows through to the development of the scenario outputs.

Concretely, to determine the relative level of impact of the criteria, each criterion is *weighted* on a scale from 1 – 9, with 9 being the highest importance and 1 being the lowest.» See Figure 3.10.

Description of Weights	
Weight	Description
1 - 3	Criteria is less important to project outcomes
4 - 6	Criteria is related to project outcomes
7 - 9	Criteria has highly related to project outcomes

Figure 3.10. Weights applied to evaluation criteria used by Westinghouse of Figure 3.9.

Next, the technologies receive a 1-5 score for each criterion, with 5 being the best relative score possible and 1 being the worst; cfr Figure 3.11.

Description of Scores		
Criteria Score	Description	
1	Technology is highly disadvantaged on this criteria	Red
2	Technology is disadvantaged on this attribute	
3	Technology has neutral impact on this criteria	Yellow
4	Technology is advantaged on this attribute	Green
5	Technology is highly advantaged for this criteria	

Figure 3.11. Scores applied to evaluation criteria used by Westinghouse of Figure 3.9.

Using prior industry knowledge as well as in-country experts for local implications, the weights and scores are applied to each criterion using a rigorous review of both demonstrated performance and reasonably expected future outcomes. Each criteria score is then scaled by the criteria weight and this results in an overall weighted score for each technology alternative. The scores are then indexed to provide a distribution of OCC estimates and the AACE “design maturity curve”. Using this methodology results in a range of possible OCCs for each technology considered for a project.

3.2.3 Overnight Cost New Build – Post-Consultation Wrap-Up

Recall that our OCC generic estimate before consultation was the following:

- For **NOAK₂ (5+)** on a **brownfield**: **3,400 €₂₀₁₂/kW**
 - With uncertainty range between – **10% to + 15%**
 - Hence, estimate: 3,060 ...**3,400**...3,910 €₂₀₁₂/kW
- For **FOAK₂ single unit** on **brownfield**: **4,250 €₂₀₁₂/kW**
 - With uncertainty range between **-20% to +30%**
 - Hence, range spans: 3,400...**4,250**...5,525 €₂₀₁₂/kW

To accommodate comments by industry, one may try to Europeanize the “estimate”, perhaps as follows:

- 1) Take out the Asian (Korea & Japan) numbers from data base (especially [NEA/IEA, 2010] and [MIT, 2010]) to rely only on “Western”, i.e., European and USA numbers:
 - leads to Median=3,445 & Mean=3,541
 - Average = 3,493 → **About 3500 €₂₀₁₂/kW generic**
- 2) Take out the Asian (Korea & Japan) and USA numbers from data base of [NEA/IEA, 2010] to have a strict set of European numbers:
 - leads to Median=3,344 & Mean=3,292
 - Average = 3,318 → **About 3,300 €₂₀₁₂/kW generic**

From these attempts to “Europeanize the numbers”, there is no unidirectional guidance towards an upgrade of our “proposed estimate” for an OCC.

However, to accommodate the clear signal from the industrial actors, and endorsed by the ENEF Steering Committee, it makes sense for Europe, to **emphasize the high uncertainty bracket of estimate** and to attach less importance to the lower end of the uncertainty range.

This would mean that our recommended estimate for the OCC in the end is as follows:⁸⁵

For NOAK₂ (5+) on a brownfield :	3,060... 3,400 ...3,910 € ₂₀₁₂ /kW
For FOAK₂ twin unit on brownfield :	3,128... 3,910 ...5,083 € ₂₀₁₂ /kW
For FOAK₂ single unit on brownfield :	3,400... 4,250 ...5,525 € ₂₀₁₂ /kW

⁸⁵ To remain methodologically consistent, no new values for the OCC estimate were inserted in the set of numbers of our database after the intermediate report was issued (May 20 2013) and distributed for the review process. Since then, however, three extra sets of numbers have come to the author’s attention, which do point towards higher numbers for Europe. More recent numbers for the UK than the ones used in our database are the following “medium” estimates from [PB, 2012]: 4,217 €₂₀₁₂/kW for a NOAK (three units), and 4,960 €₂₀₁₂/kW for a FOAK₂ (three units). In a further update, the UK numbers have been adjusted [PB, 2013a] as follows: 4,762 €₂₀₁₂/kW for a NOAK (three units), and 5,452 €₂₀₁₂/kW for a FOAK₂ (three units). Similarly, for NOAK-type plants, [Hirschberg, 2011] suggests a somewhat lower value than in the UK, with a medium value of 3540 €₂₀₁₂/kW for Switzerland. Both values are higher than our medium numbers, hinting towards a somewhat higher value than our midpoint. Hence our suggestion to focus on the high bracket.

Chapter 4

Investment for Long-Term Operation (LTO) / Refurbishments

Contents of Chapter 4

- 4.1 Introductory Considerations
- 4.2 “Life-time” of a Nuclear Power Plant
- 4.3 Investment Cost for Major Refurbishments for LTO

4.1 Introductory Considerations

When considering the economics of nuclear power, it is instructive not only to focus on new build, but to reflect on the desirability, from an economics point of view, to consider *long-term operation* of existing plants, likely after appropriate refurbishment to keep the safety level of the plants in line with current expectations. Indeed, since our electricity generation system in Europe is currently going through almost revolutionary changes on its path towards a zero CO₂ emission target by 2050,⁸⁶ which is expected to cost considerably, it may be an interesting option to extend the operational life of NPPs beyond their originally ‘estimated’ design life, so as to keep a dispatchable and firm CO₂-free electricity generation technology on line at reasonably low cost. This would give the electric power sector more time to thoroughly analyze the transitional aspects of system integration with ample intermittent, decentralized and centralized, generation, with substantial non-dispatchable overcapacity.⁸⁷ In addition, it gives reactor developers some breathing space to reflect on design changes that meet the challenges of future electricity systems, such as load-following participation, whilst still guaranteeing sufficient rotational inertia into the system to support grid stability.

4.2 “Life Time” of a Nuclear Power Plant⁸⁸

It is important to recognize that there is no pre-determined life time for a *system* such as a nuclear power plant. There does exist a lifetime for ‘safety-qualified’ *components*, but in principle all components are replaceable. The most crucial components to replace are the reactor vessel (neutron-induced embrittlement) and the primary piping (fatigue due to thermal transients), and they effectively determine the maximum practical technical life. At the time of reactor design, the so-called ‘design life’ is *estimated* by assuming an expected neutron fluence and a set of operational thermal transients. However, with careful monitoring of the embrittlement status of the vessel, mitigation of transients and more detailed numerical computations than utilized at the time of the design in the 1970-1980’s, currently operating plants do usually⁸⁹ not see

⁸⁶ See e.g., http://ec.europa.eu/energy/energy2020/roadmap/index_en.htm and http://ec.europa.eu/clima/policies/roadmap/documentation_en.htm

⁸⁷ The system integration aspects are considered in more detail in Chapter 9.

⁸⁸ A more comprehensive delineation of the arguments is available in [Frédéric, 1996]

⁸⁹ Clearly, the status of every individual plant must be thoroughly analyzed and evaluated. The outcome may also be different from plant to plant.

insurmountable barriers for extended operation. The fundamental requirement to which there are no compromises possible is the safety requirement. Regardless of their age, unsafe plants should not operate. Conversely, safe plants, properly qualified by competent regulatory authorities, need not be shut down prematurely. So, in a technical sense, the only really important life time of an NPP is an economic life, subject to non-negotiable stringent safety requirements. Indeed, from the moment that it becomes too expensive to replace most components to keep the plant safe, then the owners will decide to shut down the plant. In some countries, there are fixed 'regulatory lifetimes' (e.g., USA); in other (like e.g., France), there is no predetermined regulatory lifetime, but a major safety review every ten years after which the plant obtains the green light for a further 10 years of operation.⁹⁰ In yet other countries (Germany, Belgium), there is also something that some call a 'political' life time, where political authorities have decided to shut down the plants at a certain moment in time (independent of their safety condition).

Different aspects of prolonged operation of nuclear power plants is discussed in several sources in the literature ([IAEA, 2002], [Chockie, 2006], [JRC, 2010a], [IAEA, 2011], [DOE, 2013b]), but the most updated, timely and comprehensive document on the economics of LTO has been published late 2012, by the Nuclear Energy Agency of the OECD. [NEA, 2012c] Our reflections are based on this last mentioned document.

4.3 Investment Cost for Major Refurbishments for LTO

Plants that have been built in the past, whether or not depreciated in a bookkeeping sense, are characterized by a "sunk" investment cost. Such plants will keep operating as long as the marginal operational cost (consisting of the O&M cost and the fuel cost) is lower than the electricity market prices.

If operational costs are too high in comparison with other generation means and the market price, then it may be that owners/operators decide to shut down plants for pure economic reasons, regardless of the technical end/or safety related status of the plant. Such early retirement has taken place on May 07 2013 in the state of Wisconsin, USA, where the Kewaunee nuclear plant was shut down, even though it had received a regulatory operational extension by the NRC until 2033, because of low market prices mostly driven by cheap shale-gas electricity generation.

In other markets and circumstances, especially in Europe, where a possible shale-gas breakthrough is not obvious, it certainly makes economic sense to continue operation of existing plants. Even if safety concerns become an issue so that major refurbishment investments are necessary, it may still be advantageous in several markets to consider prolonged operation. A precondition for operational extension after refurbishment, however, is a stable political decision climate. When substantial investments are made to refurbish a plant, then an expected operational period must be part of the regulatory operational license (clearly always subject to the future safety status of the plant). The possibility for changes in future standpoints of the authorities must be foreseen in the LTO-related agreement with government authorities, with possible (contractual) compensation when a premature shutdown would be enforced.

The crucially important parameter for prolonged operation is the investment cost for refurbishment. This investment is to a large extent determined by the overnight refurbishment cost (ORC).

⁹⁰ More details on the regulatory aspects of operational life of plants can be found in [NEA, 2012c], Table E.2.

A set of specific overnight refurbishment costs has recently been obtained for a variety of countries by the NEA, as shown in Figure 4.1. [NEA, 2012c] The figure has been limited here to OECD countries. As shown in the table of Figure 4.1, post-Fukushima upgrades have been included in the numbers given.

Country	Specific investment in LTO	Comment
Belgium	USD ₂₀₁₀ 650/kWe	Including ~11% increase due to post-Fukushima measures.
France	USD ₂₀₁₀ 1 090/kWe	Including all investments from 2011 to 2025: maintenance, refurbishment, safety upgrades, performance improvement; and ~10% increase due to post-Fukushima measures.
Hungary	USD ₂₀₁₀ 740-792/kWe	Including 10-17% increase due to post-Fukushima measures.
Korea, Republic of	USD 500/kWe	Including ~10% increase due to post-Fukushima measures.
Switzerland	USD ₂₀₁₀ 490-650/kWe	Specific future investment in NPP refurbishment and maintenance (approximately the double of the specific LTO investment) is USD ₂₀₁₀ 980-1 300/kWe.
United States	About USD ₂₀₁₀ 750/kWe	Electric Power Research Institute (EPRI) survey data and current spending on capital improvement.

Fig 4.1: Cost summary of specific ‘Overnight Refurbishment Investment Cost’ in some OECD countries - Ref: [NEA, 2012c] Table E4 - partim

From these numbers, we distill an *order of magnitude* that is representative for refurbishments in Europe.

Range for the specific **Overnight Refurbishment Cost (ORC)**:

specific ORC ~ 500 – 1,100 \$/kW, or with 1 \$₂₀₁₀ = 0.754 €₂₀₁₀, → range ~ 377 – 830 €₂₀₁₀/kW

or thus⁹¹

specific ORC ~ 400 – 850 €₂₀₁₂/kW

This refurbishment investment is usually considered to “buy” another 20 years of extended operation. When computing the LCOE for LTO, we will use **T=20 years** as a typical operational life extension period.

The formula to obtain the LCOE after refurbishment for prolonged operation, has been presented in Section 2.4.2 above. The refurbishment duration is designated by ‘ t_R ’ and ‘ $Refurbishment_t$ ’ is the part of the ORC expended in year t .

The LCOE based on our retained order of magnitude for the ORC, together with some examples from [NEA, 2012c], will be presented in Chapter 6.

⁹¹ Note: €₂₀₁₀ = 1.02 €₂₀₁₂ (adapted nuclear S curve Europe)

Chapter 5

Fuel-Cycle Costs and Operation & Maintenance (O&M)

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- 5.2 Operations & Maintenance Costs

In this chapter, the costs to operate nuclear power plants are considered. We distinguish two items, the full Fuel-Cycle cost, up to and including nuclear waste management and disposal, and the cost for Operation & Maintenance (O&M), excluding fuel costs and major refurbishments (the latter of which have been covered in Chapter 4). These items are discussed in Sections 5.1 and 5.2, respectively.

5.1 Fuel-Cycle Costs

5.1.1 Introductory Considerations on Fuel-Cycle Costs

Some stage-setting reflections on the nuclear fuel-cycle cost have been given in Section 2.2. In this section, we treat the subject matter in some detail, with the aim of providing appropriate cost numbers. As is the case in most parts of this report, it is again the objective to come up with a representative ***generic order of magnitude for the fuel-cycle cost*** – as before, exact numbers (which depend on many parameters reflecting different circumstances) are not very meaningful.

The fuel-cycle costs to be included in the LCOE, are for the full fuel cycle, both the upstream (or front-end) part and the downstream (or back-end) part.

The costs for the fuel cycle depend on the type of cycle chosen. Most relevant for the current generations II and III of nuclear reactors are:

- the *once-through* cycle, whereby the spent nuclear fuel (SNF) after unloading from the reactor is considered as waste; and
- the cycle with *reprocessing* to recover the Pu and the unused U, and to isolate only the minor actinides and the fission products as waste in vitrified glass.

Cycles operating in a once-through mode utilize uranium oxide UO_2 as fuel, whereas the cycles with reprocessing start up with UO_2 (mostly referred to as UOX as abbreviation of uranium oxide) as fresh fuel and reload afterwards with UO_2 (in the form of reprocessed UO_2 —called REPUOX) and MOX, the latter referring to Mixed Oxide pellets, containing a mixture of UO_2 and PuO_2 . In our considerations, we consider reprocessing cycles with a single recycling. Multiple recycling is not considered.⁹²

The nuclear fuel cycle is discussed in several relevant and informative references in the literature, of which we mention [Bunn, 2003], [De Roo, 2009a, 2009b, 2011], [DOE, 2008, 2013a], [IAEA, 2009a], [Rothwell, 2010b], [MIT, 2011a], [NEA, 2013]. Especially the last two, [MIT, 2011a], [NEA, 2013] are very comprehensive documents. Since the most recent report on this subject matter by the Nuclear Energy Agency, [NEA, 2013], covers our desiderata as to the scope, provides appropriate answers to what we need, and it gives a comparison with other sources of the literature, we base most of our discussion on that reference.

To have a first indication of a fuel-cycle cost per MWh_e , it is interesting to first consult the 2010 update of the NEA/IEA “Projected Costs of Electricity Generation Electricity” study. [NEA/IEA, 2010] Figure 5.1 below copies Table 3.7a of that study, and the arrow points to the “fuel-cycle costs”.

⁹² As mentioned in Section 2.2, multiple recycling with fast reactors is beyond the scope of this study, but it is treated in [NEA, 2013].



Country	Technology	Net capacity	Overnight costs ¹	Investment costs ²		Decommissioning costs		Fuel Cycle costs	O&M costs ³	LCOE	
				5%	10%	5%	10%			5%	10%
		MWe	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	
Belgium	EPR-1600	1 600	5 383	6 185	7 117	0.23	0.02	9.33	7.20	61.06	109.14
Czech Rep.	PWR	1 150	5 858	6 392	6 971	0.22	0.02	9.33	14.74	69.74	115.06
France*	EPR	1 630	3 860	4 483	5 219	0.05	0.005	9.33	16.00	56.42	92.38
Germany	PWR	1 600	4 102	4 599	5 022	0.00	0.00	9.33	8.80	49.97	82.64
Hungary	PWR	1 120	5 198	5 632	6 113	1.77	2.18	8.77	29.79/29.84	81.65	121.62
Japan	ABWR	1 330	3 009	3 430	3 940	0.13	0.01	9.33	16.50	49.71	76.46
Korea	OPR-1000	954	1 876	2 098	2 340	0.09	0.01	7.90	10.42	32.93	48.38
	APR-1400	1 343	1 556	1 751	1 964	0.07	0.01	7.90	8.95	29.05	42.09
Netherlands	PWR	1 650	5 105	5 709	6 383	0.20	0.02	9.33	13.71	62.76	105.06
Slovak Rep.	VVER 440/ V213	954	4 261	4 874	5 580	0.16	0.02	9.33	19.35/16.89	62.59	97.92
Switzerland	PWR	1 600	5 863	6 988	8 334	0.29	0.03	9.33	19.84	78.24	136.50
	PWR	1 530	4 043	4 758	5 612	0.16	0.01	9.33	15.40	57.83	96.84
United States	Advanced Gen III+	1 350	3 382	3 814	4 296	0.13	0.01	9.33	12.87	48.73	77.39
NON-OECD MEMBERS											
Brazil	PWR	1 405	3 798	4 703	5 813	0.84	0.84	11.64	15.54	65.29	105.29
China	CPR-1000	1 000	1 763	1 946	2 145	0.08	0.01	9.33	7.10	29.99	44.00
	CPR-1000	1 000	1 748	1 931	2 128	0.08	0.01	9.33	7.04	29.82	43.72
	AP-1000	1 250	2 302	2 542	2 802	0.10	0.01	9.33	9.28	36.31	54.61
Russia	VVER-1150	1 070	2 933	3 238	3 574	0.00	0.00	4.00	16.74/16.94	43.49	68.15
INDUSTRY CONTRIBUTION											
EPRI	APWR, ABWR	1 400	2 970	3 319	3 714	0.12	0.01	9.33	15.80	48.23	72.87
Eurelectric	EPR-1600	1 600	4 724	5 575	6 592	0.19	0.02	9.33	11.80	59.93	105.84

*The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

*The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

Figure 5.1: Nuclear power plants; Levelized costs of electricity in USD₂₀₀₈ per MWh – from [NEA/IEA, 2010], Table 3.7a

As is evident from the column indicated in Figure 5.1, for most countries a cost of **9.33 USD₂₀₀₈/MWh_e** applies. This is explained on p. 42 of [NEA/IEA, 2010] as being composed of a front-end cost (from mining up to the fuel assemblies) of 7.00 USD₂₀₀₈/MWh_e (or 1.94 USD₂₀₀₈/GJ_e) and a back-end part (up to final disposal) of 2.33 USD₂₀₀₈/MWh_e (or 0.65 USD₂₀₀₈/GJ_e).⁹³ As specified in [NEA/IEA, 2010], the 9.33 is a generic fuel-cycle cost applied to all cases, except for those countries that have provided specific numbers (compatible with the computational spreadsheet method of [NEA/IEA, 2010]).

For further reference, we also mention the fuel-cycle costs taken by the MIT 2009 cost-update of the earlier (2003) study “Future of Nuclear Power” [MIT, 2009] and by the “accompanying” [Du, 2009] report. In these references, we read an upstream fuel cost of 0.67 \$₂₀₀₇/mmBtu or 6.97 \$₂₀₀₇/MWh_e and a downstream cost (taken from the USA SNF disposal fund) of 1 \$₂₀₀₇/MWh_e. However, note [4B] of [MIT, 2009] specifies that the fuel cost is assumed to escalate at 0.5% per annum in real terms, leading to a 40-year averaged real price of 0.76 \$₂₀₀₇/mmBtu or thus 7.91 \$₂₀₀₇/MWh_e. Hence, the [MIT, 2009] “update on nuclear” study leads to **8.91 USD₂₀₀₇/MWh_e**.

As mentioned above, the recent NEA study “*The economics of the back end of the nuclear fuel cycle*” [NEA, 2013] gives a comprehensive picture of the full nuclear fuel cycle. Specifically, it gives a full overview of the issues, regulatory aspects, national differences etc., and it makes interesting generic scenarios, with comparisons with other studies (such as the dedicated MIT study, “The Future of the Nuclear Fuel Cycle”, [MIT, 2011a]).

Based on the results of the “*Projected Costs of Generating Electricity*” study [NEA/IEA, 2010], the fuel-cycle study [NEA, 2013] recalls what the contributions of the fuel-cycle cost are as part of the LCOE. This is shown in Figure 5.2.

⁹³ Recall that 1 MWh = 3.6 GJ

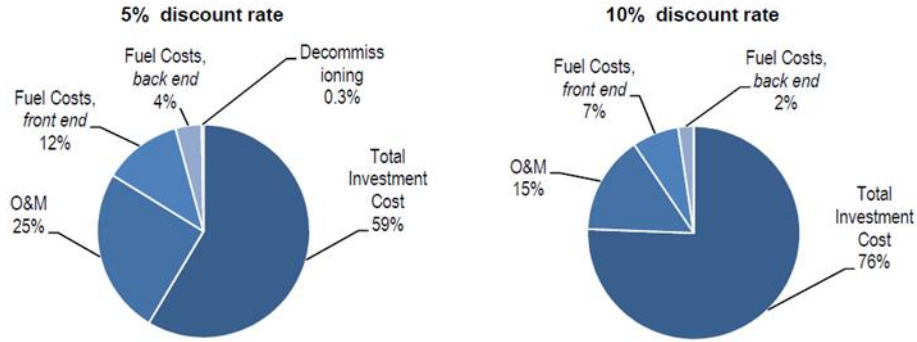


Figure 5.2: Structure of nuclear electricity generation cost; Ref [NEA, 2013], Fig 3.1, in turn based on the median case from [NEA/IEA, 2010]

According to these percentages, the fuel-cycle costs amount to a range of 9% - 16%, depending on the discount rate, in line with our earlier mentioned range (in Section 1.2), where 7% - 15% was suggested.

5.1.2 The LCOE Expressions for the Fuel-Cycle Costs

As said before, the fuel-cycle cost consists of two parts, the front-end and the back-end parts. We “borrow” the expressions to compute the LCOE contribution of the fuel cycle from [NEA, 2013] (p. 72 and 64, respectively):

$$\text{LCOE}_{\text{Fuel Cycle}} = \frac{\sum_{t=1}^T \left(\frac{[\text{UOX costs}]_t}{(1+r)^t} \right)}{\sum_{t=1}^T \left(\frac{\text{Electricity}_t}{(1+r)^t} \right)} + \text{LCOE}_{\text{Back End}} = [\text{UOX costs per MWh}] + \text{LCOE}_{\text{Back End}}$$

Further assumptions for the uranium front end include the following items:

- Fuel fabrication cost for UOX and REPUOX fuel is the same.
- The specific, per SWU, enrichment costs for natural and reprocessed uranium are considered to be identical.

$$LCOE_{Back\ end} = \sum_{\text{Back-end facilities, } i} \left[\frac{\sum_{t=T_{i, start}-T_{ref}}^{T_{i, end}-T_{ref}} \left(\frac{Investment_{i, t} + O\&M_{i, t} + Transport_{i, t} + Decommissioning_{i, t}}{(1+r_i)^t} \right)}{\sum_{t=T_{NPP, start}-T_{ref}}^{T_{NPP, end}-T_{ref}} \left(\frac{Electricity_t}{(1+r_E)^t} \right)} \right]$$

where:

T_{ref} :	The reference year (all cash-flows are discounted to the reference year). For the calculation presented in the Section 3.3 T_{ref} is 2020; ¹
$T_{i, start}$:	Year in which begins the lifecycle of the facility i ;
$T_{i, end}$:	Year in which ends the lifecycle of the facility i ;
$T_{NPP, start}$:	Year in which NPPs start producing electricity;
$T_{NPP, end}$:	Year in which NPPs are permanently shut down and cease producing power;
r_E :	Annual discount rate for electricity cash flow;
r_i :	Annual discount rate for the cash-flows associated with construction and operation of the facility i ;
$Electricity_t$:	The amount of electricity produced at NPPs in year “ t ”;
$Investment_t$:	Investments associated with the back end of fuel cycle, in year “ t ”;
$O\&M_t$:	Operations and maintenance costs at various steps of the fuel cycle, in year “ t ”;
$Transport_t$:	Transportation costs associated with the fuel cycle in year “ t ”;
$Decommissioning_t$:	Decommissioning of the back-end facilities, costs in year “ t ”;

These expressions are fully compatible with the expressions given in Section 2.4 of this report (which were taken from [NEA/IEA, 2010]). Note, however, that other parameters may apply – here the reference time $T_{ref} = 2020$ and all costs are discounted to that moment; the discount rates r_E and r_i may differ. But, through a sensitivity analysis, [NEA, 2013] has covered a reasonable range of parameters. Note, however, that most costs are expressed in **USD₂₀₁₀**.

Further explanation on the used symbols is provided in [NEA, 2013].⁹⁴

5.1.3 Scenarios for the Back-End Fuel Cycle

The report [NEA, 2013] recognizes that the fuel-cycle cost depends on many country-specific parameters. It therefore proposes to obtain a **generic estimate** for the costs, based on accepted and published numbers for the separate cost elements of the fuel cycle, supplemented by assumptions guided by engineering judgment and considering three scenarios, of which there are only two relevant for this study. The two pertinent ones for our study are:⁹⁵

1. New fuel assemblies with UO_2 and direct disposal of spent nuclear fuel (SNF)
2. Partial recycling in LWR; i.e., twice through. This means that the first load consists of UO_2 and the second of REPUOX and MOX, whereby the spent MOX and spent REPUOX are disposed of.

⁹⁴ SWU means Separative Work Unit and is a measure for the work needed to enrich the uranium fuel. REPUOX is used in [NEA, 2013] to designate reprocessed uranium oxide that is recycled together with the fresh fuel.

⁹⁵ The third scenario considered in [NEA, 2013], not considered here because it goes beyond the objectives of our study, is: multiple Pu recycling with LWRs and fast reactors (FR); i.e., MOX and REPUOX recycling once in LWRs and multiple plutonium recycling in FRs.

Using some figures, we document below the sort of ingredients (and the rigor) utilized to arrive at a generic cost estimate. For more details, the reader is referred to [NEA, 2013].⁹⁶

The flow of material of the two scenarios 1 and 2 is summarized in Figures 5.3 and 5.4, respectively.

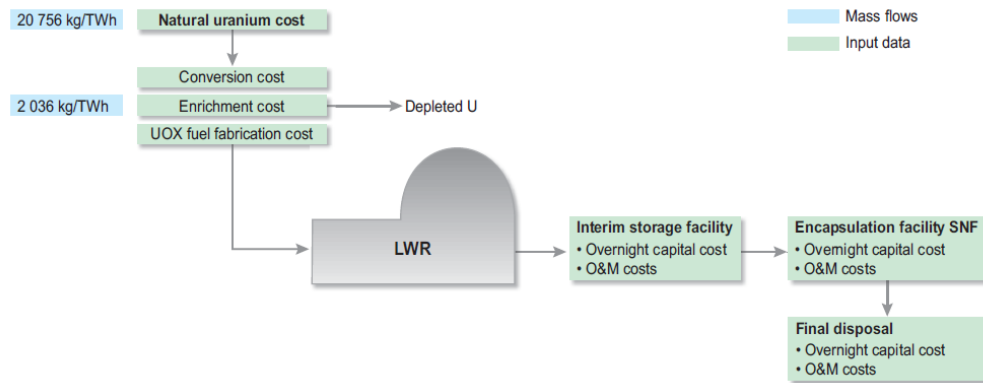
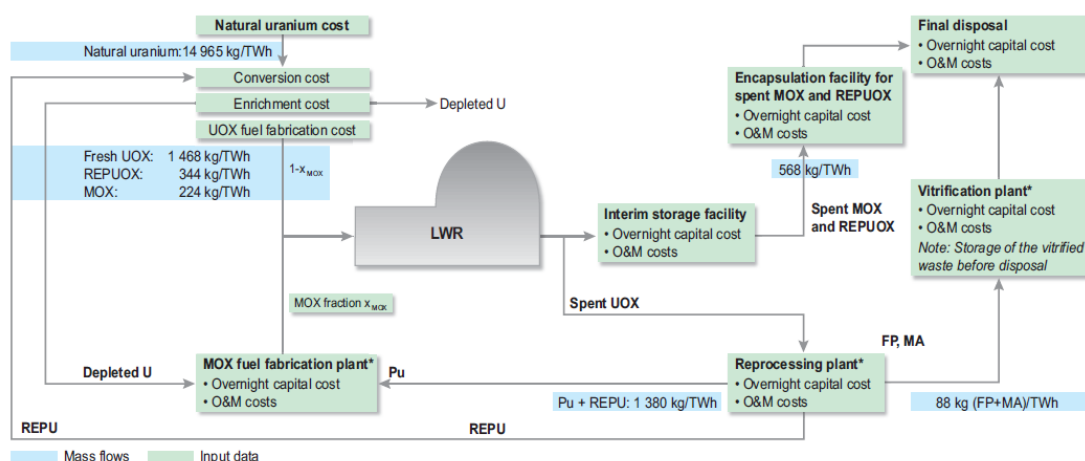


Figure 5.3: The once through cycle of scenario 1 – Reference: [NEA, 2013] Figure 3.6



* In the model an integrated reprocessing plant has been considered, including reprocessing, MOX fabrication and HLW vitrification facilities.

Figure 5.4: Partial recycling in LWR route with REPUOX and MOX recycling in LWR; scenario 2 – Reference: [NEA, 2013] Figure 3.8

As to the timelines, the NPP operates from 2015 till 2075, the SNF is cooled at the reactor site during 7 years and then transported to an intermediate storage facility where it is stored during 50 years. After that period, it is transported to the encapsulation facility to be then disposed of in the deep geological repository. The interim storage facilities, encapsulation facilities and repositories are closed/decommissioned around 2130. As similar timeline applies for the reprocessing cycle, whereby the reprocessing of UOX, high level waste vitrification and MOX fabrication run along the same timeline as the reactor operation.⁹⁷ Note that back-end fuel-cycle facilities are to be constructed, which investment costs (besides the obvious operation costs during operation) are accounted for.

The following values have been assumed:

⁹⁶ Which is freely available at the internet – see References.

⁹⁷ See Figures 3.4, 3.7, 3.9 of [NEA, 2013].

- Enrichment fresh UOX is 4.95% / REPUOX has an additional enrichment of 0.15% to account for the neutron-absorbing ^{236}U ;⁹⁸
- The fuel burn up of both UOX and MOX are 60 $\text{GWD}_{\text{th}}/\text{ton}_{\text{HM}}$;
- The conversion efficiency of the LWR reactor is 34%.

The other relevant parameters can be found in [NEA, 2013].

5.1.4 Front-End Cost Elements

The front end encompasses the raw uranium (yellow cake) U_3O_8 , conversion, enrichment, and fuel fabrication.

Figure 5.5 illustrates the evolution of the front-end costs for raw uranium and enrichment.

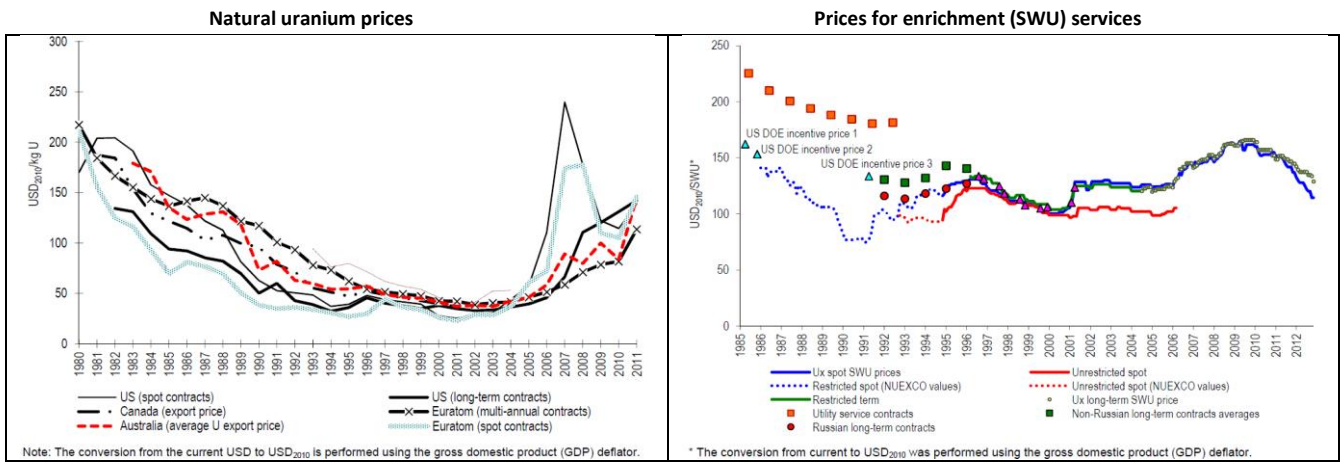


Figure 5.5: (Left panel) Evolution of the natural uranium prices during the period 1980-2011; (Right panel) Evolution of prices for enrichment (SWU) services during the period 1985-2012. Reference: [NEA, 2013] Figs 3.2 & 3.3.

Based on these historical values, the following parameters have been chosen for the reference case (Figure 5.6).

