CHAPTER 6

Cost Benefit Analysis (CBA) for Israel – Enhanced smart metering deployment

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"It ought to be remembered that there is nothing more difficult to take in hand, more perilous to conduct, or more uncertain in its success, than to take the lead in the introduction of a new order of things. Because the innovator has for enemies all those who have done well under the old conditions, and lukewarm defenders in those who may do well under the new. This coolness arises partly from fear of the opponents, who have the laws on their side, and partly from the incredulity of men, who do not readily believe in new things until they have had a long experience of them."

— Niccolò Machiavelli, *The Prince*

1. Abbreviations and terms

CBA: Cost-benefit analysis

CAPEX: Capital Expenditure

OPEX: Operational Expenditure

WAN: Wide Area Network

LAN: Local Area Network

HAN: Home Area Network

GPRS - General Packet Radio Service

IHD: In-Home Display

DLC: Direct Load Control

NPV: Net Present Value

PLC: Power Line Communication

RF: Radio Frequency

SME: Small-to-Medium Enterprises

TOU: Time of Use

CPP: Critical Peak Pricing

RTP: Real Time Pricing

BAU: Business As Usual

CML: Customer Minutes Lost

DNOs: Distribution Network Operators

O&M: Operation and Maintenance

IT: Information Technology

RES: Renewable Energy Sources

MDM: Meter Data Management

MN: Israeli Ministry of National Industries

ACEEE - American Council for an Energy-Efficient Economy

IEC: Israeli Electric Corporation

IEA: International Energy Agency

2. Introduction

The purpose of this report is to provide the first coherent, public and quantitative assessment of enhanced smart metering deployment in Israel. The current report facilitates an informed investment decision. Specifically, this report is a cost benefit analysis of enhanced smart meter deployment in Israel. Although replacing the current analog meters with smart meters is the core of this deployment, the use of the word "enhanced" points to the content of the entire system, specifically (1) smart meters, (2) communication components enabling real time, two ways communication the consumer and the infrastructure, (3) support software systems including billing system, (4) use of feedback enabling technology and (5) new and advanced tariff systems that embeds the potential of consumption pattern changes.

240 million smart meters will be installed in Europe by 2020, while the comparable number for US is 60 million (JRC and DOE, 2012). While this revolution of energy infrastructure will require large investments, there are potentially huge benefits to reap. As the benefits are critically dependent on local conditions (e.g. generation mix, load curve), a thoroughly Cost Benefit Analysis is a prerequisite for an enhanced smart meter investment. As no prior holistic financial assessment of enhanced metering has been published in Israel, this CBA is the first of its kind. Consequently, in the current report, we depend largely on international benchmarks. Once conclusions from the ongoing smart metering pilot in Binyamina are available, empirical data will replace the benchmarks. For the CBA, representing the first assessment-stage of an enhanced smart metering deployment in Israel, we encourage public feedback. Remarks and comments are welcomed.

3. Executive summary

3.1 Mission statement

The aim of this report is to facilitate an informed investment decision for enhanced smart metering in Israel. The report serves this purpose by providing a coherent assessment of the quantifiable costs and benefits related to a nation-wide enhanced smart metering deployment in Israel. The use of the term enhanced points to the content of the entire system, specifically (1) smart meters, (2) communication components enabling real time, two ways communication the consumer and the infrastructure, (3) support software systems including billing system, (4) use of feedback enabling technology and (5) new and advanced tariff systems that embeds the potential of consumption pattern changes. With nation-wide deployment we understand (1) the household sector and (2) the small-to-medium enterprises (SME), a total of 2.54 million meter-points at the assumed start of the CBA (01.01.2015).

3.2 Macro assumptions and methodology

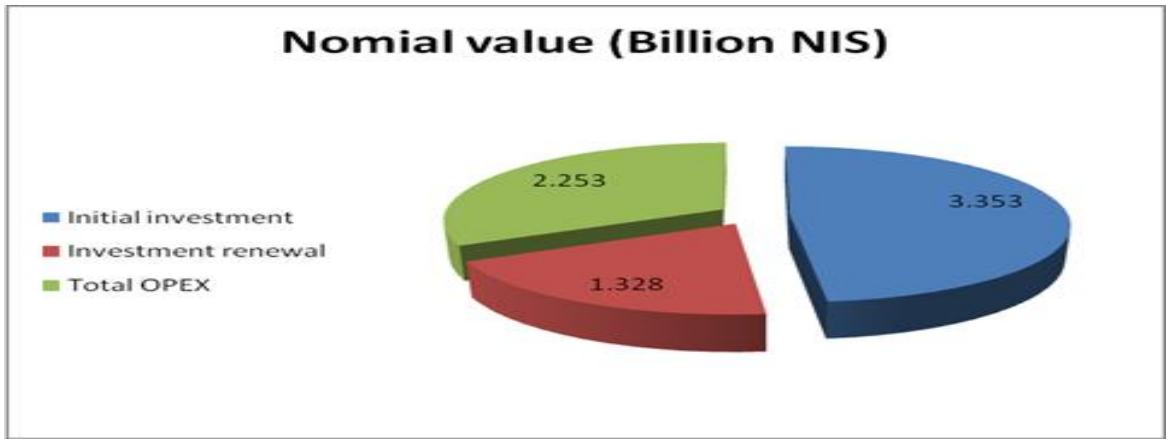
In the current report we assess (a) the incremental costs and benefits of enhanced smart metering from (b) a national point of view. An incremental analysis implies that all the costs of the business-as-usual scenario (BaU) over the horizon of the CBA will be subtracted from the costs of the enhanced smart metering deployment scenario. A national reference point implies that we calculate to what extent an investment in enhanced smart metering increases total social welfare (the size of the pie), with no reference paid to the issue of how this welfare gain is distributed (the size of each slice). To conduct the actual assessment, in lack of Israeli data, we have benchmarked costs and benefits against 20 national CBAs and more than 70 reports and research articles on pilots, technology trials and smart metering in general.

3.3 Costs of enhanced smart metering

In nominal value, the total costs of an enhanced smart metering deployment are 6.934 Billion NIS. Figure 1 displays a high level of these costs, divided into CAPEX and OPEX. Total CAPEX of enhanced smart metering is 4.681 billion NIS, sub-divided into (a) initial investment (3.353 billion NIS) and (b) investment renewal (1.328 billion NIS). Smart meters and communication is the most significant post internally (46%). Total OPEX of enhanced

smart metering is 2.253 billion NIS, with data transmission as the most significant post internally (48%). CAPEX is more significant than OPEX since it includes both (a) the initial investment (3.353 billion) and (b) renewal investments (1.328 billion).

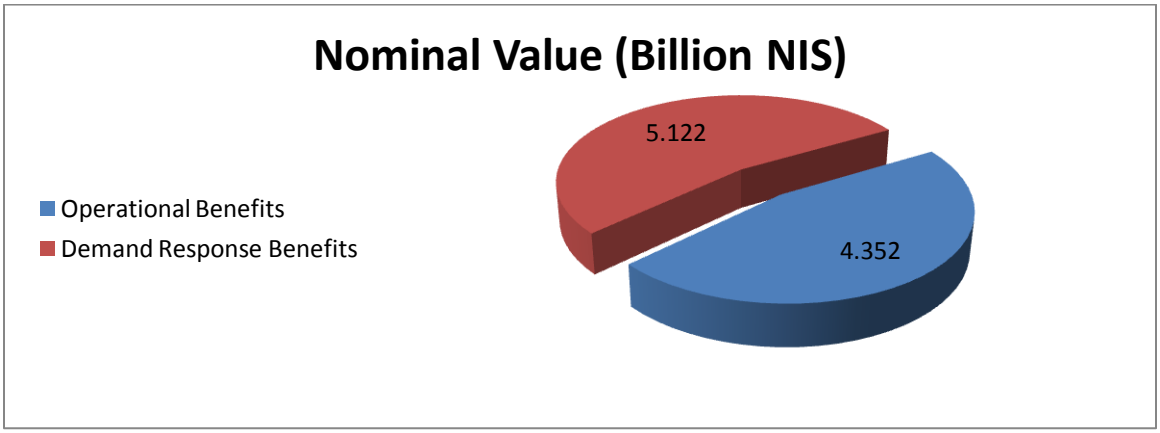
Figure 1: High level overview of CAPEX and OPEX



3.4 Benefits of enhanced smart metering

The total benefits of enhanced smart metering are 9.447 billion NIS. Figure 2 displays a high level of these benefits divided into Operational Benefits and Demand Response Benefits. Total Operational Benefits of enhanced smart metering are 4.352 billion NIS, with information benefits as the most significant post internally (47%). Total Demand Response Benefits of enhanced smart metering are 5.122 billion NIS, with consumption reduction as the most significant post internally (51%).

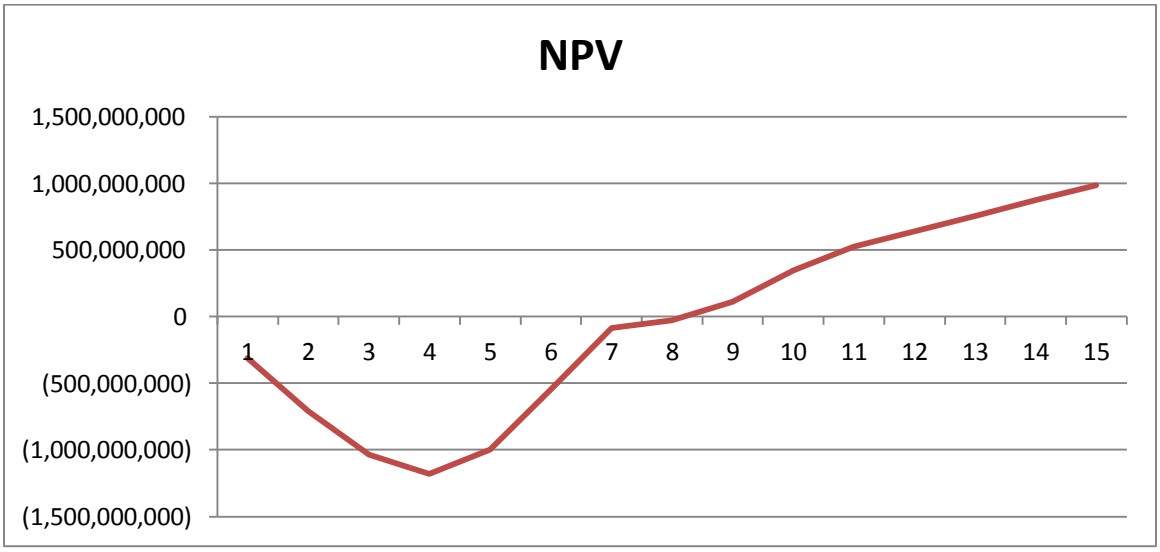
Figure 2: High level overview of Benefits



3.5 Main results

Over the 15 years time horizon of this CBA, enhanced smart metering deployment in Israel has a net benefit of 986.73 million NIS. Figure 3 displays how this NPV develops in time given the discount rate of seven percent. After the Initial IT CAPEX (407 million NIS) is completed after three and a half years, NPV shows a constant positive slope. In the fifth year there is a kink in the graph resulting from the deferring investments of a new power plant[1]. In the ninth year we get the first positive NPV.

Figure 3: NPV 2015-2030 given discount rate of 7%

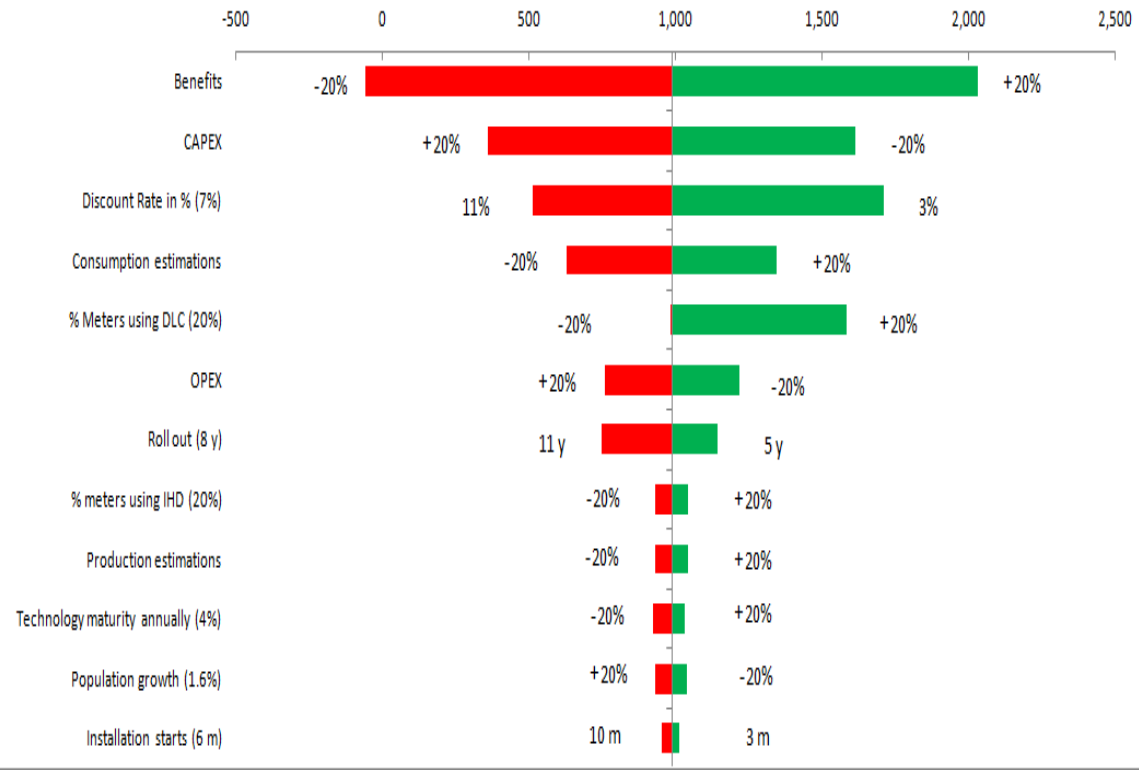


3.6 Sensitivity analysis.

From figure 4 we see that the NPV is most sensitive to changes in (1) benefits, (2) CAPEX, (3) discount rate and (4) consumption estimations. The positive NPV remains robust across a range of sensitivity tests carried out. A reduction in benefits of 20% is the single parameter with a potential of turning the NPV marginally negative. It is worth noting that the NPV would still be highly positive should the CAPEX of enhanced smart metering be 20% higher than what we assumed.