Front End Assumptions			UOX Costs	
	Value	Unit		
Natural uranium cost	130	USD per kgU	[UOX fuel weight] = $(1 - X_{\text{MOX}})/(\eta \cdot \text{BU} \cdot 24/1000)$, tU/TWh	
Conversion cost	9	USD per kgU	X_{MOX} – fraction of MOX fuel,	
Enrichment cost	140	USD per SWU	BU – average LWR fuel burn-up, GWD/tHM	
Fuel fabrication cost for UOX and REPUOX	300	USD per kgU	η – average NPP thermal conversion efficiency	
Fuel enrichment (fresh UOX)	4.95%	Percent	[Natural uranium weight] = $(e_{\text{fuel}} - e_{\text{tail}})/(e_{\text{nat}} - e_{\text{tail}}) \cdot [\text{UOX fuel weight} - \text{REPUOX fuel weight}]$, tU/TWh	
Additional enrichment for the REPUOX fuel ⁴⁵	0.15%	Percent	e – enrichment,	
Enrichment tailings	0.25%	Percent	[Cost U _{nat}] = $\text{Cost}_{\text{U308}} \cdot [\text{natural uranium weight}]$, USD/TWh	
U-235 content in the spent fuel	1.00%	Percent	[Cost conversion] = $\text{Cost}_{\text{conversion}} \cdot [\text{natural uranium weight}]$, USD/TWh	
			[Cost enrichment from natural uranium] = $N_{\text{SWU}} \cdot \text{Cost}_{\text{SWU}} \cdot [\text{fresh UOX fuel weight}]$, USD/TWh	
			where $N_{\text{SWU}} = V(e_{\text{fuel}}) - V(e_{\text{nat}}) + (e_{\text{fuel}} - e_{\text{nat}})/(e_{\text{nat}} - e_{\text{tail}}) \cdot (V(e_{\text{tail}}) - V(e_{\text{nat}}))$, SWU/kg _{fuel}	
			and $V(z) = (2z - 1) \cdot \log(z/(1 - z))$	
			[Cost enrichment from reprocessed uranium] = $N_{\text{SWU}} \cdot \text{Cost}_{\text{SWU}} \cdot [\text{REPUOX fuel weight}]$, USD/TWh	
			$N_{\text{SWU}} = V(e_{\text{fuel}}) - V(e_{\text{REPU}}) + (e_{\text{fuel}} - e_{\text{REPU}})/(e_{\text{REPU}} - e_{\text{tail}}) \cdot (V(e_{\text{tail}}) - V(e_{\text{REPU}}))$, SWU/kg _{fuel}	
			[Cost fuel fabrication] = $C_{\text{fuel fabrication}} \cdot [\text{UOX and REPUOX fuel weight}]$, USD/TWh	

Figure 5.6: (Left panel) Assumptions for the front-end of the fuel cycle; (Right panel) Calculation guidelines for front-end computations. Reference: [NEA, 2013] Tables 3.1 & 3.2.

⁹⁸ We assume that %-pts are meant, which would lead to an enrichment for REPUOX of 5.1%; but there is a discrepancy with Table 3.6 of [NEA, 2013] which gives 5.00% as enrichment for the reference case of REPUOX. Table 3.1 of [NEA, 2013], on the other hand, mentions the additional 0.15%.

5.1.5 Back-End Cost Elements

The back-end cost elements include the interim storage facilities, construction of reprocessing facilities, SNF encapsulation and final disposal.

[NEA, 2013] provides cost figures (as a function of the *Capacity* expressed in *ton_{HM}* or *ton_{HM} per year*) for the overnight investment cost and O&M costs for a typical Interim Storage Facility, an Integrated Reprocessing Plant, an SNF Encapsulation Plant, and a Geological Repository. Furthermore, closure costs for the Geological Repository are estimated as well as the transport costs for the whole back-end chain.

Figure 5.7 gives an example for the Integrated Reprocessing Plant (which incorporates a reprocessing plant using aqueous technology, a MOX fabrication plant and a FP/MA vitrification plant).

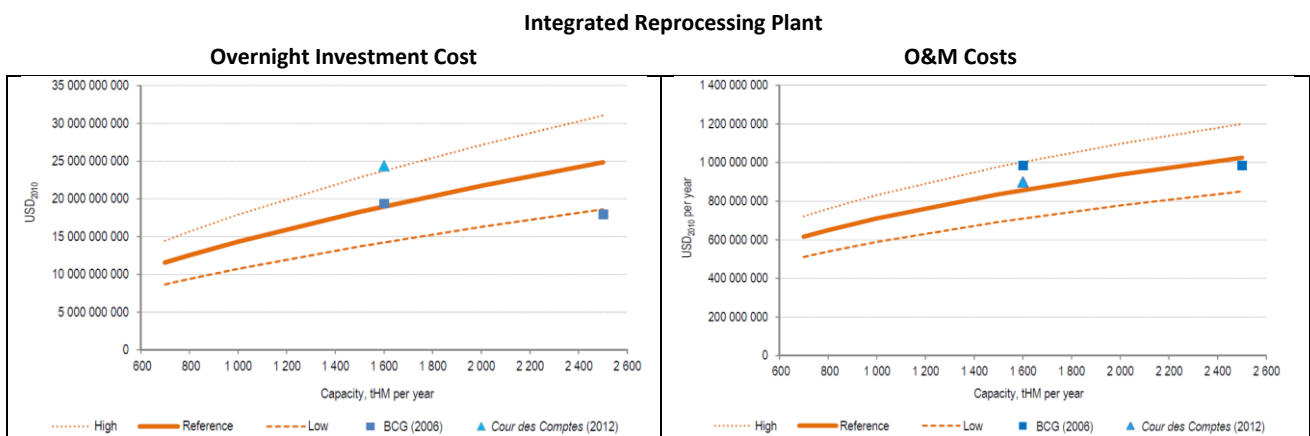


Figure 5.7: (Left panel) Overnight Investment Cost as a function of the annual processing capacity for an Integrated Reprocessing Plant (Right panel) O&M Cost as a function of the annual processing capacity for an Integrated Reprocessing Plant. Reference: [NEA, 2013] Figures 3.14 & 3.15.

The analysis in [NEA, 2013] has been performed for nuclear generation systems of **25, 75, 400 and 800 TWh per annum**. This compares as follows to the nuclear generation of the following countries:

- USA → 821 TWh/a in 2011,⁹⁹
- France → 421 TWh/a in 2011,¹⁰⁰
- UK → 70 TWh/a in 2012,¹⁰¹
- Sweden → 63.5 TWh/a in 2012,¹⁰²
- Belgium → 40.3 TWh/a in 2012,¹⁰³
- Switzerland → 25.4 TWh/a in 2012.¹⁰⁴

The levelized cost was mostly computed using **real discount rates of 0% and 3%**; low discount rates being preferred for long-term public benefits projects. However, a sensitivity analysis for a range of values 0% to 10% was undertaken and the results for 7% are also explicitly presented in an Annex of [NEA, 2013]. As mentioned before, the cash flows have been discounted to the reference year 2020, but are usually

⁹⁹ www.world-nuclear.org/info/Country-Profiles/Countries-T-Z/USA--Nuclear-Power/

¹⁰⁰ www.world-nuclear.org/info/Country-Profiles/Countries-A-F/France/

¹⁰¹ www.world-nuclear.org/info/Country-Profiles/Countries-T-Z/United-Kingdom/

¹⁰² www.world-nuclear.org/info/Country-Profiles/Countries-O-S/Sweden/

¹⁰³ www.world-nuclear.org/info/Country-Profiles/Countries-A-F/Belgium/ - note that in "normal" years nuclear generation is about 50-55 TWh/a. 2011 and 2012 were low-nuclear years because of the temporary (but long) shut down of the units Doel 3 and Tihange 2 because of the so-called "hydrogen-flakes" issue.

¹⁰⁴ www.world-nuclear.org/info/Country-Profiles/Countries-O-S/Switzerland/

expressed in USD₂₀₁₀. Decommissioning of the back-end facilities assumes 15% of the overnight investment cost (to be available at the time of decommissioning).

Three types of cost cases were considered: a **reference** case, a **low-cost** case and a **high-cost** case. For some elements, this spread was defined by the available spread of data, for other, a band of $\pm 25\%$ was taken.

5.1.6 Results for the Different Back-End Strategies Following [NEA, 2013]

5.1.6.1 LCOE of the Fuel-Cycle; Standard Results

Figures 5.8 and 5.9 present the results for the LCOE contribution of the full fuel-cycle cost as a function of the annual nuclear electricity system size; they are plotted for the two standard discount rates used in [NEA, 2013], 0% and 3%, respectively.

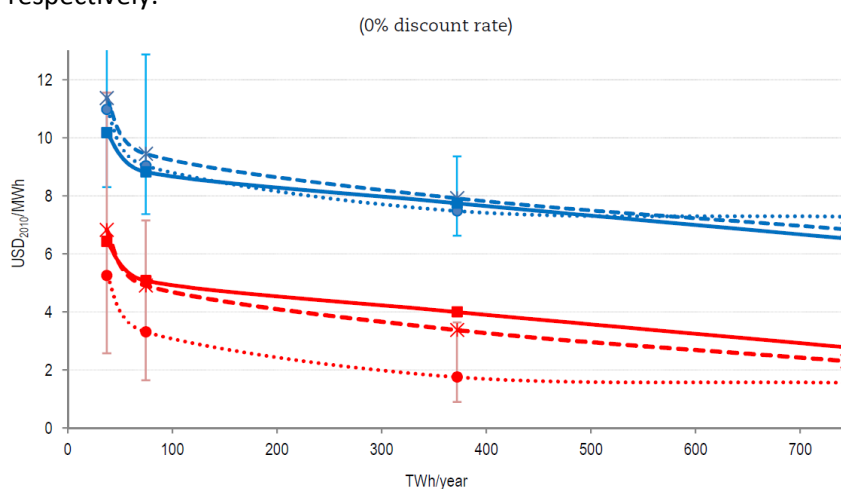


Figure 5.8 LCOE of the fuel cycle for different nuclear system sizes and back-end strategies; 0% discount rate. Ref: [NEA, 2013], Figure 3.22

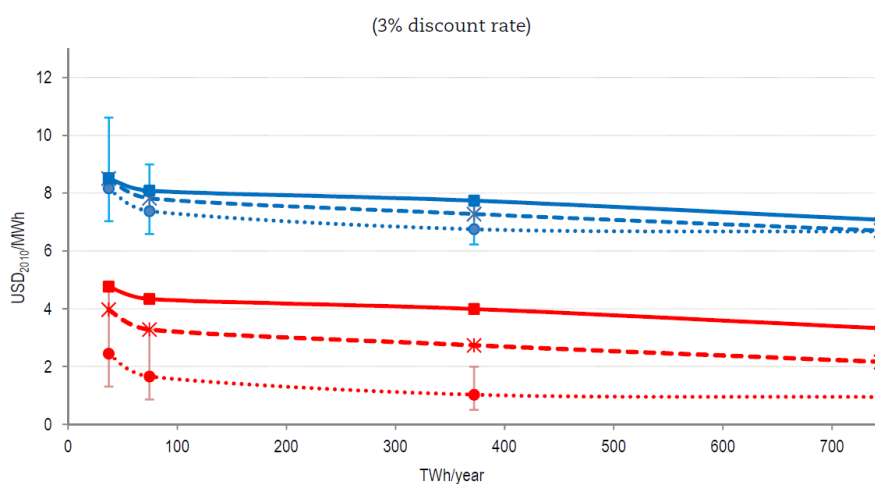
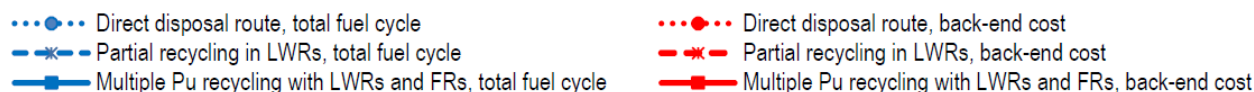


Figure 5.9 LCOE of the fuel cycle for different nuclear system sizes and back-end strategies; 3% discount rate. Ref: [NEA, 2013], Figure 3.23

For both Figures 5.8 and 5.9 the blue curves are for the full fuel cycle, i.e., back-end and front-end costs, whereas the red curves applies to the back-end costs. For both, the following legend applies.



In addition, four comments are in order:

- The marks on the curves represent the “reference” scenario and the error bars correspond to the “low” and “high” cases;
- The error bars have only been indicated for the direct disposal scenario, but they have also been computed (and are shown on the stacking diagrams in [NEA, 2013] and also below in Figures 5.11 and 5.12);
- The marks were actually plotted for slightly different values than the sizes 25, 75, 400 and 800 TWh/a, but the LCOE for these rounded system sizes can be read from the figure, and they have been given (with considerable breakdown of the numbers) in Table 3.5 of [NEA, 2013];
- For our objectives in this study, only the dotted and dashed results are of importance. The solid lines are of less interest here.

We insist in also showing the results for the discount rate of 7%, because these results are meaningful for our LCOE computations with discount rates of 5% and 10%.¹⁰⁵ This case is shown in Figure 5.10.

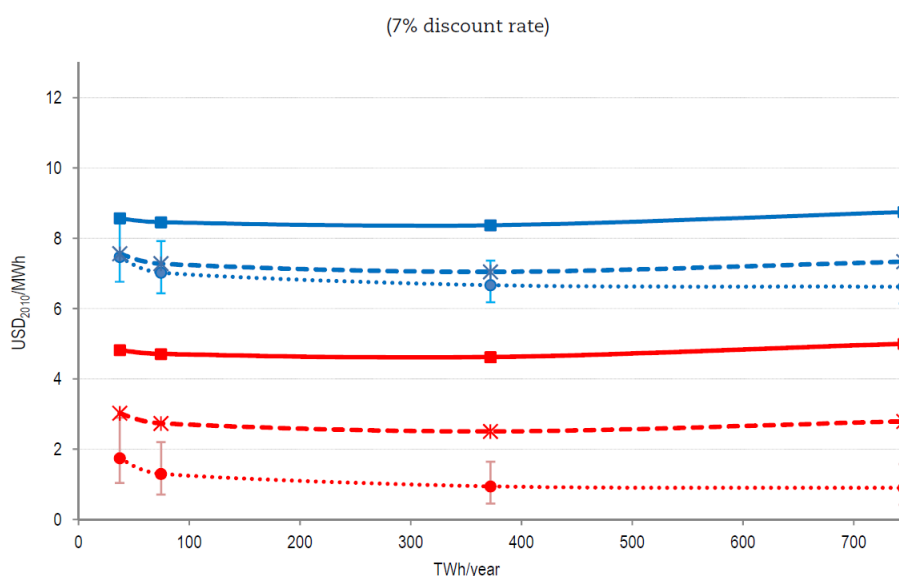


Figure 5.10 LCOE of the fuel cycle for different nuclear system sizes and back-end strategies; 7% discount rate. Ref: [NEA, 2013], Figure A5.1

The detailed results in [NEA, 2013] make clear that part of the extra costs of the cycle with reprocessing is “paid back” by the savings in fresh fuel requirements. [NEA, 2013] also provides an interesting set of stack diagrams with the different cost components. These stack diagrams also illustrate the savings in fresh fuel when opting for reprocessing. As an example, we show here a comparison of the three scenarios for a system size of 75 TWh/a in Figures 5.11 and 5.12. The error bars represent the low-cost and high-cost cases.

¹⁰⁵ The results for 7% are shown in Appendix 5 of [NEA, 2013].

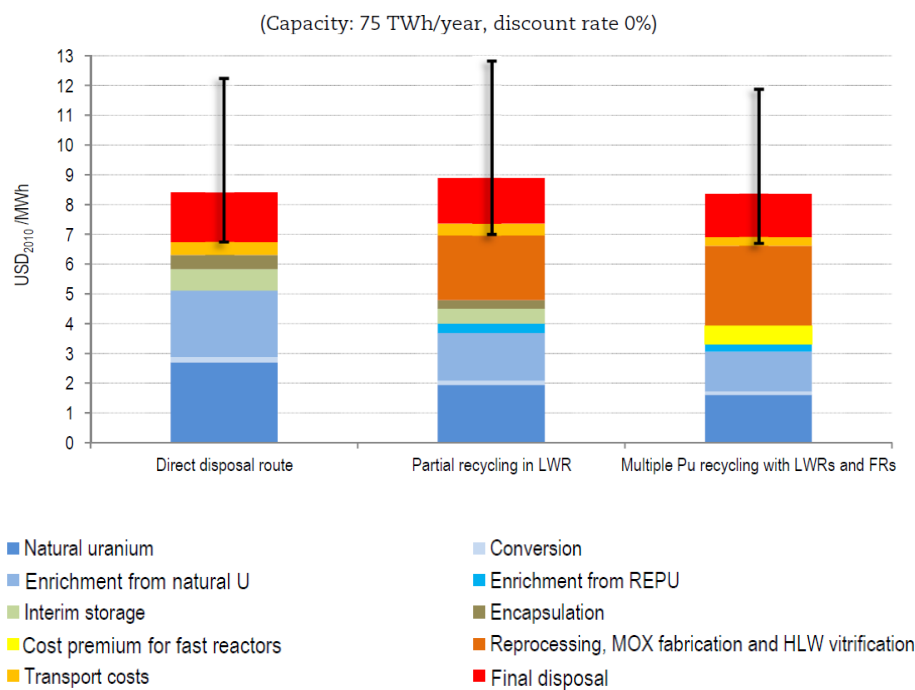


Figure 5.11 LCOE breakdown of the fuel cycle for 75 TWh/a and different back-end strategies; 0% discount rate. Ref: [NEA, 2013], Fig 3.24

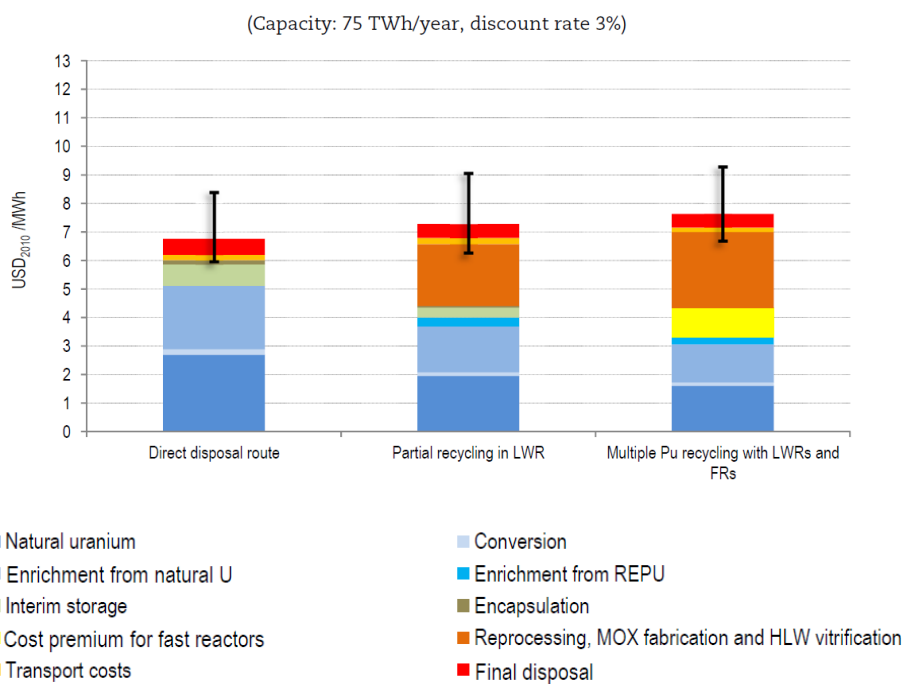


Figure 5.12 LCOE breakdown of the fuel cycle for 75 TWh/a and different back-end strategies; 3% discount rate. Ref: [NEA, 2013], Fig 3.24

This leads to the following **conclusions for the order of magnitude of the LCOA fuel-cycle cost**:

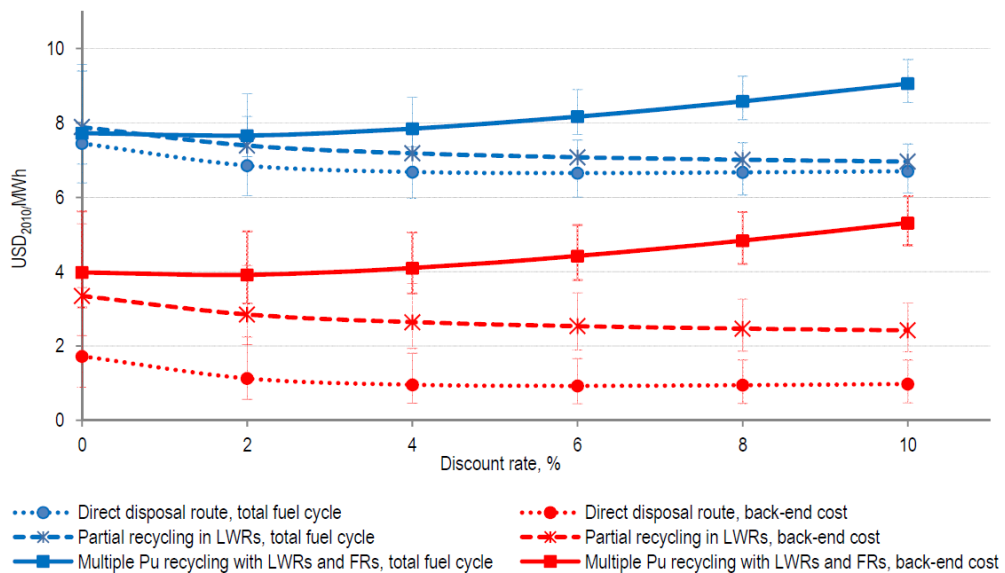
- The **total fuel-cycle cost of the “once-through cycle” (direct SNF disposal)** is roughly equal to the **cost of the single reprocessing cycle!**
- The **extra cost for reprocessing is gained back in the primary fuel supply**
- The cost for **final disposal** is very **small** in all cases and scenarios
- **Overall cost** is (as order of magnitude) about **~ 7-9 \$₂₀₁₀/MWh**.¹⁰⁶

5.1.6.2 Dependence of the LCOE of the Fuel Cycle on Various Parameters

The NEA study on the back-end cost [NEA, 2013] considers a variety of sensitivities. The reader is invited to explore the tornado diagrams presented in Figure 3.27 of [NEA, 2013]. Although the other sensitivities are certainly worth understanding, three types of dependencies are of particular interest for our purposes: the dependence on the discount rate, the dependence on the fresh UOX cost and the dependence on possible time delays for SNF back-end implementation.

a. Dependence on the Discount Rate

Although the title of this section refers to the “dependence” on the discount rate, it actually seems that the order of magnitude for the fuel cost is by and large rather insensitive to the discount rate! This is shown in Figure 5.13. Recall that the dotted and dashed curves are most relevant for our purposes.



Note: The central values represent the results from the reference cost scenario, and the error bars correspond to the low and high cost scenarios.

Figure 5.13: Dependence of the fuel-cycle cost on the discount rate for a nuclear electricity system of 400 TWh/a. Ref. [NEA, 2013], Fig. 3.28

¹⁰⁶ With somewhat higher values for small system sizes and 0% discount rate. Note that [NEA, 2013] suggests that back-end strategies for small systems are perhaps best “grouped together”, so as to reduce the overall costs.

b. Dependence on the Fresh UOX Cost

The pie chart of Figure 5.14 shows the different cost components to arrive at a fresh UOX fuel load (i.e., assembly), with the parameters chosen as given in Figure 5.6

Cost of UOX in reference case (USD₂₀₁₀ per kg of UOX)

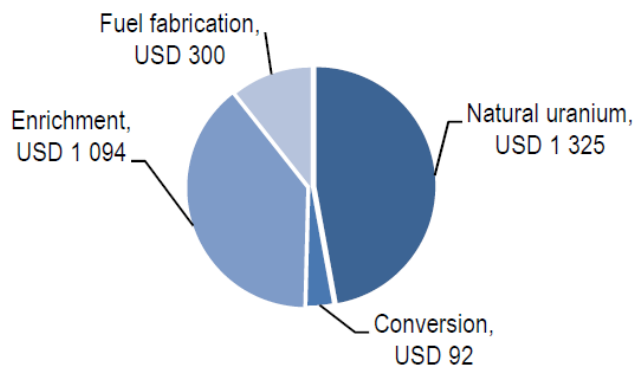


Figure 5.14: Cost breakdown of a fresh UOX fuel assembly. Reference: [NEA, 2013] underneath Table 3.6

The sum of the cost components of Figure 5.14 equals 2811 USD₂₀₁₀ per kg of UOX, which is also the reference case shown in Figure 5.15.

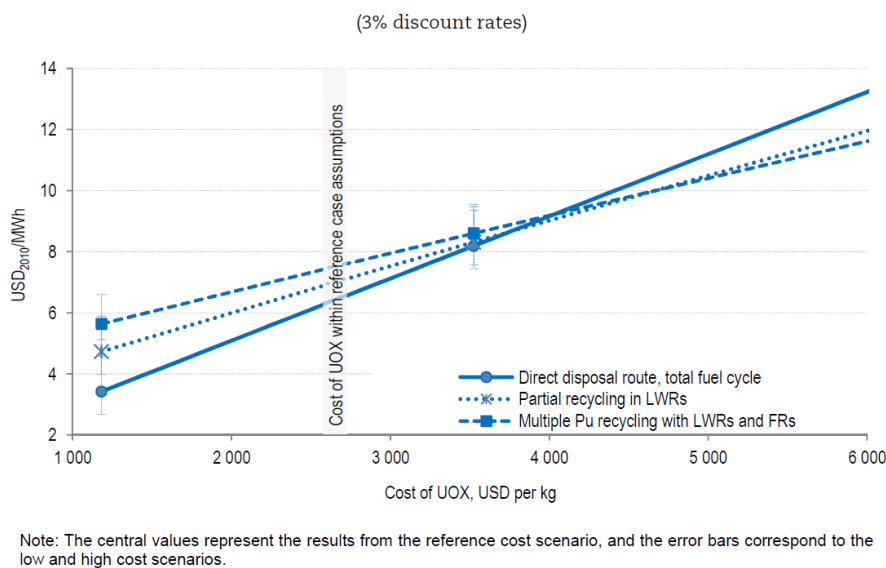


Figure 5.15: Dependence of fuel cycle cost on UOX cost for different strategies (system of 400 TWh/a). Ref. [NEA, 2013] Fig. 3.31

Figure 5.15 shows that the cost of the total fuel cycle is reasonably independent on the UOX cost (note that in this picture the solid and dotted lines are the relevant ones for our purposes). The difference for 0% discount rate is even smaller (see [NEA, 2013], Fig. 3.31 upper panel).

Concerning these fresh fuel dependencies, it should be stressed that Figure 5.15 shows the dependence on the cost of fuel assemblies and not on the raw material U₃O₈ (yellow cake). Note that the natural uranium

contribution mentioned in Figure 5.6 was 130 USD₂₀₁₀ per kg U; in Figure 5.14 above, the natural uranium cost is 1325 USD₂₀₁₀ per kg UOX (i.e., the fuel assembly). From the several bar charts shown in [NEA, 2013] for the different scenarios, sizes and discount rates, one can discern the following:

- ➔ Fraction of natural uranium cost of fuel-cycle LCOE cost part:
~ 15 – 50% depending on case

At the outset of Section 5.1, we stated that the

- ➔ fraction of fuel-cycle cost of the total LCOE:
~ 7 – 16% depending on the discount rates

Hence, as an **order of magnitude**, we conclude that¹⁰⁷

- ➔ LCOE fraction of natural uranium ~ 1% to 8% depending on the cases at hand.

c. Dependence on the Time Schedule for Implementation

Figure 5.16 illustrates the cost impact of delayed decision to implement a back-end strategy (for the case of direct SNF disposal and a 400 TWh/a nuclear generation system). Each time the difference in the $LCOE_{\text{back-end}}$ between a timely implementation and delays by 20 and 50 years are shown. Not unexpectedly, delayed decisions are penalized for 0% discount rates, whereas there are some small cost savings for delayed decisions when applying finite discount rates.

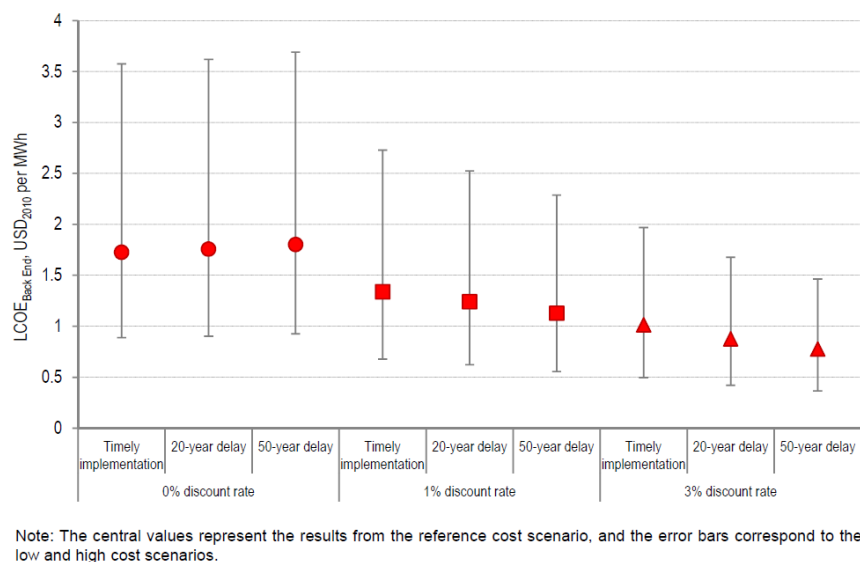


Figure 5.16: Impact of delays of implementation for SNF disposal for 0%, 1% and 3% disc rates (400 TWh/a system). Ref. [NEA, 2013], Fig 3.35

¹⁰⁷ It turns out that the low boundaries are both for the lowest discount rates, and vice versa for the high boundaries and the high discount rates.

Taking the value of timely implementation at 3%/a as a focal point, being about 1 USD₂₀₁₀/MWh, it is clear that the differences are small, and that figures like this should not be “abused” to delay decisions on the back-end implementation.

5.1.7 Comparison with Other Studies

[NEA, 2013] has compared its results with those of other studies on the fuel-cycle costs.¹⁰⁸ The different assumptions of all the studies compared are given in [NEA, 2013]. Figure 5.17 shows the comparison. All numbers are expressed in USD₂₀₁₀/MWh_e and with the following convention:

“X/Y” stands for: “total fuel-cycle (FC) cost / **back-end fuel cycle cost**”

Results	AFCI (2009)	MIT (2011)	NEA (1994)	NEA (2006)	Rothwell (2011)	Harvard (2003)	Results from Section 3.2, reference case, 3% discount rate		
							System size		
							25 TWh/year	400 TWh/year	800 TWh/year
	Total FC/back-end costs								
Once-through, USD ₂₀₁₀ /MWh	6.7/2.7	8.2/1.3	9.4/1.3	5.6/1.7	7.5/1.1	6.5/2.1	8.9/3.2	6.7/1.0	6.8/0.9
Twice-through, USD ₂₀₁₀ /MWh	N/A	9.7/2.8	10.4/2.6	6.4/N/A	12.4/6.7	8.1/3.8	9.2/4.6	7.3/2.7	6.6/2.1
Adv. recycling, USD ₂₀₁₀ /MWh	8.4/6.0	(10.3-11.3)/ (3.3-4.3)	N/A	7.0/N/A	N/A	9.2/4.8	8.9/5.2	7.7/4.0	7.0/3.3
FC cost premium for closed fuel cycle	26%	18-37%	14%	14%-25%	66%	25-42%	20%		

N/A = not applicable.

Figure 5.17: Comparison of results from [NEA, 2013] with those of other studies. Reference: [NEA, 2013] Table 3.10

From the table depicted in Figure 5.17, it follows that the order of magnitude obtained by [NEA, 2013] is generally similar to that of the other studies.¹⁰⁹ But as stated in [NEA, 2013], the results are sensitive to the size of the magnitude of the nuclear generation system, the discount rates assumed and the chosen input data of the different studies.

¹⁰⁸ Some of the references given at the beginning of Section 5.1 apply; for the other references, the reader should consult the reference list of [NEA, 2013].

¹⁰⁹ Section 3.2 of that report – here in Figure 5.17 shown in the upper right corner of the figure.

In conclusion, we take as generic figure:¹¹⁰

Fuel-cycle cost ~ 8 / 2 \$₂₀₁₀ per MWh_e

Or, with 1 \$₂₀₁₀ = 0.754 €₂₀₁₀ and €₂₀₁₀ = 1.02 €₂₀₁₂ (adapted from the nuclear S curve for Europe), we obtain:

Fuel-cycle cost ~ 6.15 / 1.55 €₂₀₁₂ per MWh_e

So, finally, as a rounded figure:

➔ **Generic order of magnitude fuel-cycle cost ~ 6 / 1.5 €₂₀₁₂ per MWh_e or**

- **Full fuel-cycle cost ~ 6 €₂₀₁₂ per MWh_e**
- **Front-end fuel-cycle cost ~ 4.5 €₂₀₁₂ per MWh_e**
- **Back-end fuel-cycle cost ~ 1.5 €₂₀₁₂ per MWh_e**

The full fuel-cycle cost indicated in blue is the one we retain for our LCOE computations:

Full fuel-cycle cost ~ 6 €₂₀₁₂ per MWh_e (± 0.75 €₂₀₁₂ per MWh_e)¹¹¹

¹¹⁰ This is compatible with our 7-9 USD₂₀₁₀/MWh range taken in Section 5.1.6.1.

¹¹¹ The range ± 0.75 arises from our earlier range 7 - 9 USD₂₀₁₀ in Section 5.16.1 and the conversion to €₂₀₁₂.