[1] The benefit is spread over three years with a 20%, 40% and 40% distribution respectively.

Figure 4: Sensitivity Analysis, changes in NPV



4. Background

4.1 Macro assumptions and methodology

This report is (a) an assessment of the incremental costs and benefits of enhanced smart metering from (b) a national point of view. An incremental analysis implies that all the costs of the business-as-usual scenario (BaU) over the horizon of the CBA will be subtracted from the costs of the enhanced smart metering deployment scenario. Consequently, on the benefit side of enhanced smart meter deployment, the BaU-costs are counted as "avoided costs" (e.g. the avoided cost of manual meter-reading) [2]. A national reference point implies that we calculate to what extent an investment in enhanced smart metering increases total social welfare (the size of the pie), with no reference paid to the politicized issue of how this welfare gain is distributed (the size of each slice). The national level of analysis also implies

2 For details on the calculation of incremental costs and benefits, see Deloitte (2011).

that tax issues are of no relevance for the model as they only represent transfer of money between groups.

Since limited Israeli data is available for enhanced smart metering, we depend heavily on international benchmarks collected from national CBAs and pilots. We have included 20 CBAs from national smart meter deployments, summarized in table 1. From these 20 CBAs, we created a detailed benchmark-matrix for all the relevant costs and benefits. Additionally, we have gathered more than 70 reports and research articles on pilots, technology trials and smart metering in general. Wherever Israeli data was available, these were deployed. In the process of conducting this CBA, we collaborated closely with a range of local expertise. Consequently, several of our benchmarks findings are adjusted after local expert advice.

Table 1: Overview of global CBAs of national rollouts forming the base of our benchmark-matrix

CBAs of national roll-out read for this analysis (Electricity Only)	Europe	Other	Total
CBAs read for this analysis (in some cases more than one from each country/state)	12	9	20*
Positive result of CBA	8	7	15**
Negative Result of CBA	4	1	5***
* Netherlands, Austria, UK, Sweden, Hungary, Slovenia, France, Ireland, Germany (2), Lithuania, Denmark, Australia, Australia Victoria (2), New Zealand, US (2), Canada, US Vermont			
** Netherlands, Austria, UK, Sweden, Hungary, Slovenia, France, Ireland, Australia, Australia Victoria, US (2), US Vermont, New Zealand, Canada			
*** Germany (2), Lithuania, Denmark, Australia Victoria			

4.2 Parameters for the CBA

In this section major parameters of the CBA are presented. All the parameters are displayed in table 2, while only the controversial ones are described in detail. These are (4.2.1) inflation rate, (4.2.2) time horizon of the CBA, (4.2.3) discount rate and (4.2.4) annual technology maturity rate.

4.2.1 Inflation rate

Where general CPI is easy to extrapolate, the price of future electricity is generally hard to predict. Israel is currently undergoing a radical transformation in the energy sector with large natural gas reserves identified in the eastern Mediterranean (e.g. the Tamar-field, the

Leviathan-field). In the time of writing this CBA, several questions concerning the Israeli gas adventure remain unsolved. Consequently, the future cost of generating electricity in Israel is highly uncertain. Of this reason, the CBA is conducted in fixed 2013 prices.

4.2.2 Scope of the CBA

The time scope of the CBA is 15 years. We argue that this is the appropriate assessment time based on the following three arguments: (1) the period of financial analysis recommended for other projects in the guidelines of cost-benefit analysis is no longer than 15 years (JRC,2012); (2) the lifetime/amortization-period of smart metering infrastructure is no longer than 15 years; (3) the average time horizon applied in our benchmark material is 18 years, with several CBAs arguing for 15 years as the appropriate time[3]. In this report we operate with a 10 years lifespan for smart meters and demand response technology (i.e. IHD). This is a conservative assumption since we do not reap the full benefit of this CAPEX renewal in our 15 year time horizon.

4.2.3 Discount rate

In the European guidelines for conducting smart metering CBAs it is strongly argued in favor of choosing a public policy discount rate (i.e. the lowest rate at which "society" can borrow money in the long-term, excluding short term volatilities) (JRC, 2012). Such social discount rate is preferred in several European CBAs[4]. On the contrary, if the discount rate is to give a fair reflection of the relative risk of the projects, then a higher discount rate should be applied to "smart investments" relative to conventional utility investments (JRC, 2012). From our benchmarks, the discount-rate applied in national rollouts of smart metering ranges between a lower value of 3.5 % for UK, to a higher value of 8% for Victoria and Hungary, with an average of 5.5%. In our view the appropriate discount rate should reflect macroeconomic conditions, capital constraints and risk. The risk of the enhanced smart meter investment is mitigated through customer financing, rather than private finance initiative. Customer financing is the dominating alternative in other CBAs[5]. On these

[3] See for example the Lithuanian CBA by Ernst and Young (2012).
[4] See for example the Lithuanian CBA by Ernst and Young (2012) and the UK CBA (DECC, 2013). In other parts of the world, for example the CBA from Victoria (Deloitte, 2011), the discount rate is set equal to WACC.
[5] See the German CBA (Ernst and Young, 2013) for a detailed analysis of customer financing alternatives.

grounds, we have adopted a discount rate of 7% for this CBA. The discount rate will be subjected to a sensitivity analysis for determining its effect on the net present value.

4.2.4 Annual technology maturity rate

From our benchmarks, annual rate of technological progress is between 1% and 2%. From local expert advice, we operate with an annual technology maturity rate of 4%. The maturity rate is taken into account for all significant investments that occurs in a larger time-span: smart meters, communication modules, concentrators, balancing meters, in house displays (IHD) and automation devices (DLC). To the extent that 4% diverts from the literature, it should be noted that we assume a 2% maturity effect for analog meters and maintenance costs of the BaU-scenario. Consequently, due to the incremental character of the analysis, the enhanced metering maturity NPV effect is partially counterbalanced[6]. There is a strong case for including an annual OPEX cost reduction due to "learning effects"[7]. For conservative reasons, however, we have not applied such an OPEX maturity-rate in this CBA.

Table 2: General Parameters for the CBA

Parameters	Value
Inflation-Rate	Constant
Horizon CBA in years	15
Discount Rate in percent	7.00%
Annual technology maturity-rate in percent	4.00%
Annual population growth	1.60%
Exchange rate from Euro to NIS	4,8
Exchange rate from US$ to NIS	3,65
Exchange rate from LTL to NIS	1,4

[6] Since all BaU costs are counted on the benefit-side as "avoided costs", the maturity rate of analog meters reduces the benefits of enhanced smart metering.
[7] Se KEMA benchmark report (2012) where a 5-10% annual reduction of owning and operating the communication infrastructure is assumed.

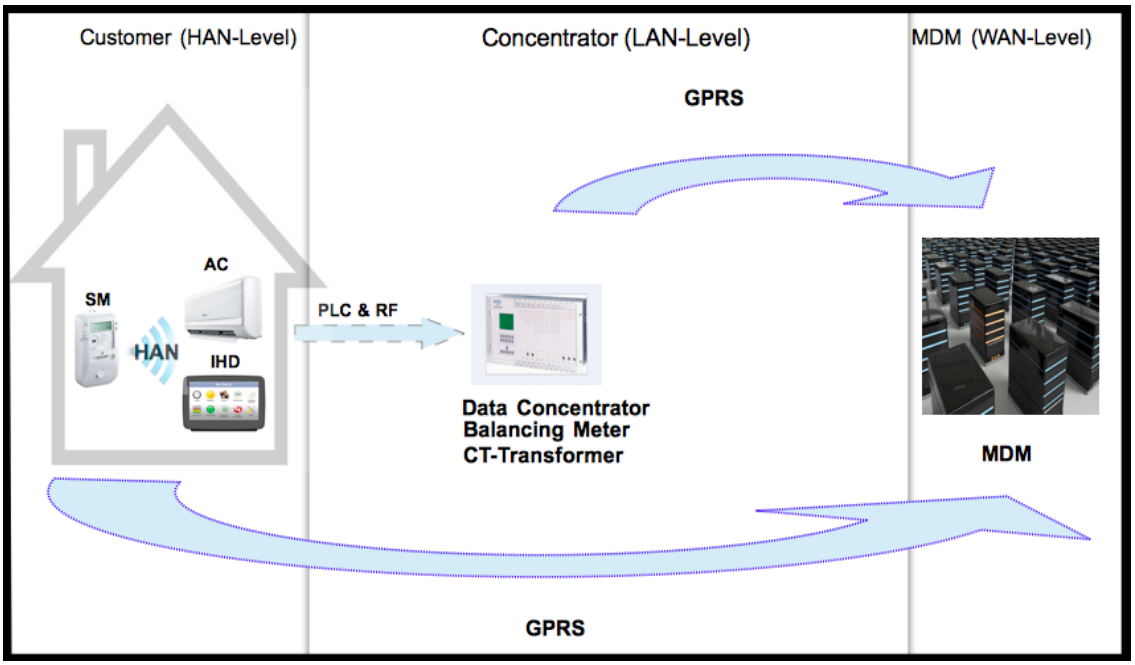
Exchange rate from AUD to NIS	3,3
Exchange rate from GBP to NIS	5,7

5. Enhanced meter system

5.1 Enhanced smart metering system – the technology

Three communication-levels are covered by an enhanced smart metering system. Taking the end customer as a starting point, we have (5.1.1) the Home Area Network (HAN-Level), (5.1.2) the Local Area Network (LAN-level) and (5.1.3) the Wide Area Network (WAN-level). In figure 5 below, we have illustrated the enhanced smart metering system we assess for Israel. It is not the aim of the CBA to guide the technology choice, but we introduce a non-exhaustive list of the major technological options available.

Figure 5: Overview of enhanced metering system



5.1.1 HAN communication

The first level of communication is the Home Area Network (HAN). HAN compromises the communication between the smart meter and appliances (e.g. In Home Display (IHD) and Air Conditioner) within the household or SME. For the HAN communication, WIFI, PLC or Zigbee are the technologies used internationally.

5.1.2 LAN communication

The second level of communication is the Local Area Network (LAN). LAN is the communication between the smart meter and a data concentrator, also called "the last mile". LAN communication is normally powered by (5.1.2.1) Power Line Communication (PLC), (5.1.2.2) Radio Frequency (RF) or (5.1.2.3) cellular-based solutions[8]. In figure 6, international deployment of the various LAN technologies is displayed.

5.1.2.1 PLC communication

PLC communication uses the low voltage power-line for two way communications between the home and a data concentrator in an existing substation. Since it requires a certain density to be cost effective, it is a communication solution for customers in urban areas, towns and villages. In Europe, there is typically one concentrator per 100- to 200 smart meters.

5.1.2.2 RF communication

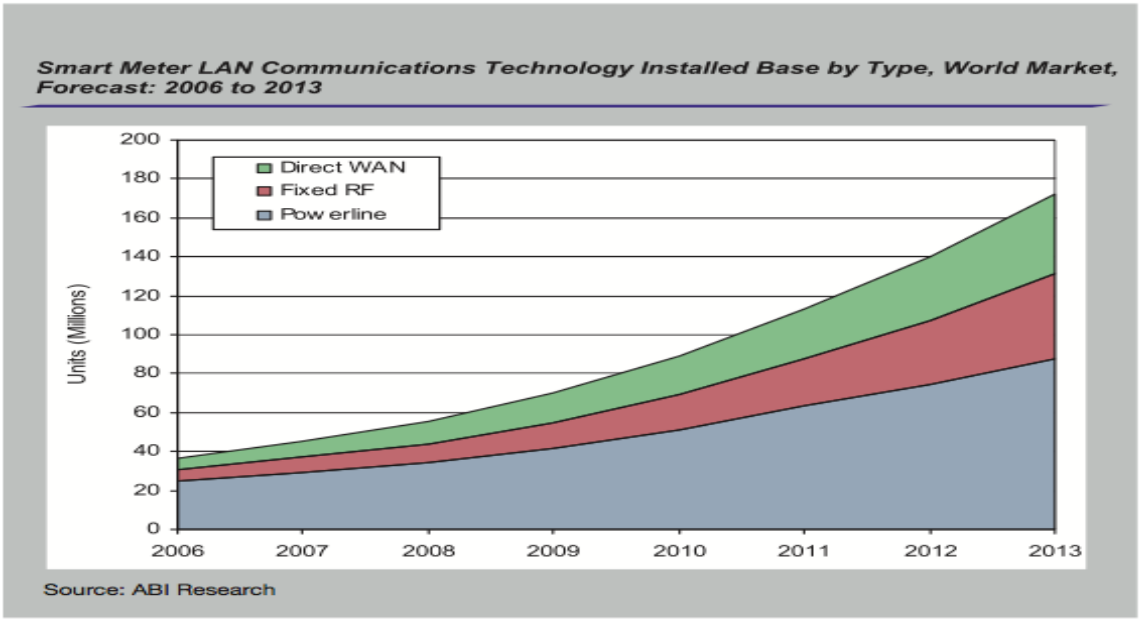
RF communication is another last mile communication technology using the radio network to communicate with a concentrator. The two technologies most commonly used is the radio-mesh/multi-hop or radio star/single-hop (Neptune Technology Group, 2010). Radio-mesh involves individual meters communicating with each other before messages are passed to a concentrator. Radio star technology is simply endpoints transmitting separately to a concentrator. RF is the predominant smart metering communications technology in use in North America.

[8] Cellular-based communication does not make use of data-concentrators and will consequently be LAN and WAN communication at the same time as the communication goes directly from the meter to the MDM.

5.1.2.3 Cellular communication

Cellular-based communication has until recently been deployed as a supporting technology where neither RF nor PLC were suitable. Cellular-based smart meters do not require data concentrators as they communicate directly with the MDM over the mobile network. Cellular solutions can be GPRS, 3G or LTE, where GPRS is favored in most cases due to lower module and transmission costs. With a recently dramatic drop in cellular module- and cellular transmission costs, these solutions are increasingly popular (ABI, 2011).