5.2 Operation and Maintenance (O&M)

First is must be specified that in our context, O&M costs *do not include fuel costs*.¹¹²

Similarly to our considerations on the fuel cycle, we will be guided by the O&M numbers of the 2010 update of the NEA/IEA “Projected Costs of Electricity Generation Electricity” study, [NEA/IEA, 2010]. Figure 5.18 below copies Table 3.7a of that study, with now the arrow pointing to the “O&M costs”.



Country	Technology	Net capacity	Overnight costs ¹	Investment costs ²		Decommissioning costs		Fuel Cycle costs	O&M costs ³	LCOE	
				5%	10%	5%	10%			5%	10%
				MWe	USD/kWe	USD/kWe	USD/MWh			USD/MWh	USD/MWh
Belgium	EPR-1600	1 600	5 383	6 185	7 117	0.23	0.02	9.33	7.20	61.06	109.14
Czech Rep.	PWR	1 150	5 858	6 392	6 971	0.22	0.02	9.33	14.74	69.74	115.06
France*	EPR	1 630	3 860	4 483	5 219	0.05	0.005	9.33	16.00	56.42	92.38
Germany	PWR	1 600	4 102	4 599	5 022	0.00	0.00	9.33	8.80	49.97	82.64
Hungary	PWR	1 120	5 198	5 632	6 113	1.77	2.18	8.77	29.79/29.84	81.65	121.62
Japan	ABWR	1 330	3 009	3 430	3 940	0.13	0.01	9.33	16.50	49.71	76.46
Korea	OPR-1000	954	1 876	2 098	2 340	0.09	0.01	7.90	10.42	32.93	48.38
	APR-1400	1 343	1 556	1 751	1 964	0.07	0.01	7.90	8.95	29.05	42.09
Netherlands	PWR	1 650	5 105	5 709	6 383	0.20	0.02	9.33	13.71	62.76	105.06
Slovak Rep.	VVER 440/ V213	954	4 261	4 874	5 580	0.16	0.02	9.33	19.35/16.89	62.59	97.92
Switzerland	PWR	1 600	5 863	6 988	8 334	0.29	0.03	9.33	19.84	78.24	136.50
	PWR	1 530	4 043	4 758	5 612	0.16	0.01	9.33	15.40	57.83	96.84
United States	Advanced Gen III+	1 350	3 382	3 814	4 296	0.13	0.01	9.33	12.87	48.73	77.39
NON-OECD MEMBERS											
Brazil	PWR	1 405	3 798	4 703	5 813	0.84	0.84	11.64	15.54	65.29	105.29
China	CPR-1000	1 000	1 763	1 946	2 145	0.08	0.01	9.33	7.10	29.99	44.00
	CPR-1000	1 000	1 748	1 931	2 128	0.08	0.01	9.33	7.04	29.82	43.72
	AP-1000	1 250	2 302	2 542	2 802	0.10	0.01	9.33	9.28	36.31	54.61
Russia	VVER-1150	1 070	2 933	3 238	3 574	0.00	0.00	4.00	16.74/16.94	43.49	68.15
INDUSTRY CONTRIBUTION											
EPRI	APWR, ABWR	1 400	2 970	3 319	3 714	0.12	0.01	9.33	15.80	48.23	72.87
Eurelectric	EPR-1600	1 600	4 724	5 575	6 592	0.19	0.02	9.33	11.80	59.93	105.84

*The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific

*The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

³ In cases where two numbers are listed for O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

Figure 5.18: Nuclear power plants; Levelized costs of electricity in US dollars per MWh – from [NEA/IEA, 2010], Table 3.7a

As is evident from the column indicated in Figure 5.1, there is really no structure in the displayed O&M costs. All one can say is that the order of magnitude of the O&M costs is roughly situated between **10 and 20 USD₂₀₀₈/MWh_e** (with outliers down to 7 and as high as 20 and even 30).

The reason for this discrepancy can be traced back to the inputs given by the country representatives in the study [NEA/IEA, 2010], and the fact that different conventions are used in different countries. In fact, O&M costs are usually split in two parts: a fixed part (\$ or € per kW/a) and a variable part (\$ or € per MWh), and it is not always very clear what is actually included. Sometimes, the fuel cost may be part of variable O&M (often in UK figures), the fixed part may contain large investments (for refurbishments), and [MIT, 2009] & [Du, 2009] use “fixed”, “variable” and “incremental capital cost” (this last one expressed in \$ per kW/a). It is unclear from the context, but we assume that this “incremental capital cost” concerns continuous refurbishment investments.

¹¹² Note that it is often the case in UK reports that O&M costs include the fuel costs.

For our purposes, we again need a generic number that reflects the appropriate order of magnitude. We take

➔ **Generic figure ~ 15 \$₂₀₀₈ per MWh (\pm 5 \$₂₀₀₈ per MWh)**

Or, with 1 \$₂₀₀₈ = 0.68 €₂₀₀₈ ,and, €₂₀₀₈ \approx €₂₀₁₂ (adapted from the nuclear S curve for Europe) we obtain:

➔ Total O&M cost ~ 10.2 €₂₀₁₂ per MWh_e or

➔ **Generic order of magnitude O&M cost ~ 10 €₂₀₁₂ per MWh_e (\pm 3.5 €₂₀₁₂ per MWh_e)**

Chapter 6

Results for the LCOE of Nuclear Electricity Generation

Contents of Chapter 6

- 6.1 Results for Nuclear New Build
 - 6.1.1 Summary of Input Parameters
 - 6.1.2 Summary of Results for LCOE
 - 6.1.3 LCOE Sensitivity for New Build
- 6.2 Results for LCOE after LTO Investments
 - 6.2.1 Illustrative Results from [NEA, 2012c]
 - 6.2.2 Summary of Input Parameters for Own LCOE Computations
 - 6.2.3 Summary of Results of LCOE for LTO

Based on the formulae for the LCOE given in Chapter 2, and the different cost components, being investment cost (including decommissioning), fuel-cycle cost, and O&M cost, we can compute the levelized costs for nuclear electricity generation. We stress again that the results are orders of magnitude, within a range, and should not be interpreted as the exact value.

Section 6.1 deal with new build; Section 6.2 give results for major refurbishments and prolonged operation.

6.1 Results for Nuclear New Build

6.1.1 Summary of Input Parameters

We first recall the generic input data:

- Construction period 6 years;
- Load Factor (LF)=85%;
- Operation time, T=60years;
- Decommissioning: 15% of the Overnight Construction Cost (OCC)

To the results of the LCOE for the investment part, we can simply add the LCOE contributions for the fuel cycle and O&M as discussed in Chapter 5. We arrived there to the orders of magnitude:¹¹³

- **LCOE fuel-cycle: 6 €₂₀₁₂ per MWh (± 0.75 €₂₀₁₂ per MWh)**
- **LCOE O&M: 10 €₂₀₁₂ per MWh (± 3.5 €₂₀₁₂ per MWh)**

¹¹³ The estimates for the LCOE contributions for the fuel cycle and O&M are taken to be independent of the discount rate. This assumption is part of the uncertainty margin of the results.

On the investment part, we recall our results for the OCC as arrived at in Chapter 3:

OCC for NOAK₂ (5+) on a brownfield:	3,060... 3,400 ...3,910 € ₂₀₁₂ /kW
OCC for FOAK₂ twin unit on brownfield:	3,128... 3,910 ...5,083 € ₂₀₁₂ /kW
OCC for FOAK₂ single unit on brownfield:	3,400... 4,250 ...5,525 € ₂₀₁₂ /kW

Recall that in our attempt to Europeanize our estimate, we stress the range in black as being most relevant. The fading grey numbers are taken along for completeness, but are less important.

6.1.2 Summary of Results for LCOE¹¹⁴

The LCOE results are each time computed for 5% and 10% annual real discount rates.

NOAK (5+) brownfield generic single/twin – rounded numbers

3,060 €	(ref – 10%)	→ LCOE(5%)= 41€ ₂₀₁₂ /MWh	&	LCOE(10%)= 69€ ₂₀₁₂ /MWh
3,400 €	(ref)	→ LCOE(5%)= 43€₂₀₁₂/MWh	&	LCOE(10%)= 75€₂₀₁₂/MWh
3,910 €	(ref + 15%)	→ LCOE(5%)= 48€ ₂₀₁₂ /MWh	&	LCOE(10%)= 84€ ₂₀₁₂ /MWh

FOAK₂ brownfield twin – rounded numbers

3,128 €	(ref – 20%)	→ LCOE(5%)= 41€ ₂₀₁₂ /MWh	&	LCOE(10%)= 70€ ₂₀₁₂ /MWh
3,910 €	(ref)	→ LCOE(5%)= 48€₂₀₁₂/MWh	&	LCOE(10%)= 84€₂₀₁₂/MWh
5,083 €	(ref + 30%)	→ LCOE(5%)= 57€ ₂₀₁₂ /MWh	&	LCOE(10%)= 104€ ₂₀₁₂ /MWh

FOAK₂ brownfield single – rounded numbers

3,400 €	(ref – 20%)	→ LCOE(5%)= 43€ ₂₀₁₂ /MWh	&	LCOE(10%)= 75€ ₂₀₁₂ /MWh
4,250 €	(ref)	→ LCOE(5%)= 50€₂₀₁₂/MWh	&	LCOE(10%)= 89€₂₀₁₂/MWh
5,525 €	(ref + 30%)	→ LCOE(5%)= 61€ ₂₀₁₂ /MWh	&	LCOE(10%)= 111€ ₂₀₁₂ /MWh

For each of these LCOE numbers, there is an additional uncertainty of the fuel-cycle cost (± 3.5 €₂₀₁₂ / MWh) and the O&M cost (± 0.75 €₂₀₁₂ / MWh). If we simply combine the uncertainties and round them off, then the above numbers each have an extra **uncertainty of ± 4 €₂₀₁₂ / MWh**.

¹¹⁴ The help of Annelore D'haeseleer for computing these results is greatly acknowledged.

6.1.3 LCOE Sensitivity for New Build

From the above discussions and variety of OCC values (for the different cases and the uncertainty ranges), discount rates (5% and 10%) and the uncertainty to the fuel-cycle cost and O&M costs, the reader should have a good grasp of the dependencies on certain parameters.

We recall that our earlier treatment has shown that decommissioning costs, spent-fuel-disposal costs and longer life-time operation for new build (operation time from 40 years to 60 years) are all effectively **unimportant**. The load factor, in contrast has an important influence.

These dependencies are confirmed by the sensitivity analysis shown in Figure 6.1 for the EPR case discussed by [Hirschberg, 2011, 2012] and mentioned in our last footnote of Chapter 3. The cost is expressed in Swiss rp/kWh with 1 rp being roughly equal to 0.8 c€. The variation of the load factor is noteworthy.

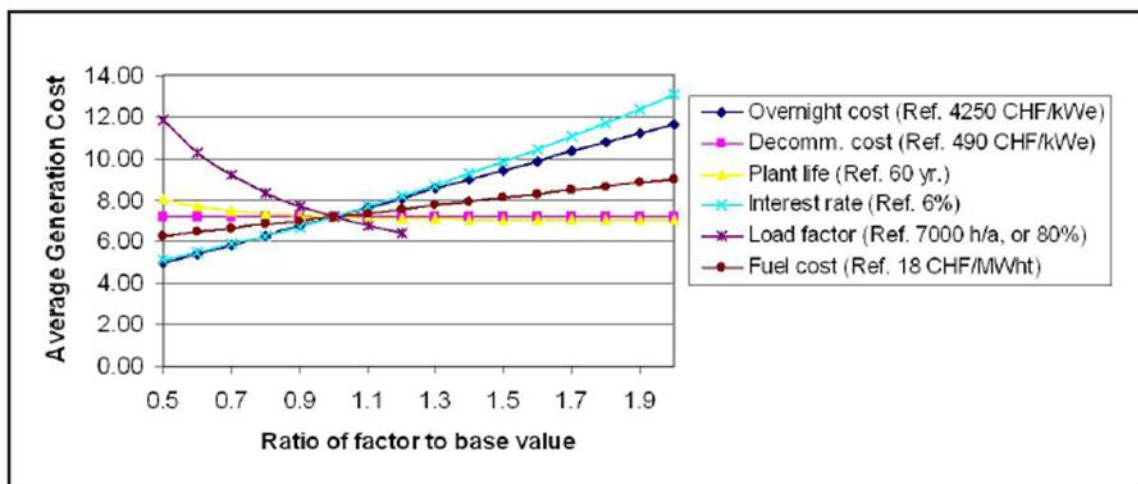


Figure 6.1: Sensitivity on a variety of parameters for a new EPR reactor under Swiss conditions. Reference [Hirschberg, 2011, 2012].

6.2 Results for LCOE after LTO Investments

6.2.1 Illustrative Results from [NEA, 2012c]

Before showing our own results, it is instructive first to have a look at the outcome of the computations performed in the LTO report of NEA, which we discussed in Chapter 4. [NEA, 2012c] Especially the comparison with other generation means (although being a subject that is beyond the scope of the present study) is illuminating.

We show two cases treated in [NEA, 2012c], one for Belgium and one for the USA.

Belgium:

Overnight refurbishment cost = 650 \$₂₀₁₀/kW

Real discount rates of 3% and 8%

Extra operation time 10 or 20 years

Results evaluated in \$₂₀₁₀

Figure 6.2 shows the results for a “low” discount rate of 3%/a. The comparison includes renewable generation (wind).

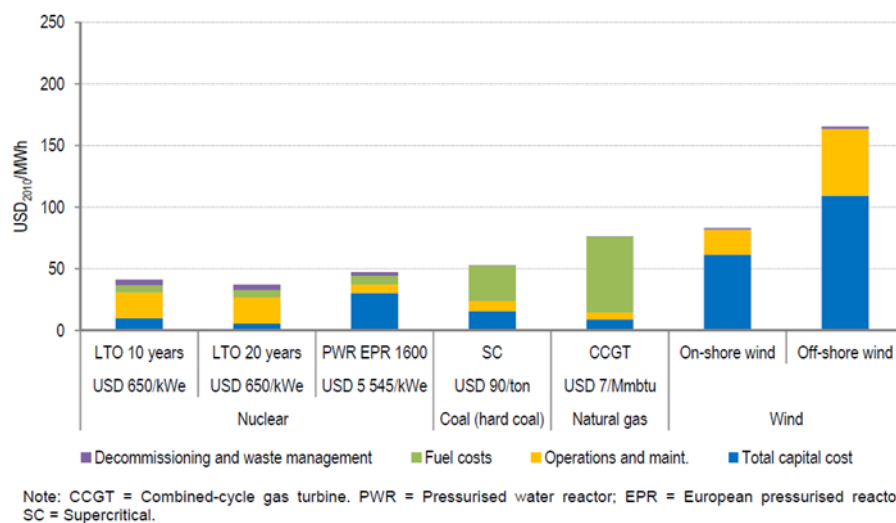


Figure 6.2 LCOE for LTO compared to new build nuclear and other generation means for Belgium. Disc rate of 3%/a. Reference: [NEA, 2012c]

Figure 6.3 shows the results for a “higher” discount rate of 8%/a. The comparison also includes renewable generation.

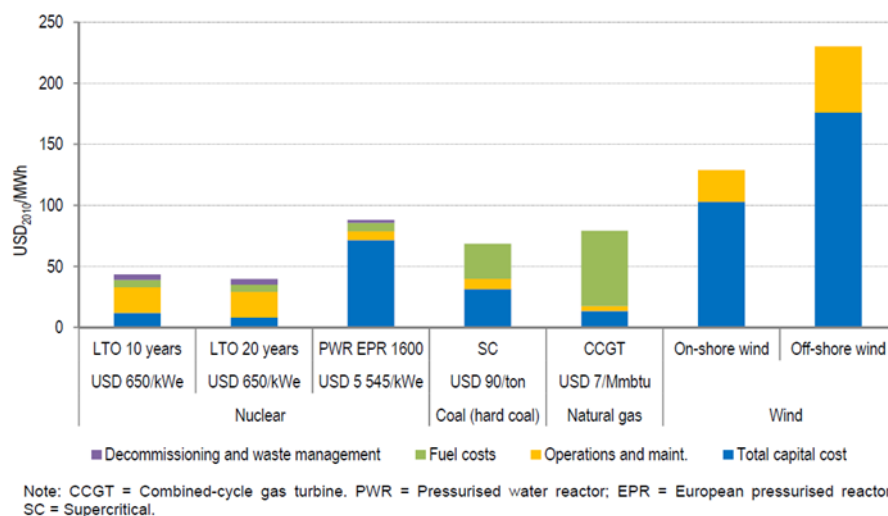


Figure 6.3 LCOE for LTO compared to new build nuclear and other generation means for Belgium. Disc rate of 8%/a. Reference: [NEA, 2012c]

USA:

Overnight refurbishment cost = 750 \$₂₀₁₀/kW and 1,000 \$₂₀₁₀/kW

Real discount rate of 8%

Extra operation time 20 years

Results evaluated in \$₂₀₁₀

Figure 6.4 shows the results for a real discount rate of 8%/a. The comparison does not include renewable generation means, but an interesting comparison with gas-fired electricity generation (with three different gas prices) is considered.

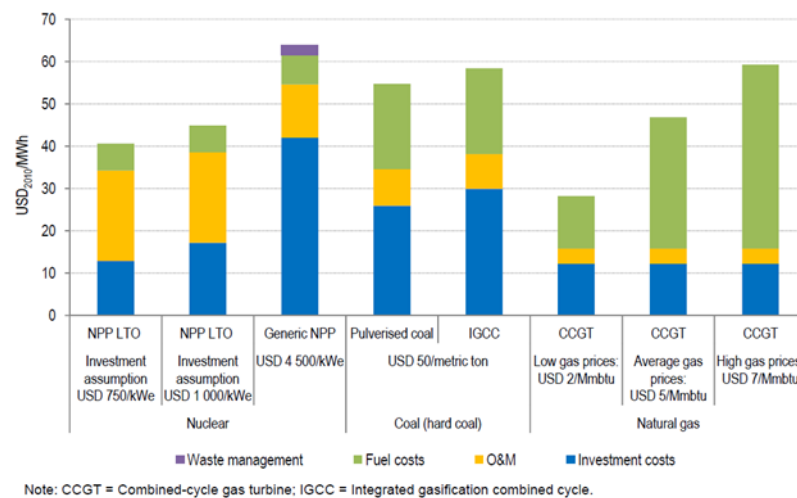


Figure 6.4 LCOE for LTO compared to new build nuclear and other generation means for USA. Disc rate of 8%/a. Reference: [NEA, 2012c]

6.2.2 Summary of Input Parameters for Own LCOE Computations

We again recall the generic input data:

Refurbishment period 2-3 years (with spending 50% or 33.3% per annum, respectively);

Load Factor (LF)=85%;

Extended operation time, T=20years;

Extra cost decommissioning: 15% of the Overnight Refurbishment Cost (ORC)

To the results of the LCOE for the investment part, we again simply add the LCOE contributions for the fuel cycle and O&M as discussed in Chapter 5. Recall the orders of magnitude:¹¹⁵

- **LCOE fuel-cycle: 6 €₂₀₁₂ per MWh (± 0.75 €₂₀₁₂ per MWh)**
- **LCOE O&M: 10 €₂₀₁₂ per MWh (± 3.5 €₂₀₁₂ per MWh)**

On the investment part for refurbishment, we recall our results for the ORC as arrived at in Chapter 4:

specific ORC ~ 400 – 850 €₂₀₁₂/kW

Since the outliers of the ORC cost in [NEA, 201c] were on the high side, we consider the following range:

ORC for extended LTO: 400...**600**...850 €₂₀₁₂/kW (i.e., ref - 33% and ref + 42%)

6.2.3 Summary of Results of LCOE for LTO

The LCOE_{LTO} results are each time computed for 5% and 10% annual real discount rates. Rounded numbers are shown.

ORC = 400 € (ref - 33%)	→ LCOE _{LTO} (5%)= 21€ ₂₀₁₂ /MWh &	LCOE _{LTO} (10%)= 23€ ₂₀₁₂ /MWh
ORC = 600 € (ref)	→ LCOE_{LTO}(5%)= 23€₂₀₁₂/MWh &	LCOE_{LTO}(10%)= 26€₂₀₁₂/MWh
ORC = 850 € (ref + 42%)	→ LCOE _{LTO} (5%)= 26€ ₂₀₁₂ /MWh &	LCOE _{LTO} (10%)= 30€ ₂₀₁₂ /MWh

Recall that for each of these LCOE_{LTO} numbers, there is an additional uncertainty of the fuel-cycle cost (± 3.5 €₂₀₁₂ / MWh) and of the O&M cost (± 0.75 €₂₀₁₂ / MWh). If we simply combine the uncertainties and round them off, then the above numbers each have an extra **uncertainty of ± 4 €₂₀₁₂ / MWh**.

Clearly, the LCOE_{LTO} results are very favorable. Hence the conclusion, if safety can be guaranteed during the extended operational period, then refurbishment investments do make economic sense. Basically with an LCOE of about 25-30 €₂₀₁₂/MWh, an extra 20 years operation looks like a bargain.

¹¹⁵ The estimates for the LCOE contributions for the fuel cycle and O&M are taken to be independent of the discount rate. This assumption is part of the uncertainty margin of the results.

Chapter 7

External Costs / Externalities

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Although in this chapter we consider externalities in a general sense, the focus is mainly on *damage costs due to routine activities*. *Accidents* (which are more characterized by discrete occurrences) and their risk metrics are discussed in Chapter 8. Interesting literature, discussing these issues (and the many references therein) are [Laes, 2006] and [IRGC, 2006]. *System-integration cost effects* are discussed in Chapter 9.

We recall from Chapter 1 the definition of external costs or externalities, as used in EU documents, and supplement it with some other similar definitions:¹¹⁶

[CEU, 2003], p 5:

External costs or externalities, «are costs that arise when the social or economic activities of one group of persons have an impact on another group and when that impact is not fully accounted, or compensated, for by the first group»

[NEA, 2003], p 11:

«External costs, that is, costs that are borne by society as a whole rather than by consumers of a good, product or service, are detrimental to global economic, social and environmental optimization since they prevent market mechanisms from operating efficiently through adequate price signals. Therefore, identifying and quantifying external costs of energy systems are essential in a sustainable development perspective.»

[Laes, 2006], p 175

An externality is “... a service or disservice rendered to persons other than the contracting parties...”

7.1 General Considerations on Sustainability and External Costs

Determining the external costs of an activity only makes sense if one has an idea of the relative magnitudes of external costs of other activities, or the costs society tends to spend to avoid harm, damage or loss of life and/or property. For that reason, we launch into an introductory chapter to put matters into perspective.

The author of this report does not make a moral judgment, but it seems instructive to present some facts and figures to make the readers reflect upon the value of certain types of fatality indicators of a variety of activities. For many activities, our perception and consequent appraisal of the harm or danger is different from the hard-reality numbers.

We do not comment on the numbers but let them speak for themselves. However, in the end, the question is whether the perceived degree of harm, danger and/or “risk” should be the determining factor to perform certain activities and if so, up to which level, and at what point do the authorities have to intervene to protect the people against their own ‘skewed’ value judgment of real dangers. It is clear that these introductory reflections go beyond the possible desirability of, or aversion/antipathy for, nuclear energy as an electricity-generation source.

¹¹⁶ The quoted definitions are in turn obtained from other sources in the literature. For references, see the respective documents.

7.1.1 Sustainable Development

Although numerous definitions of *sustainable development* exist and many interpretations have been given (see e.g., [Laes, 2006]¹¹⁷), it is useful to go back to the original definition in the so-called Brundtland report [Brundtland, 1987] and to recall important elements that are often neglected.

Sustainable Development according to the Brundtland Report “Our Common Future” [Brundtland, 1987]:¹¹⁸

- **[development that] meets the needs of the present without compromising the ability of future generations to meet their own needs;**
- **but sustainable development requires meeting the basic needs of *all* and extending to *all* the opportunity to fulfill their aspirations for a better life.**

On the first point, the report reads: «The concept of sustainable development does imply limits—not absolute limits but limitations imposed by the present state of technology and social organization on environmental resources and by the ability of the biosphere to absorb the effects of human activities. *But technology and social organization can both be managed and improved to make way for a new era of economic growth.*»¹¹⁹

On the second point, the report makes clear that poverty eradication is as much part of sustainable development as the environmental part (see also p. ix of [Brundtland, 1987]). Even stronger, «A world in which poverty is endemic will always be prone to ecological and other catastrophes.» (p. 8)

One could say that the first point addresses sustainability in time, i.e., intergenerational sustainability, whereas the second point emphasizes the importance of sustainability in space; i.e., more north-south equity and poverty.

Similar concerns on poverty and equity in the context of sustainable development were made by the EU “European Group on Ethics in Science and New Technologies” (EGE) in their recent opinion nr 27 (of January 16, 2013) entitled: “An ethical framework for assessing research, production and use of energy”.¹²⁰ [EGE, 2013] Likewise, the same idea is behind the Trilemma project of the World Energy Council.¹²¹

7.1.2 Cost-Benefit Analysis

Determination of the external cost is important in the framework of performing a **cost-benefit analysis** (CBA) of the different alternatives for electricity provision. Sometimes CBA is criticized as being too rational and mechanistic, but since CBA was actually developed as a subject to be a practical guide to social decision making, it is important to stress that it is based on a comprehensive theory, whereby all the nuances can be

¹¹⁷ [Laes, 2006] addresses also at length philosophical, social, societal and organizational issues.

¹¹⁸ Page 8 of [Brundtland, 1987]; the italics emphasis for the word “*all*” is by the author of this report.

¹¹⁹ Our italics

¹²⁰ The EGE is a team supporting the Bureau of European Policy Advisors (BEPA). See: http://ec.europa.eu/bepa/european-group-ethics/welcome/index_en.htm and http://ec.europa.eu/bepa/european-group-ethics/docs/publications/opinion_no_27.pdf

¹²¹ See <http://www.worldenergy.org/publications/2013/world-energy-trilemma-2013>; also reports on the previous years are available at that site.

taken into account. As an example, some social preferences can be reflected by assigning appropriate weighting coefficients for benefits and costs.^{122 123}

As explained by [Brent, 1996], so-called social CBA «relates to *any* public decision that has an implication for the use of resources.»¹²⁴ «[T]he word “social” in this context does *not* imply the existence of an organismic view of the state, that is, an entity that has preferences different from individual valuations. Rather, the word is used to stress that one is attempting to give full expression to the preferences of all individuals, whether they be rich or poor, or directly or indirectly affected by the project.»

The following point made by [Brent, 1996] is important. «...there is nothing esoteric about the subject matter of CBA. Welfare economics is at the heart of public policy and hence at the core of CBA. *One cannot avoid making judgments when making social decisions. The choice is only whether one makes these judgments explicitly or implicitly. Since there is nothing ‘scientific’ about making value judgments implicitly, and it obscures understanding, all the necessary value judgments will be made explicitly [when using CBA].*»¹²⁵

To some extent, the EU has adopted a sort of CBA philosophy by requiring that important policy decisions are accompanied by an impact assessment.¹²⁶

So, the goal of a CBA for electricity provision entails that one tries to estimate and evaluate the ‘objective’ full social **cost** (incl. health, environmental costs) of electricity generation by different technologies, energy savings, all kinds of transaction costs related to regulation, setting standards etc., and that these are compared with the **benefits** for society, now, for future generations, here and geographically distributed.

The fact that the metric of CBA is a monetary unit stresses the point that economic prosperity is important. Indeed, this is mostly recognized in periods of economic sluggish behavior; it is always the lowest category of the population that suffers (lack of hygienic care, medical care, food quality,...); the developing-world prosperity improves when the world economy thrives, which in turn saves many lives; finally, one should not waste money since one must have the capital available for investment in clean, efficient energy-conversion technologies. In addition, it is important to evaluate the effect of transfers, such as subsidies and taxes.

It is perhaps superfluous to dwell on the fact that life expectancy in a country is strongly dependent on the average GDP per capita of a country, but the results are striking and deserve attention.¹²⁷ The point we wish to make is that money should be spent wisely; with the same amount of money available, it is important to set the right priorities. Hence, the need for the right indicators on the (sometimes hidden) costs.

¹²² As a matter of fact, we will address a so-called Multi-Criteria Decision Analysis approach, which to some extent reflects a kind of weighing of certain criteria, resulting from expressed preferences in participatory consultations of public, stakeholders and policy makers.

¹²³ The reader may consult some scientific literature on the CBA theory; examples are [Brent, 1996] and [Layard, 1994].

¹²⁴ The italics originate from [Brent, 1996]

¹²⁵ The italic emphasis is by the author of this report.

¹²⁶ See e.g., http://ec.europa.eu/governance/impact/index_en.htm

¹²⁷ See e.g., http://en.wikipedia.org/wiki/Life_expectancy for a first impression

7.1.3 Comparative Examples of Harmful Activities and Cost Spending

7.1.3.1 Loss of Life Expectancy

To be able to properly interpret the harmfulness of certain activities or operations, it is instructive to look at statistical observations that may be counterintuitive, but are nevertheless true. Being confronted with such realities is sobering, and may help to put matters into the right perspective.

In an updated version of earlier work, [Cohen, 2003] has presented an overview of harmful activities, situations or operations, expressed in loss of days of life expectancy.¹²⁸ His results are presented in Figure 7.1.

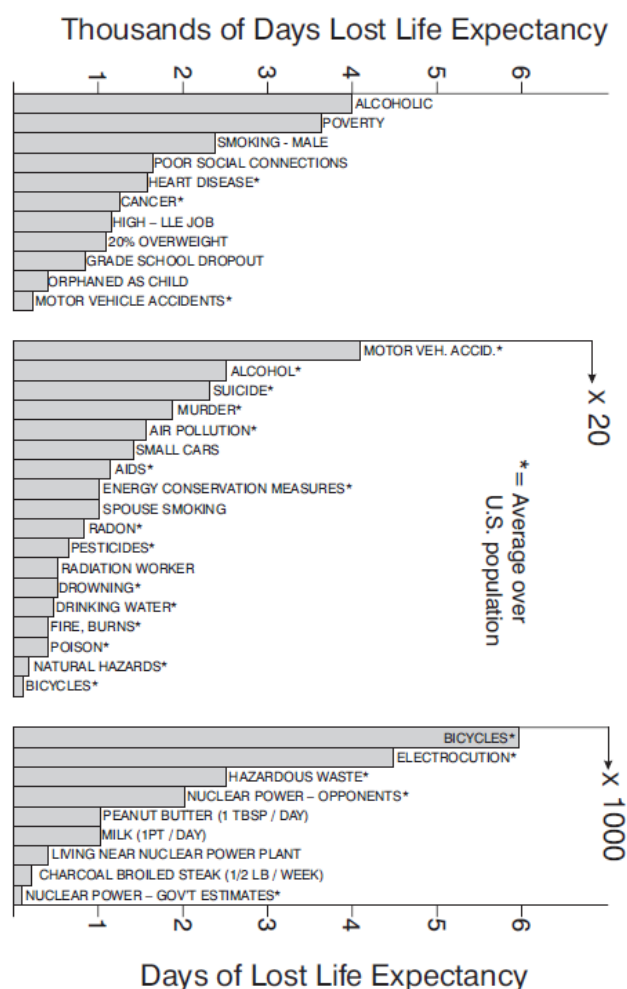


Figure 7.1 A catalog of risks expressed in loss of life expectancy. Reference [Cohen, 2003]. The top axis shows thousands of LLE; it gives the LLE for the top set of bars; the reading of the middle set must be divided by 20; the reading of the bottom set must be divided by 1000. Or alternatively, the bottom set of bars can be read on the bottom axis. As an example, the last bar of the top set (motor vehicle accidents) represents 207 days of LLE. The first bar of the second set reads $4140/20=207$.

¹²⁸ Earlier figures were presented in [Cohen, 1983, 1990]. A detailed treatment is found in [Cohen, 1991]. The following example is due to [Cohen, 1983]. Suppose that statistics indicate that, on average, a 40-year old person is expected to live for another 34.8 years (so that the average life expectancy is 74.8 years) and that that person engages in a risky activity that has a 1% chance of being immediately fatal. Participation in that activity leads to an LLE of 0.01×34.8 or 0.348 years, being 127 days. Note that a loss of life expectancy (LLE) of 0.348 years, or thus 127 days, of a particular individual, does not mean that he will die 127 days earlier as a consequence of that activity/situation/operation. But, if 1000 people his age are exposed to the same "risk", 10 might die immediately, having their life shortened by 34.8 years, while the other 990 would not have their life shortened at all. Hence, the average lost lifetime for the 1000 people would be 0.348 years.

The values are for the USA. Effects labeled with an asterisk (*) have been averaged over the entire US population, those without asterisk refer to the people involved in the activity. According to [Cohen, 2003], the comparison of the several thousands and hundreds of LLE for the top and middle set of bars, with the LLE due to nuclear power, both for US government's and opponents' estimates, is striking. (Even though the difference between both nuclear estimates is also remarkable, differing by a factor of 20.)

Along the same spirit, it is worth reminding the reader that there are particular consequences of activities/situations that lead to vast number of premature victims. Responsible "agents"¹²⁹, that could be called "silent killers", are often insufficiently recognized by both population and policy makers. According to the World Health Organization, *every year*, about 1.2 million people worldwide die prematurely due to air pollution.¹³⁰ The report of 2009, refers to mortality numbers of 2004. Even for Europe, the numbers are daunting: A total of 225,000 people die prematurely due to "urban outdoor air pollution" in Europe, with 76,000 per year in the high-income countries and 149,000 in low- to middle-income countries. (See Table A3 – part 1, p 51 of the WHO report). Table A4 of that same report gives the amount of "Disability-Adjusted loss of Life Years" (DALY), being almost 1.5 million for Europe alone.¹³¹ This air pollution is mainly due to road transport, coal- or lignite-based electricity generation, fossil-fuel heating and heavy industry.