Figure 6: International deployment of LAN technology types (in millions)



5.1.3 WAN communication

The third level of communication is the Wide Area Network (WAN). WAN deals with the backhaul communication to the MDM. If the enhanced smart metering system is based on PLC or RF for the LAN-communication, WAN will represent the communication from the data concentrators back to the MDM. For enhanced smart metering, WAN communication is largely done by cellular solutions, mostly GPRS.

5.2 Enhanced smart metering system – meter functions

From broad literature the core functionalities of smart meters are identified. To identify the smart meter functionalities with highest consensus, a major study was recently conducted among European countries (European Commission, 2011). For this CBA, the smart meter functions serving as a basis for the enhanced smart meter deployment costs, and the potential realized benefits, are presented in table 3 below.

Table 3: Smart meter function-set and examples of related benefits

Function Category	Function	Examples of benefit
Remote reading	Remote meter reading	Avoided regular meter reading costs
	Remote transmission of meter status	Reduced O&M
Remote control	Remote tariff change, software update and calendar configuration	Avoided special meter visits
	Remote control of maximum permissible power	Peak Reduction
	HAN capability	Peak- and energy consumption reduction
	Remote disconnection and reconnection	Avoided costs of disconnection and reconnection
Monitoring	Fraud prevention and detection (including alarm if tampering)	Electricity theft reduction
	Grid monitoring	Faster outage response
Information	Two way communication	Avoided maintenance costs
	Saving of 15 min load sampling	Better network planning
	Record data of different parameter types (consumption data and tariff)	Facilitating detailed billing
	Data storage for at least 3 month	Avoiding billing errors
Other functions	Flexible tariffs	Electricity consumption savings
	Secure data communication, strong encryption	Consumer privacy protection
DLC	Direct Load Control	Peak Reduction
	Automation	Consumption reduction
IHD	Better information	Consumption reduction

6. The Israeli meter park – an overview

6.1 Classifying the Israeli meter-park

The CBA start date is set to 1/1/2015. Based on 2012 data, table 4 displays the extrapolated number of meters and consumption for each sector for this date. As presented, there will be 2.64 million meters at the start date of the CBA, with a total annual consumption of 67 Twh[9]. For the sake of clarity, we refer to these numbers throughout the report unless otherwise stated. This sector division of table 4 is the standard way to classify the meter-park.

Table 4: Classification of meter-points by sector

Distinction by sector	Number of meters	Consumption in annual TWh	% of total consumption in Israel
Households	2313305	21.99	32.82%
Public Commercial	276908	23.5	35.07%
Industry	35329	15.1	22.54%
Agriculture	9787	2.35	3.51%
Water Pumping	4144	4.06	6.06%
Total	**2639473**	**67.00**	**100.00%**
**Source: IEC statistical report 2012 extrapolated to 1/1/2015 values*			

For this CBA we classify the meter-points by annual Kwh consumption. The expected benefits from enhanced smart metering deployment vary mainly by consumption, not by sector. We make the distinction between end customers consuming less than 40Mwh a year (Households and Small-to-Medium Enterprises (SME)) and end customers that consumes more than 40Mwh a year (Large enterprises). An overview of this classification is provided in table 5 below. All enterprises in Israel with an annual consumption of more than 40Mwh are already equipped with smart meters and tariffed with Time Of Use (TOU). Consequently,

[9] Based on a population growth of 1.6% applied to each sector. The total consumption is based on numbers from ministry of energy (2013) and divided between the sectors by 2012 weights taken from IEC statistical report (2012).

a large part of the potential for demand-response benefits for these large enterprises is already emptied. For this reason, in the current CBA, we deal only with households and Small to Medium Enterprises (SME). Large enterprises, composing about 100.000 meters-points and 60 percent of the total consumption, are excluded from the analysis.

Table 5: Classification of meter-points by Kwh annual consumption

Distinction by KWh *	Households	Small-to Medium businesses	Large businesses	Total
Meter-points below 40Mwh	2.31 mil (33%)**	223 K (7%)		2.54 mil (40%)
Meter-points above 40Mwh			103 K (60%)	103 K (60%)
Meter-points total	2.31 mil (33%)	223 K (7%)	103 K (60%)	2.64 mil (100%)
** Source: IEC statistical report 2012 extrapolated to 1/1/2015 values*				
** Signifies percentage of total consumption of the meters-points included in the analysis				

7. Scenarios

7.1 Scenario assumptions

We operate with one scenario for enhanced smart metering deployment. A detailed overview of the assumptions guiding this "Full rollout scenario" is provided in table 6. The Business as Usual scenario (BaU), outlined in section (8.1), is the baseline in which the rollout scenario is compared to. As explained in section (4.1), costs of the BaU-scenario appear as benefits in of the full rollout scenario, taking the form of "avoided costs" (e.g. the avoided cost of manual meter-reading). In the following the assumptions of the Full rollout scenario are spelled out in detail. These assumptions are divided into three categories: (7.1.1) Meter-assumptions (7.1.2) Demand-response assumptions; (7.1.3) Rollout assumptions. The assumptions mentioned here in brief, such as opt-in rates and technology mix, are based on exhaustive argument presented at a later stage in the CBA.

7.1.1 Meter assumptions

With reference to *meter function-set*, all meters deployed are advanced smart meters. Most crucially, advanced in this context is equivalent to Home Area Network (HAN-function) in all meters deployed. This is in line with the assumptions made for the US-, the UK-, the German- and the Australian CBAs. For the *communication technology*, we model 50 percent of the smart meters as deployed with PLC and 50 percent with GPRS[10]. This is an assumption, not a recommendation or a well-funded belief about an actual deployment. It is not in the scope of this report to guide the choice of technology.

7.1.2 Demand-response assumptions

For *tariff systems*, Time Of Use (TOU) is the default option coming with the smart meter for every deployment. We assume, however, that some of the customers opt back to flat tariff (10%) and some customers shift from TOU to Real Time Pricing (RTP) (5%). We also assume that some customers will upgrade the TOU tariff with Critical Peak Pricing (CPP) (20%). Since TOU and CPP are assumed coexist, all CPP consumers are TOU consumers (see section 9.2.1.2.2 for details). With regards to *feedback type*, enhanced billing and web-portal access is the default option, coming with the smart meter for every deployment. We estimate an opt-in rate for In Home Display (20%). With reference to *Automation of appliances (DLC),* we include only automation of Air Conditioning. We estimate an opt-in rate of 20% for such Air Conditioning automation. We assume that all opt-in and opt-out rates are immediate, total and final (i.e. they do not change over time).

7.1.3 Rollout assumptions

The *rollout penetration* is limited to households and Small to Medium Enterprises (SME). For these 2.54 million end users, and the relevant population growth during the 15 years scope (1.6%), we assume 100% deployment. Large consumers, composing 103.000 meter-points consuming more than 40Mw/h annually, are excluded from the CBA for reasons elaborated in section (6.1). *The rollout time* is assumed to be 8 years, compared to a 7 years average in the European CBAs.

[10] In a NPV meter-comparison done over the timespan of the CBA, cellular (GPRS) technology turned out most expensive followed by PLC technology and lastly RF technology. From our benchmarks, the cost estimate for RF technology was the most uncertain. Being the cheapest and least reliable estimate, we omitted RF technology from the analysis.

Table 6: Assumption overview of the enhanced smart metering scenario

Main Parameters of the scenarios	Full Rollout Scenario
Tariffs*	TOU: 85%; CPP: 20%; RTP: 5%: Flat: 10%
Feedbacks	Enhanced Billing:100%; Web:100%; IHD: 20%
Meter Functionalities	Advanced meter – HAN capability
Communication Technologies	Mixed - PLC (50%) and Cellular (50%)
Automation (DLC)	20% of population
Roll-out time	8 Years
Scope of rollout	0 – 40 Mwh
* Note that TOU and CPP are assumed to coexist, so the percentage will not sum to 100.	

8. Costs – business as usual and smart meter rollout

8.1 Costs of the business as usual scenario (BaU)

In the BaU-scenario we count all the costs that are associated with running the existing meter-park. These costs will be reduced, or eliminated altogether, from an enhanced smart meter rollout. In this section we purely account for the BaU-costs, while we in section (9.1) quantify to what extent enhanced smart meter deployment reduces or eliminates these costs. Costs of the BaU-scenario are divided into (8.1.1) Analog meter visits, (8.1.2) Analog meter replacement and maintenance, (8.1.3) Customer minutes lost, (8.1.4) Technical losses in the transmission and distribution network, (8.1.5) Bad Debt, (8.1.6) Electricity Theft, (8.1.7) Call center costs, (8.1.8) Generation-expansion costs (8.1.9) Network-enforcement costs.

8.1.1 Analog meter visits

We divide analog meter visits into (a) analog meter reading, (b) analog special visits and (c) disconnection and reconnection. *Analog meter reading* is a significant cost associated with

the analog meter park. All the 2.64 million meters below the 40Mwh limit are read 6 times a year. From IEC numbers, we have calculated the average reading cost per meter to be 3.33 NIS[11]. *Analog special visits* are done in addition to, and separately from regular meter-readings. IEC reports an annual average of 30.000 such special-visits. In other words, 1.2% of the analog meters are assumed to receive a special visit each year. These special visits are given a threefold rational: (a) request from customer (e.g. voltage complaints, bill disputes); (b) statistical reads (e.g. identification of drift in "families" of meters) and (c) suspicion of theft. The cost of each special visit is assumed to be 155 NIS, calculated from IEC data and benchmarked against the literature[12]. *Disconnection and reconnection* represent a third cost with the current meter-park. We assume from the benchmarks that reconnection and disconnection is offered to 1% of the population, a conservative number. Each disconnection and reconnection process is priced at 153 NIS by Public Utility Authority (PUA, 2013).

8.1.2 Analog meter replacement and maintenance

Analog meters have an average lifetime of 35 years. In procurement, analog 1-phase meters cost 57 NIS, while analog 3-phase meters costs 110 NIS. These costs were provided by IEC. The installation costs are 212- and 327 NIS respectively[13]. Every year IEC install 100.000 meters on average, roughly 4% of the existing meter park. Half of it is due to malfunctioning, half of it is due to population growth. For the CBA, we operate with an analog meter malfunctioning rate of 2% and a population growth of 1.6%. Further, we assume that (a) malfunctioning in analog meters and population growth stay at the same level throughout the scope of this CBA and (b) malfunctioning and population growth apply with the same proportion to households and SME. There are also maintenance costs associated with the analog meter-park, given by IEC to be 6.6 NIS for 1-phase meters and 9.4 NIS for 3-phase meters per year. The costs are indexed from 2009. Analog meters and maintenance are assumed to have a maturity rate of 2%, reflecting the potential for costs reductions also in the BaU scenario.

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[11] Calculated on 2012 numbers. Based on 329 meter reading employees with a salary on cost of 160.000 NIS. 2.45 million meters are read 6 times a year, while of the 100.000 TOU-meters 90.000 are read 12 times a year (the last 10.000 are large consumers that are read remotely).

[12] In the UK CBA (DECC, 2013) special-visits are priced at 10 – 17.5 GBP depending on the specific service. While the cost assumption is somewhat lower than what we operate with, the service is assumed to be provided to 10% of the total meter park.

[13] Prices from IEC for installation where 2009 estimates and are in our CBA indexed to 2015 costs.

8.1.3 Customer minutes lost

CML is counted as the average of the years 2010, 2011 and 2012. The numbers are reported in the IEC financial report (2012a). Both scheduled and non-scheduled minutes are counted, and we reduce the average downwards by 10% to allow for baseline improvement. Consequently, 134 minutes of non-supplied minutes is used for the BaU-scenario in this CBA[14]. These customer minutes lost are counted per meter-point and no distinction is done between households and SME. Customer minutes lost are valued at 1.6125 NIS per minute. This is a conservative number, adjusting the value reported by Ministry of National Infrastructure (MNI, 2011) downwards by 25%[15].

8.1.4 Technical losses in the transmission and distribution network

Losses in transmission and distribution network in Israel have varied between 4-5 percent over the years 2002-2012. An average over the last 6 years of this time series, 4.2 percent, is deployed for this analysis for the BaU-scenario. Losses are valued at the current price of generation, 0.33 NIS. Note that losses are counted as 4.2% of the relevant population for the CBA, here 39.12% percent of total consumption[16].

8.1.5 Bad Debt

From the IEC financial report (IEC, 2012a), we have a total bad debt of 45 million NIS for the year 2012. We assume that 70% of this bad debt, or 31.5 million NIS, arise from households and SME. Hence, 31.5 million NIS is the bad debt BaU-scenario cost.

8.1.6 Electricity Theft

Electricity theft in Israel is assumed to be 0.5% of total electricity production valued at the cost of generation. The percentage of theft is an Israeli expert-evaluation found consistent

[14] 149 was the average identified and we use 90% of this value for our baseline. The adjustment allows for IEC to get more efficient before the perceived start of the deployment in 2015.
[15] CML in low-voltage network was by MNI (2011) valued at 129 NIS per Kwh (2.15 NIS per minute).
[16] Since the total generation includes generation to East-Jerusalem and the Palestinian Authorities, but smart meter deployment is not assumed for these areas, their share of consumption (8%) is subtracted from total generation before the 40% is valued.

with a lower bound of international benchmarks[17]. We believe, in line with the literature, that theft in Israel today occurs exclusively in the household and SME sector. Electricity theft is valued at the price of generation, namely 0.33 agorot per Kwh. Total annual electricity production at the start of the CBA, given by ministry of energy (MNI, 2013), is expected to be 72.7 Twh.

8.1.7 Call center costs

Customer enquiries and complaints generate call center costs. We have estimated, based on number of employees and other OPEX costs, annual call center costs to be 58.08 million NIS. We use this number as the BaU call center costs. It is found to be in the upper range of our benchmarks[18].

8.1.8 Generation-expansion costs

Generation expansion costs can be represented as an annual value, as done by Deloitte (2010) for Victoria[19]. In this CBA, however, we deploy a total value estimation given in a report by the Israeli Ministry of National Industries (MNI, 2010). Their calculation, based exclusively on the procurement cost of an average power-plant in Israel, is 1250 US$ (4563 NIS) per KW capacity increase. This KW cost translates into an average power-plant cost (360 MW) of 1.643 billion (MNI, 2010). The calculation of generation expansion costs mirrors the calculation of deferred generation capacity, outlined in detail in section (9.2.2.3). For establishing the base cost of generation-expansion costs over the period 2015-2030, we depend on the MNI (2013) generation forecasts.

8.1.9 Network-enforcement costs

We use data from IEC (2012a) to determine total annual network enforcement costs. From available data, over the time period 2010-2017, the average annual costs of network investments amount to 3.1 billion. For the specific period 2013-2017, according to IEC Financial Report (2012), the annual expected network expansion costs are 3.5 billion NIS.

[17] The CBA of Ireland and Austria both operate with 0.5% of electricity theft. Other countries, like Hungary and UK, operates with levels of 1% and more.

[18] From our benchmarks, call-center costs averaged 4 euros per meter per year, or an equivalent of 48 million NIS annually for the relevant Israeli meter-park.

[19] In Victoria Australia (Oakley Greenwood, 2010), the comparative value is given by 130 AU$ per year, while in an analysis by the Brattle group of 2007 the value was 54 US$ per year.

Of these 3.5 billion, 1.1 billion will be invested in transmission and 2.4 billion in distribution. We follow this prognosis and deploy 3.5 billion as our base-estimate for annual network enforcement costs.

8.2 Costs of enhanced metering deployment

Costs of smart metering are divided into two main categories; (8.2.1) CAPEX and (8.2.2) OPEX. In some reports, on the ground of functionality differences, meters supplied to SME are more expensive than meters supplied to the household sector (KEMA, 2012 and EPRI, 2011). In this CBA, however, all the meters are assumed to have the same, sophisticated functions. A difference in the average meter-price between households and SME occurs automatically as there are more three-phase meters among the SME than among the households. 3-phase meters are more expensive than 1-phase meters in both procurement and installation.

We want to underscore that it is not the aim of the CBA to guide the technology choice. In some CBAs either (a) the technology mix is fixed by expert estimation[20], or (b) technological alternatives are basis for scenario creation.[21] In other CBAs, a CAPEX and OPEX estimate is given without details about technology choice.[22] In this CBA we follow the last model, basing our CAPEX and OPEX estimates on an average technology-mix cost. We have, however, done a full cost estimation of all the technology types to (a) provide a model for such a technology assessment in the future, and (b) be explicit about the base of our estimations.

In this section, and in the benefit section that follows (section 9), we present in detail how we reach to each individual estimate, while the result part (section 10) aggregates all the individual parts into a high-level cost- and benefit calculation.

8.2.1 CAPEX

In this section we deal with the individual parts of enhanced smart metering CAPEX. From a macro perspective, a distinction is deployed between “CAPEX” and “CAPEX renewal”. Brief, the former is initial required investment while the latter is refresh costs in the end of a

[20] See for example the Lithuanian CBA (E&Y, 2012) and the Austrian CBA (PWC, 2010).
[21] See for example the Irish CBA (CER,2011a)
[22] See for example the Hungarian CBA (Force Motrice and ATKEARNEY, 2010)

technologies' lifecycle[23]. From a micro perspective, CAPEX is divided into (8.2.1.1) Smart meter costs, (8.2.1.2) Communication equipment costs, (8.2.1.3) IT-system costs, (8.2.1.4) Demand response component costs and (8.2.1.5) Unexpected costs. Renewal costs are not singled out, but rather included under the relevant section.

8.2.1.1 Smart meter costs – meter types and installation

In our benchmark overview, across relevant communication technologies and meter-phases, unit-prices vary between a low 264 NIS for single-phase PLC-meters in Hungary (Atkearney and Force Motrice, 2010), and 662 NIS for GPRS three-phase meters in Lithuania (E&Y, 2011). The average unit-price in our benchmarks is 370 NIS. This is the same cost-scope found in pilots across the world by the KEMA benchmark-report (2012). The large price gap is largely due to functional differences of the meter. For the relevant meter functionalities considered in this CBA (see table 3), the Lithuanian CBA (E&Y, 2012) and the Irish CBA (CER, 2011) provides detailed cost estimates. Table 7 displays the average price of the two CBAs by communication technology and meter-phases.

Table 7: Smart meter costs in Ireland and Lithuania without HAN-module

Smart Meter*	Single Phase, Price NIS	Three Phase, Price NIS
Smart Meter with PLC communication	338	502
Smart Meter with GPRS communication	504	595
Data from CBA Lithuania (E&Y, 2012) and CBA Ireland (CER, 2011). Costs without HAN		

The costs in Table 7 are found to represent an upper-, middle ground of the larger benchmark-matrix. The cost differences between the meter types are also reasonable[24]. Thus the meter prices above, HAN excluded, are deployed for this CBA. We assume

[23] For model purposes they are treated as equal, while the practical implication is that CAPEX renewal can be postponed to a certain extent.

[24] From the German CBA (E&Y,2013) and the Austrian CBA (PWC,2010), the GPRS meter should cost around 100 NIS more than the PLC meter due to communication module price differences. From the KEMA (2012) benchmarks, GPRS meters are expected to costs 168-240 NIS more than PLC meters. Our numbers are in the upper line of the German numbers, but in the lower line of the KEMA numbers.

installation costs for smart meters to be 150 NIS for one-phase meters and 232 NIS for three-phase meters. The cost difference is based on the current meter-installation costs provided by IEC, and the estimation is the average of what is found in the European CBAs[25].

The rollout of smart meters is assumed to take 8 years, and the actual deployment is initialized six month after the start date of the CBA[26]. This delay is included to facilitate project planning and initial build-up of the MDM system. The deployment is modeled to be proportional in time and between sectors so (a) the same amount of smart meters are installed every year and (b) the same proportion of smart meters are changed for both households and SME every year[27]. We do not include the potential NPV effect of a strategic deployment – i.e. that an actual rollout could give initially higher than average benefits and lower than average costs (by deploying in high consuming, densely populated areas). By assumption, no analog meter will be deployed from the start of the CBA. Consequently the rollout scenario accounts for population growth and analog meter malfunctioning.

For conservative reasons, we assume the lifetime of smart meters to be 10 years. This is significantly lower than the 15 years consensus deployed globally for a variety of CBAs, and it also counters empirical observations (KEMA, 2012). The re-deployment starts in the 126th month, and follows the pattern of the initial enrollment at a rate of 90%[28]. It is important to note that, in a lifetime perspective, the benefits of this re-investment for the years 16-20 are not quantified by this CBA as the time scope is only 15 years. Hence, the benefits of this CAPEX renewal are significantly understated.

8.2.1.2 Communication equipment costs – concentrator, balancing meter and CT-transformer

As outlined in section (5.1.2.1), PLC is a last mile communication. Hence a data-concentrator is needed for backhaul communication. We assume that a concentrator will be installed in every distribution transformer[29]. In 2012 numbers, there were 45.868

[25] Benchmark average 190 NIS, ranging from 50 NIS in Lithuania to 300 NIS in Denmark.
[26] We do not quantify stranded costs, i.e. the cost of replacing analog meters before the end of their economic lifetime (JRC, 2012).
[27] The opportunity of postponing or delaying some investment, with a potentially positive effect on NPV, is not included.
[28] In other words, 10% less meters are installed in every moth of the re-deployment compared to the initial deployment. The reduction is explained by the annual replacement of 0.5% due to malfunctioning.
[29] This is the general assumption (see for example the Lithuanian CBA (E&Y,2012) and it is confirmed by IEC as the way PLC would be installed in Israel.

distribution transformers in Israel, giving a ratio of meter per concentrator of 53:1 for the 2.46 million meters the same year (IEC, 2012a, large consumers excluded). Extrapolated to 1/1/2015, we assume this ratio to be constant around 50:1[30]. As there will be several instances where this rate cannot be obtained (e.g. geographical factors), we assume an inefficiency reduction of 5%. In line with the Lithuanian CBA (E&Y, 2012), and from IEC information, each concentrator will have a balancing meter and a current transformer[31]. Balancing meters records the quantity of electricity being transmitted to the corresponding transformer station. The only CBA that clearly distinguishes between the CAPEX of concentrators and balancing meters is the Lithuanian CBA by Ernst and Young (2012). They operate with a total CAPEX (procuration and installation) of 3200- and 4640 NIS for concentrators and balancing meters respectively. We use these cost estimated for our CBA as they are in line with broader benchmarks[32]. We do not account for any renewal costs for communication equipment in the scope of the CBA.

8.2.1.3 Demand response technology costs – HAN, IHD and DLC

Every meter point is assumed to be deployed with HAN. The cost of the HAN module varies from a low range of 11 NIS in the UK CBA (2013), to a high range of 48-72 NIS provided by the Lithuanian CBA (E&Y,2012) and the Irish CBA (CER,2011). An even higher estimate is given for the case of New Zealand[33] (Nzier, 2009). In the current report, we assumed a HAN module cost of 60 NIS. In table 8 below, meter prices are given included HAN.

In Home Display (IHD) has a price range of 80 to 240 NIS in our CBA-matrix. The average over 8 CBAs is 160 NIS. We adopt this average value for the current CBA since it is found to be in line with the most recent estimate available, the German CBA by Ernst and Young (2013). The installation costs of IHD are rarely singled out in the CBAs. KEMA (2012), in a reliable and highly cited benchmark report based on pilot results, estimates the IHD installation costs to be in the range of 38 – 120 NIS. This range is adopted for Germany as well (E&Y, 2013). For this CBA we adopt a higher range estimate of 100 NIS for the CBA.

[30] In the benchmarks, the range is from 44-200 with an average of 126.
[31] In line with the Lithuanian CBA we do not provide a separate estimate for the current transformer but rather bake it into the price of concentrator and balancing meter cost.
[32] From our benchmark matrix, a PLC concentrator has an average cost of 3900 NIS. In the benchmark report of KEMA (2012) the cost range is 1680 – 3360. From these benchmarks, however, it is not clear whether the cost reported includes balancing meters or not.
[33] For New Zealand the estimate is 200 NIS, but this includes installation and is modeled as a retrofit of existing meters.

The costs of automation, or more specifically DLC, are not standardized to the same degree as IHD[34]. The cost-effectiveness for mass distribution of automation technologies is tightly linked to air condition saturation, thus it has not been a relevant benefit for most European CBAs[35]. Benchmarks are mainly available from New-Zealand, Australia and the US. In the US, the Brattle Group et. al. (2009) operates with an estimate of 730 NIS[36] for the total cost of a DLC device with installation and 15% up-front OPEX included. In a detailed Australian cost estimation, the unit-cost of DLC ranges between 270- and 335 NIS, with an installation cost of 250 NIS[37] (NERA, 2008). We opt for a middle ground cost estimate of 300 NIS per DLC device and 250 NIS per installation.

The lifetime cycle of IHD and the automation device is assumed to mirror that of smart meters. Hence, a CAPEX renewal at 90% rate of initial CAPEX is assumed from the 126th month. Note also that for all the costs above, meters, communication equipment and demand response technology, we assume a technology maturity rate of 4%. Its justification is elaborated in section (4.2.4).

8.2.1.4 IT-systems CAPEX – MDM and web page

The centralized IT-center for storing and managing all the data from the smart metering system is named the Meter Data Management system (MDM). The MDM system is ensuring that metering data is safe, verified and easily accessible. Regarding the total CAPEX of the MDM, there is a large variety in the available benchmarks, ranging from 21 NIS per meter point in Lithuania (E&Y, 2012) to 921 NIS per meter point in Australia Victoria (Deloitte, 2011)[38]. Excluding these two extremes and looking at the average range identified in UK (134 NIS), Austria (47.5 NIS) and Ireland (54 NIS) gives us an average value of 79 NIS per meter. For 2.54 million meter-points that gives a total investment of approximately 200 million NIS[39]. An expert estimation for Israel, given the services enhanced smart metering will supply, is 100 million US$ (365 million NIS). Though higher than what has been

[34] Automation technology is the broad category for all sort of home appliance automation. We refer to DLC and automation interchangeably.
[35] In the Brattle Group et al. (2009) analysis of US potential, automation-potential is measured exclusively on the ground of air conditioner saturation.
[36] NIS to US $ 3.65
[37] NIS to Australian Dollars 3.35
[38] All the estimates include MDM set-up for an advanced meter function-set
[39] The UK estimate includes OPEX of running the MDM-system.

suggested in Europe, we have deployed 365 million NIS for this CBA. The complete MDM-CAPEX will occur over the first 3 years of the rollout.

A Web Portal will be offered to all end customers with online direct and secure access to all their detailed consumption data. The details of the portal have yet to be decided, and the costs will evidently vary with functionality. For the total investment, the Irish CBA (CER, 2012), has quantified a range from 1.31 – 17.45 NIS per meter-point, deploying 4.32 NIS for the actual CBA. In the Austrian CBA (PWC, 2010), the web-portal is quantified to 15 NIS per meter-point. To allow for an extensive function-set, we use the upper estimate of 17 NIS per meter-point for the current CBA, resulting in a total investment of 41.8 million NIS[40]. Also this investment will occur over the first 3 years of the rollout.

For the total IT-CAPEX, MDM and the Web-portal, the literature, operates with an amortization period of 7-8 years[41]. In our model, we have included an annual recurrent investment to allow for replacing and upgrading IT equipment. We refer to this recurrent investment as IT CAPEX renewal. Starting 2 years after the IT-system installations are finalized, we assume a CAPEX renewal at 10% of the relevant IT-CAPEX[42]. This implies that, during the time scope of the CBA, we invest twice in MDM and web-page. The assumption is in line with international benchmarks and local expert estimations[43].

8.2.1.5 Unexpected costs

Unexpected costs are largely related to exchange rate risks, exchanging fees and hedging. Such costs are included both from the CAPEX- and the OPEX-side separately. From the CAPEX-side, we have determined unexpected costs to be 8% of total CAPEX. This cost is not benchmarked, but included after local expert recommendation.