Another "silent killer" is the broad spread of chemical agents. The UN Environment Program (UNEP)'s publication "Global Chemicals Outlook of 2013" reports 964,000 premature deaths worldwide "attributable to chemicals that could be addressed through sound management of chemicals".¹³²

These examples of silent killers due to man-made activities are domains where appropriate priority setting and deliberate "action" can make a substantial difference.

7.1.3.2 Life-Saving Costs

An important point in estimating the external costs related to all kinds of unaccounted for harm or damage, it is interesting to see how much society tends to spend on measures for saving lives.

In his lecture series, [Kröger, 2011] presents a remarkable figure (shown here in Figure 7.2), adapted from [Tengs, 1995], in which results of a comprehensive study (considering more than 500 life-saving "interventions") are reported.¹³³

¹²⁹ "agent" in the chemical or biological sense

¹³⁰ See http://www.who.int/healthinfo/global_burden_disease/GlobalHealthRisks_report_full.pdf

¹³¹ The concept DALY is explained below.

¹³² See Table 23 p 56 of the UNEP GCO 2013 report, available at:

http://www.unep.org/hazardoussubstances/Portals/9/Mainstreaming/GCO/The%20Global%20Chemical%20Outlook_Full%20report_15Feb2013.pdf

¹³³ See Lecture 11 - http://www.lsa.ethz.ch/education/vorl/methods_of_technical_risk_assessment_in_a_regional_context.html

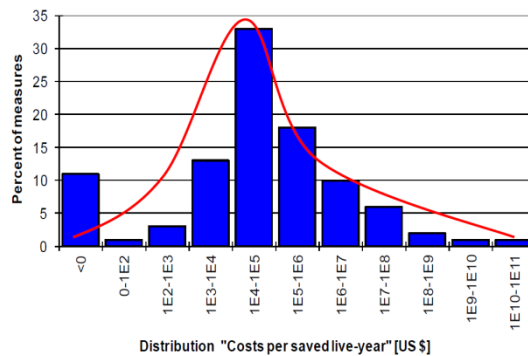


Figure 7.2: Distribution of cost per life-year saved estimates, expressed in 1993 dollars; taken from [Kröger, 2011]

Figure 7.2 shows the distribution of costs that society spends per life-year saved (expressed in \$₁₉₉₃).¹³⁴ The whole list with measures is available in [Tengs, 1995].

There is a variation of over 11 orders of magnitude! The majority of measures costs between 10,000 and 100,000 \$₁₉₉₃. Some measures are extremely efficient as they save money (indicated by <\$0). In contrast, extreme outliers like the two bars on the right hand side cost as much as 1 to 100 billion \$₁₉₉₃ per life-year saved. It is perhaps an understatement to say that these extremely costly measures are not very cost effective and drain away resources from other categories where may more lives could have been saved.

7.1.4 Difficulties/Challenges for Evaluating External Costs

Although being disliked, deplored and even despised by some as being distasteful or immoral, there is no escape or alternative to arrive at a “common denominator” for estimating the damage caused by harmful substances or activities. Amongst various possible yardsticks, it turn out that a monetary valuation simplifies matters considerably.¹³⁵ Note that the idea behind valuation of external costs is to obtain representative *orders of magnitude* of the overall impact so as to allow comparative analyses in order to inform the public and the policy makers about the most and least damaging applications/activities.

Attaching cost figures to harm, damage and/or loss of human life and/or property is delicate and even more so if long-term effects must be evaluated.

Two points of attention deserve careful attention:

- what is the *value of human life*? and;
- which *discount rate* is to be used for *long-term* considerations?

A third “touchy” element is the concept of *risk*.

¹³⁴ These types of measures are related to airplane safety (e.g., automatic fire extinguishers in airplane lavatory trash receptacles — \$16,000); automobile design improvements; automobile occupant restraint systems (e.g., drivers automatic vs manual belts in cars — ≤\$0); construction safety; fire, heat, and smoke detectors; flammability standards; highway improvement; school-bus safety; natural-disaster preparedness; speed limits; arsenic control; asbestos control (e.g., ban asbestos in brake blocks — \$29,000, but ban asbestos in diaphragms — \$1,400,000,000; benzene control (with measures varying from \$76,000 to \$20,000,000,000); radiation control (e.g., radionuclide control via best available technology in uranium mines — \$850,000, but radionuclide emission control at uranium fuel cycle facilities — \$34,000,000,000); childhood immunization (all categories ≤\$0); drug and alcohol treatment (all categories ≤\$0); etc etc.

¹³⁵ Below we will discuss a different approach through a weighted value index (through a so-called Multi-Criteria Decision Analysis index – MCDA)

Although ‘risk’ applies to all kinds of activities, whereby it implies that there is a finite probability for negative consequences of whatever activity or circumstance, it usually receives most attention in the context of accidents. Therefore, the concept of ‘risk’ will be briefly dealt with in Chapter 8 on Accidents.

The other two aspects, ‘human life’ and ‘discount rate’ are now considered.

7.1.4.1 The Value of Human Life

Early work on the “value of human life” is referenced in the booklet by [Viscusi, 1998]. He summarizes the values considered to be reasonable up to that time (1998), as being around 3M\$ – 7 M\$.

The newest update of the ExternE methodology [ExternE, 2005]¹³⁶ addresses the issue of “Monetary Valuation” of loss of human life and loss of life expectancy, as follows. On **mortality**, it states (§ 4.4.2): *«The cost of mortality is usually evaluated by means of the **value of a prevented fatality (VPF)**, often called “**value of statistical life**” (VSL), an unfortunate term that often evokes hostile reactions among non-economists. In reality, VPF is merely a shorthand for “**willingness-to-pay (WTP)** to avoid the risk of an anonymous premature death”. WTP (including ability to pay) is limited, even if we feel that the value of life is infinite — to save an individual in danger, no means are spared. Typical values recommended for policy decisions in Europe and North America are in the range of €1 to 5 million. Previous phases of ExternE ([...]) had used values around €3 million, chosen as average of the VPF studies that had been carried out in Europe. More recently ExternE (2004) carried out a new CV¹³⁷ study and lowered the value to €1 million.»¹³⁸*

However, [ExternE, 2005] makes the point that: *«whereas VPF is relevant for accidental deaths, it is not appropriate for air pollution mortality; the latter is primarily cardio-pulmonary and the associated loss of **life expectancy (LE)** per premature death is much shorter than for accidents. [...] Number of deaths is therefore not a meaningful indicator of the total air pollution mortality [...]. Rather, one has to use loss of LE which is indeed a meaningful indicator.»*

*«For the valuation of LE loss one needs the **value of a life year (VOLY)**. [...] Based on the results in France, Italy and the UK, ExternE is now using a VOLY of €50,000.»*

More elements on the monetary valuation of the “Impact Pathway Approach”, including the health impacts of air pollution, are discussed in Chapter 7 of [ExternE, 2005]. As a matter of fact, on p 146/147 (in Chapter 7), [ExternE, 2005] recommends the values 1 M€₂₀₀₀ for VSL or VFP, with upper value 3.3 M€₂₀₀₀ and an estimate of about 75,000 €₂₀₁₀ for a VOLY, with upper bound 225,000 €₂₀₁₀.¹³⁹ These values are also those of the NewExt project. [NewExt, 2004]¹⁴⁰

¹³⁶ ExternE is a major project started in the 1990’ by the European Commission and the US Department of Energy. Its first series of publications was published in 1995. Later, the EU continued with further reports in 1998, and with later comprehensive projects trying to improve the ExternE methodology and results. See http://www.externe.info/externe_2006/; and http://www.externe.info/externe_d7/ → Tab page “Projects” and “Publications”. Major project updates of ExternE are NexExt, NEEDS and CASES. The [ExternE, 2005] methodology is an update of earlier ExternE methodologies, and replaces the earlier Volumes 2 (1995) and 7 (1998). See http://www.externe.info/externe_d7/?q=node/4. The document can be found at: http://www.externe.info/externe_d7/sites/default/files/methup05a.pdf

¹³⁷ CV stands for “contingent valuation”, being a tool for determining non-market costs.

¹³⁸ Bold font has been used by the author of this report to stress the definitions.

¹³⁹ Note that 75,000 is the undiscounted value, arrived at by discounting back the value obtained via a life-table analysis 50,000, as 50,000/0.67. For details, see [ExternE, 2005], p 147.

¹⁴⁰ NewExt project: see <http://www.ier.uni-stuttgart.de/forschung/projektwebsites/newext>

A recent report by the OECD, [OECD, 2012], proposes as values for the average adult VSL for OECD countries a range of 1.5 – 4.5 M\$₂₀₀₅, with a base value of 3 M\$₂₀₀₅. For EU-27, the corresponding range is 1.8 – 5.4 M\$₂₀₀₅, with a base value of 3.6 M\$₂₀₀₅.

On the value of a statistical life year, VOLY, [OECD, 2012] mentions a value for EU-27 of 40,000 €. This is also the value retained in “the final stage of the NEEDS project” [CE, 2008b]¹⁴¹. According to computations in [CE, 2008b], the value of 40,000 is expressed in €₂₀₀₀ and was adjusted for inflation to 46,560 €₂₀₀₇. [IER, 2013] likewise refers to the work by Desaignes et al, and concludes with a “recalculated” value of about 60,000 €₂₀₁₀.

Not only monetary figures for mortality are relevant, but also harm to health, usually referred to as **morbidity** is important to be taken into account.¹⁴² Table 7.6 of [ExternE, 2005] summarizes a variety of morbidity central values (for air-pollution consequences) as used in that study. As an example, it ranges from e.g., 38 €₂₀₀₀ for a “minor restricted activity day” to 190,000 €₂₀₀₀ per case for chronic bronchitis. [IER, 2013] utilizes values of 57 €₂₀₁₀ for a “minor restricted activity day” to 300,000 €₂₀₁₀ per case for chronic bronchitis.

[IER, 2013] then shows the explicit way on how to integrate all these values for mortality and morbidity, through the metrics used by the World Health Organization (WHO). The basic concept there is called DALY and is a combined metric expressing the “**Disability-Adjusted Life Years**”.¹⁴³ Note that DALY refers to a loss of life(time) years.¹⁴⁴

As an example on how to arrive at combined numbers, [IER, 2013] mentions the case of radiation-induced cancer and genetic effects. Supposedly following the recommendations of ICRP (ICRP 60, 1991), [IER, 2013] states that the number of non-fatal radiation-induced cancers is a factor 2.4, and the number of genetic effects a factor 0.2, larger than the number of fatal radiation-induced cancer deaths.¹⁴⁵ It arrives (using Huijbregts et al 2005 and Frischknecht et al 2000 as references)¹⁴⁶ at 11.5 YOLL per fatal cancer case, 0.5 YLD (years lost due to disability) per non-fatal cancer case, and 61 YLD per genetic disease case. Using these values, [IER, 2013] arrives at a cost for a deadly cancer victim of about 1.3 M€₂₀₁₀ (based on 11.5 years at 60,000 €₂₀₁₀/year plus 606,000 €₂₀₁₀ from the willingness to pay for avoidance).

Precautionary note.

The reader should be careful with all these numbers. Clearly, as in many cases, it is the *order of magnitude* that is most relevant, since there are considerable uncertainties and statistical

¹⁴¹ All these studies refer to the same base study by Desaignes et al. (2007/8 or 2011). For references see [OECD, 2012] or [CE, 2008b]

¹⁴² Wikipedia defines the term as: **Morbidity** (from *Latin morbidus*, meaning “sick, unhealthy”) is a diseased state, disability, or poor health due to any cause. See <http://en.wikipedia.org/wiki/Disease>, under “Terminology, “Concepts”.

¹⁴³ For details, see: http://www.who.int/healthinfo/global_burden_disease/metrics_daly/en/, “DALYs for a disease or health condition are calculated as the sum of the Years of Life Lost (YLL) due to premature mortality in the population and the Years Lost due to Disability (YLD) for people living with the health condition or its consequences”. Or, see also [IER, 2013]. Note that WHO uses YLL, whereas [ExternE, 2005] and also [IER, 2013] use YOLL to express the same concept, “Years of Life Lost”. This is in the end equivalent to what still others call LLE, which stands for “Loss of Life Expectancy”.

¹⁴⁴ A more “suggestive” name would perhaps have been DALLY, being “Disability-Adjusted **Loss** of Life Years”.

¹⁴⁵ The author of this report believes that [IER, 2013] should be read as follows, that according to (ICRP 60 1991) radiation induced cancer incidence is a factor 2.4 larger than cancer mortality. Along the same line, it must be mentioned that the new ICRP guidelines of 2007 the genetic effects in humans are a factor 5 to 10 smaller than what was believed in 1990. See A D Wrixon, “New ICRP recommendations”, *Journal of Radiological Protection* **28**, 2008, 161–168 doi:10.1088/0952-4746/28/2/R02

Available at: http://iopscience.iop.org/0952-4746/28/2/R02/pdf/0952-4746_28_2_R02.pdf. See also [Stabin, 2008]. Following results from [BEIR, VII, 2006] and repeated by [Stabin, 2008], current cancer mortality in the western world (both general and radiation-induced) is about half of cancer incidence (combined for all cancers and ages).

¹⁴⁶ References to be found in [IER, 2013]

variations. Sometimes, the year of the currency is specified, but often it is not. Also, especially for numbers quoted in \$ versus €, we recall our “Exchange Rate” figure of Section 2.5. Note that before 2003 the \$ was worth more than the €; as of 2003, it has been the other way around, but with considerable fluctuations.

Finally, based on the particular methods used for determining these values, there would be differences between regions, to some extent determined by the economic status of a country or region. That may be the case, but as a moral principle, the author of this report takes an ethical standpoint that ***the value human life is independent of the region, and is similar for all human beings, no matter where.***

7.1.4.2 Long-Term Discount Rates

The issue on the ‘longer-term’ discount rates related to policy appraisal has been considered above in Section 2.8 (dealing with “Discount rates / WACC definition”) with observations/analyses as seen through the eyes of [Lévêque, 2013a] and [Laes, 2006]. Their arguments need not be repeated here. In summary, there is a tendency to accept that longer-term discount rates for these purposes should progressively decrease towards small values of the order of 0% - 1% after several hundreds of years. Negative discount rates do not seem to receive much support in the scientific literature.

In addition to what has been said in our earlier Section 2.8, we mention that the updated methodology of the ExternE project [ExternE, 2005] also addresses the discount-rate issue (pp 29-32). After having made several considerations, [ExternE, 2005] states... «Combining estimates for the social time preference rates with the social opportunity cost give a range of *recommended*¹⁴⁷ discount values for use in the ExternE project of: *Low: 0%; Central: 3%; High: 6%.*¹⁴⁸» And on the “Theoretical rationale for declining discount rates”, it says: «... This profile of a declining discount rate over future time periods is *not uncontroversial*¹⁴⁹. There is, for example, no reason why we need to assume a fall in productivity growth. [...] These issues are ripe for further research efforts. [...] Rounded values of those above would suggest the following: for about the next 25 years from the present, use a “low-normal” real annual interest rate of around 3-4%. For the period from about 25 to 75 years from the present, use a within-period instantaneous interest rate of around 2%. For the period from about 75 to about 300 years from the present, use a within-period instantaneous interest rate of around 1%. And for more than about 300 years from the present, use a within-period instantaneous interest rate of around 0%.¹⁵⁰

We recall that we wrote in Section 2.8 that long-term issues are in the sphere of public discount rates and that the time limits mentioned above are perhaps too short for typical industrial projects during operation. The long-term rates seem to apply more after plant closure, and counting from then on.

¹⁴⁷ Our italics

¹⁴⁸ Our italics

¹⁴⁹ Our italics

¹⁵⁰ The author of this report assumes that it concerns *real* discount rates for all rates mentioned, also for the so-called “*within-period instantaneous interest rate*”.

7.1.5 External Costs due to Electricity Generation

7.1.5.1 Methodology

The ExternE methodology for estimating external costs of electricity generation is well summarized in a report by the NEA [NEA, 2003] (p 17/18):

1. describe all stages (or process steps) in the fuel cycle chain;
2. provide information on material and energy flows and environmental burdens (e.g., emissions and wastes) associated with each stage;
3. allow the estimation and environmental impacts resulting from the burdens; and finally,
4. provide a mechanism for estimating the costs of the impact.

Steps 1 and 2 are usually dealt with via a “life-cycle analysis” of the processes involved, whereas steps 3 and 4 are studied using a so-called “impact-pathway” analysis (IPA).

7.1.5.2 Peculiarities for External Costs for Nuclear Electricity Generation

Concerning nuclear electricity generation, there is sometimes confusion on what exactly amounts to an externality. The reason is that, under normal circumstances, and under expected “civilized” and responsible behavior of national authorities and regulators, appropriate funds (should) have been set up for radioactive waste management & disposal, decommissioning and the like. The premiums for those funds are paid by the electricity producers and in some markets (partly) charged to electricity consumers, and are therefore properly internalized. It is therefore important not to confuse external costs due to currently and future operating nuclear reactors with possible awaiting or ongoing clean-up activities due to historic neglect (and sometimes even in the non-civil sector).

Our remarks are confirmed by the [NEA, 2003] (p 12):

«Aspects of nuclear energy that often are suggested to entail external costs include: *radioactive waste disposal*, future financial liabilities arising from *decommissioning and dismantling of nuclear facilities*, health and environmental impacts of radioactive releases in routine operation and effects of severe accidents. Those aspects are included in the scope of the report, since they indeed could become external costs if adequate funds for discharging them would not be established on a timely basis, guaranteed through reliable and independent bodies, and included in the market price of nuclear-generated electricity.»

With the italicized¹⁵¹ elements in mind, [NAE, 2003] (p 25) makes the point that ...

«... it is relevant to identify and quantify, as comprehensively and accurately as possible, the cost elements already included in the generation costs borne by electricity producers (i.e. already internalized).»

Hence, the need for a word of caution: from published numbers on external costs, it is not always clear whether the already internalized costs are still (even unintentionally) included or not.

¹⁵¹ The italics are by the author of this report.

Before addressing the published external costs, or negative externalities, we mention that there exist also *positive externalities or external benefits*. For nuclear power, we mention three elements:¹⁵²

- security of supply (in terms of primary fuel);
- constant generation cost, if so desired guaranteeing constant prices without volatility
- guaranteeing inertia for overall electric-system stability / possibility to allow easy reactive power control if needed.

The positive externalities are not discussed explicitly in this report.

7.2 Results for External Costs of Nuclear Generation

We now present some published results, whereby results stemming from the ExternE methodology (ExternE itself, NewExt, NEEDS, CASES)¹⁵³ will be of central interest. If available, other results are also presented.

In this Chapter, we concentrate mostly on consequences of non-accidental electricity generation activities (often referred to as “routine” operation), although some of the numbers quoted do include values for accidents. Chapter 8 will focus on nuclear accidents.

We stress again that the *orders of magnitude* of the results below are of importance, with sufficient attention for the degree of uncertainty, often expressed as ranges. Mostly, similar methodologies, based on full life-cycle analyses, are used. But the results may differ because of different boundary conditions (i.e., population density in particular countries/regions), different hypotheses, different input data, etc.

Clearly, this is not a full-scope review of all possible results ever published. We do think, however, that the most relevant ones are quoted. We try to rely on the most recent reports (that include or ‘situate’ the updates with respect to earlier computations); that way, we kill two birds with one stone, and the reader can retrace the basic historical references.

7.2.1 NEA 2003 Report – Reporting on ExternE Results and Other Sources

The NEA report “Nuclear Electricity Generation: What are the External Costs?”, provides a useful summary of earlier published results.

a. ExternE – Nuclear Only

a.1 France

In turn relying on Dreicer et al 1995 and Schieber & Schneider, 2002¹⁵⁴, [NEA, 2003] presents the results for the French nuclear-fuel cycle and operation. See Figure 7.3.

¹⁵² Sometimes the absence of CO₂ emissions is considered as a positive externality of nuclear electricity generation. We do not adopt that point of view, to avoid double counting, since we consider CO₂ emissions by fossil-fuel plants as a negative externality for those fossil-fired plants.

¹⁵³ http://www.externe.info/externe_d7 ; see tab page “Projects”

¹⁵⁴ Reference see NEA report

Fuel cycle stage	Discount rate		
	0%	3%	10%
Mining and milling	6.45E-02	1.84E-02	6.26E-03
Conversion	9.74E-04	4.78E-04	2.26E-04
Enrichment	1.19E-03	7.90E-04	4.13E-04
Fuel fabrication	1.89E-03	7.35E-04	3.10E-04
Electricity generation:			
Construction	3.94E-02	3.94E-02	3.94E-02
Operation	4.41E-01	1.68E-02	4.12E-03
Decommissioning	1.93E-02	6.91E-03	9.26E-04
Reprocessing	1.92E+00	1.45E-02	1.90E-03
LLW disposal	4.80E-03	8.52E-06	4.13E-07
HLW disposal	2.54E-02	6.41E-09	1.12E-10
Transportation	6.54E-04	2.66E-04	1.21E-04
Total	2.52	0.10	0.054

Source: ExternE, 1995.

Figure 7.3: External costs of the French nuclear fuel cycle in routine operation (€/MWh) – Ref. [NEA, 2003] Table 3.3

Clearly, there is a strong dependence on the discount rate. One notes a factor 50 difference in overall cost: 2.52€/MWh versus 0.054 €/MWh. The relative magnitude of reprocessing is noted to be strongly dependent on the discount rate. At 3% discount rate, the occupational effects on employees in the fuel cycle are important. However, if higher wages compensate for this, then (according to Pearce, 2002)¹⁵⁵ these costs are already internalized.

a.2 Other countries (EU)

Still following [NEA, 2003], the results for Belgium, Germany, the Netherlands and the UK (as published in EC, 1999 ExternE Vol X, National Implementation) are compared with the results for France, for a 0% discount rate and are as presented in Figure 7.4.

Country	External cost (m€/kWh)
Belgium	4.0-4.7
France	2.5
Germany	4.4-7.0
The Netherlands	7.4
United Kingdom	2.4-2.7

Source: ExternE, 1999.

Figure 7.4: External costs of the nuclear fuel cycle in different countries in €/MWh. Reference [NEA, 2003] Table 3.4 p 35 – in turn taken from ExternE Vol X, EC 1999¹⁵⁶

Clearly, the orders of magnitude are the same, with results differing by about ~ factor 3. For France, only the routine operation results are shown. Accidents are not part of these quoted values.

¹⁵⁵ Ref see [NEA, 2003]

¹⁵⁶ It seems that the results for the UK must come from a later source than the version of Volume 10 of ExternE, available on the ExternE website, since the UK results are not presented there. See http://www.externe.info/externe_d7/sites/default/files/vol10.pdf Table 19.8 (and Chapter 18).

b. Other Studies on Nuclear

[NEA, 2003] compares the previously mentioned ExternE results with other studies performed at about the same time span (1990-1993).¹⁵⁷ See Figure 7.5.

Study	External cost (m€/kWh)
ORNL (1993)	0.2-0.3
Pearce et al. (1992)	0.8-1.8
Friedrich and Voss (1993)	0.1-0.7
PACE (1990)	29.1

Figure 7.5: External costs of the nuclear fuel cycle from different studies in €/MWh. Reference [NEA, 2003], Table 3.5

As is obvious from Figure 7.5, the PACE study has very high numbers; this can be explained as follows [NEA, 2003]:

- It includes 5€/MWh for decommissioning.
 - ➔ As has been made clear in our earlier treatment, this is not warranted since decommissioning cost is negligible when the appropriate funds with a reasonable discount rate have been set up from the outset.
- It assumes high frequency for accidents, being a frequency of major releases similar to the scale of Chernobyl every 3300 years
 - ➔ This is much higher than «*experts consider appropriate for new plants in OECD*».¹⁵⁸ [NEA, 2003], p36
- Subtracting those “anomalous” numbers, leads to a result for routine operation in PACE of about ~1 €/MWh. [NEA, 2003]

c. Summary of ExternE results for EU-15 countries Studies on Nuclear and Other Generation Means

The external costs (from ExternE) are compared to other generation means in [NEA, 2003] (p 36/7), as displayed in Figure 7.6.

¹⁵⁷ For references, see [NEA, 2003]

¹⁵⁸ See also our considerations in chapter 8 on Accidents, with the Bayesian treatment by Lévêque.

External costs	Coal & Lignite	Oil	Gas	Nuclear	Biomass	Solar PV	Wind
Austria			11-26		24-25		
Belgium	37-150		11-22	4-4.7			
Germany	30-55	51-78	12-23	4.4-7	28-29	1.4-3.3	0.5-0.6
Denmark	35-65		15-30		12-14		0.9-1.6
Spain	48-77		11-22		29-52		1.8-1.9
Finland	20-44				8-11		
France	69-99	84-109	24-35	2.5	6-7		
Greece	46-84	26-48	7-13		1-8		2.4-2.6
Ireland	59-84						
Italy		34-56	15-27				
Netherlands	28-42		5-19	7.4	4-5		
Norway			8-19		2.4		0.5-2.5
Portugal	42-67		8-21		14-18		
Sweden	18-42				2.7-3		
UK	42-67	29-47	11-22	2.4-2.7	5.3-5.7		1.3-1.5
Generat Cost	32-50	49-52	26-35	34-59	34-43	512-853	67-72

Figure 7.6. RS: External and direct costs of electricity generation in the EU in €/MWh. Reference [NEA, 2003], Table 3.6 p 37.¹⁵⁹

According to these results, external costs for coal & lignite, oil, gas are of a similar order of magnitude as their generation costs (as estimated at that time – 1999). For nuclear, wind and PV, external costs are substantially lower. Biomass has an intermediate position.

7.2.2 Other Studies Using the ExternE Methodologies¹⁶⁰

a. Torfs et al. (2001, Belgium) Based on ExternE (1995) Methodology; but Updated

In an updated study, of which the results have been published in 2001, and in the framework of a National CO₂ project, under the auspices of the National Regulator Committee for Electricity and Gas (CCEG), researchers of the VITO lab have updated and refined the earlier Belgian ExternE numbers. [Torfs, 2001] These results have also been quoted by [Laes, 2006]. The central value for an open fuel cycle is of the order of **0.6 - 0.7 €/MWh** (depending on a low or high value for external costs due to greenhouse gasses - GHG). This central value does not contain the results for accidents. Expressed, differently, the authors arrive at a total result with confidence interval 68% of 0.1 to 3.7 €/MWh, but now including accidents.¹⁶¹

b. NEEDS EU FP6 Project, Based on ExternE (1995/1998/2005) and NEEDS-Update Methodologies [NEEDS, 2009c]

The NEEDS-project results for the nuclear fuel cycle are as follows [NEEDS, 2009a], Section 3.7:

- For today's typical nuclear technology: **0.9 - 1.5 €₂₀₀₀/MWh**

¹⁵⁹ "Generat Cost" stands for "generation cost", actually being what we usually refer to in this report as "the LCOE". The author of this report has changed the labeling in Figure 7.6, fully compatible with the meaning, as explained in [NEA, 2003], which states: «Generation costs (also referred to as "direct costs") include three main components, investment; operation and maintenance (O&M); and fuel.» This was done to avoid confusion with the usage of the terminology "direct costs" as done in this report in Chapter 2.

¹⁶⁰ A recent study by the National Research Council of the National Academies in the USA was published in 2010, "Hidden Costs of Energy", Washington, DC, 2010. Available at: http://www.nap.edu/catalog.php?record_id=12794. However, that report «did not quantify damages associated with nuclear power». It merely quotes the ExternE results of 1995, as discussed above. On nuclear, that report does not anything new.

¹⁶¹ Accidents were estimated in the range $8 \cdot 10^{-4}$ – 0.35 €/MWh.

- For plants operating in 2025: **0.7 – 1.1 €₂₀₀₀/MWh**

The range depends on the climate-change-damage assumptions; the numbers do not include accidents, nor waste disposal.¹⁶²

c. *CASES EU FP6 Project, Based on ExternE (1995/1998/2005) methodology [CASES, 2008]*

The CASES-project results for the nuclear fuel cycle are as follows [CASES, 2008], 7. Annex 1, §7.1:

- For today's (2005-2010) nuclear technology: **2.1 €₂₀₀₅/MWh**
 - For plants operating in 2020: **1.4 €₂₀₀₅/MWh**
 - For plants operating in 2030: **1.1 €₂₀₀₅/MWh**

The CASES report also provides a comparison with other generation technologies. This is shown in Figure 7.7.

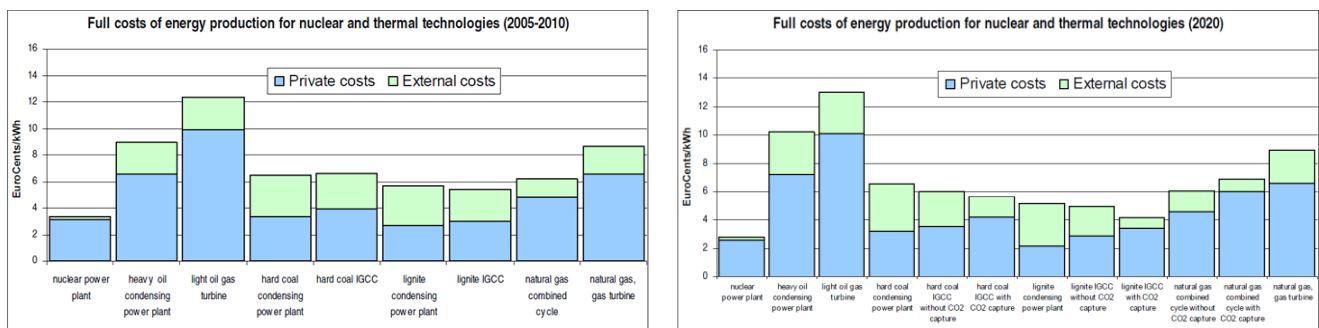


Figure 7.7: Full cost of nuclear and fossil generation in 2005-2010 and 2010, expressed in c€/kWh=10€/MWh. Reference [CASES, 2008], Figs 4.1 en 4.4

Compared to fossil-fuel generation, the external costs of nuclear-generated electricity are very small. Note that the 2.1 €₂₀₀₅/MWh for nuclear compares to 31 €₂₀₀₅/MWh for hard coal. As a matter of fact, the external costs for coal are about the same as the private cost (the external costs are 48% of the full cost); for nuclear generation, the external costs are 4% of the full cost as computed by [CASES, 2008].

The CASES results do not include accidents.

d. *Rabl & Rabl [Rabl, 2013]*

Recently, a publication by Rabl & Rabl [Rabl, 2013] estimates the external costs with and without nuclear accidents. Here, only the non-accident results are given; the values for accidents will be given and discussed in Chapter 8.

For normal operation, [Rabl, 2013] takes the most recent ExternE values, being 2.1 €/MWh. Lower and upper bounds are taken as 1/3 and 3 x that value.

For nuclear waste, [Rabl, 2013] accepts that the fund set up in the US (i.e., 1€/MWh) suffices for the disposal cost to be appropriately internalized. For France, [Rabl, 2013] takes the value from the information provided by [CdC, 2012]. From these numbers, Rabl & Rabl consider a range of 1 to 3 €/MWh, «and that a significant

¹⁶² As to waste disposal, this means that it is assumed that appropriate funds have been set up and those costs are internalized. See also Chapter 5 of this report. The NEEDS report does provide numbers for accidents in its Appendix A; they will be mentioned in Chapter 8 below.

fraction of that is already internalized». In their further analysis of their paper, however, they assume an external cost of 2 €/MWh «as external cost for waste management, i.e., the cost that is not yet internalized».

In summary, their numbers for normal operation are, **4.1 €/MWh** (consisting of 2.1 from “current operation” and 2.0 from waste management and disposal).

e. External Costs for Nuclear Generation in Germany (Preiss et al., [IER, 2013])¹⁶³

In a recent report, [IER, 2013], an extensive analysis of the risks of nuclear energy in Germany has been undertaken. In this chapter, we report the results for “routine operation”, keeping the results for nuclear accidents to Chapter 8.

Again, the 2005-updated methodology of ExternE has been utilized. The report takes into account environmental and health damage, both for the public and for the job-related employees in the nuclear facilities. Both mortality and morbidity (using the metrics of WHO as explained above, i.e., DALY=YOLL + YLD) are taken into account, after which a monetary equivalent is computed.

A summarizing picture is presented in Figure 7.8.

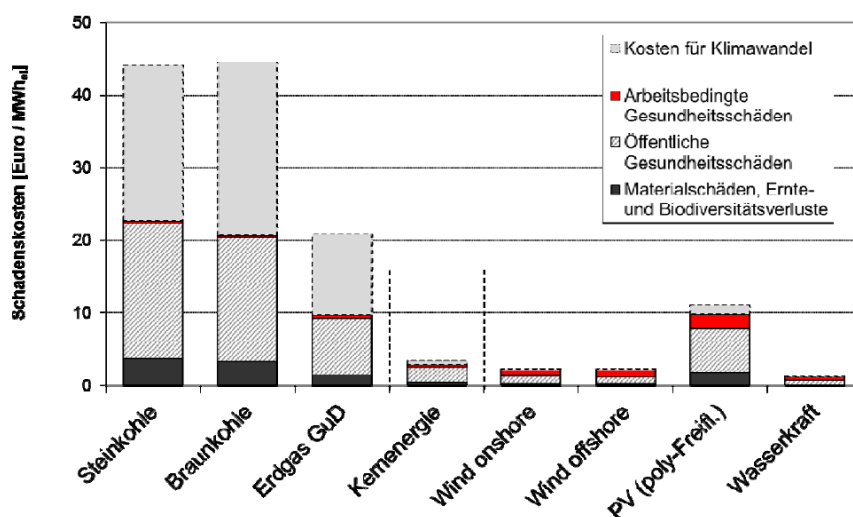


Figure 7.8 Damage cost due to a variety of electricity generation costs in €₂₀₁₀/MWh taken from [IER, 2013]; accidents are not included.