[40] Calculated on 2012 number of meter-points (IEC, 2012b).
[41] See the Victorian CBA (Deloitte, 2011) and the German CBA (E&Y, 2013).
[42] The CAPEX renewal for MDM and Web-Page is of their own relative CAPEX, not total CAPEX.
[43] In the Lithuanian CBA (E&Y, 2012), total running costs of IT are lumped together under the name "IT O&M", valued at 23% of total CAPEX annually. We have separated what we define as CAPEX on one hand (Renewal CAPEX) and OPEX on the other hand (Annual IT maintenance costs).

Table 8: Overview of CAPEX for enhanced smart metering

Smart Meter Included HAN	One-Phase (Price NIS)	Three-Phase (Price NIS)
PLC-Meter	398	562
Cellular-Meter	564	655
Installation	150	232
Communication Equipment Included Installation	PLC	
Balancing Meter	4640	
Data Concentrator	3200	
Demand Response	Price NIS	
IHD	160	
IHD Installation	100	
DLC	300	
DLC Installation	250	
IT – Costs	Price NIS	
IT-systems	365 mill	
Web-Portal	41.8 mill	
IT recurrent annual investment	10% of relevant IT CAPEX (MDM, Web-Portal)	
Other	In percent	
Unexpected costs (e.g. exchange rate risk) of total CAPEX	8% of CAPEX	

8.2.2 OPEX

Under OPEX we treat (8.2.2.1) Ongoing replacement costs, (8.2.2.2) Ongoing maintenance costs, (8.2.2.3) Ongoing data transmission costs, (8.2.2.4) Ongoing IT-system cost, (8.2.2.5) Ongoing financial and legal costs, (8.2.2.6) Unexpected costs and (8.2.2.7) Other OPEX costs. An overview of OPEX costs is given in table 9.

8.2.2.1 Ongoing replacement costs

We assume smart meter malfunctioning to be 0.5% per annum for all meter-types. This is confirmed by IEC from current smart meters, and it is in line with international benchmarks. When any technology malfunctions, it will be replaced. Further, we assume that PLC concentrators malfunction at a rate of 1.5% per annum. This is benchmarked from an extensive technology trial recently executed in Ireland (CER, 2011a)[44]. For the IHD and the DLC, we deploy an annual malfunctioning rate of 1.5% and 1% respectively (CER, 2011a).

8.2.2.2 Ongoing operation and maintenance costs

Apart from malfunctioning, there are other ongoing operation and maintenance costs associated with an enhanced smart metering park. From our benchmarks, these O&M costs are assumed to be higher in the beginning when the smart meters are recently installed[45]. Re-visits in the installation process and better routines (increased efficiency) are possible explanations of falling O&M costs. Higher initial costs are confirmed with the IEC and local expertise. With time, O&M costs are assumed to be more or less stable and can be represented by a constant malfunctioning percentage[46]. In sum, O&M costs are given an average, annual weight of 0.5%, with higher initially, gradually decreasing impact[47]. Reduced electricity consumption of the meter itself, though potentially a huge benefit of smart metering deployment, is not accounted for in this CBA[48].

8.2.2.3 Ongoing data transmission costs

Date transmission costs vary with (a) the type of communication technology, (b) the functionalities of the meter, (c) the tariff scheme deployed and (d) the penetration-rate of each technology. For cellular transmission costs, several sources expect the costs to be at

[44] A higher malfunctioning rate for concentrators than smart meters is confirmed by the CBA from Vermont (Friedman Sullivan & Co, 2007)

[45] This is confirmed by the Italian case where OPEX costs per meter have been reduced by 40% over the 9-years period 2001-2010 (Ilario Tito & Laura Panella, 2012).

[46] Most CBAs ignore this initial higher cost and assume a constant replacement rate of 0,5%-2%, as the only operation and maintenance cost (CER,2011a; E&Y,2012)

[47] For simplicity, O&M is modelled as malfunctioning of the relevant technology (e.g. smart meter, IHD). In the 15 years time scope, O&M is weighted 2% the first two years and 0.27% the resting years to give a total average of 0.5%.

[48] In the Lithuanian CBA, Ernst and Young (2011), savings of analog meter electricity costs was the most significant operational benefit.

around 22 NIS per meter per year with full scale cellular deployment (ABI research 2011 and UK CBA 2013). In our benchmark matrix, GPRS costs vary from a low estimation of 30 NIS for UK (CBA 2013) to a high estimation of 120 NIS for Germany (E&Y, 2013), with an average of 44 NIS. We adopt the average value of 44 NIS per meter per year for GPRS meters.

From the benchmarks, the annual per-meter communication cost for PLC is reported to be in the range of 5%-40% of pure cellular meter communication costs[49]. Annual, per meter communication costs for PLC ranges from 2.4 NIS in Lithuania (E&Y, 2012) to 48 NIS in Germany (E&Y, 2013). We determine the annual communication cost per PLC as a function of the cellular communication costs, valued as 20% of the cellular cost – i.e. 9 NIS per year.

Finally, we also add a communication cost for HAN. In the German CBA (E&Y, 2013), HAN is given an OPEX costs of 16.8 NIS per meter per year. As no other CBA includes this cost, and the German estimates for communication costs constantly are more than double than all other CBAs, we correct for this by deploying a cost of 8 NIS per HAN module per year.

8.2.2.4 Ongoing IT costs – management, software and maintenance

Annually IT operational costs are assumed to be 15% of total initial IT CAPEX – i.e. MDM and Web-portal. Firstly, this cost represents the management costs of the total IT-infrastructure, particularly the costs of big data analysis. Secondly, it includes the cost of software-updates and general maintenance. The estimate of 15% is benchmarked from the literature and subjected to local expertise[50].

8.2.2.5 Ongoing financial and legal costs

Ongoing financial costs are the costs of issuing guarantees, borrowing money and various fees. Financing costs are valued at 3% of the total CAPEX from the start of the model until the rollout is completed – i.e. after eight years and six months. To be conservative, the full financing cost is assumed to materialize in the first month of the CBA. Ongoing financial costs are not benchmarked but were included after local expert recommendation. *Provision*

[49] Some price ratios in Euros where 5: 20 (Flanders by Leuven,2007); 1,5:9 (Flanders by Tahon et Al 2012); 10:25 (Germany by E&Y 2013); 10:1,14 (Ireland by CER 2011a) and 10,5:0,5 (Lithuania by E&Y 2013)

50 A "thumb-rule" of 15% is applied by Ernst and Young (2013) for the German CBA. The same OPEX was applied in the Austrian CBA by PwC (2010). In the UK CBA by DECC (2013), 15% was the starting number gradually declining to 5%.

to legal lawsuits is included exclusively to cover actual property damage during deployment (e.g. power lines, phone lines). Again, from a national perspective, we have no concern for money transfers. We assume that provision to legal lawsuits will be 0.5% of annual CAPEX during the rollout.

8.2.2.6 Unexpected OPEX

Like for CAPEX, unexpected costs are largely related to exchange rate risks, exchanging fees and hedging. From the OPEX-side, we have determined unexpected costs to be 5% of total OPEX. This cost is not benchmarked, but included after local expert recommendation.

8.2.2.7 Other OPEX costs – publicity, project management

We have counted two other OPEX costs. *Firstly, publicity and education costs.* These are grouped together and spread evenly over the rollout period of 8 years and six month. The cost is benchmarked as a per-meter cost. Internationally the range is from 3.56 – 5.5 NIS per meter-point in total value, so a middle ground estimation of 4.5 NIS per meter is adopted for this CBA. *Secondly, total project management costs.* These are assumed to be 1% of the total CAPEX cost in total value[51]. Project management costs are modeled to start from the first month and last until the smart meter rollout is completed. The costs are divided equally over the eight years and six month assumed for the initial rollout to finalize.

Table 9: Overview of OPEX for enhanced smart metering.

Smart Meters	PLC	Cellular
Annual communication cost in NIS per meter*	9	44
Annual communication costs HAN in NIS per meter	8	8
Annual replacement rate in percent	0.50%	0.50%
Annual O&M-costs represented as malfunctioning in percent	0.50%	0.50%
Communication Equipment (concentrators and balancing meters)	PLC	Cellular

51 Same value as deployed by Ernst and Young (2011) for the Lithuanian CBA.

Replacement rate in percent	1.50%	n.a.
Annual O&M-costs represented as malfunctioning in percent	0.50%	n.a.
Demand Response	IHD	DLC
Replacement rate in percent	1.50%	1.00%
Annual O&M-costs represented as malfunctioning in percent	0.50%	0.50%
IT-systems operation and management costs	Annually	
Annually total IT O&M costs in percent of total IT-CAPEX (MDM and Web-page)	15.00%	
Financial and legal costs	Total Value	
Financial OPEX in percent of total CAPEX (during rollout)	3.00%	
Provision to legal lawsuits in percent of annual CAPEX	0.50%	
Unexpected OPEX	In percent	
Unexpected costs (e.g. exchange rate risk) of total CAPEX	5.00%	
Other	Only during rollout	
Publicity and Education costs in NIS per smart meter deployed	4,5 NIS	
Project Management costs in percent of total CAPEX	1.00%	
*Communication-costs for PLC represents data-transmission costs from the concentrator to the MDM divided per meter-point, while for cellular it represents the data-transmission directly from the meter-point to the MDM.		

9. Benefits – Operational benefits and Demand-Response

9.1 Operational Benefits

Operational benefits arise from reducing, or for some variables eliminating in total, the costs of the business as usual scenario. The BaU base-numbers for this reduction, i.e. the costs of the BaU-scenario, are described in detail under section (8.1) and will not be

repeated here. Operational benefits can be benchmarked without contextual adjustment as they are tightly linked to the enhanced smart metering technology (e.g. avoiding manual meter reading). From the literature, operational benefits are expected to cover somewhere between 50%-80% of the total smart metering investment (i.e. total CAPEX) depending on the context[52]. In this section we present the benchmarked assumption for each operational benefit together with its total nominal value over the scope of the CBA (i.e. 15 years). Where direct benchmarks are available, we break down the benefits to per-meter value to facilitate comparison[53]. Operational benefits are given the following fourfold structure: (9.1.1) Remote reading benefits, (9.1.2) Increased information benefits, (9.1.3) Better billing benefits and (9.1.4) Other operational benefits.

9.1.1 Remote reading - reduced field service management benefits

From the literature, we have identified two benefits under the umbrella term of reduced field service management. This cluster of benefits arrives from the meter-function of remote meter reading and remote control over the meter. In the following we treat (9.1.1.1) avoided meter reading and meter visit costs, and (9.1.1.2) avoided costs of disconnection and reconnection.

9.1.1.1 Avoided meter reading and meter visit costs

Since smart meters are read remotely, enhanced smart meter rollout eliminates the costs of analog meter reading. The nominal benefit of avoided meter-reading over the time scope of the CBA is 632 million NIS, or 16.6 NIS per meter per year. This value is in the mid-range of what we identified in our benchmarks[54]. For special visits, however, we do not assume that these will be avoided, but reduced. It is reasonable to assume, in line with the UK CBA (2013), that also smart meters require special visits, though to a lesser extent than analog meters[55]. In sum, taking a conservative approach, we assume that the total cost of BaU special visits will be reduced by 80% with the deployment of enhanced smart metering[56].

[52] See Ahmad Faruqui, Dan Harris, and Ryan Hledik, (2009)
[53] Note that the comparison should be taken as a "ballpark" rather than exact value as the per-meter values differ in how they are calculated. To arrive at our per-meter-value, number of meter-points 1/1/2015 is used (2.54 million).
[54] Average from out benchmarks was 2.64 Euros per meter per year with a range from 0.3 (Lithuania) – 6 (UK).
[55] In the UK CBA (DECC, 2013) these special visits are referred to as "special safety inspection visits".
[56] In the UK CBA, the total cost reduction is assumed to be 90% of initial costs.

The 80% reduction of special meter-visit costs translates into total nominal value of 565 million NIS over the scope of the CBA.

9.1.1.2 Avoided costs of disconnection and reconnection.

One of the smart meter functions specified for this CBA is remote connection and disconnection of electricity supply to a customer unable to pay the electricity bill. The BaU-cost of physical, on sight disconnection and reconnection is elaborated in section (8.1.1). With remote disconnection and reconnection this cost will be eliminated altogether, at a total nominal benefit of 48 million NIS over the scope of the CBA.

9.1.2 Increased information – network optimization benefits

Network optimization benefits occur due to the function of interval reading providing the benefit of increased and more precise information. Better information, again, is assumed to reduce: (9.1.2.1) network enforcement investments, (9.1.2.2) transmission and distribution losses, (9.1.2.3 customer minutes lost and (9.1.2.4) electricity theft.

9.1.2.1. Reduction in network enforcement investments due to better planning

Detailed, continuously historical data of power flow, grid connection, voltage and maximum loads will guide new network investment as well as network enforcement more precisely. By greatly easing the identification of bottlenecks, investments will be directed towards the critical parts of the network. There is consensus in the literature on these effects, but lack of consensus towards how to quantify them. The UK CBA (2013) is the only report presenting a precise estimate, placing the value at 5% reduction of total, required network enforcement investments. Large investments in the Israeli distribution network will occur irrespectively of an enhanced smart meter deployment. Smart metering deployment would, however, be helpful in directing future investment prioritization. In sum, we adopt a conservative estimation of 2.5 % for network enforcement investment reduction. As planning by nature is a long run activity, we assume the benefit to initialize only after 50% of the smart meters are deployed. Over the scope of the CBA, the total benefit of better planning is 856 million NIS.

9.1.2.2 Reduction in transmission and distribution losses

Identification of where losses occur, and to what extent, is the key to its reduction. Again increased access to information is the driver, so a significant regional coverage will have to be in place before any effect materializes. We assume the critical point to be 40% deployment. In the Hungarian CBA by Atkearney and Force Motrice (2010), a total reduction of 20% is assumed for electricity. In the Lithuanian CBA (E&Y, 2012), the reduction is estimated to be 50%[57]. In consultation with local expertise, 10% reduction is deployed in the current CBA. Note that the reduction of losses is calculated from the total consumption of the relevant population – i.e. households and SME. A conservative 10% reduction in transmission and distribution losses gives a total benefit of 540 million NIS over the scope of the CBA.

9.1.2.3 Reduction customer minutes lost

Detailed information about location, numbers of customers affected and causes of power failure will increase efficiency in resolving network failure and generally simplify outage management. From quicker and more precise response, non-supplied customer minutes are assumed to be reduced by the introduction of an enhanced smart metering system. This benefit, however, should not be estimated meter by meter. A significant regional coverage will have to be in place before any effect materializes, established at 30%[58]. Further, the benefit derives from the low voltage distribution grid, as other parts of the voltage system already is equipped with more advanced, remotely controlled monitoring systems. Both households and SME are low voltage customers so all 2.54 million meter-points are assumed to benefit equally. In Victoria (Deloitte, 2011), a 5% reduction of CML is assumed. In the UK national CBA (DECC, 2013), a 10% reduction is assumed[59]. We deploy 5% as a conservative estimate, producing a total nominal benefit of 332 million over the scope of the CBA.

[57] In the Lithuanian CBA theft, CML and network losses are grouped together in the category "commercial losses"

[58] In the UK CBA (2013) the benefit is realized gradually from 30% installation, in the Victorian CBA the benefit is realized in full only from 80% installation.

[59] In an umbrella term "Commercial Losses", where both theft, CML and grid losses are included, the Lithuanian CBA (E&Y) estimate a reduction of 50% for this category.

9.1.2.4 Reduction in electricity theft

Deployment of an enhanced smart metering system significantly improves the possibility for electricity suppliers to detect electricity theft. There is, however, no consensus on the extent to which electricity theft can be reduced. Italy is an interesting case with nationwide empirical data for more than ten years. The success rate of theft detection has increased by 70% as a result of smart meter deployment (Ilario Tito & Laura Panella, 2012). From the benchmark it ranges from a low 10% in the UK CBA (2013) to a high 70% in the Hungarian CBA (Atkearney and Force Motrice, 2010). The average of our benchmarks is a 40% reduction. In a separate benchmark report by European Regulators Group for Electricity and Gas (ERGEG, 2009), a range of 20-33% theft reduction is given[60]. Hence we adjust our own benchmarks average downwards to an expected 30% reduction in electricity theft. Reducing electricity theft by 30% has a total nominal value of 348 million NIS over the scope of the CBA. This gives an annual per-meter value of 9 NIS, somewhat higher than what was identified from our benchmarks[61].

9.1.3 Better billing – reduced bad debt and call center costs

This group of operational benefits arises from better and more detailed billing. We treat (9.1.3.1) debt management and (9.1.3.2) reduced call-center costs.

9.1.3.1 Debt management

From a large sample of literature, smart meters are expected to help avoiding debt for the consumers (CBA UK 2012, Capgemini, 2008 and CER,2011a). Consequently also the electricity supplier benefits due to reduced costs in debt management and recovery. The extent of the benefit depends on BaU-characteristics, particularly the detail-level and frequency of billing. We assume a bad debt reduction of 20% for Israel with the introduction of enhanced smart metering. We assume that the benefit materializes from the point of 40% deployment. In nominal value, this reduction in bad debt produces a total benefit of 77 million NIS over the course of the CBA. It translates to a value of 2 NIS per meter per year, and is consequently placed in the

[60] Quoted from Atkearney and Force Motrice (2010)
[61] We have two benchmarks, UK and Ireland with per annum meter-values of 0.34 and 1 euro accordingly.

lower rage of our benchmarks[62]. Another benefit of that relates to debt management is the reduction in days of outstanding customer bills. The Enhanced metering system reduces the gap between meter reading and billing and thus improves the cash flow of the supplier. In brief, less outstanding debt will reduce financing fees (e.g. interest expenses. We have not quantified this benefit due to uncertainty of the estimate.

9.1.3.2 Reduction in call center costs

It is assumed that call center costs will be reduced by the deployment of an enhanced smart metering system. Two reasons are stated in the literature. Firstly, there will be less invoice related questions resulting from the end of estimated billing and the elimination of reading errors. Secondly, there will be more precise answers in the case of outages due to better and more detailed information. Automated responses are facilitated. The benchmarks, in estimated percentage reduction in call center costs, ranges from a low 20% in the UK CBA (2013) to a high 90% in the Lithuanian CBA (2012). The average value is 50%. From the KEMA (2012) pilot benchmark report, the average reduction in call center costs is 56%. Thus, 50% reduction is deployed for this CBA. The full realization of this benefit depends on a certain regional coverage (e.g. precise outage detection). Hence the benefit is modeled to materialize from 20% deployment. In nominal value, this reduction in call center costs produces a total benefit of 307 million NIS over the 15 years time scope of the CBA, or a per meter annual value of 8 NIS per. From our benchmarks, the average annual benefit per meter is 2 Euros, or 9.6 NIS.

9.1.4 Other operational benefits - Avoided analog meter deployment and maintenance

From the time enrollment of smart meter stars, no analog meter will be deployed. Hence, smart meters will be installed both where (a) analog meters are malfunctioning (2% of the meter park annually) and (b) where population growth enlarges the meter-park (1.6% annually). In the BaU scenario, these costs would have occurred at the cost of analog meter deployment. Additionally, smart meter deployment will eliminate maintenance costs for analog meters. To identify the true, incremental societal cost of enhanced smart metering

[52] From the benchmarks, Ireland (CER, 2011a) and the UK CBA (2013) values this benefit to 0,37 and 2,60 euros per meter per year respectively.

deployment, these BaU costs are subtracted from the rollout scenarios. Hence, avoiding BaU-costs of analog meters due to (a) malfunctioning, (b) population growth and (c) maintenance is counted as a benefit in this section. The benefit is valued at the full procurement- and installation costs of analog meters, and amounts to 621 million NIS over the scope of the CBA.

Table 10: Operational Benefits

Remote reading benefits	Reduction in per cent
Avoided regular meter-reading costs	100.00%
Avoided special meter-reading costs	80.00%
Avoided disconnection/reconnection costs	100.00%
Information benefits	**Reduction in per cent**
Reduced network enforcement	2.50%
Reduced network losses	10.00%
Reduced customer minutes lost	5.00%
Reduced electricity theft	30.00%
Billing Benefits	**Reduction in per cent**
Reduced bad debt	20.00%
Reduced call center costs	50.00%
Other operational benefits	**Reduction in per cent**
Avoided analog-meter deployment, replacement and maintenance	100.00%

9.2 Demand response benefits

Demand response benefits are benefits that arise from consumer response to (1) tariff-systems, (2) feedback and (3) DLC. The actual benefit derives from (a) consumption

reduction and (b) peak-shift. These benefits are less predictable as they have a strong contextual element and are linked to human behavior (e.g. peak-shift and electricity consumption reduction). To cover the gap between the total costs of enhanced smart metering and operational benefits, or to create positive net benefit, consumer involvement through demand response is necessary. When peak-demand is shifted, it is likely that overall consumption is reduced. In the same line of reasoning, when overall consumption is reduced, it is likely that the peak load is reduced accordingly. To avoid double-counting, however, we calculate each effect independently, assuming no such correlation internally between the variables[63]. Demand response benefits are given the following twofold structure: In (9.2.1) we identify the potential of demand response benefits, while we in (9.2.2) monetize the potential of demand response benefits.

9.2.1 Identifying the potential

With reference to inter-sectorial differences, households are found to be more responsive than SME for both consumption reduction and peak-shifting[64]. For this CBA, we assume the SME consumption reduction and peak shifting to be 50% of households. *With reference to peak shift potential*, the two crucial variables are (a) the load curve (depending largely on climatic variations) and (b) discretionary load (depending largely on central air conditioner saturation) (The Brattle group et. al. 2009 and CRA, 2005). Israel is positioned in the high end potential with regard to both. In identifying the potential for demand response we look at (9.2.1.1) Pilot reviews vs. National rollout; (9.2.1.2) Tariff systems; (9.2.1.3) Feedback effects and (9.2.1.4) DLC effects. To avoid double counting, we report only independent effects of each variable, controlled for the other variables[65]. Finally, when all the independent effects are counted, we summarize the total demand response effects on the household sector and the SME.

9.2.1.1 Pilot reviews vs. National rollout

We make use of two sources for estimating the effect of demand response, pilot

[63] The findings of the Californian Pricing Pilot (CRA, 2005) supports that peak-shifting occurs without consumption reduction.

[64] See for example Ernst and Young (2012), CER (2011b) and Charles River Associates (2005). A UK study by Carbon Trust 2007 disputes this evidence.

[65] In the strict sense this requires multiple regressions. Where multiple regressions are not conducted we still refer what the authors classify as independent effects of the variables.

reviews and CBAs of national rollouts[66]. The pilot reviews considered cover a total of 170 pilots in various parts of the world, based on diverse designs regarding size, time-span and methodology. For an overview of the relevant CBAs see table 1 in section (4.1). In table 11 below, the data gathered from the pilot reviews and the national CBAs is summarized. One should note two reasons for why the pilot-reviews show higher savings and peak-shifts than the CBA results. First, the majority of pilots are based on an opt-in design[67]. Second, pilot results tend to weaken when sample size and the time horizon increases[68].

Table 11: Comparison of Pilot Reviews and National CBAs

Comparison Pilots and National CBAs – Averaged numbers	Energy reduction % min- (Average)- max	Peak-Shift % Min – (Average) – Max
From Pilot Reviews	2.95 - (5,95) – 9.1	14,4 – 14,5
From National CBAs	1,5 - (2,6) – 3,6	2,5 – 10
*Average numbers from 5 large pilot reviews of 170 pilots together		

9.2.1.2 Tariff-systems – TOU, CPP and RTP

One of the principal features of smart metering is the ability to record individual customer energy usage in fifteen-minute intervals. Interval data enables retail and network prices to reflect the different costs of supplying electricity at different times of day. There is conclusive evidence drawn from a large database of pilot studies to that tariff-systems moving away from flat-pricing towards more dynamic pricing will lead to peak reduction and total consumption reduction[69]. In this section we look at (9.2.1.2.1) Time Of Use (TOU), (9.2.1.2.2) Critical Peak Pricing (CPP) and (9.2.1.2.3) Real Time Pricing (RTP). It is important to note, however, that the effects of each tariff crucially depend on adequate tariff policies.

[66] In total, the results are based on 40 reports and articles.
[67] See Klopfert et. al. (2011)
[68] Se ACEE 2010 and Vasaett (2011)
[69] See Vasaett (2011), ACEE (2010), Faruqui (2005, 2007, 2009 and 2011) and Klopfert et. al. 2011.

9.2.1.2.1 Time Of Use (TOU)

TOU, as defined in this CBA, is a tariff that divides the 24 hours of the day into three different price levels. The price varies between these price-blocks, but not within. The price variations are the same every day and are engineered to approximate the peak and non-peak hours. TOU is the default tariff accompanying every smart meter deployed. . We do, however, assume a dropout rate of 15% with 5% moving to RTP and 10% moving back to flat tariff. For the sake of simplicity, we assume this dropout to be immediate – i.e. it will appear in the model as if only 85% of the meters come with TOU. *First, we look at peak shift resulting from TOU.* In four recent, extensive pilot reviews based on 185 pilots, the average effect of TOU on peak shift is 5%[70]. The often cited California Pricing Pilot (CRA, 2005), reports a peak shift of 5.9%. The range in the available data is large, from 0-25%, depending crucially on peak to off peak price ratio deployed for the TOU rate (Faruqui and Sergici, 2013). *Second, we look at consumption reduction resulting from TOU.* Vasaett's (2011) review of 13 pilots finds an average consumption reduction of 5% from TOU. In the sophisticated CER (2011) trial from Ireland, TOU was found to reduce consumption with 2.7%. As elaborated in 9.2.1.1, the pilot results will be dramatically higher than what can be expected in a nation-wide deployment[71]. Consequently, for the 85% of customers covered by TOU, we assume an independent effect of 0.25% and 0.5% from consumption reduction and peak-shift respectively.

9.2.1.2.2 Critical peak pricing (CPP)

CPP is a tariff design where customers are charged a higher price during a few hours and a discounted during the remaining hours. For these critical peak hours, the price-ratio of peak to non-peak is larger than in the TOU-tariff. We assume CPP will be combined with TOU as a complementary tariff[72]. Given the unfamiliarity of Israeli customers to choose tariffs, we deploy a conservative opt-in rate of 20%. We model

[70] Vasaett (2011), ACEEE (2010), Newsham and Boker (2010), and Faruqui and Sergici (2013).
[71] As an example for TOU, three Australian CBA for Victoria by (1) Oakley Greenwood (2010), (2) Futura (2011) and (3) Deloitte (2011) uses 1% and 1.5% for consumption reduction and peak-shifts respectively. But because of their opt-in design, we have adjusted this downward to 0.25% and 0.5% respectively
[72] See Faruqui, Ahmad 2012.

this as if 20% of the meters are "installed" with CPP. Because CPP only is used during a few critical hours of the year, it is not assumed to impact overall consumption reduction. *Regarding peak shift*, data from the Vasaett study (2011) displays an effect of 16% from CPP[73]. The Californian Pricing Pilot (CRA, 2005) finds a peak shift of 13.1% - 15.8% for critical days[74]. In an extensive pilot review from the brattle group (Faruqui and Sergici, 2013), the range is from 10-50% depending on peak to off-peak price ratio. For CPP we assume an opt-in design, so the pilot results are credible indicators of what can be expected in a nation-wide rollout[75]. Consequently, we expect CPP customers to reduce the peak consumption of electricity by 15%. Since the evidence is inconclusive, we do not expect CPP to affect overall consumption.

9.2.1.2.3 Real time pricing (RTP)

Real time pricing exists when the consumer at all times pays the real market cost of delivering electricity. Thus, (1) the price is not known far in advance, (2) no two days have the same rate structure, and (3) there can be much greater extremes of on-peak to off-peak price compared to CPP. In the Vasaett (2011) study, across a sub-set of 22 pilots, RTP is found to reduce consumption by 13% and shift peak consumption by 12%. The extent to which these results can be replicated depends on the wholesale energy price and its variations. To be conservative, we model an opt-in rate of 5%, with an according consumption reduction and peak shift of 10%.