Legend to Figure 7.8:¹⁶⁴

- Schadenskosten
- Kosten für Klimawandel
- Arbeitsbedingte Gesundheitsschäden
- Öffentliche Gesundheitsschäden
- Materialschäden, Ernte- und Biodiversitätsverluste
- Steinkohle
- Braunkohle
- Erdgas GuD
- Kernenergie
- PV (poly-Freifl.)
- Wasserkraft

- Damage costs
- Climate change costs
- Work-related health damage
- Health damage for the public
- Material damage, harvest and bio-diversity losses
- Hard coal
- Lignite
- Natural Gas CCGT
- Nuclear Energy
- PV (polycrystalline – open space)
- Hydro power

¹⁶³ [IER, 2013] is only available in German.

¹⁶⁴ Only the German terms are translated.

From this Figure 7.8, one sees that the external cost of nuclear power in Germany for routine operation is of the order of **3 to 3.5 €₂₀₁₀/MWh**.

7.2.1 Overall Summary of Studies

As stated often in this report, the orders of magnitude are of importance.¹⁶⁵ The same applies to external costs. To see the forest for the trees, we here present *a summarizing generic figure* for Europe on the

external costs for nuclear-generated electricity → 1 – 4 €₂₀₁₂/MWh

7.3 Multi-Criteria Decision Analysis (MCDA)

A most interesting approach to aid decision making for energy provision is the so-called Multi-Criteria Decision Analysis (MCDA). Although the method is not new, it has received a boost during the European NEEDS project, over the period 2004-2008. This is not the place to explain every detail of the method, but it is nevertheless interesting to give the major lines of thought and to present some results.¹⁶⁶ Summarizing brief accounts can be found in [PSI, 2010] and [Roth, 2009], while the full methodological development in the NEEDS project is explained in the reports [NEEDS, 2008a-c, 2009b]. For our purposes here, we take the liberty to rely heavily on [PSI, 2010] and [Roth, 2009].

By means of the MCDA method «the performance of competing technologies [is measured] by different decision-making criteria. Performance for each criterion is judged by what may be called “indicators” or “measures” or “metrics”. Such indicators are either quantitative or qualitative.» [NEEDS, 2008a] Hence, measured indicators on certain electricity-supply options can be combined with subjective preferences by a chosen group of stakeholders, or the public at large, if so desired. This method is thus a handy tool to quantify the outcome of so-called participatory approaches on energy-policy decision making. (cfr. [Laes, 2006]) As part of the methodology, the comparative “sustainability” of individual technologies depends on the weights attributed to the different indicators by the participating people surveyed. (When mainly relying on expert judgment, a so-called Delphi method can be used.)¹⁶⁷

The criteria are supposed to reflect the “3-pillar” model of sustainability (basically relying on [Brundtland, 1987]), consisting of environmental, economic and societal requirements. The MCDA thus selects a set of criteria for each of these three pillars, which are then *scored* (based on objective/rational methods for those that are quantifiable, and based on subjective appraisal/valuation for the less tangible indicators). Next the criteria are *weighted* as to the relative importance in the overall basket of assessment criteria.

As explained in [NEEDS, 2008a] a systematic screening & filtering process with the help of experts in a Delphi procedure was undertaken to reduce a total of 1320 initial indicators to a final set of 36 indicators, of which 16 are environmentally related, 9 economic, and 16 of a social nature. Figure 7.9 gives a delineation up to a level showing 23 criteria. Some of the criteria still have subdivisions. The full list of 36 final indicators is given in Table 5 of [NEEDS, 2008a].

¹⁶⁵ Whereby it is recalled that the exact numbers may differ on a variety of parameters reflecting the situation at hand, like population density, etc.

¹⁶⁶ The application to electricity supply options has been co-developed by several research groups, but it must be said that especially researchers from PSI, Switzerland have been at the center point to further comprehensively develop and concretely apply this methodology, and to promote its use.

¹⁶⁷ See e.g., http://en.wikipedia.org/wiki/Delphi_method

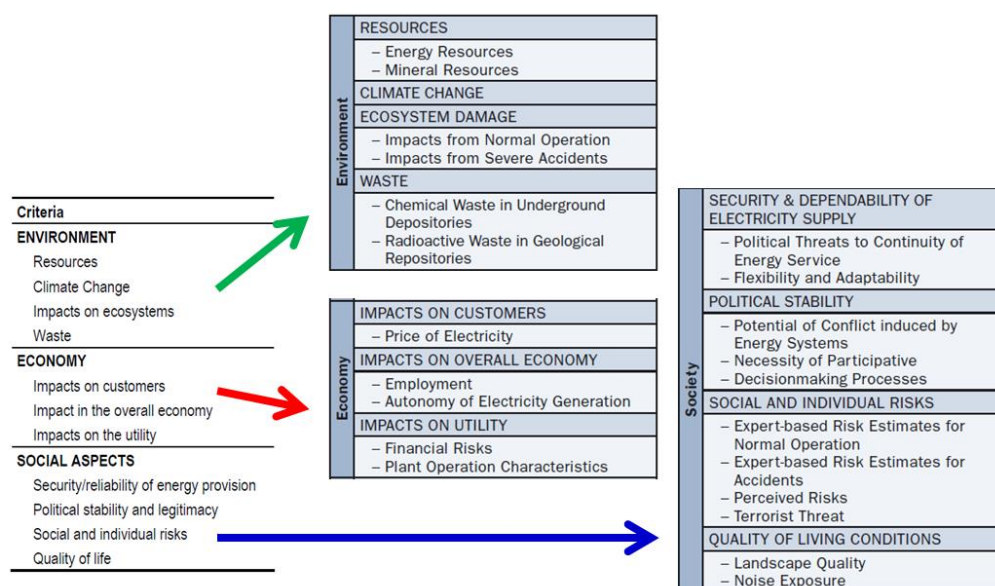


Figure 7.9: Set of 23 evaluation criteria for MCDA (constructed from [NEEDS, 2008a] and [PSI, 2010] – Some criteria on the RHS still have sub-criteria. The full list of criteria is available in Table 5 of [NEEDS, 2008a]

We provide two examples from [PSI, 2010] to illustrate the method.

In a first assessment, a group of 85 employees of Axpo Holding AG¹⁶⁸ in Switzerland (a sample not quite representative of the general population in Switzerland, as acknowledged in [PSI, 2010]) was surveyed. Figure 7.10 shows the weights attached to the different criteria, on the LHS; on the RHS, the overall scored outcome is shown. Low average scores are considered “best”; high scores are “bad”. [Roth, 2009][PSI, 2010]¹⁶⁹

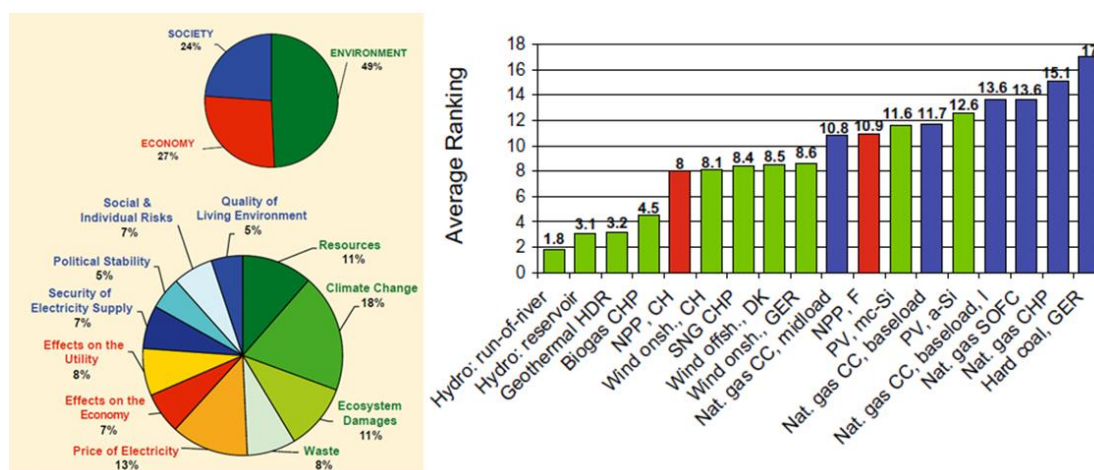


Figure 7.10: Outcome of a scoring in a workshop with 85 Axpo Holding AG (CH) employees. The LHS shows the weights attached to each criterion—taken from [PSI, 2010]; the RHS shows the average scored outcome, ranked from “best” to “worst”—taken from [Roth, 2009]. This is a linear scale of “appreciation”. The colors on the LHS relate to those in figure 7.9. The colors on the RHS have a different meaning (green: renewables; blue: fossil fuel; red: nuclear).¹⁷⁰

¹⁶⁸ See <http://www.axpo.com/axpo/ch/en/home.html>

¹⁶⁹ A composite figure with the scores and the total cost (generation and external costs) is given in [PSI, 2010]. We have given preference to a figure of [Roth, 2009] since the [PSI, 2010] picture shows somewhat dated costs, and whereby the external costs are not visible on the scale of the plot.

¹⁷⁰ The abbreviations are explained in the “List of Abbreviations”.

Nuclear power plants score on average, but by and large, still in the first half of the group, with higher “confidence” in Swiss plants than in French plants.

The next example shows that MCDA results can change depending on the view of those engaging in the participatory approach. In this second type of assessment, we take the case considered in [PSI, 2010] which could be called “uni-thematic”. Rather than searching for a balanced approach —reflected by the relative weights— the case at hand depicted in Figure 7.11 shows three very one-sided profiles.

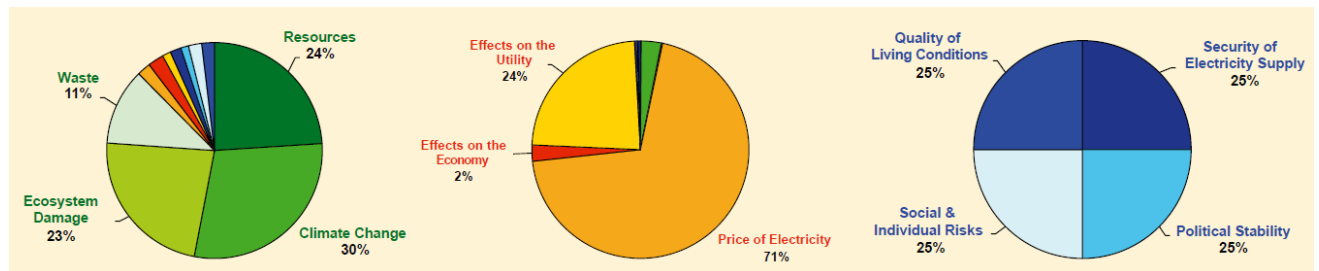


Figure 7.11: Three very different types of weighting profiles for MCDA criteria. For the group of respondents on the left, basically only the environmental criteria are of interest. The group in the middle is by far most concerned about the economy, while the group on the right values societal aspects as basically the only elements worth considering.

The view on the LHS of Figure 7.11 is basically only environmentally focused; the middle viewpoint is dominantly economy concerned, while the panel on the right concentrates mostly on societal aspects. These types of one-sided profiles usually only occur with small groups, which have the same “beliefs”. A cross section of society is expected to give a more balanced picture.

The scoring result for the three profiles is shown in Figure 7.12.

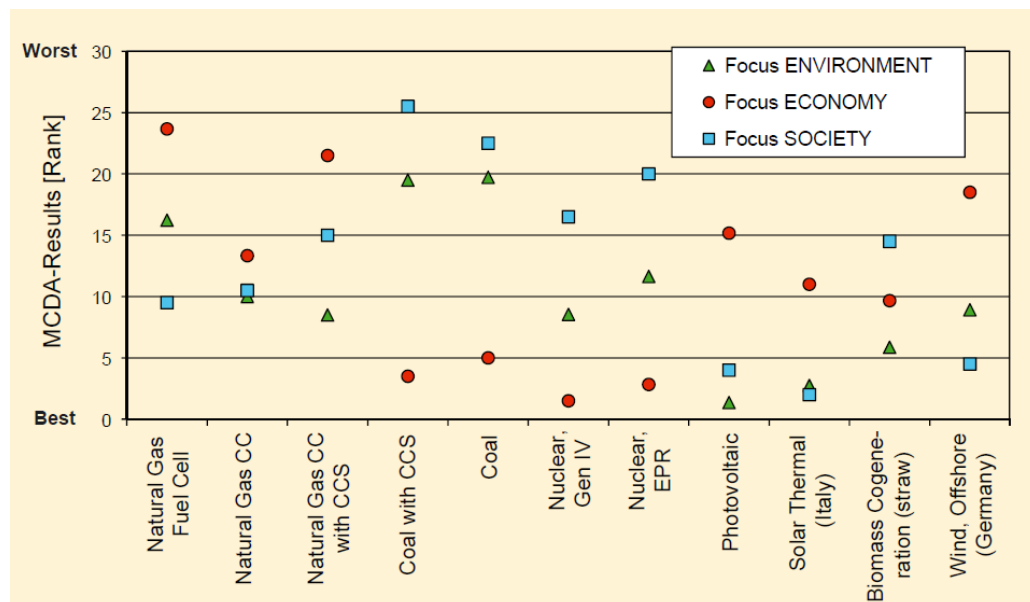


Figure 7.12: Average scoring result for three different uni-thematic profiles. Reference: [PSI, 2010]

The economic focus (red) opts for nuclear and coal; natural gas and renewables score poorly. When societal issues dominate (blue), the outcome is the reverse: renewables and gas perform well, while nuclear and coal do badly. In the dominantly environmental (green) focus, renewables score best, then nuclear and gas, with coal being the worst.

To wrap up the section on MCDA, it should be mentioned that the European Group on Ethics (EGE) in Science and New Technologies, a team around the Bureau of European Policy Advisors (BEPA), reporting directly to the President of the European Commission, was asked by Mr. Barroso to contribute to the debate on a sustainable energy mix in Europe by studying the impact of research on different energy sources on human well-being. They issued their Opinion Nr 27 on January 16, 2013.[EGE, 2013] As a matter of fact, the EGE has performed an implicit MCDA, since in chapter 3 of the Opinion, on Ethics, the four so-called “ethical criteria” are discussed, evaluated and “weighted”: 1) access to energy as human right, 2) security of EU energy supply, 3) sustainability/environmental responsibility; 4) Safety, imminent, indirect and long term. EGE concludes that the rationale to their recommendations is «to achieve the best possible *equilibrium* between the four criteria of analysis (access rights, security, safety and sustainability) in light of social, environmental and economic concerns.»¹⁷¹

The identification and evaluation of externalities is of uttermost importance to have the appropriate facts and figures on the harmful effects of our activities. The aspiration as expressed by the EGE is the objective to be aimed at. But to perform even better overall “multi-criteria” analyses, we need even better tools for evaluation. Hence, still *more research on external costs* (and benefits) for energy provision is called for.

¹⁷¹ The italic emphasis is from [EGE, 2013].

Chapter 8

Cost of Nuclear Accidents and Liability

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8.1 Introductory Considerations

8.1.1 The Concept of Risk

8.1.1.1 Objective Risk and Probabilistic Safety Assessment

In principle, the concept of **risk** as defined in the safety literature is quite simple. It is the *probability* that a certain harmful *consequence* results from that activity. Mathematically, it is expressed as a simple product:¹⁷²

$$\text{Risk} = P * C$$

This expression is also often referred to as the “rational risk”, the “objective risk”, the “scientific risk” or the “technical risk”. The principles to compute this technical risk are well known in the technical safety literature, and go by the names *Probabilistic Safety Assessment* (PSA) or *Probabilistic Risk Analysis/Assessment* (PRA).¹⁷³ Simply stated (and leaving out the nuances and technical intricacies, being the playground of the experts), the point is to disentangle the route to an undesired event —i.e., an accident— into the different pathways leading to that event and to which then a probability of occurrence (formally called failure frequency or rate) is assigned. This is done through a combination of so-called event trees and fault trees, so that by using Boolean algebra and the theory of probability, a final probability is obtained. Comprehensive PSA studies go beyond the determination of the probability and compute also the consequences. To perform a full PSA, it is necessary to go through three subsequent stages, called PSA levels 1, 2 and 3. These are defined as displayed in Figure 8.1 which is a scan taken from [IAEA, 2010a] (p. 3).

- (1) In Level 1 PSA, the design and operation of the plant are analysed in order to identify the sequences of events that can lead to core damage and the core damage frequency is estimated. Level 1 PSA provides insights into the strengths and weaknesses of the safety related systems and procedures in place or envisaged as preventing core damage.
- (2) In Level 2 PSA, the chronological progression of core damage sequences identified in Level 1 PSA is evaluated, including a quantitative assessment of phenomena arising from severe damage to reactor fuel. Level 2 PSA identifies ways in which associated releases of radioactive material from fuel can result in releases to the environment. It also estimates the frequency, magnitude and other relevant characteristics of the release of radioactive material to the environment. This analysis provides additional insights into the relative importance of accident prevention and mitigation measures and the physical barriers to the release of radioactive material to the environment (e.g. a containment building).
- (3) In Level 3 PSA, public health and other societal consequences are estimated, such as the contamination of land or food from the accident sequences that lead to a release of radioactivity to the environment.

Figure 8.1: Definition of PSA Levels 1, 2 and 3. Taken from [IAEA, 2010a], p. 3

As is clear from these different PSA levels, it is very important to distinguish between *core-damage frequency* (CDF) and *large early release frequency* (LERF). It is only after release of “sizable amounts”¹⁷⁴ of radioactive material that possible harm or damage is done to the surroundings and environment. The probability of containment break/bypass (being < 1) reduces the severe accident probability further compared to core

¹⁷² Sometimes, the frequency *F* is used instead of probability. Technically speaking there is a difference, especially with respect to normalization, but in practice, both concepts can be used. See e.g., [Kröger, 2011], lecture 1.

¹⁷³ Introductory information on these concepts applied to nuclear power plants can be found in [Lamarsh, 2001] (chapter 11), [Bodansky, 2004] (chapters 14 & 15); for a more advanced and comprehensive treatment, we refer to the lecture series on “Methods of Technical Risk Assessment in a Regional Context” by W. Kröger at ETH, Zürich, CH, which is available on line. [Kröger, 2011] also provides ample references on line and in the slides.

¹⁷⁴ Usually defined in relation to the “normal” discharge or emission limits.

damage. The containment can be most helpful in diminishing or avoiding outside harm. It is customary to utilize the definitions given by the US Nuclear Regulatory Commission (US NRC); see Figure 8.2. [NRC, 2009]

Core damage frequency is defined as the sum of the frequencies of those accidents that result in uncover and heatup of the reactor core to the point at which prolonged oxidation and severe fuel damage are anticipated and involving enough of the core, if released, to result in offsite public health effects.

Large early release frequency is defined as the sum of the frequencies of those accidents leading to rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of offsite emergency response and protective actions such that there is the potential for early health effects. (Such accidents generally include unscrubbed releases associated with early containment failure shortly after vessel breach, containment bypass events, and loss of containment isolation.)

Figure 8.2: Definition of CDF and LERF. Taken from [NRC, 2009], p. 7

In the early computations of [ExternE, 1995], a LERF of about 1/5 of the CDF was taken (precisely 0.19). In 1990, an NRC report on “Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants” (NUREG-1150) was published; a summary table is presented in [Bodansky, 2004] (Table 14.1), showing that the ratio LERF/CDF is of the order of 0.1 for PWR reactors.¹⁷⁵ Currently, it is estimated that the ratio LERF/CDF is between 1% to 10%, with a maximum of 10%, for PWRs. The following figure (Figure 8.3) is taken from [Hirschberg, 2011, 2012] and applies to current Swiss nuclear plants and the EPR, but it may be taken as a generic order of magnitude for a European plant. The objectives listed are those of IAEA.¹⁷⁶

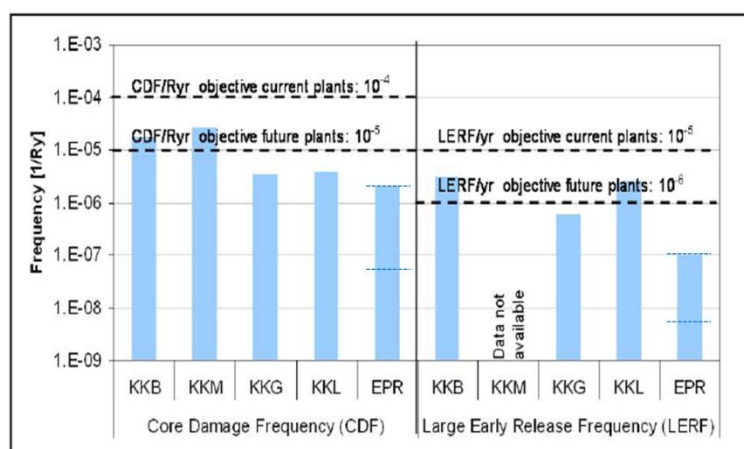


Figure 8.3: CDF and LERF objectives for current and future NPPs, and actual computed results for current Swiss plants and the EPR.

Ref: [Hirschberg, 2011, 2012]¹⁷⁷

It sets the objectives for CDF and LERF as follows:

CDF **objective *current* plants** < 10^{-4} **per reactor-year**
 objective *future* plants < 10^{-5} **per reactor-year**

¹⁷⁵ For BWR reactors, the ratio is not as small (only a factor 1/2 or 1/4), but it is reported that the CDF itself is about a factor 10 smaller than in PWRs.

¹⁷⁶ IAEA, International Nuclear Safety Advisory Group, 1999 (# 27 p 11); available at: http://www-pub.iaea.org/MTCD/publications/PDF/P082_scr.pdf

¹⁷⁷ For the abbreviations of the Swiss plants, see [Hirschberg, 2011, 2012]

LERF	objective <i>current</i> plants < 10^{-5}	per reactor-year
	objective <u>future</u> plants < 10^{-6}	per reactor-year

The Swiss plants satisfy the objectives (some more than others); the EPR is expected to do considerably better. The blue horizontal dashed lines for the EPR indicate a range, to a large extent depending on the safety measures against earthquakes. [Hirschberg, 2012]¹⁷⁸. The EPR values listed here are also in agreement with the PSA results by AREVA/EdF for the UK.¹⁷⁹

Clearly, to be credible, it is necessary that PSA assessments are made with the greatest care and that strict review processes are foreseen. One must assure that all possible paths are considered and that the interactions are properly taken into account. Some important concepts and points of attention in this type of analysis (here merely mentioned as keywords) are emphasized by [Kröger, 2011]: The difference between “complicated systems” & “complex systems”, interdependency, vulnerability and resilience of a system, human behavior, so-called “dependent failures” such as “common cause failure”, “common mode failure”, “cascading failures”, etc. This list of focal points is evidently incomplete, but it shows that competent PSA experts are well aware of the intricacies of complicated/complex systems and that the outcome of (well-performed) analyses is to be taken seriously and have a high degree of trustworthiness. Having said that, however, it must be acknowledged that a PSA outcome is the result of a theoretical exercise.

Historically, the first PSA was finalized in 1975 in the USA by N. Rasmussen, with a document known as the WASH-1400. This “foak”-nuclear-PSA-report was reviewed by the so-called Lewis Committee. According to [Bodansky, 2006] (Chapter 14), the Lewis committee basically concluded, a.o., that the methodology used was sound, but that some mistakes were made using some of the statistical methods. Furthermore, the uncertainties were larger than quoted in the report and the committee «could not conclude whether the probabilities were higher or lower than those quoted in the study». In a later congressional testimony, Lewis himself stated that he felt “the plants are actually safer than stated in the Rasmussen report”. [Bodansky, 2006], p 391. In Germany, a similar reactor study was performed by GRS; it was found that “the probabilities for a nuclear catastrophe are very low. This is in agreement with the results of WASH-1400. [Birkhofer, 1979]

Clearly, since the seventies of previous century, considerable improvements on the PSA methodology and implementation have occurred, making the approach much more credible, as explained above. For an authoritative view on PSA, see [Kröger, 2011] and the references found there. It is actually worth mentioning that W. Kröger was already strongly involved in PSA studies of what he calls “critical infrastructures” in the early 2000’s. See, e.g., [Kröger, 2009]. Although applicable to many sorts of systems, it is interesting to note that an important topic of study was/is electricity transmission systems. Since one of the reminders of the accident in Fukushima is the crucial nature of the external electrical grid, it is reassuring to know that the expertise exists to tackle the PSA reliability of such systems. But clearly, it should be used in practice and be promoted as a tool for evaluation.

¹⁷⁸ These dashed lines have been added by the author of this report to the English version of this figure to be found in [Hirschberg, 2011]. The lines are available in the more extensive German version in Figure 4 of [Hirschberg, 2012]

¹⁷⁹ See Office for Nuclear Regulation (of the UK), “Generic Design Assessment — New Civil Reactor Build”, “Step 4 - Probabilistic Safety Analysis Assessment of the EDF AREVA UK EPR Reactor”; Table 3 p 69 of <http://www.hse.gov.uk/newreactors/reports/step-four/technical-assessment/ukepr-psa-onr-gda-ar-11-019-r-rev-0.pdf>

8.1.1.2 Risk Perception

Having discussed rational or objective risk, it must be acknowledged that the risk perception and appraisal of human beings differs from what scientists call rational risk. As a matter of fact, it is instructive to confront the literature of social scientists with that of practitioners of exact sciences. Many treatises have been written on the subject of accidents and risk by social scientists. Amongst the most influential, and from those on the author's bookshelf, we mention [Perrow, 1999], [Sagan, 1993], [Gertsein, 2008], [Perrow, 2007] [Adams, 1995] and contrast them with the more science-engineering type of viewpoints like [Cohen, 1983, 1990], [Lewis, 1990], [Bate, 1999].¹⁸⁰ This is not the place to discuss these works in detail; the reader is invited to consult them. Especially the work by [Perrow, 1999] – which is an update of an earlier 1984 version – has been pertinent in “soft-science” circles. With a title “Normal Accidents”, it defends the thesis that systems are characterized by complex interactions and that accidents are just waiting to happen. As a matter of fact, it is interesting to see that analyses of almost-accidents make plenty of use of words like “could”, “should”, “might”, etc. Very rarely, quantitative estimates are made. In contrast to such viewpoint, the more technically-oriented literature quoted accepts that components and humans fail, leading to incidents, but they try to figure out what is the *probability* that such incidents evolve into accidents. In a sense being aware of both sides of the aisle, the book by [Reason, 1997]¹⁸¹, entitled “Managing the Risks of Organizational Accidents”, acknowledges that “organizational accidents”¹⁸² (in contrast to individual accidents) can and do happen within complex modern technologies. However, Reason is not fatalistic and argues that risk can be managed through careful organizational attitudes. He stresses the importance of *quality control* and (continued) *quality assurance*, and most importantly, a correct *safety culture* that penetrates the whole organization. Furthermore, a good *regulatory framework and oversight* is crucial. That way, major accidents can be avoided and/or its consequences severely mitigated.

Some social-science works on *risk* just mentioned stress the *perception* of risk. It is clear that every human being is facing risks basically from birth till death and that we make day-to-day decisions based on our perception and appraisal of the risks. See especially [Adams, 1995], but also [Lévêque, 2013b]. [Lévêque, 2013b] discusses several illustrative cases where agents behave subjectively when it comes to certain risk situations. He stresses the point that those perceptions are important to understand and to explain customers' behavior in an economic context. However, he also argues using probability theoretical considerations that objective risk has a clear meaning and that it makes sense to evaluate the rational risk of a nuclear accident by *multiplying the consequences with the probability of occurrence*. According to the author of this report, risk perception and appraisal are indeed an important influencing factor in our behavior, but one must dare to ask the question at what point we need to be protected against ourselves. Said differently, when does it become necessary that authorities set standards based on “rational” risk and not merely on risk perception or even “gut feeling”?

Suggestions have been made to adjust the above “rational risk” formula to take into account risk perception and even risk aversion for accidents with large consequences, even if they occur very rarely. As examples, we mention that a “risk-aversion” factor of e.g., 20 has been used to multiply the originally computed rational risk. Another possibility is to suggest a “weighted” risk by raising the consequences *C* by a certain power between 1.2 and 2, whenever *C* is larger than a certain threshold value. (See e.g., [Kröger, 2011], lecture 1).

¹⁸⁰ Also economic theory has been studying risk issues, as e.g., shown by [Viscusi, 1998], [Gollier, 2001], [Eeckhoudt, 2005].

¹⁸¹ James Reason is at the origin of the so-called “Swiss cheese model” for system accidents, which illustrates how different lines of defense can be breached (if the holes in the sliced cheese slabs line up).

¹⁸² «*Organizational accidents* have multiple causes involving many people operating at different levels of their respective companies. By contrast, *individual accidents* are ones in which a specific person or group is often both the agent and victim of the accident.» [Reason, 1997]

The issue of risk perception and appraisal is quite comprehensively addressed in the white paper by IRGC of 2005 on 'Risk Governance' and an integrative approach.¹⁸³ [IGRC, 2005] It suggests a risk-governance framework with four different stages: a Pre-Assessment phase (with problem framing,..., determination of scientific conventions); a Risk-Appraisal phase (with a risk assessment, followed by a "concern assessment" encompassing risk perceptions, social concerns and socio-economic impacts); a Risk Characterization and Risk Evaluation phase (or 'tolerability' & acceptability judgment); and finally, a Risk Management phase (with decision making and implementation). It is clear that such or similar integrative or participative approaches must be encouraged for decision making for new major projects, but ***it is the conviction of the author of this report that an evaluation of the rational numbers are the right starting point for every subsequent reflection and discussion.***

8.1.2. Documented Risks of Activities

In Chapter 7, we have mentioned the catalog of risks collected and presented by [Cohen, 2003], expressed in terms of loss of life expectancy (LLE) for individuals. From that schematic, it was already clear that we do not always realize well where the real risks are.

In this section, we illustrate that our risk perception is severely 'skewed', and that we perhaps should 'force' ourselves to react more rationally than emotionally.

8.1.2.1 Car-Accident Victims versus Airplane Victims

It is instructive to remind the reader of the enormous discrepancy between the rational risk and the perceived risk in the case of car accidents and airplane accidents. The two may not be exactly comparable (as perhaps the metrics such as 'per passenger-km' etc., must be aligned), but the difference in numbers is so overwhelming, that the orders of magnitude basically speak for themselves.

Few people think of car accidents when they step into a car, or when they ride a bike or take a walk, although these accidents occurs *massively* on a daily basis. According to the latest report on traffic safety by the World Health Organization [WHO, 2013], 1.24 million people died in accidents with road vehicles in 2010 worldwide; in 2004 the number was 1.2 million. That means, in plain words, that globally, about 1.2 million people *annually* die prematurely due to car accidents. This is on average 3300 people a day! Without any doubt, the car is the most deadly machine ever invented!

In contrast, still many people boarding a flight take a short 'mental reflection pause' right before take-off, thinking/believing that flying is a somewhat risky activity. However, flying is by far the safest means of displacement. Indeed, according to the International Civil Aviation Organization (ICAO) Safety Report of 2013, over the last 7 years, the number of fatalities in commercial flights, worldwide, has been less than 1000 a year. As a matter of fact, in 2011 and 2012 the number of fatalities was even less than 500.¹⁸⁴ This is out of about 100,000 commercial flights a day (or about 36.8 million a year).¹⁸⁵

¹⁸³ A comparable but different, and in the broader context of sustainable energy policy governance, participatory approach has been developed by [Laes, 2006].

¹⁸⁴ As a matter of fact, in 2011 there were 414 victims and in 2012 only 372 victims, worldwide.

See http://www.icao.int/safety/Documents/ICAO_2013-Safety-Report_FINAL.pdf

¹⁸⁵ Ref. Emilie D'haeseleer, "Reductie van de CO₂-uitstoot in de luchtvaartsector", MS Thesis KU Leuven, Belgium, 2011 (in Dutch)

The strange thing is that we perceive an airplane accident as much more serious than a car accident. The media reaction is likewise. Occurrences that happen frequently with only a few victims at a time are perceived less risky than rare events with more fatalities at once.

To the sometimes heard argument that it is more serious when a plane crashes with 400 fatalities compared to 400 car accidents with each time one fatality, [Cohen, 1983] replies that indeed the plane accident looks more grave when one is an ‘observing spectator’. However, as soon as one is an affected party in that an acquaintance or family member is amongst one of the victims, the appraisal changes completely as it does not make a bit of difference whether the acquaintance got killed in a car accident or together with the 399 victims in the plane crash. One human life is as valuable as the other human life, regardless of how and where the accident occurs.

It seems perhaps advisable to try to “reorient” our risk perception towards what happens in reality.

8.1.2.2 Energy-Related Accidents

Statistics and considerations on past energy related accidents have been kept and made in a variety of sources. We mention [NEA, 2010a], the ENSAD database at PSI, and the Energy Policy paper by Sovacool. The last two are discussed below.

a. The ENSAD Database

Focusing now more on energy-related accidents, we must regrettably observe that over the years many fatalities have occurred in all kinds of mishaps. We mention two types of “sobering” results.

At PSI (CH), a comprehensive database, *Energy-related Severe Accidents Database (ENSAD)*, is kept.¹⁸⁶ A major accident is defined as shown in Figure 8.4¹⁸⁷:

The PSI database ENSAD uses seven criteria to define a severe accident:	
1)	at least five fatalities or
2)	at least ten injured or
3)	at least 200 evacuees or
4)	extensive ban on consumption of food or
5)	releases of hydrocarbons exceeding 10 000 t or
6)	enforced clean-up of land and water over an area of at least 25 km ² or
7)	economic loss of at least five million USD(2000).
Whenever any one of the above criteria is satisfied, the accident is considered to be severe.	

Figure 8.4: Defining criteria to be considered in the ENSAD database of severe accidents. Ref, PSI

The ENSAD database is also explained in [ExterneE, 2005], as an important part of the “appreciation” to properly interpret severe energy accidents. In Figure 8.4, we present two figures taken from [NEEDS, 2008b]:

¹⁸⁶ See e.g., <http://gabe.web.psi.ch/research/ra/index.html>

¹⁸⁷ Taken from: http://gabe.web.psi.ch/research/ra/pdfs/ENSAD_Overview.pdf

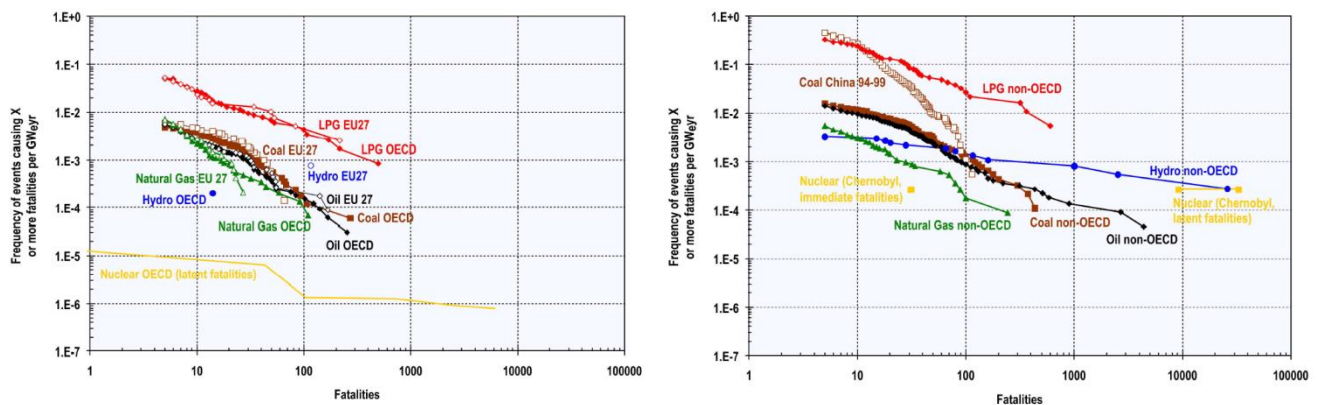


Figure 8.4: Comparison of the frequency-consequence curves for fatalities in severe energy-related accidents (covering the full energy chain) as defined in the ENSAD database between different technologies and between OECD & EU-27 (LHS) and non-OECD (RHS). The period covered is 1970-2005. Reference: [NEEDS, 2008b], Figs 14 and 15.¹⁸⁸

Two comments are in order.

As also explained in [NEEDS, 2008b], the numbers of latent fatalities due to the Chernobyl accident shown in Figure 8.4 (RHS) ranges from 9,000 to 33,000. This PSI estimate covers the whole northern hemisphere for the next 70 years and is based on applying the concept of collective dose together with the linear dose response hypothesis without threshold (LNT hypothesis), a practice that the ENSAD authors themselves qualify.¹⁸⁹ In [NEEDS, 2008b] it is mentioned that the Chernobyl Forum (with organizations such as the IAEA, WHO, UNDP, FAO, UNEP, UN-OCHA and UNSCEAR) estimates a total of about 4,000 irradiation-induced cancer fatalities.¹⁹⁰ We mention also the factsheet of the WHO,¹⁹¹ which estimates the number of latent irradiation-induced cancer fatalities due to the accident in the range between 4000 – 9000.

The Banqiao/Shimantan hydro dam system failure of 1975 in China is listed in Figure 8.4 (RHS) with 26,000 fatalities. According to [Sovacool, 2008] (to be discussed below), the number of fatalities was much larger, being 171,000. It seems¹⁹² that indeed about 26,000 people died from flooding (hence relatively directly) while another 145,000 died from the subsequent epidemics and famine. It would perhaps be advisable to split the Banqiao/Shimantan case on the RHS of Figure 8.4 in two parts, with 26,000 “immediate casualties” and 145,000 “latent fatalities”. This regrettable observation shows that uncared design and operation of a hydro-energy (and flood-control) system can lead to huge human suffering.

b. The Sovacool Overview of Energy Accidents

A second source of information is the paper by [Sovacool, 2008] on “The cost of failure: A preliminary assessment of major energy accidents, 1907 – 2007”. It thus covers a period of 100 years, and the listed table is not pleasant reading. It collects information on 279 accidents (small and large), listing the number of deadly victims and “property damage”. As a total, 282,000 fatalities and 41 billion \$ loss in “property

¹⁸⁸ On the RHS, the coal accidents in China from 1994-1999 are not included. See [NEEDS, 2008b].

¹⁸⁹ See http://manhaz.cyf.gov.pl/manhaz/szkola/materials/S3/psi_materials/ENSAD98.pdf, page 141

¹⁹⁰ See Chernobyl Forum at <http://www.iaea.org/Publications/Booklets/Chernobyl/chernobyl.pdf>, p 16

¹⁹¹ See Factsheet WHO at http://www.who.int/ionizing_radiation/chernobyl/background/en/index.html (see “Mortality”)

¹⁹² See <http://theenergylibrary.com/node/13072>

damage” are reported. The Banqiao/Shimantan case appears in the list with 171,000 casualties, while for Chernobyl the Chernobyl Forum numbers (4056 expected victims) are given. The cost estimates refer to direct “property damage”, and for Chernobyl, 6.7 billion \$ is indicated. For the dam failure in China, 8.7 billion \$ is given. The third largest accident in terms of human loss is the NNPC petroleum pipeline rupture in the Niger Delta (Nigeria) in 1998, where 1078 people got killed. The property damage was a mere 54 million \$. Finally, we mention the TMI accident of 1979 in Pennsylvania, USA, which did not cause any human fatalities, and is reported to have cost 2.4 billion \$.

8.1.3. Computed Risks for Nuclear Accidents Using PSA

To wind up the discussion of risk, we present the results of PSA computations performed in the framework of the [NEEDS, 2008b] project. This permits comparison with the yellow PSA computed curve on the LHS of Figure 8.4. Figure 8.5 is taken from [NEEDS, 2008b].

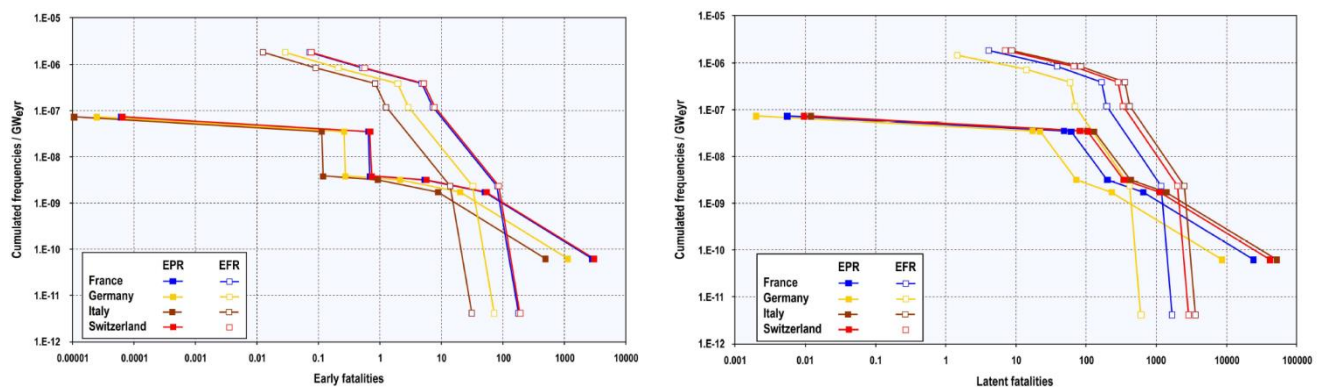


Figure 8.5: Computed frequency-consequence curves for four countries and for two nuclear technologies: the European Pressurized Reactor (EPR – Gen iii) and the envisaged European Fast Reactor (EFR – Gen iv), as defined in NEEDS for 2050. The LHS panel shows early fatalities; the RHS panel shows latent fatalities. In ordinate is the cumulative frequency per GW_eyear. Taken from [NEEDS, 2008b], p 41.

8.2 Cost of Nuclear Accidents

8.2.1 Introductory Considerations

Attaching a cost to nuclear accidents is not straightforward, first because the valuation of the consequences is not trivial, as not only direct property losses must be accounted for, but also less tangible costs, such as e.g., the “image” of a country might come into play. It thus depends on the boundary conditions and the hypothesis taken for the calculations. As long as these points of departure have been well documented, then matters are transparent and interpretation is possible.

The overall cost of an accident depends on the “magnitude” or “severity” of the accident envisaged, varying from small accidents to major accidents. Large accidents will lead to larger costs, but they are expected to occur less frequently. It is thus important to recognize that merely quoting the costs of whatever accident is

very incomplete information, and there are valid arguments, based on the rational risk concept (see Section 8.1.1) to multiply the consequences of the accident (i.e., the cost) with the probability or expected frequency of occurrence. As explained in Section 8.1.1, during the interpretation of the expected-cost result, some may be inclined to incorporate an implicit or explicit a risk-aversion weighting factor.

Early exercises on the methodology for assessing the consequences of nuclear reactor accidents were considered in ExternE (1995, 1998) and [NEA, 2000]. An update for ExternE is found in [ExternE, 2005], with the monetary conversion of mortality and morbidity as considered in Chapter 7 on External Costs / Externalities of this report. At the Nuclear Energy Agency of the OECD, in 2013-2014, a new project on the "Cost of Nuclear Accidents, Liabilities Issues and their Impact on Electricity Costs" is going on. This new NEA initiative is in line with what was stated in [NEA, 2003] that *«The NEA study on methodologies for assessing the consequences of nuclear reactor accidents [NEA, 2000b] highlights the need for further work on methodologies and tools to evaluate the impacts of accidents and their monetary values. Although the imperfections and limitations of economic estimates should be acknowledged, they provide some relevant insights on orders of magnitude and ranges of values.»*

8.2.2 Survey of Results for External Costs due to Nuclear Accidents

We first report on the external costs due to accidents that we already encountered in Chapter 7 on External Costs / Externalities, but that were deliberately moved to this Chapter.

8.2.2.1 [NEA, 2003] External Costs due to Electricity Generation

The results for France reported in [NEA, 2003] are those of ExternE (1995):

With a core melt frequency of 10^{-5} per reactor year (a conditional probability of massive containment failure of 0.19)¹⁹³ and a release of about 1% of the core after meltdown the results lead to a direct cost of **0.0046 €/MWh** at 0% discount rate. (The internalized portion by insurance has not been subtracted in the ExternE study of 1995.) As explained in [NEA, 2003], beyond the direct costs of an accident, *«indirect impacts induce a multiplying factor that has been estimated at 1.25 based on macroeconomic analyses.»* *«Furthermore, a multiplying coefficient approximately equal to 20 may be applied to reflect risk aversion.»* All this would lead to an external cost due to a nuclear accident of **0.12 €/MWh**. It should be noted that NEEDS, 2009a] also mentions these [ExternE, 1995] results in its Appendix A (without any update or further comment).

The “out-of-bounds” result by PACE (1990) based on the assumption of a very large assumed major release fraction (leading to an external cost of 29.1 €/MWh) has been reported before when discussing Figure 7.5.

8.2.2.2 [Torfs, 2001] External Costs due to Nuclear Accidents in Belgium

In the already in Section 7.2.2 mentioned update study for Belgium, Torfs et al., report an external cost due to accidents in the range of **8×10^{-4} to 0.35 €/MWh**.

¹⁹³ The part in parentheses is not in [NEA, 2003], but has been taken by the author of this report from [ExternE, 1995] p 204 directly.

8.2.2.3 [NewExt, 2004] External Costs due to Non-Nuclear and Nuclear Accidents

The project [NewExt, 2004] deals mostly with non-nuclear energy technologies, but it presents a table with external costs due to severe accidents, of non-nuclear and nuclear origin, based on the accident valuation methodology by [Hirschberg, 1998]. This is shown in Figure 8.6 below.

Energy chain	Reference countries	Damage costs in €-Cents(2002)/kWh _e			External costs in €-Cents(2002)/kWh _e		
		Occupational	Public	Total	Occupational	Public	Total
Coal	OECD	1.7E-3	1.2E-5	1.7E-3	3.4E-4	6.1E-6	3.5E-4
	non-OECD w/o China	6.5E-3	4.3E-5	6.5E-3	3.2E-3	3.5E-5	3.3E-3
	China (1994-1999)	1.2E-2	ng ³	1.2E-2	6.1E-3	ng ³	6.1E-3
Oil	OECD	9.9E-4	9.0E-4	1.9E-3	2.0E-4	4.5E-4	6.5E-4
	non-OECD	1.8E-3	1.1E-2	1.3E-2	9.1E-4	8.7E-3	9.6E-3
Natural gas	OECD	2.2E-4	4.4E-4	6.6E-4	2.2E-4	2.2E-4	4.4E-4
	non-OECD	3.3E-4	5.9E-4	9.2E-4	1.6E-4	4.7E-4	6.3E-4
Hydro	OECD	ng ³	4.1E-5	4.1E-5	ng ³	2.0E-5	2.0E-5
	non-OECD	ng ³	1.2E-1	1.2E-1	ng ³	9.8E-2	9.8E-2
	non-OECD w/o Bangqiao/Shimantan	ng ³	1.6E-2	1.6E-2	ng ³	1.3E-2	1.3E-2
Nuclear	OECD ¹	ng ³	ng ³	ng ³	ng ³	ng ³	ng ³
	non-OECD ²	5.7E-4	ng ³	5.7E-4	2.9E-4	ng ³	2.9E-4

¹Based on PSA for the Swiss plant Muehleberg ²Based on the Chernobyl accident ³ng = negligible

Summary of full chain damage costs and external costs (€-Cents(2002)/kWh) of severe accidents with at least five immediate fatalities; the reference coal, oil and natural gas electricity generating plants have efficiencies of 41, 30 and 53%, respectively.
(Value of a Statistical Life (central value) = 1.045 million Euro)

Figure 8.6: External costs due to accidents with at least five immediate fatalities, expressed in c€₂₀₀₂/kWh, or, 10 €₂₀₀₂/MWh.
Ref: [Newext, 2004], Table 8 p 41

Note that it concerns the costs of accidents with at *least five immediate fatalities*, and may thus be a bit misleading for nuclear power generation as accident indicator.¹⁹⁴

8.2.2.4 [Rabl, 2013] External Costs Nuclear Accidents

Referring to the same work by Rabl & Rabl [Rabl, 2013] that we already considered in Section 7.2.2_d, we now discuss their estimate of the cost of nuclear accidents. In their estimate, they consider: *the cost of the lost reactors; the cost of lost power; fatal cancers; lost agricultural production; displaced populations; and the cost of clean-up*. As total cost of an accident (if it happens today) [Rabl, 2013] reports a central value of 354 billion €₂₀₁₀, with a low value of 165 billion €₂₀₁₀ and a high value of 1390 billion €₂₀₁₀.¹⁹⁵ As a gauge, [Rabl, 2013] makes reference to the ENSAD database and Hirschberg of PSI to quote their estimate of the cost of Chernobyl being 339 billion \$₁₉₉₆, which [Rabl, 2013] then converts to approximately 360 billion €₂₀₁₀. After some discounting (if the accident were not to occur today) this number is multiplied by an accident frequency of one accident in 25 years (the period between Chernobyl and Fukushima)¹⁹⁶. Following that reasoning, the results per MWh would be: a **central value 3.8 €₂₀₁₀/MWh, a low value of 0.8 €₂₀₁₀/MWh, and a high value of 22.9 €₂₀₁₀/MWh**.

¹⁹⁴ It should be recalled that the nuclear accident of Fukushima did not cause any immediate fatalities.

¹⁹⁵ Although not explicitly stated in the [Rabl, 2013] paper, we take it from the context that the currency is €₂₀₁₀.

¹⁹⁶ Following [Lévêque, 2013b], such approach is not quite a correct way of reasoning according to proper probability theory, as he comments on a "similar" approach by Dessus and Laponche in their article in Libération of June 5, 2011.

8.2.2.5 [IRSN, 2007] and [IRSN, 2012] Evaluation of the Cost of French Nuclear Accidents

The technical branch IRSN of the French Nuclear Regulator ASN has made a computation of the costs of nuclear accidents in France, reporting the results in 2007. [IRSN, 2007] These results were communicated more widely at the Eurosafe Conference of 2012 as explained in [IRSN, 2012]. Two sorts of accident scenarios were considered; a so-called *severe* accident and a so-called *major* accident. The cost results are summarized in Figure 8.7.

Severe accident			Major accident		
	b€	%		b€	%
On-site costs	6	5%	On-site costs	8	2%
Offsite radiological costs	9	8%	Offsite radiological costs	53	13%
Contaminated territories	11	10%	Contaminated territories	110	26%
Costs related to power production	44	37%	Image costs	166	39%
Image costs	47	40%	Costs related to power production	90	21%
Total (rounded)	120	100%	Total (rounded)	430	100%

Figure 8.7 Overall cost estimates for nuclear accidents in France. Taken from [IRSN, 2012]

As seen, the total cost is estimated to range from **120 billion € to 430 billion €** for the two types of accidents.

These IRSN references limit themselves to absolute cost computations, for the accidents postulated. They do not consider the accident probabilities.

To compare with published reports to be reported on below, the author of this report has performed the exercise of multiplying these cost figures with the scientific-technical IAEA objectives for the LERF (large early release frequency) as shown in Figure 8.3.¹⁹⁷ For existing reactors, one recalls that the LERF is 10^{-5} /Ry, for future reactors the LERF is 10^{-6} /Ry. A reactor of 1,250 MW_e, operating 8,000h/y produces 10 TWh_e annually. Hence, for a LERF of 10^{-5} , the range would be situated between **0.12 €/MWh and 0.43 €/MWh**. For the future reactors (of Gen iii) with a LERF of 10^{-6} , the average “expected” value for the cost would be between 0.012 €/MWh and 0.043 €/MWh. For a pessimistic view applied to the current generation reactors with a LERF of 10^{-4} , the result would be between 1.2 €/MWh and 4.3 €/MWh. This little exercise shows that the actual value of the LERF (and thus also of the role of the containment) is of crucial importance in this type of computations.

8.2.2.6 [IER, 2013] Expected External Cost Estimates of Nuclear Accidents in Germany

The recent work [IER, 2013] that was already discussed for routine operation in Section 7.2.2_e is now reconsidered for the cost of a nuclear accident in Germany. As explained above, costs for morbidity and mortality as well as damage costs to property and material goods has been taken into account. Six categories of accidents were examined, ranging from a minor accident to a sort of catastrophic accident. The estimates for the absolute costs range from 11 billion €₂₀₁₀ to 14,000 billion €₂₀₁₀. The probability of occurrence runs in the other direction, with only 10^{-7} per Ry for the most heavy accident scenario.¹⁹⁸ For the types of reactors considered, this results in an expected specific external accident cost of about 0.15 €₂₀₁₀/MWh for the most

¹⁹⁷ The “rational-risk” computation by multiplication (as expressed at the outset of Section 8.1 of this report) is an exercise that the IRSN authors are reluctant to perform themselves.

¹⁹⁸ The authors of [IER, 2013] state that these through-PSA-obtained probabilities are not to be questioned because of the events in Fukushima since there it was a clear “*design error*” or “*error in the safety design*” (in German: “*Auslegungsfehler*”) and not a *residual or remaining risk* (in German: “*Restrisiko*”). *Residual Risk* is defined by [Kröger, 2011] as the risk that remains after implementation of all planned safety measures, arising from consciously accepted risks, mis-assessed risks and unrecognized risks. See also [IER, 2013], Annex.

severe accident. As is shown in Figure 8.8, the specific accident cost ranges from 0.13 m€₂₀₁₀/MWh to the already mentioned 0.15 €₂₀₁₀/MWh.

Unfall- kategorie	Gesundheits- schäden Mortalität [€/MWh _{el}]	Gesundheits- schäden Morbidity [€/MWh _{el}]	Umsiedlung [€/MWh _{el}]	Wirtschafts- leistung [€/MWh _{el}]	Anlage [€/MWh _{el}]	Summe [€/MWh _{el}]	absolute Schadens- höhe [Mrd. €]
1	4,1E-05	9,2E-04	9,1E-02	6,1E-02	1,1E-04	1,5E-01	14.100
2	1,5E-05	4,3E-04	4,6E-02	3,0E-02	1,1E-04	7,7E-02	7.075
3	2,9E-07	9,2E-06	3,4E-04	2,3E-04	1,1E-05	5,9E-04	545
4	8,2E-08	1,7E-06	6,8E-05	4,5E-05	1,1E-05	1,3E-04	115
5	1,3E-06	2,2E-05	7,3E-04	4,8E-04	1,1E-03	2,4E-03	22
6	6,2E-08	9,9E-06	1,1E-06	7,0E-07	1,1E-03	1,2E-03	11
Σ	5,8E-05	1,4E-03	1,4E-01	9,2E-02	2,5E-03	2,3E-01	-

Figure 8.8: Specific external cost and absolute cost figures for nuclear accidents in Germany. Taken from [IEA, 2013], Tabelle 6.

Legend for Figure 8.8:

<i>Unfallkategorie</i>	<i>accident category</i>
<i>Gesundheitsschäden Mortalität</i>	<i>health damage / mortality</i>
<i>Gesundheitsschäden Morbidity</i>	<i>health damage / morbidity</i>
<i>Umsiedlung</i>	<i>relocation</i>
<i>Wirtschaftsleistung</i>	<i>economic performance</i>
<i>Anlage</i>	<i>facility</i>
<i>Summe</i>	<i>sum</i>
<i>absolute Schadenshöhe [Mrd. €]</i>	<i>absolute damage cost [billion €]</i>

As can be seen, from this analysis, the overall specific cost is estimated to be about **0.23 €₂₀₁₀/MWh**.

8.2.2.7 [Lévêque, 2013a&b]

As a last set of external cost figures for nuclear accidents, we consider the recent and most interesting work by [Lévêque, 2013a&b], especially on the computation of accident probabilities taking into account that accidents have occurred and by using proper probability theory.

In a recent set of working papers, culminating in a book [Lévêque, 2013c], Lévêque has discussed the cost of nuclear electricity generation, including the costs of accidents.

i. Simple Back of the Envelope Estimate

Before launching into the rigorous probabilistic/statistical computations, [Lévêque, 2013a] makes an intuitive guess for an upper bound of the specific external cost of an accident, by means of a back of the envelope calculation.

He starts from the estimated cost of the accident of Fukushima, which he understands to be 100 bln €. He then assumes this pessimistically to be an underestimate by a factor of 10. Hence, the accident cost is pessimistically estimated as 1,000 bln €.

Next, he takes the LERF as «cited by AREVA for the EPR» to be 10^{-7} per Ry, but since that is a most sensitive parameter, he assumes a much more pessimistic value of 10^{-5} per Ry. With a reactor that produces about 10 TWh/y, this leads to an order of magnitude of **1 €/MWh**.

ii. Bayesian Probabilistic/Statistical Treatment

In his treatment of the risk of a major accident, [Lévêque, 2013b] sets out a methodology to properly “mix” the theoretical results obtained by PSA with the frequency of actually occurred accidents. To do so he calls upon what he names the “Bayesian magic”. Indeed, by relying on the rule of Bayes in statistics, and to consider past accidents as the equivalent of “experiments” in such approach, he manages to get a combined expected probability. The methodology relies on somewhat sophisticated mathematics, using probability density functions designated as “prior”, “posterior” and “likelihood” functions, and choosing a beta function for the prior function and a binomial distribution for the likelihood function.¹⁹⁹

He then applies his derived formula with the following parameters:

- 11 “core damage accidents”²⁰⁰ in 14,000 reactor years $\rightarrow 7.8 \times 10^{-4}$ /Ry observed accident frequency
- a theoretical core damage probability of 6.5×10^{-5} per Ry²⁰¹

The outcome of the computation equals a combined effective accident probability of **3.2×10^{-4} /Ry**.

However, although the methodology applied seems to be sound, the reader of [Lévêque, 2013b] will observe that he is not always clear when speaking about large accidents, core damage, core melt, large release of radioactivity, etc. Therefore, the parameters are not all well-chosen. There is some “refinement” necessary on the input parameters. To have a serious nuclear accident, one must have *major* core damage (i.e., a real core melt), and in addition, the containment must be seriously breached. In other words, the observed accident frequency of 5 serious “meltdowns” should have been used for the CDF, instead of 11. Furthermore, the LERF/CDF fraction must be taken into account.²⁰²

An alternative, and perhaps more reasonable set of inputs, could therefore be:

- 5 major “core damage accidents”²⁰³ in 14,000 reactor years $\rightarrow 3.6 \times 10^{-4}$ /Ry observed accident frequency
- a core damage probability of 6.5×10^{-5} per Ry

With those parameters, the result based on only the CDF would be 1.7×10^{-4} /Ry. But since it is the LERF that counts and knowing that $\text{LERF} \approx 0.1 * \text{CDF}$, in attempt to come up with a “*pragmatic*” estimate, we reduce the outcome of the expected frequency by a factor of 10, to obtain 1.7×10^{-5} /Ry. Given the fact this adapted “pragmatic” computation is not quite rigorous, in that the LERF should likely be taken into the Bayesian formulae rather than multiplying afterwards by the fraction LERF/CDF,²⁰⁴ but also acknowledging that the parameters differ for PWRs, BWRs, and RBMKs, this value is rounded upwards to be **$\sim 2 \times 10^{-5}$ /Ry**.

To arrive at a specific external cost for nuclear accidents, we consider the upper estimate of [IRSN, 2012] given in Figure 8.7, namely 430 billion €. For a reactor with annual production of 10 TWh, the specific cost would be ~ 0.86 €/MWh, rounded to **1 €/MWh**.

¹⁹⁹ For more information on these Bayesian statistical methods, see, e.g., the book by [Bolstad, 2007]

²⁰⁰ Thereby following [Cochran, 2011]

²⁰¹ Mean value estimate according to NUREG 1560 (1997)

²⁰² Note the definitions of CDF and LERF given in Figure 8.2.

²⁰³ The 5 so-called serious “melt downs” are TMI, Chernobyl, Fukushima 1, 2 & 3, although this is still a bit “generic” since the parameters are clearly different for PWRs, RBMKs, and BWRs.

²⁰⁴ With the information available in [Lévêque, 2013b], it is not evident how to apply the Bayesian formulae by using new LERF parameters rather than the quoted CDF parameter. In that sense, it would be interesting to perform an exercise with two hypothetical limit cases, one with a LERF “mathematically small” (e.g. 10^{-10} /Ry but 5 recorded major accidents), and another with a realistic theoretical LERF (e.g., $\sim 10^{-7}$ /Ry and only 1 recorded major exercise). This would then define the limits of the Bayesian estimate.

8.2.3 Summary of Results for External Costs due to Nuclear Accidents

Having surveyed a variety of results for the specific external cost of nuclear accidents and observing the considerable variation, we nevertheless seem to be able to discern a reasonable order of magnitude value. Furthermore, as range of uncertainty, we apply the simple “rule” mentioned by [Rabl, 2013]²⁰⁵, taking 1/3 as lower bound and x 3 as upper bound.

In summary, therefore,

the order of magnitude of external cost due to nuclear accidents is $\sim 0.3 \dots 1 \dots 3$ €/MWh.

As a final comment on the estimated absolute cost (expressed in €) and the expected specific costs (i.e., taking into account the probability of occurrence and normalized per MWh) of nuclear accidents, the above “walk” through the literature shows that *more research on this subject is highly desirable!*

8.3 Liability for Nuclear Accidents

Under current legal regimes, in many countries there is a limited liability of nuclear operators with respect to nuclear accidents. This is considered by some as a hidden subsidy to the nuclear industry, since the external cost related to accidents would not fully internalized.

It is therefore useful to reflect on the issue of so-called hidden subsidy and to see whether and how full internalization would make sense. From a general point of view, as is implicit in what we discussed in earlier chapters, there is no convincing reason why external costs caused by electricity-generation technologies should not be internalized. So, if *all* generation technologies are expected to internalize *all* their externalities (GHG emissions, local air pollution, accidents,..., system-integration costs), then there is no argument why that should not be done for nuclear power. This, of course is a matter of principle; the major challenge, however, is that a quantification of the externalities is not an easy task. This has been made clear from the discussion in Chapters 7 & 8, and will be evident from the considerations on system effects in Chapter 9. Having said that, this challenge is not an excuse not to try to identify and evaluate the externalities correctly. Even if imperfect and unfinished, it stimulates the scientific exchange of ideas and allows sharpening the discussion.

The discussion on a so-called hidden subsidy has been going on for quite some time, and has not been fully “resolved”, if that would be at all possible. Up to about 2003, the issue is well summarized in [MIT, 2003], in relation to the US liability Price-Anderson Act. We reproduce part of the arguments in Figure 8.9.²⁰⁶ The excerpt of [MIT, 2003] shows that the scientific literature has not always clear on the issue.

²⁰⁵ Which supposedly has been used for external costs of air pollution.

²⁰⁶ Note that the number of 9.5 billion \$ quoted there is applicable at the time of publication of [MIT, 2003]. The newest numbers are given below at the end of Section 8.3.1.

Perhaps the most controversial aspect of Price Anderson is the current \$9.5 billion limit on the civil liability of a licensee where the accident has occurred. Critics argue that this represents a significant subsidy to nuclear power. Estimates vary from about \$3.5 million per plant per year to \$30 million per plant per year (\$2001). Critics of Price-Anderson often cite a 1990 study by economists Jeffrey Dubin and Geoffrey Rothwell that estimated the cost of the subsidy at about \$30 million per year per plant or over \$3 billion per year for the entire industry.⁷ However, these calculations contain several errors that are now widely recognized, except perhaps by those who find it convenient to argue that Price Anderson represents a large subsidy. Heyes and Liston-Heyes show that errors in the original calculation reduce the level of the “subsidy” by a factor of between four and ten.⁸ A subsequent paper by Rothwell argues that further corrections would reduce the value of the subsidy by as much as a factor of one million.⁹ The correct value of the “subsidy” that would arise from the appropriate application of these methods is very small.

Figure 8.9: Excerpt on the Price-Anderson liability Act in the USA and its possible relationship to a hidden subsidy. Ref [MIT, 2003], p 82²⁰⁷

Besides the discussion on the magnitude of the alleged subsidy in the USA whereby authors have corrected their earlier “misinterpretations”, there was also a discussion as to whether there actually is a subsidy at all. [Rothwell, 2002] reasons, along the same lines as Benjamin Zycher²⁰⁸ in 1992, that there is no real subsidy in the proper economic sense (thereby invoking the MIT Dictionary on Modern Economics of 1992). His argument reads: «there is no subsidy payment unless there is an accident and damages are above the [Price-Anderson Act] limit. Because there is no payment, there is no “direct subsidy”, although there is a potential (or expected) subsidy» [Rothwell, 2002]. That subtle difference in the meaning of a real subsidy (i.e., the distinction between an *“expected subsidy with actual value and an actual subsidy”*) is disputed by [Heyes, 2002], who argues that «the nuclear power industry receives a subsidy each and every quarter in which it does not have to buy insurance to cover the full risk associated with its activities». However, this argument is then, in turn, questioned by [MIT, 2003], which asserts that [in the US] «there is no obligation placed on businesses to carry full insurance against damages caused by an accident. Indeed, full insurance would be quite unusual. While businesses would still be liable for damages in excess of its insurance coverage, any corporation effectively has limited liability, since a very large accident could exceed the financial resources of the company, and it would seek protection under the bankruptcy laws. So, for example, the collapse of a dam or the explosion of an oil tanker could cause substantial damages and these damages could exceed both the firm’s liability insurance coverage and the value of the equity in the business».

Whatever the arguments, most authors seem to agree that much more work is needed resolving this issue and that the evaluations of an alleged “potential or expected” subsidy depends crucially on assumptions. To remain “neutral” in this discussion on such subtleties, the author of this report shall below always refer to “alleged”, “so-called” or “supposed” subsidies.

²⁰⁷ For original references on the quoted papers, see [MIT, 2003]

²⁰⁸ Reference given by [Heyes, 2002]

8.3.1 Currently Existing Rules on Liability of Nuclear Operators in Case of Accidents

The international situation on legally binding rules for liability in case of a nuclear accident is quite diverse and not immediately evident. An interesting brief summary is given in [Faure, 2009],²⁰⁹ but it remains confusing for non-legalistic specialists. There is the set of so-called “Conventions” of Paris, Brussels, Vienna, a Protocol between these Conventions, some between OECD members, others through the UN-sponsored IAEA, some of them ratified, others not yet ratified. To some extent related to, but also more or less independent of these international (non-)Agreements, national authorities have decided on their own liability rules. The European Union is currently in the process to straighten out some of these issues and has just finished a public consultation;²¹⁰ the status of national liability regimes as of June 2011 can be found in a list summarized by the NEA of the OECD.²¹¹

On these liability regimes, we wish to make four short clarifications and comments.