9.2.1.3 Feedback

Smart metering will open up for consumers to get more detailed and meaningful information about their consumption. The presentation of this information to the customer is called feedback. Several studies are dedicated to isolate the effect of various feedbacks[76]. The results are straight forward, the closer to real-time the feedback the larger the effects. The results, however, are also showing that sample-size and time horizon influence the

[73] Based on a sub-set of 69 pilots.
[74] Customers in warm areas with central air condition are identified as the most responsive consumer group.
[75] Three CBAs for Victoria all operate with 15% peak-reduction from CPP (Oakley Greenwood 2010, Futura, 2011 and Deloitte, 2011)
[76] See particularly ACEE (2010), Vasaett (2011), CER (2011b) and Faruqui et. al. (2009)

effect of feedback – larger samples and increased time-frame are both inversely correlated to customer responsiveness[77]. We operate with three type of feedback, each given an independent demand-response contribution. Specifically we look at (9.2.1.3.1) Enhanced Billing, in (9.2.1.3.2) Web-Portal and (9.2.1.3.3) In Home display. Feedback is not assumed to have any impact on peak-shift, only consumption reduction[78].

9.2.1.3.1 Enhanced billing

Enhanced billing provides more detailed information about energy consumption patterns attached to the regular electricity bill. It is a service that will be provided to every customer. In the Vasaett (2011) study, based on a sub-set of 27 pilots, enhanced billing reduces consumption by 5.9%. In another comprehensive pilot-review by ACEEE (2010), the comparable result for 34 pilots is 3.8%. In a recent, large scale customer trial from Germany, the combined effect of enhanced billing and web-portal information was found to reduce consumption reduction by 5%. The results were tried econometrically and found to be statistically significant. In the California Pricing Pilot (CRA, 2005), however, increased information without price signals did not significantly reduce consumption. For the current CBA, benchmarking to other CBAs, we estimate the independent effect from enhanced billing to be 0.5%[79].

9.2.1.3.2 Web-Portal

The enhanced smart metering system will also provide a web-portal where end users can login to receive real time consumption feedback. A well designed web-portal can serve as a substitute for an In Home Display. Depending on its exact functionalities, a web-portal is found to reduce consumption significantly across a range of studies. In the Vasaett (2011) study based on a sub-set of 7 pilots, a web-portal is found to reduce consumption by 5.13%. In another pilot review by ACEEE (2010), the comparable result for 34 pilots is 6.8%. As explained in section 9.2.1.1, the savings for a nation-wide deployment will be dramatically lower. Conservatively, we give web-portal the same weight as enhanced billing, 0.5%.

[77] See Van Dam S. S., Bakker C. A. and Van Hal J. D. M, (2010)
[78] This assumption is in line with the Victorian CBA (Deloitte, 2011)
[79] See Oakley Greenwood (2010).

9.2.1.3.3 In home Display

In Home Display provides real time consumption feedback to the consumer. The display is connected to the smart meter through the HAN. We assume that 20% of the consumers opt-in for an IHD, and we model this as if 20% of the smart meters are deployed with an IHD. In short, (a) 100% of the consumers will receive enhanced billing and web-portal feedback, and (b) 20% of the consumers will receive enhanced billing, web-portal feedback and IHD. In the Vasaett study (2011), based on a sub-set of 30 pilots, IHD is found to reduce consumption by 8.68%. In the ACEEE study (2010), based on 34 pilots, the comparable reduction is 9.2%. Both of these studies, however, report declining effect when sample size and time horizon is enlarged. Another ACEEE (2012) study, looking at nine recent, large-sample pilots, found the effect of real time feedback (IHD) to range from 0-25% with an average of 3.8%. This is confirmed by BEUC (2011). Also the CER trial (2011b) in Ireland, one of the most trusted and cited customer trials conducted, displays a modest effect of 2.1% from IHD. A widely cited study from Netherlands (Dam, Bakker and Hal, 2010), despite initial positive figures, finds no statistically significant effect of IHD on consumption after four month. These considerations have led us to adopt a conservative saving rate of 3% for IHD[80].

9.2.1.4 Automation - DLC[81]

There are limits to the speed with which customers can manually react to price signals even with appropriate feedback. Thus, automated responses strengthen the effect of demand response. Through the Home Area Network (HAN), smart meters can automate home appliances. In this CBA, appliances equal Air Condition[82]. Consumption reduction through DLC is achieved through either (a) higher thermostat set-points or (b) limited cycling. Since automation here depends on price signals, customers with a DLC device are a subset of those enrolled in TOU, CPP or RTP. We assume that 20% of the population will opt-in to some sort of automation,

[80] Three CBAs for Victoria all operate with 6% energy saving from IHD (Oakley Greenwood 2010, Futura, 2011 and Deloitte, 2011). We have adjusted the number down to 3% based on recent studies reported.
[81] In this CBA we make use of a general category for automation, and we use DLC and automation as interchangeable concepts. I.e. we do not distinguish between the different types of automation (e.g. DLC, cycling).
[82] In a recent, sophisticated statistical analysis performed by The Brattle Group (2009) of demand response potential in the US, peak reduction potential is uniquely tied to centralized Air Condition saturation.

and for the sake of modeling we expect identical response from these consumers. This is a low opt-in number compared to findings of The Brattle Group et.al. (2009) in the US, but it matches the number given for the Victorian CBA by Deloitte (2011). In the Vasaett (2011) study, based on a sub-set of 85 pilots, DLC is found to have an incremental effect on peak-shifts of 16%. Their findings are confirmed by a large range of studies and particularly robust for consumers living in warmer climates with central air conditioning[83]. Consequently, we assume that customers subscribed to automation will reduce peak consumption by 15%[84].

9.2.1.5 Demand response variables in this CBA – an overview

We now, based on all the assumptions above, present an overview of the estimated energy-savings and peak-shifts for (a) the household sector and (b) the small-to-medium-enterprises (SME). The overviews are displayed in table 12 and table 13 respectively. As described in the methodology, to arrive at the expectations given for the SME, we simply multiply the Household results with a factor of 0.5 as we expect only half of the response. Note that the weighted total consumption reduction and peak-shift reduction for the household sector (2.31% and 6.93% respectively), should not be confused with total economic impact. Given that the households compose 32.4% of total consumption, the economy wide effect on consumption reduction and peak-shift is 0.94% and 2.24% respectively. The same logic applies for SME where the corresponding values for the nation-wide impact are 0.10% and 0.23% given that their share of total consumption is 6.7%.

[83] See for example: Newsham Guy R. and Bowker Brent G. (2010) and CRV (2005)

[84] From the three Victorian CBAs an average of 17.5% is deployed as the independent effect of DLC (Oakley Greenwood 2010, Futura, 2011 and Deloitte, 2011).

Table 12 : Demand response effects from the Household Sector

Demand-Response Variables*	Percent of population in each group	Independent Contribution to Consumption Reduction	Independent Contribution to Peak-shift	Weighted total consumption reduction for household sector	Weighted total peak-shift for household sector
Tariff-systems					
Time Of Use	85.00%	0.25%	0.50%	0.21%	0.43%
Critical Peak Pricing	20.00%	0.00%	15.00%	0.00%	3.00%
Real Time Pricing	5.00%	10.00%	10.00%	0.50%	0.50%
Stay of flat tariff	10.00%	0.00%	0.00%	0.00%	0.00%
Feedback					
Enhanced Billing	100.00%	0.50%	0.00%	0.50%	0.00%
Web-Page	100.00%	0.50%	0.00%	0.50%	0.00%
In Home Display	20.00%	3.00%	0.00%	0.60%	0.00%
Other					
Direct Load Control	20.00%	0.00%	15.00%	0.00%	3.00%
Total Household Consumption reduction and peak-shift				**2.31%**	**6.93%**

*Note that the percentages are not meant to summarize to 100% as several demand-control variables are coexisting (e.g. TOU and CPP; Enhanced billing, Web-Page and IHD)

Table 13: Demand response effects from the Small to Medium Enterprises (SME)

Demand-Response Variables*	Percent of population in each group	Independent Contribution to Consumption Reduction	Independent Contribution to Peak-shift	Weighted total consumption reduction for SME	Weighted total peak-shift for SME
Tariff-systems					

Time Of Use	85.00%	0.13%	0.25%	0.11%	0.21%
Critical Peak Pricing	20.00%	0.00%	7.50%	0.00%	1.50%
Real Time Pricing	5.00%	5.00%	5.00%	0.25%	0.25%
Stay of flat tariff	10.00%	0.00%	0.00%	0.00%	0.00%
Feedback		0.00%	0.00%		
Enhanced Billing	100.00%	0.25%	0.00%	0.25%	0.00%
Web-Page	100.00%	0.25%	0.00%	0.25%	0.00%
In Home Display	20.00%	1.50%	0.00%	0.30%	0.00%
Other		0.00%	0.00%		
Direct Load Control	20.00%	0.00%	7.50%	0.00%	1.50%
Total SME consumption reduction and peak-shift				**1.16%**	**3.46%**
*Note that the percentages are not meant to summarize to 100% as several demand-control variables are coexisting (e.g. TOU and CPP; Enhanced billing, Web-Page and IHD)					

9.2.2 Monetizing the potential

In monetizing the potential of demand response effects, we separate between (a) the effect of peak-shifts and (b) the effect of consumption reduction. The effect of peak-shifts is divided into (9.2.2.1) Short term value of peak-shift and (9.2.2.2) Long term value of peak-shifts, while the effect of consumption reduction is divided into (9.2.2.3) Consumption reduction and (9.2.2.4) Co2-value of consumption reduction.

9.2.2.1 Short term value of peak-shifts

When load is shifted from peak to off-peak periods, a short run marginal cost saving will be realized as a given amount of energy can be generated at a lower average generation cost, minimizing production-related costs within the wholesale market by balancing generation and demand in a more cost effective way. Note than since peak-shifts are not assumed to

contribute to overall consumption reduction, the lower peak consumption is assumed to be counter-balanced by higher off-peak consumption. With this constrain, the short run value of peak-shifts is the difference in generation costs between peak and off-peak periods. In other words the society saves the incremental marginal cost (above average generation costs) of generating peak electricity. To capture the full value of this benefit, every Kwh during the year shifted from higher- to lower marginal generation cost should be valued, even at small cost differences. This, however, is not in the scope of the current CBA, so we account only for the most critical hours, estimated to be 100 peak-hours per year[85]. We value each Kwh shifted from peak-hours to non-peak hours at 0.314 NIS. This is based on current generation cost differences of production provided by IEC adjusted to facilitate future use of natural gas[86]. In nominal values, the short term value of peak shift is 160 million NIS over the scope of the CBA.

9.2.2.2 Long term value of peak-shifts

There is broad literature on how peak-demand is concentrated around 1% of the time, about 80-100 hours a year. It is uniquely for this 1% we build new power stations. For Israel, peak-hour in summer is 2-3 o'clock. At winter-time, the peak is in the evening around 6-9 o'clock. Both peaks results to a large extent from use of air condition for cooling and heating respectively. Winter and summer peaks have come closer and closer (IEC statistical report, 2012). The long term value of reducing this peak can be divided into (a) deferred generation capacity and (b) deferred grid enforcements.

Firstly, we look at the value of deferring generation capacity. We have the BaU-scenario growth in production over the time scope of the CBA from the Israeli Ministry of National Industries (MNI, 2013). Reduction in peak-demand will defer building of planned power plants. As outlined in section (8.1.1), we value deference of power-plants in line with the Israeli Ministry of National Industries (MNI, 2010). Their calculation, based exclusively on the cost of an average power-plant in Israel, is that each KW capacity not built has a value/cost of 1250 US$, or 4563 NIS[87] . Since an average power-plant has a capacity of 360

[85] 100 hours are reported by the IEC as the most critical peak hours of the year. This is supported by broad literature, see for example Faruqui et. al. (2007).

[86] Specifically we reduced the current peak price of generation given by IEC downwards by 40% before we calculated the difference.

[87] From the report it is quoted: "Assuming it is a 'combined cycle power plant', with an installed capacity of 360 Megawatts, 4,500 hours of activity per year, and an efficiency rate of 85%, which allows the supply

MW, the total value of deferring a power-plant is 1.643 billion (MNI, 2010). Increasing generation capacity is done stepwise. Consequently, also deferring generation capacity is valued stepwise, not marginally. Capturing the stepwise value and taking into account a time-lag representing the planning horizon of such an investment, we value the deference of a power-plant gradually from the moment 60% of the 360MW is deferred[88].

Secondly, we look at the value of deferring grid enforcements. Increased generation capacity requires grid enforcements. Consequently, for every KW generation capacity deferred, there will be a corresponding reduction in network-enforcement costs. Grid enforcements, however, particularly in the distribution grid, are lumpy, and there is no international consensus of how to measure this effect. In a recent, detailed cost assessment done by Oakley Greenwood for Victoria (2010), for every dollar saved in deferring generation, 54 cents was assumed to be saved in deferring network-enforcement. Their estimate is referred to as conservative[89]. Looking at the Israeli ratios of "total network investments" to "total generation investments", these have averaged at exactly 0.54:1[90]. From Israeli expert assessments, however, a much lower ratio has been suggested for this CBA. We agree with the conclusion of Brattle group (2007) that the value is unlikely to be zero, but even their own estimate of a 0.1:1 ratio is found unreasonably high. Consequently, we adopt a 0.05:1 ratio for this CBA. As one KW generation capacity deferred is valued at 1250 US$, the corresponding value for deferred network-enforcement is 62 US$, or 228 NIS. Adding the per-KW-value of avoided network generation, the total long term benefit of avoiding one power-plant is 1.725 billion NIS. Over the time scope of the CBA, resulting from the peak-shifts elaborated in table 12 and table 13, one power-plant is deferred at a nominal value of 1.725 billion NIS.

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of 1.386 billion Kwh. In the present paper, a conservative production assumption of 1.1 billion Kwh was applied to the plant (20% lower)."

[88] The value of not building an additional power-plant starts when 60% its total capacity is deferred, and is spread over 3 years in the following manner: 20% first year, 40% in second and third year. The logic is that the project horizon of an average power-plant is 3 years.

[89] The CBA by Oakley Greenwood for Victoria (2010) notes that $110.000 MW/yr for deferral of network augmentation was deployed in a recent CBA, with 130.000 MW/yr for generation deferral. For their own CBA they deploy a common value of 200.000 MW/yr.