- “Strict liability” refers to the fact that a nuclear operator is liable for compensating damages after an accident «irrespective of his behavior; there is no need for the victim to prove the fault or negligence of the operator». «“Channeled liability” means that the nuclear operator will be exclusively liable in the case of accidents. The formal justification for channeling is that it avoids the multiplication of procedures against constructors, suppliers or subcontractors and thus, makes lawsuits for victims easier. This rule is, however, debatable from an economic perspective, more particularly since channeling excludes liability of others who could have contributed to the accident risk as well.» (Quotes from [Faure, 2009].)

- In some countries the liability is “unlimited”. This is strange since the liability of an operator is clearly defacto limited to the value of his balance sheet. If the requirements exceed the total value of the company, then evidently bankruptcy follows.

- It is not entirely clear how “liability” of a state-owned company is to be considered (or of companies in which the state is a majority shareholder). For (almost) fully state owned companies, one could pretend that in a bookkeeping sense that here is a difference, but in the end, it is the State who is the beneficiary of the financial gains of the nuclear operator, but who is also responsible to take up the “losses” or “dues” when needed.

- The US seems to have a fairly “interesting” system through its “Price-Anderson Act”. After some amendments, the situation is currently as follows. The compensation system consists of two tiers. For the first layer, the nuclear electricity generator has to acquire an insurance from the commercial market up to a level of 373 million \$, but on top of that, a second layer requires all licensed nuclear plants in the US to contribute to a fund that can be called upon in case of an accident. As of September 2013, that second layer contains a total of 12.6 billion \$. Hence, the total amount available as of this writing is almost 13 billion \$.²¹²

²⁰⁹ As a matter of fact, an extensive legal treatise on nuclear liability issues with focus on Belgium and the Netherlands has been made under the supervision of Faure in 2001 by [Vanden Borre, 2001]

²¹⁰ See: http://ec.europa.eu/energy/nuclear/consultations/20130718_powerplants_en.htm; Latest access November 16, 2013

²¹¹ <http://www.oecd-nea.org/law/2011-table-liability-coverage-limits.pdf>; Latest access November 16, 2013

²¹² See e.g., <http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/funds-fs.pdf>; and for the latest update http://www.world-nuclear-news.org/NP-US_nuclear_liability_premiums_adjusted-1507134.html

8.3.2 Economic Arguments to Fully Internalize External Costs of Accidents

In the above referenced paper [Faure, 2009], Faure & Fiore set out their arguments as to why external costs as a consequence of nuclear accidents should be fully internalized. As they argue, failing to do so, which would be reflected by a limited liability, amounts to granting a subsidy to the nuclear operator. «The inefficiencies created by a nuclear subsidy [...] are of three kinds. Firstly, it might generate an artificial competitiveness of nuclear energy. Secondly, it may not provide the sufficient incentives to the operator [to be sufficiently dedicated to safety issues in order] to prevent nuclear accidents. Thirdly, the compensation capacity for the victims in case of an accident is made clearly deficient.»²¹³

These three arguments are further developed in [Faure, 2009], and need not be repeated here.²¹⁴ It seems that for each of these elements, valid points are made. However, some comments are in order.

As to the first point, [Faure, 2001] stresses that not internalizing the risk costs of accidents, creates a bias in favor of the competitiveness of the operator, «*because all the costs are not reflected in the kWh price*». The spirit of what is written is correct, but it must be clear that in liberalized electricity markets the wholesale price is set by the marginal generation unit, and that is rarely a nuclear plant (except for France and except in other heavily nuclearized countries in case of low load). Also transferring a levy to the end-consumer price is not evident since that would also affect customers of suppliers without nuclear in their generation portfolio. What happens is that external costs of all kinds of generation (as this does not only apply to nuclear) must be taken into account in the generation cost, which in turn somewhat “penalizes” the affected generation means in the merit order. This internalized cost does then appear in the books of the operator (who will indeed recover part of it when nuclear is the marginal unit).

The second point likewise seems to make sense, because of the intended feedback mechanism on the safety-related behavior of the operators. The argument applies to the operators as a whole as long as their liability requirements (being identical for all on a per MWh basis) would be related to an overall common level of safety standards in the EU and their successful fulfilment. The argument does not really apply to an individual operator since adjusting individual liability requirements according to the “state of safety” of a particular plant is obviously not practicable, since “insufficiently safe” plants are not supposed to operate. It is up to the Nuclear Regulators, hopefully after European “concertation” to set justified minimum standards. There seems to be no fundamental problem then by setting the height of the liability requirement in accordance with the objective for LERF (as e.g., the IAEA objective in Figure 8.3). It makes sense economically that a lower LERF would lead to a lower expected external cost of an accident, which is then also reflected in a smaller specific external cost per MWh.

The third point is indeed a valid argument, but only applies to non-state owned electricity companies. Regardless of the height of the compensation fund, in case of state-owned companies, the state will have to pick up the bill. Colloquially speaking, with state-owned companies, there is always a left-pocket / right-pocket situation when this type of situations applies.^{215 216}

²¹³ Except for what is written in square brackets, [...], the text is quoted literally from [Faure, 2009]

²¹⁴ The paper is free of charge available on the internet; see our bibliography / reference list → [Faure, 2009]

²¹⁵ More generally, such left/right pocket arguments apply whenever if subsidies or taxes are an issue, for state-owned companies.

²¹⁶ Independent of state-owned companies, it is interesting to learn that the French state has made some expenditures for nuclear, but that it almost completely recovers that amount through tax revenues from the nuclear sector (numbers of 2010 – see [CdC, 2012] English Exec Summary p 19). But

8.3.3 Evaluation of the Alleged Nuclear Subsidy Related to a Liability Ceiling

To have an idea of the sort of so-called hidden subsidy due to a liability ceiling, it is instructive to see how [Faure, 2009] (relying on earlier work by co-author Fiori) tackle the issue; we rely on their treatment and reproduce their results.

The calculation is done for France, and we present the results assuming that the most recent increases of the liability caps of the international Paris and Brussels Conventions apply (the so-called 2004 Protocol).²¹⁷ That means that the operator has a financial cap of 700 million € and the state's cap is 500 million €. These values are integrated in the evaluation of the alleged subsidy.

There are four accident scenarios considered, with costs varying as follows: $C_i = 10, 40, 70$ and 100 billion €. Next, three CDF probabilities are investigated: $p_j = 10^{-4}, 10^{-5}, 10^{-6}$ per Ry. Finally, for out-of-containment release of radioactivity, the conditional LERF/CDF factor of 0.19 of [ExternE, 1995] is utilized.²¹⁸ Finally, the R_k stand for the share of a risk-aversion premium (5% or 10%) in the total insurance premium.

The outcome of the computations is presented in Figure 8.10.

	$p_1=10^{-4}; p_2=0.19$		$p_2=10^{-5}; p_2=0.19$		$p_3=10^{-6}; p_2=0.19$	
Cost of major accidents	$R_1=5\%$	$R_2=10\%$	$R_1=5\%$	$R_2=10\%$	$R_1=5\%$	$R_2=10\%$
$C_1=10,000$	0.320	0.310	0.080	0.079	0.020	0.019
$C_2=40,000$	1.230	1.220	0.315	0.310	0.250	0.230
$C_3=70,000$	2.040	1.900	0.540	0.530	0.360	0.350
$C_4=100,000$	2.800	2.700	0.730	0.670	0.540	0.510

Figure 8.10: Values of the supposed French nuclear subsidy expressed in Million € per Ry. The numbers take account of the 2004 Protocol.
Reference: [Faure, 2009]

Concentrating for a moment on the central value of the CDF of $p_2 = 10^{-5}$, the worst-case accident scenario with 100 billion € damage, would lead to a so-called subsidy of ~ 0.7 million per Ry. Following [Faure, 2009], and considering next the full range of accident frequencies, for the whole nuclear fleet as a whole (with 59 operating reactors), and according to the regime of the 2004 Protocol, the estimates lead to a total so-called subsidy spread of ~ 1.1 million €/year (upper right corner, $0.0195 * 59$) to ~ 162 million €/year (lower left corner, $2.75 * 59$) after 2004. Assuming that a typical French reactor produces 7 TWh/year,²¹⁹ the maximum value amounts to $162/(59*7)$ €/MWh or **0.4 €/MWh**. Further in the paper, [Faure, 2009] makes the point that with an average electricity generation cost of 30 €/MWh in France, the 0.4 €/MWh, being a bit more than 1%, clearly exists, but would only negligibly affect the price.²²⁰ Nevertheless, according to the spirit of the paper, they support the idea that that externality be properly internalized.

as a state heavily involved in electricity generation (via EdF and GdF-Suez) the profits & losses of those companies should be taken into account as well.

²¹⁷ Individual countries are allowed to go higher than these amounts. [Faure, 2009] also presents the results if the 2004 Protocol would not apply. In summary, in France, the new 2004 Protocol would reduce the so-called hidden subsidy by 44%. Since it is only fair that the 2004 Protocol numbers would apply, it does not serve a real purpose here to present the pre-2004 results. Having said that, the interested reader can consult [Faure, 2009]

²¹⁸ The notation in Figure 8.10 is confusing. The p_i are the CDF, while the conditional LERF/CDF factor, being 0.19 is (also) represented by p_2 (which symbol has therefore two meanings). In the body of the paper, the authors use upper-case letters: P_i and P_2 . A better notation would have been $p_i = 10^{-4}, 10^{-5}, 10^{-6}$ and $P_1=0.81$ & $P_2=0.19$.

²¹⁹ Number assumed in [Faure, 2009]

²²⁰ This is a paraphrase of what is literally written on p 441 of [Faure, 2009]; but they do indeed use the word "price"; as explained above, it would be better to refer to the "cost", since the wholesale price is set on a European-market scale.

The order of magnitude of this computation is in line with what we have concluded in our computation of the specific cost of a nuclear accident, expressed in €/MWh (see Section 8.2.3).

8.3.4 Possible Approach for Avoiding an Alleged Hidden Nuclear Subsidy

After the reflections, considerations and results given in this Chapter 8, but especially in Sections 8.2 and 8.3, it seems reasonable to suggest a possible approach for internalizing the external cost of a nuclear accident and to avoid a so-called hidden subsidy. The actual implementation is dependent on the outcome of the external-cost computations with their uncertainties, but it should be possible to converge on a “representative” number. A possible line of thought may be to set up a liability scheme based on a current-day accepted number for the external cost. As a start, a base figure of **1 €/MWh** seems reasonable.

Chapter 9

System Costs

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9.1 Introduction

Determining the cost of electricity system-integration is not an easy subject. In the past when the electric system operated in a regulated market with basically vertically integrated utilities, the issue was less crucial, since it was not really necessary to allocate all the cost properly since all costs were transferred to the customers anyway. In liberalized markets, with unbundling and hence, different market players, a clearer cost picture is highly desirable. In addition, in the past, basically mostly *dispatchable* units were present in the electricity system, whereas recently the amount of intermittent²²¹ (and limitedly controllable) renewable energy sources (RES) has increased significantly and is bound to increase even more massively in the EU over the years to come. That means that the operational challenges put on balancing and controlling the system have increased considerably, and that future investments in transmission capacity (and possibly electricity storage) will have to grow substantially. As a consequence of the imposed RES target fraction in terms of renewable energy compared to the end energy at the level of the consumer (having been set at 20% by 2020), this means that the *electric* renewable energy fraction in the EU is expected to be about 34%. Furthermore, because of the limited effective number of operating hours of wind and PV-solar generation, this will result in a considerable overcapacity (i.e., installed power) at moments of low electricity demand. Further in the future, the overcapacity issue will become even more challenging. As a combination of the liberalized market, where the wholesale price is set by the merit order, and thus the marginal generation unit, it is possible that massively deployed RES with quasi zero marginal cost become so dominant that there is a downward pressure on the price setting and in cases of low demand, leading to negative electricity prices. The fact that even in cases of oversupply the RES have priority access to the grid and continue to receive financial support does not make matters easier. In contrast, during nights and during wind-deficient-cold-spell periods, installed PV and/or wind capacity are/may be idle leading to a lack of generation. If “intelligent” recipes are found and are allowed to be implemented (cfr. grid extensions, access to the grid, forced operation or shut down by the grid operator, ...), then by 2030 and beyond, the situation may be manageable; but lacking the necessary measures, the situation is expected to aggravate. But even when technically acceptable, the overall system costs will have increased substantially.

This is not the place to discuss the whole issue of electricity-system integration. The reader is referred to the literature, such as e.g., [Freris, 2008], [Holttinen, 2009], [IEA, 2011], [D’haeseleer, 2011] and the references therein. Our own earlier work [D’haeseleer, 2011] considers the technical situation with ample RES and nuclear units as part of the electricity system.

On the cost of system integration, first considerations have been and are being undertaken, and recent studies are becoming more extensive, but it is clear that much more work is necessary. We mention again [Holttinen, 2009], [IEA, 2010] (chapter 10, p 322), [IEA, 2011] (Chapter 10, p 81), [UKERC, 2006] (which has made a large scan of the literature up to 2005), [MIT, 2011b], [NREL, 2010], [NREL, 2013].

It seems, however, that the most recent full-scope treatment of RES integration and the role of nuclear is the comprehensive work by the NEA/OECD “Nuclear Energy and Renewables – System Effects in Low-carbon Electricity Systems”. [NEA, 2012a]²²² In this Chapter, we will almost exclusively rely on that report. There are several reasons for taking this report as a guide throughout our discussion on the cost of system integration. First, the report is free-of-charge available at the internet, and is thus freely accessible for everybody who

²²¹ In our definition, “intermittent” comprises two aspects: first the variability (even if perfectly predictable) and the uncertainty due to the imperfect predictability.

²²² It may be mentioned that the author of this report has (to a minor extent) collaborated on that study by providing information for Section 2.1 and for Section 6.1, being sections on the technical integration and the role of smart grids, respectively.

wishes to study the issues. Second, the report delineates and quantifies all cost components, whereby the Excel-based quantitative model is explained, and the data are given, in Appendices, and thus can be “checked” by third parties. Third, a comprehensive in-depth analysis using two integrated models—independent of the main authors of the report—has been made for the case of Germany by IER Stuttgart, and has been included in Chapter 7 of the report, serving as an independent “validation” of the Excel-model results. And finally, this report should be read by a wide audience so that the techno-economic discussion can continue, whereby the results are confirmed or challenged, possible omissions are identified, potential methodological or other errors are discovered, models are made more sophisticated—in short, so that the scientific method can take its course.²²³ Having said that, the qualitative reasoning of the report seems correct; the analyses are well explained and straightforward, albeit sometimes using simplified models and understandably relying on a set of modeling assumptions and boundary conditions, but unless proven otherwise, we take it that the quantification of the costs is sufficiently “accurate” in the sense that it gives the right orders of magnitude for the system costs and is a guidance for further reflection on the system-integration issue.

In this Chapter, we give a summary of the reasoning and results found in [NEA, 2012a]; the reader is invited to consult the report for further clarification, details and references.

9.2 Load Following of Nuclear Power Plants

Before launching into the cost issue, it is first necessary to clear up a possible misunderstanding on a technical issue, namely the possibility of nuclear power plants (NPPs) to cycle, i.e., to participate in load following. (See e.g., [JRC, 2010a], [NEA, 2011], [NEA, 2012a] (Chapter 3), and references therein.)

Although most NPPs usually run in baseload mode because of cost reasons, and are usually designed to do so, it is technically possible for plants to participate in load following. The French NPPs have always been participating in load following, and recently, because of the large share of intermittent renewables, the German NPPs have started to cycle as well.²²⁴ The table in Figure 9.1 (taken from [NEA, 2012a]) shows the technical capabilities of a set of dispatchable power plants.

	Start-up time	Maximal change in 30 sec	Maximum ramp rate (%/min)
Open cycle gas turbine (OCGT)	10-20 min	20-30%	20%/min
Combined cycle gas turbine (CCGT)	30-60 min	10-20%	5-10%/min
Coal plant	1-10 hours	5-10%	1-5%/min
Nuclear power plant	2 hours - 2 days	up to 5%	1-5%/min

Source: EC JRC, 2010 and NEA, 2011.

Figure 9.1: Comparison of relative load-following capability of a set of dispatchable plants. Taken from [NEA, 2012a], Table 3.2.
The sources indicated are our mentioned references [JRC, 2010a] and [NEA, 2011].

In absolute value, the ramp rate of NPPs is larger than might be concluded from Figure 9.1. Indeed, compared to a CCGT of installed capacity of 400 MW, the ramp rate of NPPs of 1000 MW or 1600 MW, is

²²³ An aspect of incompleteness in the monetization exercise is e.g., the fact that in the calculations, national systems are considered and not integrated system on continents whereby power cross-border exchange (export/import) takes place and whereby one could perhaps contract from foreign hydro-pump storage plants. These issues are discussed qualitatively in Chapters 5 & 6 of [NEA, 2012a], but not quantified.

²²⁴ German nuclear plants were originally designed for a flexible load. (See [NEA, 2012a], p 69.)

comparable: 10%/min of 400 MW is 40 MW/min, while 5%/min of 1000 MW or 1600 MW is 50 MW/min or 80 MW/min, respectively.

The thorny issue regarding load following for nuclear power plants is the *economics*. From a bookkeeping-point of view, there should be no “problem” for existing depreciated plants, but when thinking in terms of opportunity cost, matters are different. Clearly, for new NPPs, the issue of load following is translated into a reduced load factor, which negatively affects its LCOE.

9.3 Delineation of the Cost Elements of System Integration

The overall system integration cost of electricity generation technologies can be considered at different levels and may be summarized as follows.²²⁵

Grid related costs

- *grid connection* i.e., the extension of the existing grid to plants outside the current grid area; this is a special point of attention for offshore wind-power farms;
- *grid reinforcement* i.e., upgrading the current grid in terms of voltage or load-carrying capability;
- *grid extension* i.e., extension of the existing grid to plants inside the current grid area.

Balancing supply and demand

- *short-term balancing* i.e., the provision of the appropriate flexible generation reserves, being heavily affected by the intermittent²²⁶ nature of the wind and PV feed-in, in order to ensure a given level of electricity supply; ramping costs for the back-up generation technologies;
- *long-term adequacy* i.e., the provision of sufficient back-up capacity to satisfy electricity demand at any moment. This issue is related to the so-called capacity credit of the deployed RES technologies in the system. It is important to specify the time at which the analysis for adequacy is done. To earmark the difference, the report [NEA, 2012a] makes a difference between a so-called *ex post analysis*, which focuses on the short time whereby the back-up capacity is already present in the system. In a longer-term scenario, referred to as an *ex ante analysis*, the investment costs for the new back-up capacity must be taken into account. As this requires careful explanation, with the right nuances and appropriate “ifs and buts”, we have taken the liberty to “borrow” the explanatory Box 1.1 of [NEA, 2012a] in Figure 9.2.

²²⁵ Our discussion summarizes the discussion of [NEA, 2012a], Sections 1.3 & 1.4., sometimes quoting or paraphrasing from the report.

²²⁶ Cfr. our definition of “intermittency” in the first footnote of Chapter 9.

Box 1.1
The true costs of long-term adequacy

Capacity provided by variable renewables such as wind and solar requires almost complete matching by dispatchable technologies in order to provide electricity during the hours when the wind does not blow or the sun does not shine. While estimates of the capacity credit of variable renewables, their ability to fully substitute for dispatchable capacity, vary widely and depend heavily on local circumstances, they rarely exceed 10% of total capacity and decline with rising shares of variable renewables in electricity production. Estimating the costs of such back-up capacity is less straightforward than it seems.

The cost of long-term adequacy depends largely on the position in time where the analysis is situated. The cost estimates of the system effects of variable renewables made under different assumptions vary widely and have thus been carefully distinguished throughout the study. If the analysis is situated in a present where adequate dispatchable capacity to cover peak demand is already available and renewables are forced into the existing system overnight, then adequacy costs are very low or even zero. Throughout this study this short-term snapshot based on the current situation is referred to as *ex post* analysis. In this case, renewables do, in general, not require any additional investments in back-up capacity until the end of the operating lifetimes of the existing dispatchable capacity.

However, if the analysis is situated in a long-term future, where renewables are introduced over time, old dispatchable capacity is retired and new dispatchable capacity has to be introduced only to produce during the moments in which variable renewables are not available, then adequacy costs are substantial. Throughout the study, this is referred to as long-term *ex ante* analysis. An *ex ante* assessment of back-up needs considers a country's energy system a clean slate, where the installed capacity of variable renewables needs to be matched by nearly equivalent amounts of dispatchable capacity (the precise amounts depend on the capacity credit of the renewables) that needs yet to be built and whose fixed costs still need to be paid for. A long-term *ex ante* assessment of back-up capacity needs is also required each time that renewables are considered for satisfying new demand. Chapter 4 reports the figures for such long-term *ex ante* analysis.

If all costs including past capital costs were accounted for correctly, the total costs of the electricity supply system will be higher in the *ex post* than in the *ex ante* case, since the total generation fleet will be uneconomically large. However, most costs would fall on dispatchable producers ("which are there anyway") and not to variable renewables in terms of back-up costs. While it is true that these capital costs are sunk as far as the present generation of dispatchable plants is concerned, it would be an error to transfer this assumption to a new generation of dispatchable plants once the current one has reached the end of its useful life. In the long run, the costs for a least-cost mix of dispatchable back-up technologies thus needs to be taken into account.

The question as to what are the true costs for adequacy in practice is difficult to decide and depends on the time frame. For a share of 10% of renewables in electricity supply, *ex post* analysis is possibly sufficient. For a share of 30% of renewables clearly *ex ante* analysis is warranted as substantial shares of current capacity with sunk capital costs would be retired by the time the target of 30% was reached.

Figure 9.2: Clarification of "The true costs of long-term adequacy". Taken from [NEA, 2012a], p 31.

The combination of the *plant-level cost* and the *costs related to the five aspects* mentioned above, is further referred to as the "*total cost of electricity supply*".²²⁷ This cost is estimated for six different OECD countries, depending on a future penetration of 10% or 30% of variable renewables (% in terms of electrical energy, not capacity). It may already be reported that the results are very different depending on the country considered because of a different cost for the RES but also because of the different structure of the electricity system.

As a next step, on the system-integration cost issues, [NEA, 2012a] addresses the "*pecuniary*²²⁸ and *dynamic effects*" of variable renewables. A three-fold concern is raised, whereby [NEA, 2012a] also discusses rather extensively, albeit qualitatively, «whether such dynamic pecuniary externalities contribute to an overall

²²⁷ Stated differently, the *total cost of electricity supply* at the macro level includes «plant-level costs; system costs at the grid level; and variable and fixed cost savings or increases due to the displacement of electricity production from conventional plants.» The [NEA, 2012a] report also reflects on what it calls the "*total system cost*". That cost includes, on top of the "*total cost of electricity supply*", also the cost due to *externalities*. The externality issues are only qualitatively discussed in the [NEA, 2012a] report; the nuclear-related issues are similar to what we discussed in Chapters 7 and 8 of this report. Perhaps useful to mention are two elements that we have not addressed, but for which the reader can consult the available literature. Security of Supply is often considered as a positive externality of nuclear power, as is demonstrated by the "Simplified Supply and Demand Index" (SSDI), developed in [NEA, 2010b]. As to the indirect GHG emissions of nuclear power, the reader is referred to Chapter 2 of [NEA, 2012b], which gives a more comprehensive treatment than presented in [NEA, 2012a].

²²⁸ "pecuniary" = money or financially related.

increase in the cost of the energy system, or primarily constitute transfers between competitors in a dynamically evolving system»²²⁹. The issues as a consequence of large-scale renewables integration are:

- *Lower and more volatile electricity prices* in wholesale markets. This is a consequence of marginal-cost pricing and the merit order in liberalized markets, and leads to a problem for electricity generators since they are «no longer able to pay for the fixed costs of their installation, as long as they are not subsidised by feed-in tariffs. To maintain the security of supply, alternative means of financing (feed-in tariffs, contracts-for-difference, capacity payments, or other) have to be found, whose cost is, of course, billed back to consumers, while market prices decline.[...] In the long run the issues of declining wholesale prices question the very role of the market place to provide adequate signals for power generation investments.»
- *Reduction of the load factors of dispatchable power generators* (compression effect). Not only are operators of dispatchable plants facing lower wholesale prices, they are pushed out of the merit order, resulting in an overall lower load factor. «Due to their low marginal operation cost renewables will have precedence in the merit order over dispatchable supply as long as their system costs are not internalized.»
- *De-optimization of the current structure of generation*: dispatchable units feel the compression effect in a different manner. In the short run, with existing plants, it will be those plants with the highest marginal cost (i.e., open-cycle gas turbines and CCGTs) that will drop out first; nuclear power plants, characterized by lower marginal costs are able to remain longer in the merit order. This effect is currently seen all over Europe with many gas fired units sitting idle. In the long run, when new investments are taken into account, low-fixed-cost units will be favored over high-capital-cost technologies, like NPPs.²³⁰

9.4 System-Integration Costs / Quantitative Results

[NEA, 2012a] performs a system cost analysis for six OECD countries (of which four European ones).²³¹ The six countries are: Finland, France, Germany, S. Korea, the UK and the USA. Three dispatchable technologies are considered: gas, coal and nuclear, and three intermittent RES: solar PV, wind onshore and wind offshore. To account for the non-linearity of the grid-level system costs, two types of penetration (in terms of annual MWh generated in the country in question) are considered: 10% and 30%.

The study provides its quantitative analysis of the electricity system-integration costs in four steps.

1. Plant-level costs only (LCOE), but at 7% discount rate and 30 \$/ton CO₂
2. “System cost at grid level” per technology in typical countries
3. “Total cost of electricity supply” of the overall system as a function of RES penetration
4. Pecuniary externalities (de-optimization electricity generation mix)

The results of these four steps are now discussed.

²²⁹ These issues are more extensively explained in Chapter 1 of [NEA, 2012a].

²³⁰ These long-term effects could change in case of higher gas prices and if CO₂-emission penalties were to apply.

²³¹ See [NEA, 2012a] Section 4.2.

9.4.1 Plant-Level Costs Only (LCOE)

The results presented here are basically for reference. They are the bare plant-level LCOE, analogous to the ones reported in [NEA/IEA, 2010] and our computations in Chapter 6.

There are two main differences compared to [NEA/IEA, 2010]: 1) one has chosen to use an “average” discount rate of 7%/a, instead of the 5% and 10% in [NEA/IEA, 2010] and in our Chapter 6; 2) some of the values for overnight investment cost have been updated. As in [NEA/IEA, 2010], a CO₂ penalty of 30 \$/ton has been assumed.

The LCOE results are shown in Figure 9.3.

	Plant-level costs (USD/MWh)					
	Nuclear	Coal	Gas	Onshore wind	Offshore wind	Solar
Finland	73.8	71.6	88.1	111.0	158.4	488.3
France	72.2	85.7	87.3	110.8	143.2	413.4
Germany	67.8	85.7	87.3	119.5	158.4	249.3
Republic of Korea	42.3	69.4	92.3	111.0	174.2	222.3
United Kingdom	86.0	94.3	105.7	113.4	137.4	363.7
United States	63.6	75.5	74.3	93.2	114.2	214.9

Figure 9.3: Bare plant-level LCOE for different generation technologies and countries. Taken from [NEA, 2012a], Table 4.5

9.4.2 System Cost at Grid Level per Technology

In Figures 9.4 and 9.5, we present the results for the “grid-level system cost” for two European countries, Germany and the UK. When reading these figures, it is important to correctly interpret the 10% and 30% penetration levels. As already mentioned, it is a penetration level in terms of TWh/a. But also important, for each technology, there is an assumed penetration level, against the background mix of that country. Thus, e.g., 10% and 30% solar means that there is a penetration of PV generation of 10% and 30%, neglecting the other RES, and assuming the current (roughly 2010-2011) generation mix of dispatchable units. Likewise, 10% gas would mean that there is only 10% gas penetration.

Clearly, the background generation mix of each country has an impact on the computation of system costs, in particular for the short-term balancing costs. The balancing costs of intermittent renewables have been taken from the literature (country studies) that takes into account the generation mix of dispatchable technologies that ensure the balancing, in most of the cases. No balancing costs have been attributed to gas and coal. Concerning nuclear, the balancing costs are calculated as the additional spinning reserves requirements due to the larger size of a nuclear unit.

Germany												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.04	0.04	0.00	0.00	7.96	8.84	7.96	8.84	19.22	19.71
Balancing costs	0.52	0.35	0.00	0.00	0.00	0.00	3.30	6.41	3.30	6.41	3.30	6.41
Grid connection	1.90	1.90	0.93	0.93	0.54	0.54	6.37	6.37	15.71	15.71	9.44	9.44
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	1.73	22.23	0.92	11.89	3.69	47.40
Total grid-level system costs	2.42	2.25	0.97	0.97	0.54	0.54	19.36	43.85	27.90	42.85	35.64	82.95

Figure 9.4: The “grid-level system cost” for Germany, expressed in \$₂₀₁₁/MWh. Taken from [NEA, 2012a], Table 4.6

United Kingdom												
Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.06	0.06	0.00	0.00	4.05	6.92	4.05	6.92	26.08	26.82
Balancing costs	0.88	0.53	0.00	0.00	0.00	0.00	7.63	14.15	7.63	14.15	7.63	14.15
Grid connection	2.23	2.23	1.27	1.27	0.56	0.56	3.96	3.96	19.81	19.81	15.55	15.55
Grid reinforcement and extension	0.00	0.00	0.00	0.00	0.00	0.00	2.95	5.20	2.57	4.52	8.62	15.18
Total grid-level system costs	3.10	2.76	1.34	1.34	0.56	0.56	18.60	30.23	34.05	45.39	57.89	71.71

Figure 9.5: The “grid-level system cost” for the UK, expressed in \$₂₀₁₁/MWh. Taken from [NEA, 2012a], Table 4.6

From the results presented in [NEA, 2012a], we conclude *roughly* as follows for the *orders of magnitude* (for the EU countries investigated):²³²

Grid-Level System Cost (for penetrations of 10% & 30% for each technology):

Nuclear: ~ 2 – 3 \$₂₀₁₁/MWh

Coal: ~ 1 \$₂₀₁₁/MWh

Gas: ~ 0.5 \$₂₀₁₁/MWh

Wind onsh: ~ 20 – 30 \$₂₀₁₁/MWh - with outlier Germany (30%) ~ 44 \$₂₀₁₁/MWh

Wind offsh: ~ 30 – 40 \$₂₀₁₁/MWh - with outlier UK (30%) ~ 45 \$₂₀₁₁/MWh

PV: ~ 35 – 55 \$₂₀₁₁/MWh - with outliers Germany (30%) ~ 83 \$₂₀₁₁/MWh
- with outlier UK (30%) ~ 72 \$₂₀₁₁/MWh

9.4.3 Total Cost of Electricity Supply for Different RES Penetration Levels

In the next step of the analysis, the total system cost for different RES penetration levels is computed. On top of the “plant-level cost” and the “grid-level system cost”, a next step is now added to account for the variable and fixed cost savings or increases due to displacement of electricity generation from conventional plants.²³³ The analysis is done by comparing two cases, one without RES (called the “reference system”) and one with the prescribed fraction of intermittent RES. The “reference” system is a mix of conventional dispatchable

²³² For all four EU countries considered in [NEA, 2012a], hence also Finland and France.

²³³ «Unaccounted for benefits at the system level of conventional dispatchable plants include the fuel savings and other variable cost savings arising from the reduced use as well as the capital and other fixed cost savings from the dispatchable units that would be effectively displaced.» ([NEA, 2012a], p 129)

technology such as gas (CCGT), coal and nuclear based on the respective shares in the electricity generation mix of the countries considered. The “new” electricity system is constituted by intermittent RES at 10% and 30% each of the individual technologies while the residual load is covered by dispatchable technologies (whereby —in a first instance— the mix of dispatchable generation technologies was taken the same as in the “reference” case).^{234 235}

The results of the analysis for the 10% and 30% cases are shown in Figure 9.6.

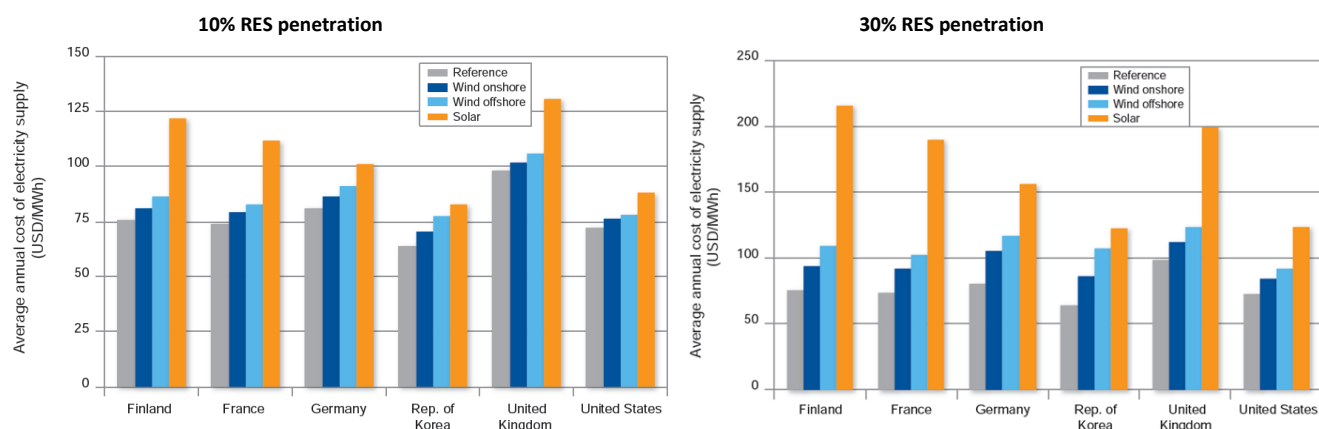


Figure 9.6: Average cost of electricity supply as a function of individual RES penetration in \$₂₀₁₁/MWh (averaged over the year). Note that the ordinates in both panels are on a different scale. Taken from [NEA, 2012a], Figures 4.10 & 4.11

The actual numbers for the EU countries are provided in the table of Figure 9.10.²³⁶

		Total cost of electricity supply (USD/MWh)						
		Reference	10% penetration level			30% penetration level		
		Conv. mix	Wind onshore	Wind offshore	Solar	Wind onshore	Wind offshore	Solar
Finland	Total cost of electricity supply	75.9	81.2	86.5	121.8	93.5	109.0	215.9
	Increase in plant-level cost	-	3.5	8.2	41.2	10.5	24.7	123.7
	Grid-level system costs	-	1.8	2.3	4.7	7.1	8.3	16.3
	Cost increase	-	5.3	10.6	45.9	17.6	33.1	140.0
France	Total cost of electricity supply	73.7	79.5	82.9	112.0	92.1	102.5	189.6
	Increase in plant-level cost	-	3.7	6.9	34.0	11.1	20.8	101.9
	Grid-level system costs	-	2.0	2.3	4.3	7.2	7.9	14.0
	Cost increase	-	5.8	9.2	38.3	18.3	28.8	115.9
Germany	Total cost of electricity supply	80.7	86.6	91.3	101.2	105.5	116.9	156.2
	Increase in plant-level cost	-	3.9	7.8	16.9	11.6	23.3	50.6
	Grid-level system costs	-	1.9	2.8	3.6	13.2	12.9	24.9
	Cost increase	-	5.8	10.6	20.4	24.8	36.2	75.4
United Kingdom	Total cost of electricity supply	98.3	101.7	105.6	130.6	111.9	123.6	199.4
	Increase in plant-level cost	-	1.5	3.9	26.5	4.5	11.7	79.6
	Grid-level system costs	-	1.9	3.4	5.8	9.1	13.6	21.5
	Cost increase	-	3.4	7.3	32.3	13.6	25.3	101.1

Figure 9.10: Total Cost of Electricity in \$₂₀₁₁/TWh (averaged over a year). From [NEA, 2012a], Table 4.7

²³⁴ In Appendix 4.D of [NEA, 2012a], a quantitative estimation of changes in the generation mix due to the introduction of the RES is provided.

²³⁵ Note that in the exercise with, e.g., 10% PV means a penetration of 10% PV in terms of TWh/a, while all wind is set to 0. Likewise, for the case of, e.g., 30% wind offshore, wind onshore and PV are 0.

²³⁶ The results for S. Korea and the USA have been taken out of the table by the author of this report.

*** **Intermezzo** ***

It is at this level interesting to complement the results for the “total cost of electricity supply” obtained with the Excel-based quantitative model developed by the NEA/OECD energy economists with the independent study for Germany (DE) performed by researchers of the IER of the University of Stuttgart. The analysis is presented as Chapter 7 of [NEA, 2012a]. The analysis is performed using the two integrated models E2M2s and JJM.²³⁷ Twelve different scenarios are modeled, combining three nuclear installed capacities (0 GW, 20.7 GW, 41.4 GW), and four RES penetration cases —as a fraction of the annually electric energy generated in TWh/a— (15%, 35%, 50% and 80%).²³⁸

The RES contribution consist of a mix of dispatchable generation (bio and hydro) and intermittent (wind onshore, wind offshore and PV solar). This is shown in Figure 9.11.

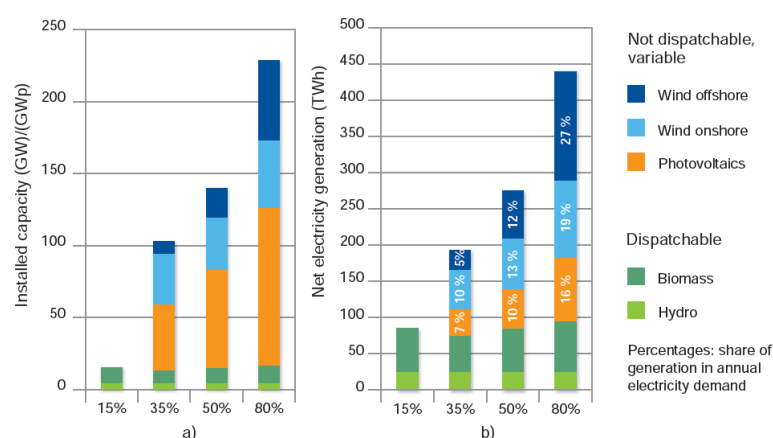


Figure 9.11: RES mix for the different scenarios for the IER Germany study.
a) is installed capacity and b) is annual electricity generation. Taken from [NEA, 2012a], Figure 7.1

The computations are performed with a CO₂ price of 50 €/2007/ton in all scenarios; and an annual discount rate of 7.5% is applied.

The outcome of the simulations is shown in the table of Figure 9.12.

Installed capacities of nuclear power plants/share of renewables	(EUR/MWh)		
	0 GW	20.7 GW	41.4 GW
15%	95	84	71
35%	120	109	101
50%	132	122	119
80%	174	171	174 ^a

a) Variation RES-80%_NUCL-41(21LE) with one half of the nuclear power plant portfolio being entirely depreciated but retrofitted: EUR 169/kWh.

Figure 9.12: Average annual generation cost expressed in €/2007/MWh for the various scenarios of the IER Germany study.
Taken from [NEA, 2012a], Table 7.5

²³⁷ The European Electricity Market Model (E2M2s) and the Joint Market Model (JMM) are briefly described in Appendix 7.A of [NEA, 2012a].

²³⁸ The 20.7 GW nuclear was the installed nuclear capacity in Germany right before the Fukushima accident on March 11, 2011. The RES shares of 35%, 50% and 80% are the German targets for 2020, 2030 and 2050, respectively. The 15% RES case has been added as an extra case by the IER researchers; it consists only of dispatchable biomass generation and dispatchable hydro generation.

According to those simulations by IER, the scenario with 15% RES and 41.4 GW nuclear has the lowest overall system cost (the grey box on the right-hand upper corner of Figure 9.12). The most expensive one is in the bottom row, roughly independent of the nuclear capacity. The total annual cost for the entire German system would be as shown in Figure 9.13.

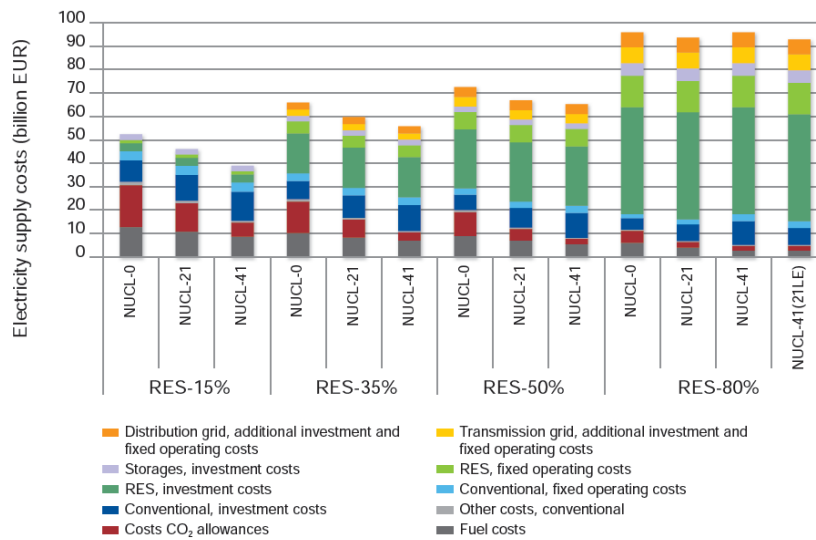


Figure 9.13: Total annual electricity system cost obtained by the IER scenario simulations for DE, expressed in G€₂₀₀₇. From [NEA, 2012a], Fig. 7.7

These numbers are sobering. The results are not out of line with those presented earlier in this subsection, using the more simplified Excel model. (E.g., for “validation”, compare both wind results for 30% penetration in the Excel case —Figure 9.10 for Germany— with the 35% RES penetration for ~ 20.7 GW nuclear in the IER case —Figure 9.12.) But clearly, it is desirable that more such analyses are performed so as to cross check the results. Understandably, the results are dependent on a variety of assumptions, but if the orders of magnitude are roughly accurate, then one must reflect on the desirability of such far reaching policies. Transparency helps in the decision making by the elected representative.

As some commentators might say, these results do not take into account the external environmental effects of nuclear power. That argument can be countered replying that the environmentally-related external costs of nuclear are very likely below ~ 5 €/MWh. Furthermore, as has been remarked by an observer, the extra costs derived in the IER analysis largely compensate for the external costs of NPPs. As an example, the difference between the two most extreme scenarios is as follows:

Least cost scenario RES-15%_NUCL-41 → 39 G€₂₀₀₇ per year (or 71 €₂₀₀₇/MWh)

Highest cost scenario RES-80_ NUCL-0 → 96 G€₂₀₀₇ per year (or 174 €₂₀₀₇/MWh)

→ Annually Δ = 57 G€ → e.g., after 20 years (at 0% discount rate) = 1,140 G€

→ e.g., after 20 years (at 7.5%/a discount rate) ~ 2,470 G€. ²³⁹

²³⁹ The future worth after N years (F_N) is computed via the standard engineering-economics formula $F_N = A \left[\frac{(1+d)^N - 1}{d} \right]$ with d the discount rate and $A \equiv \Delta$ in this case. If the extra-cost situation would last 40 years, then the result for $d = 7.5\%$ would be ~ 13,000 G€.

This extra cost, which is expected to occur with certainty²⁴⁰ (i.e., probability = 1), should then, e.g., be compared to the total cost of a nuclear accident as explained in Chapter 8, which only is expected to occur with a small probability. Such comparisons are undoubtedly oversimplifications, but the numbers, if they are in the right ballpark, are so overwhelming that they should be an invitation for reflection.

9.4.4 De-Optimization of the Energy Mix and Pecuniary Externalities

As explained above, two time scales must be considered when evaluating the impact of changes in the merit order for generation. The [NEA, 2012a] analysis presented in the first part of Section 9.4.3 was a static analysis.²⁴¹ In the analysis below, the dynamic aspects are taken into account.

In the graphical analysis to follow, the electricity generation & demand *profile* of France of 2011 was utilized. Instead of the current French generation mix, four types of dispatchable plants have been assumed: Gas (OCGT), Gas (CCGT), Coal and Nuclear. The optimal theoretical investment in the absence of RES injection would be as displayed in Figure 9.14. The fixed and operational cost of the plants is reflected in the top panel of Figure 9.14. A CO₂ price of 30 \$/ton is assumed throughout. Via the load-duration curve, the optimal mix is then obtained as shown in the left lower panel.²⁴²

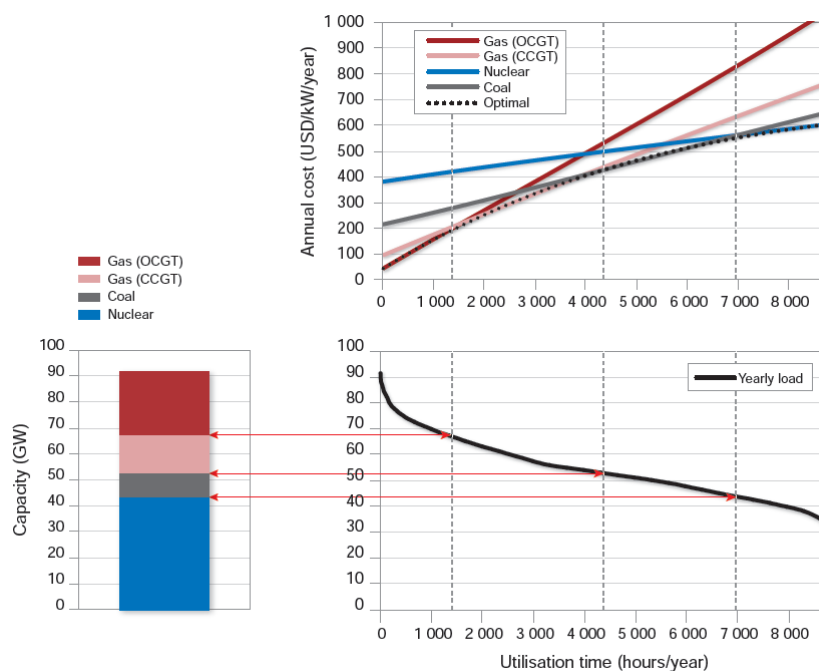


Figure 9.14: Theoretical characterization of the optimal generation mix. Taken from [NEA, 2012a], Figure 4.12.

²⁴⁰ If the simulated results are correct.

²⁴¹ The simulations performed by IER Stuttgart discussed in the second part of Section 9.4.3 do take into account these dynamic effects and the impact on investments.

²⁴² No cross border exchanges are assumed, nor any hydro storage or active demand response.

a.- Short term

In the short-term frame, the installed capacity is assumed not to change; investments do not enter the picture. The merit order is made up of the existing plants. As explained before, the RES feed-in leads to the so-called compression effect of dispatchable plants (smaller load factors and lower wholesale market prices). This leads to a profitability loss of the existing dispatchable units. The lost load for dispatchable units is shown via the difference between the two load-duration curves (the “yearly load” and the “residual load”) in Figure 9.15, for the case of a wind penetration of 30%. The colors indicate that indeed the OCGTs are pushed out first, then the CCGTs, next coal and lastly NPPs.

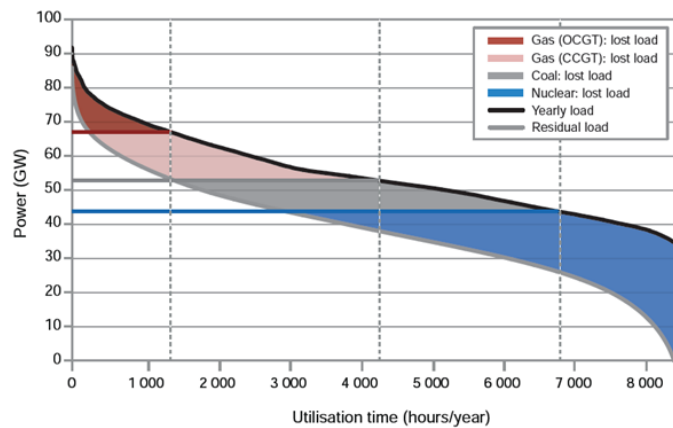


Figure 9.15: Lost load for existing power plants after introduction of 30% wind penetration. Taken from [NEA, 2012a], Figure 4.13

The colored horizontal lines in Figure 9.15 are those of the left lower panel in Figure 9.14.

The table in Figure 9.16 shows the lost load and the profitability loss of each technology. For each RES penetration, the short-term profitability losses are running in the order from OCGT (highest) to nuclear (lowest).

Penetration level		10%		30%	
Technology		Wind	Solar	Wind	Solar
Load losses	Gas turbine (OCGT)	-54%	-40%	-87%	-51%
	Gas turbine (CCGT)	-34%	-26%	-71%	-43%
	Coal	-27%	-28%	-62%	-44%
	Nuclear	-4%	-5%	-20%	-23%
Profitability losses	Gas turbine (OCGT)	-54%	-40%	-87%	-51%
	Gas turbine (CCGT)	-42%	-31%	-79%	-46%
	Coal	-35%	-30%	-69%	-46%
	Nuclear	-24%	-23%	-55%	-39%
Electricity price variation		-14%	-13%	-33%	-23%

Figure 9.16: Loss of electric load and loss of profitability relative to the scenario without RES injection. Taken from [NEA, 2012a, Table 4.8]

b.- Long term

In the long-run, the effects are different as the investment pattern will adjust itself according to the residual load curve. This is shown in Figure 9.17, for the case of 30% wind energy penetration.

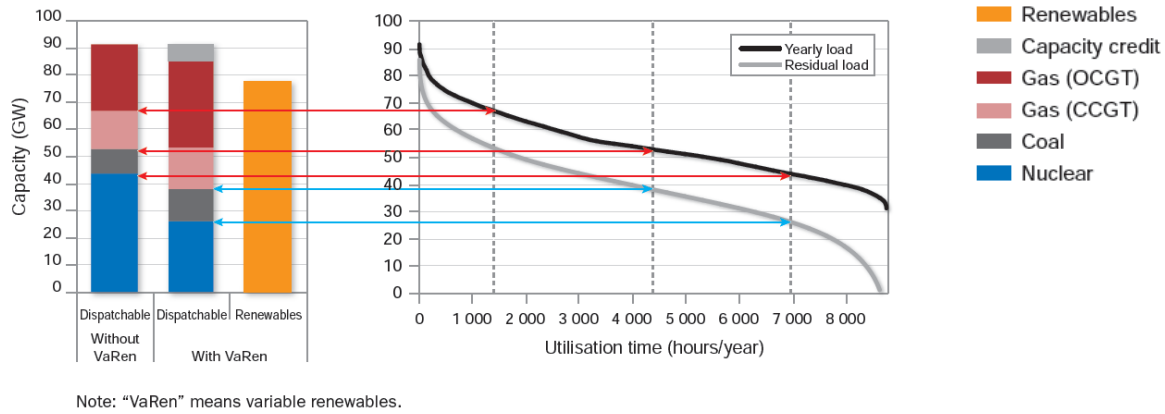


Figure 9.17: Changed dispatchable generation mix with 30% wind RES penetration. Taken from [NEA, 2012a], Figure 4.14.

The next Figure 9.18 shows the same results for all four cases (plus the base case) in terms of installed capacity.

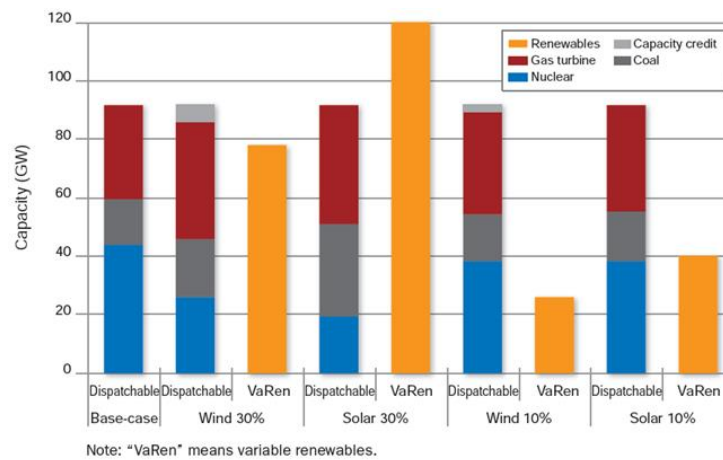


Figure 9.18: Optimal generation capacity mix for the different RES penetration scenarios. Taken from [NEA, 2012a], Figure 4.15.

Finally, we focus on the long-term impact of nuclear investment as a function of an imposed CO₂ price. Figure 9.19 shows the optimal nuclear capacity compared to the reference case for the two wind-energy penetrations, 10% and 30. The figure shows that the optimal investments in nuclear are lower than the reference in all cases, but that the difference becomes smaller with a higher the CO₂ price.

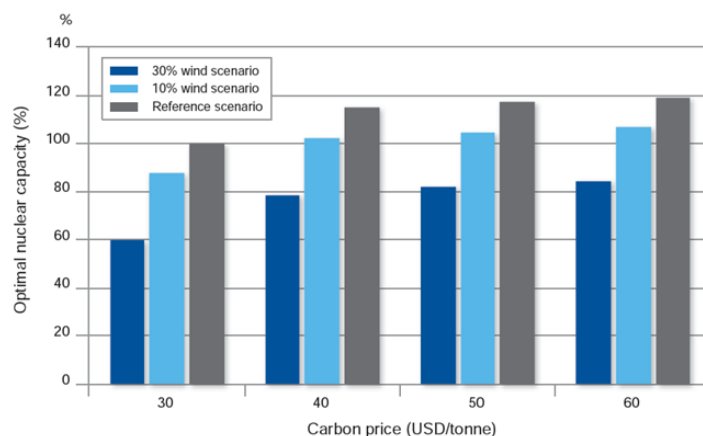


Figure 9.19: Optimal nuclear capacity for two wind penetration cases and a variable CO₂ price. Taken from [NEA, 2012a], Figure 4.17.

As a final point, it is instructive to see what happens with the CO₂ emissions in case of a CO₂ price of 30 \$/ton in each of the four cases considered in this subsection, compared to the reference. The results are shown in the table of Figure 9.20.

	Reference (million tonnes of CO ₂)	10% penetration level		30% penetration level	
		Wind	Solar	Wind	Solar
Short-term	59.3	-31%	-29%	-66%	-44%
Long-term		2%	4%	26%	125%

Figure 9.20: Short and long-term CO₂ emissions for a 30 \$/ton CO₂ price. Taken from [NEA, 2012a], Table 4.9.

In the short term, the RES penetration is very helpful in reducing the CO₂ emissions since the RES displaces mostly fossil-fuel combustion. In the long run, however, the CO₂ emissions would rise because of an adapted composition of the dispatchable generation mix, as a consequence of new investments in especially low-capital cost plants.

This type of exercises shows that one has to be careful with certain policy options. What may be a good option in the short run, might lead to reverse results in the longer term, unless policy adjustments are considered.

* * * * *

Chapter 10

Overall Cost of Nuclear – Adding Things Together

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Chapter 10	Overall Cost of Nuclear – Adding Things Together
10.1	New Build Nuclear Reactors – Levelized Electricity Cost (LCOE)
10.2	Long Term Operation Refurbishment – Levelized Electricity Cost (LCOE)
10.3	External Costs
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10.4	System Costs
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10.4.2	Overall System Cost
	i. Results from Excel-based model for Germany (by NEA/OECD economists)
	ii. Comprehensive in-depth modeling for Germany, using two integrated computer codes (by IER)

In this final chapter all concluding ***orders of magnitude*** of the previous chapters are summarized. The reader can easily make the total calculation. The focus is on nuclear electricity generation, but from the figures from the literature shown earlier in the report, the LCOE of other generation means can be read. The reader certainly knows those orders of magnitude. For the *external costs* and the *system costs*, we are obliged to quote numbers for the other generation means so as to be able to put the values for nuclear in perspective.

The orders of magnitude arrived at are the result of sifting through and analyzing a considerable amount of the published nuclear-related literature. The final numbers are based on a common sense “engineering judgment” to be able to appreciate the situation.

But, behind that engineering judgment, there is a substantial amount of interpretation, nuances, assumptions, boundary conditions, etc. It is on purpose that those “ifs-and-buts” are not repeated here in this summary. If interested, the reader should make the effort to read through the report and properly absorb those “qualifying conditions”.

10.1.- New Build Nuclear Reactors – Levelized Electricity Cost (LCOE)

→ Overnight Construction Cost (OCC):

For **NOAK₂ (5+)** on a **brownfield**: 3,060...**3,400**...3,910 €₂₀₁₂/kW

For **FOAK₂ twin** unit on **brownfield**: 3,128...**3,910**...5,083 €₂₀₁₂/kW

For **FOAK₂ single** unit on **brownfield**: 3,400...**4,250**...5,525 €₂₀₁₂/kW

→ Fuel-Cycle Cost-Part of LCOE:

Full fuel-cycle cost ~ 6 €₂₀₁₂ /MWh_e (± 0.75 €₂₀₁₂ /MWh_e)

→ Operation & Maintenance (O&M):

Generic order of magnitude O&M cost ~ 10 €₂₀₁₂ /MWh_e (± 3.5 €₂₀₁₂ /MWh_e)

→→ **LCOE New Build (rounded numbers):**

NOAK (5+) brownfield generic single/twin

3,060 €	(ref – 10%)	→ LCOE(5%)= 41€ ₂₀₁₂ /MWh	&	LCOE(10%)= 69€ ₂₀₁₂ /MWh
3,400 €	(ref)	→ LCOE(5%)= 43€₂₀₁₂/MWh	&	LCOE(10%)= 75€₂₀₁₂/MWh
3,910 €	(ref + 15%)	→ LCOE(5%)= 48€ ₂₀₁₂ /MWh	&	LCOE(10%)= 84€ ₂₀₁₂ /MWh

FOAK₂ brownfield twin

3,128 €	(ref – 20%)	→ LCOE(5%)= 41€ ₂₀₁₂ /MWh	&	LCOE(10%)= 70€ ₂₀₁₂ /MWh
3,910 €	(ref)	→ LCOE(5%)= 48€₂₀₁₂/MWh	&	LCOE(10%)= 84€₂₀₁₂/MWh
5,083 €	(ref + 30%)	→ LCOE(5%)= 57€ ₂₀₁₂ /MWh	&	LCOE(10%)= 104€ ₂₀₁₂ /MWh

FOAK₂ brownfield single

3,400 €	(ref – 20%)	→ LCOE(5%)= 43€ ₂₀₁₂ /MWh	&	LCOE(10%)= 75€ ₂₀₁₂ /MWh
4,250 €	(ref)	→ LCOE(5%)= 50€₂₀₁₂/MWh	&	LCOE(10%)= 89€₂₀₁₂/MWh
5,525 €	(ref + 30%)	→ LCOE(5%)= 61€ ₂₀₁₂ /MWh	&	LCOE(10%)= 111€ ₂₀₁₂ /MWh

For each of these LCOE numbers, there is an additional uncertainty of the fuel-cycle cost (± 3.5 €₂₀₁₂ / MWh) and the O&M cost (± 0.75 €₂₀₁₂ / MWh). If we simply combine the uncertainties and round them off, then the above numbers each have an extra **uncertainty of ± 4 €₂₀₁₂ / MWh**.

10.2.- Long Term Operation Refurbishment – Levelized Electricity Cost (LCOE)

→ Overnight Refurbishment Cost (ORC):

Specific ORC ~ 400 – 850 €₂₀₁₂/kW

→ Fuel-Cycle Cost-Part of LCOE:

Full fuel-cycle cost ~ 6 €₂₀₁₂ /MWh_e (± 0.75 €₂₀₁₂ /MWh_e)

→ Operation & Maintenance (O&M):

Generic order of magnitude O&M cost ~ 10 €₂₀₁₂ /MWh_e (± 3.5 €₂₀₁₂ /MWh_e)

→→ LCOE LTO (rounded numbers):

ORC = 400 € (ref – 33%) → LCOE_{LTO}(5%)= 21€₂₀₁₂/MWh & LCOE_{LTO}(10%)= 23€₂₀₁₂/MWh

ORC = 600 € (ref) → LCOE_{LTO}(5%)= 23€₂₀₁₂/MWh & LCOE_{LTO}(10%)= 26€₂₀₁₂/MWh

ORC = 850 € (ref + 42%) → LCOE_{LTO}(5%)= 26€₂₀₁₂/MWh & LCOE_{LTO}(10%)= 30€₂₀₁₂/MWh

For each of these LCOE numbers, there is an additional uncertainty of the fuel-cycle cost (± 3.5 €₂₀₁₂ / MWh) and the O&M cost (± 0.75 €₂₀₁₂ / MWh). If we simply combine the uncertainties and round them off, then the above numbers each have an extra **uncertainty of ± 4 €₂₀₁₂ / MWh**.

10.3.- External Costs

10.3.1 Without Accidents

External costs for nuclear-generated electricity → 1 – 4 €₂₀₁₂/MWh

Compare with other means (cfr [IER, 2013] – Fig 7.8 this report)

Coal ~ 40 €₂₀₁₂/MWh

Gas ~ 20 €₂₀₁₂/MWh

PV ~ 10 €₂₀₁₂/MWh

Wind ~ 2 €₂₀₁₂/MWh

10.3.2 Nuclear Accidents

Order of magnitude of external cost due to nuclear accidents is ~ 0.3 ... 1 ... 3 €/MWh.

10.4.- System Costs²⁴³

System costs are considered in two steps:

3. grid-level system costs
4. overall system costs (encompassing 1., but also variable and fixed savings or increases due to displacement of generation from conventional units)

10.4.1 Grid-Level System Cost

For penetrations of 10% & 30% for each technology

Includes: Back-up (adequacy); Balancing Cost; Grid Connection; Grid Reinforcement and Extension

Does not include: merit-order effects nor fuel savings

Nuclear: ~ 2 – 3 \$₂₀₁₁/MWh

Coal: ~ 1 \$₂₀₁₁/MWh

Gas: ~ 0.5 \$₂₀₁₁/MWh

Wind onshore: ~ 20 – 30 \$₂₀₁₁/MWh

Wind offshore: ~ 30 – 40 \$₂₀₁₁/MWh

PV: ~ 35 – 55 \$₂₀₁₁/MWh

²⁴³ Ref: Nuclear Energy Agency, “Nuclear Energy and Renewables - System Effects in Low-Carbon Electricity Systems” [NEA, 2012a]

10.4.2 Overall System cost

Two *independent* computations for the German electricity system are shown (permitting validation of obtained results) – other cases are discussed in the main text. Both are published in [NEA, 2012a].

i. Results from Excel-based model for Germany (by NEA/OECD economists)

Total cost of electricity generation in Germany in \$₂₀₁₁/MWh. The situation without renewables (“Reference” for comparison) and with renewables at penetration levels of 10% and 30% of annual electricity generation/consumption are compared. The total costs and the cost increases are shown in the table. In this table, the mix of dispatchable generation plants is the same as in the “Reference”.

Total cost of electricity supply (USD/MWh)								
		Reference	10% penetration level			30% penetration level		
		Conv. mix	Wind onshore	Wind offshore	Solar	Wind onshore	Wind offshore	Solar
Germany	Total cost of electricity supply	80.7	86.6	91.3	101.2	105.5	116.9	156.2
	Increase in plant-level cost	-	3.9	7.8	16.9	11.6	23.3	50.6
	Grid-level system costs	-	1.9	2.8	3.6	13.2	12.9	24.9
	Cost increase	-	5.8	10.6	20.4	24.8	36.2	75.4

ii. Comprehensive in-depth modeling for Germany, using two integrated computer codes (by IER)

Total cost of electricity generation in Germany in €₂₀₀₇/MWh. Four renewables penetration levels are considered (15%, 35%, 50% and 80%, in terms of TWh/a) for three cases of nuclear installed capacities: 20.7 GW – before Fukushima, and two extreme cases, the double (41.7 GW) and 0. The conventional dispatchable generation mix is adjusted conforming to renewables penetration.

Installed capacities of nuclear power plants/share of renewables	(EUR/MWh)		
	0 GW	20.7 GW	41.4 GW
15%	95	84	71
35%	120	109	101
50%	132	122	119
80%	174	171	174 ^a

a) Variation RES-80%_NUCL-41(21LE) with one half of the nuclear power plant portfolio being entirely depreciated but retrofitted: EUR 169/kWh.

Chapter 11

Conclusions in Brief

Having summarized the outcome of this broad literature survey on the cost of nuclear power, one can state the points to remember in a few bullet points:

1. Nuclear new build is highly capital intensive and currently not cheap, but it may be anticipated that the capital cost will come down in the future (in particular compared to ongoing new build construction in the EU, depending on return of experience and learning effects, 'fleet effects', standardization, strict construction schedules, competition in the supply chain,...). Analysis of past cost escalation and opportunities for learning and 'fleet effects', suggests that negative learning is not necessarily an 'intrinsic property' of nuclear-reactor construction. Nevertheless, it is up to the nuclear sector itself to demonstrate on the ground that cost-effective construction is possible.
2. Long Term Operation (LTO) is an interesting intermediate cost-effective route if safety standards can be guaranteed.
3. The back-end fuel-cycle costs are low; the full fuel-cycle is quite cheap.
4. External costs of nuclear are small, including accidents (and much smaller than the external costs of fossil-fuel generation).
5. Systems costs of nuclear plants are small, comparable to dispatchable fossil-fired plants, and according to two independent recent calculations (subject to given modeling assumptions), much lower than systems costs of intermittent non-dispatchable renewables.

Ref: NEA/OECD, "Nuclear Energy and Renewables - System Effects in Low-Carbon Electricity Systems" [NEA, 2012a]

If supported politically at national level and authorized by the national Nuclear Regulatory Authorities (the first being related to public acceptance, and the second subject to adequate safety characteristics), upgrades for long-term operation of existing nuclear plants may continue to provide a very competitive low-carbon, secure, stable and reliable source of electricity for the next decades. Nuclear new build may come along, inter alia to replace existing plants at time of shutdown (brownfield), to be part of national energy mix on the longer run. This will be much dependent on the investment decisions which will be linked to the *effective control of the construction costs*.

All other costs beyond extensive upgrades of existing plants and construction of new build, be it O&M, fuel-cycle costs, waste and decommissioning, liability costs, systems costs, and other external costs are marginal and position nuclear generation economically favorably versus other generation sources, certainly if all externalities of other generation sources as well would be internalized.

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