[90] Calculated from 2010–2017, where 5.937 bn was found to be total generation investments and 3.097 was found to be total network investments. The average relation between the two over the 8 years was 54%.

9.2.2.3 Consumption reduction

Consumption reduction has a direct value to the end consumer by lowering electricity expenditures. From a national point of view, ceteris paribus, lower electricity consumption equals reduced total costs of generating and supplying electricity. To value consumption reduction, only the long run variable component of the tariff should be included – i.e. components of the tariff not varying with consumption should be excluded[91]. Fixed cost elements are excluded. From IEC data, this value is determined to be 0.33 NIS per Kwh in average. In total, given the consumption reduction estimated from table 12 and table 13, the nominal value of consumption reduction is 2.619 billion NIS over the scope of the CBA.

9.2.2.4 Co2-value of consumption reduction

Reduced electricity consumption also reduces Co2-emission. Reduced CO2-emission is valued by the national economic council to 0,078NIS per Kwh[92]. In total, given the consumption reduction estimated from table 12 and 13, the nominal value of Co2 reduction is 619 million NIS over the scope of the CBA.

10. Results

In the result part of the CBA, we combine the partial costs and benefits discussed in detail over the previous sections into total costs and benefits. We aim at analyzing how the total costs and benefits of enhanced smart metering develop over time and in relation to each other. We proceed in a fourfold structure: (10.1.1) Total costs figures, (10.1.2) Total benefit figures, (10.1.3) Main results and (10.1.4) Sensitivity analysis. For ease of interpretation we present the majority of the results in nominal values. Since this report in an assessment over time, however, the final results are presented in net present value (NPV).

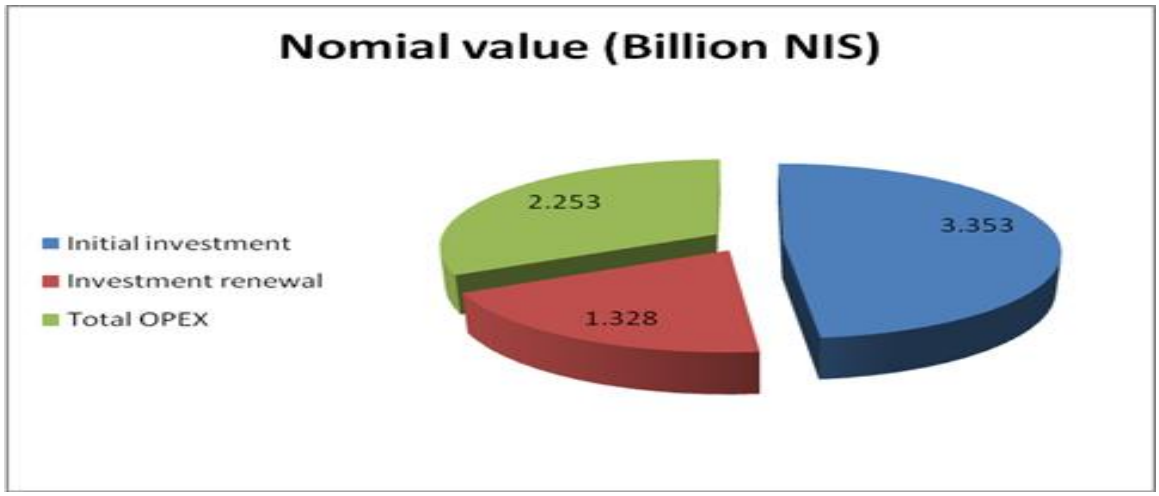
10.1 Total Cost figures

The total costs of an enhanced smart metering deployment are 6.934 Billion NIS in nominal value. Figure 7 displays a high level of these costs, divided into CAPEX and OPEX. Total CAPEX of enhanced smart metering is 4.681 billion, while total OPEX of enhanced smart

[91] See DECC (2013) for a thoroughly explanation.
[92] In the report Kwh "The committee for evaluation of the economic benefit of renewable energies" – translated from Hebrew.

metering is 2.253 billion NIS. CAPEX is more significant than OPEX since it includes both (a) the initial investment (3.353 billion) and (b) renewal investments (1.328 billion). In this section we explore in detail (10.1.1.1) Total CAPEX, (10.1.1.2) Total OPEX and (10.1.1.3) Yearly cost operations

Figure 7: High level overview of CAPEX and OPEX in nominal values



10.1.1 Total CAPEX

The total CAPEX in the model horizon is 4.681 billion in nominal value. *From a macro level*, a distinction is deployed between "the initial CAPEX" and "CAPEX renewal". Brief, the former is initial required investment whilst the latter is refresh costs in the end of a technologies' lifecycle. The distinction is important because (a) the reinvestment can be postponed, and (b) in the scope of the CBA we do not reap the full benefits of this CAPEX renewal[93].

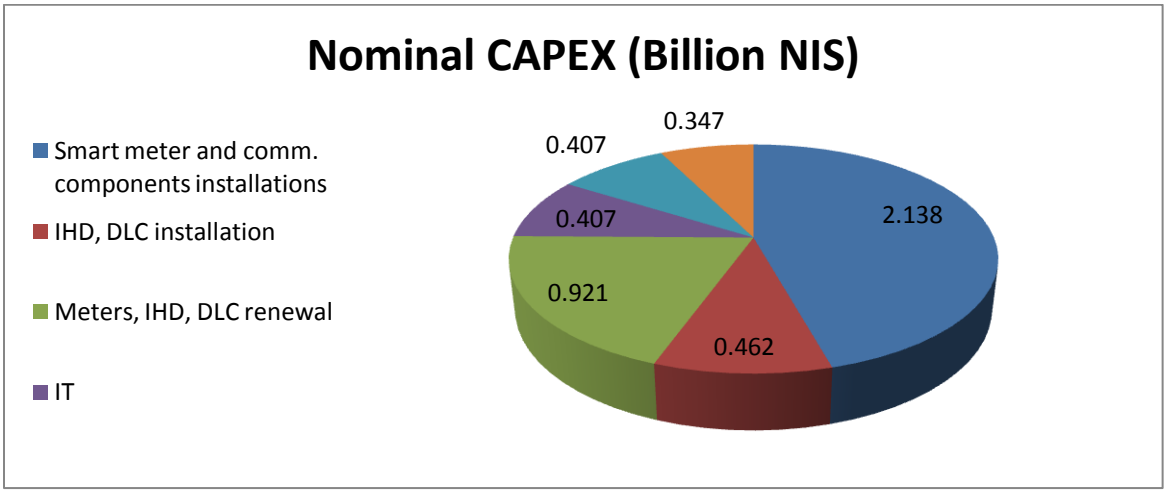
- 3.353 billion NIS is the initial CAPEX investment.
- 1.328 billion NIS is re-investment in smart meters, IHD, DLC and IT.

From a micro level, total CAPEX is divided into (1) Smart meters and communication components installations (smart meter, concentrator , balancing meter), (2) IHD and DLC

[93] Since meter-lifetime from the literature is 15 years and we assume it is 10, there is an opportunity for decision-makers to postpone the reinvestment with consequently positive impact on the NPV. We include the reinvestment for conservative reasons, though its benefits from year 15 are not reaped in our model.

installations, (3) Meters, IHD and DLC renewal (4) IT (MDM and Web-page), (5) IT renewal and (6) Unexpected CAPEX. The division of CAPEX in nominal values is displayed in figure 8 The meters and communication equipment is the most significant capital expenditure (46%), while it's renewal is the second largest investment (20%). As shown in the figure, we literally invest twice in MDM and web portal (IT), given the fact that we re-invest in both at a rate of 10% annually (two years after the initial investment is completed).

Figure 8: The division of CAPEX in nominal values throughout the model (15 years):

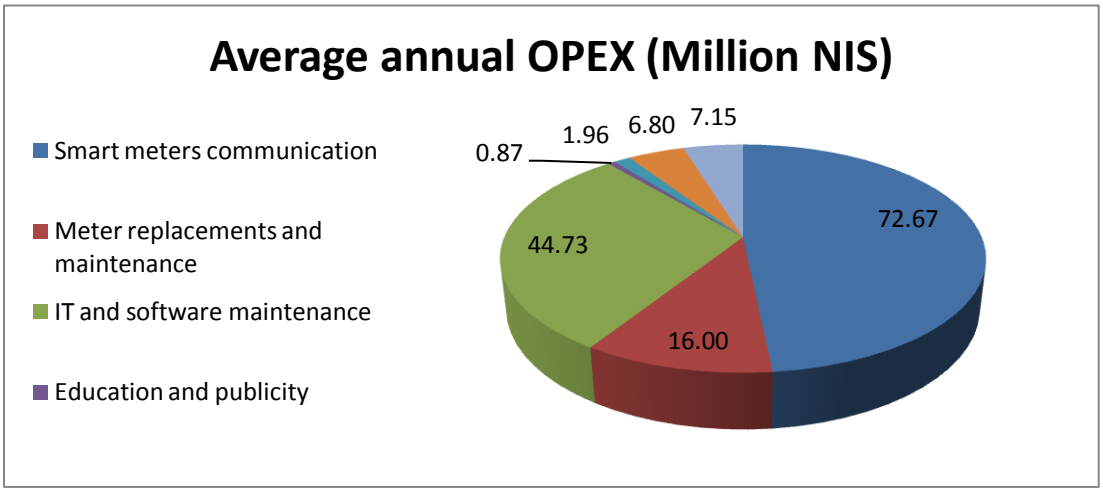


10.1.2 Total OPEX

Total OPEX in the model horizon is 2.253 Billion NIS or an average of 150 million NIS annually in nominal value. Total OPEX is divided into (1) Smart meter communications (data transmission costs of smart meters, concentrators and HAN), (2) Meter replacement and maintenance (replacement and maintenance costs of smart meters, concentrators, balancing meters, IHD and DLC), (3) IT and software maintenance (e.g. annual management costs), (4) Education and publicity, (5) Project management, (6) Financial and legal and (7) Unexpected OPEX. The division of OPEX in nominal values is displayed in figure 9[94]. Data transmission is the most significant operational expenditure (48%), with IT and software maintenance as the second largest post (30%). Other expenses are relatively small.

[94] Note that the values are annual and measured in million NIS.

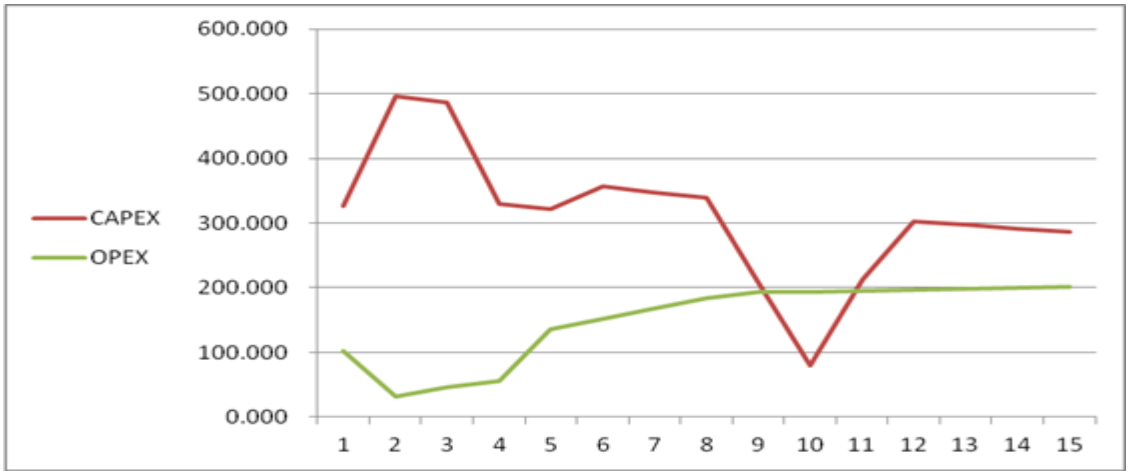
Figure 9: Division of average annual OPEX in nominal values throughout the model (15 years):



10.1.3 Yearly cost operations

Figure 10 shows how capital expenditure and operational expenditure develop over the time scope of the CBA. The OPEX is forming a stable trend increasing with the number of meters deployed, averaging at 150 million NIS annually. CAPEX rises steeply over the initial IT-investment (3.5 first years), declines steeply at the end of the initial deployment (after 8.5 years), before it increases again with the 90% re-deployment rate from the 10th year.

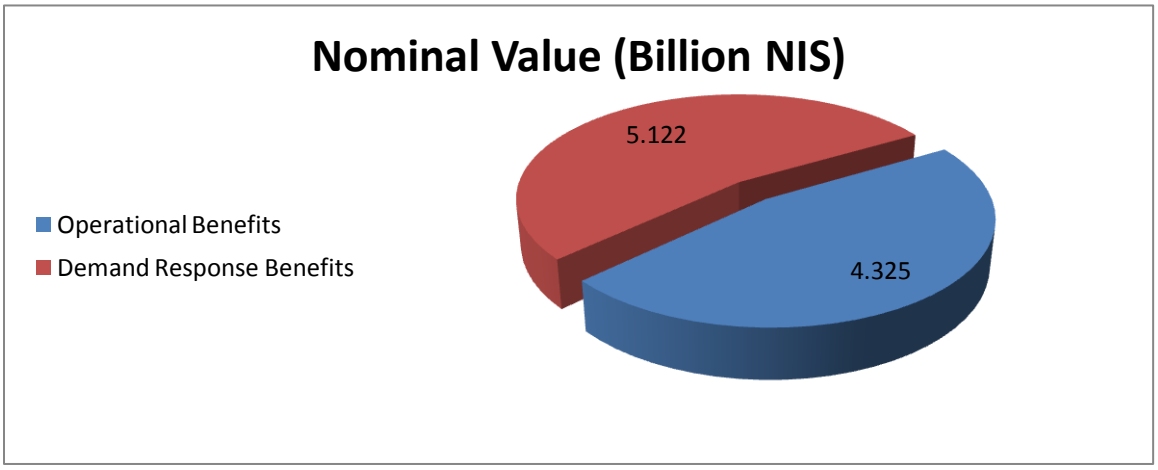
Figure 10: Development of total costs in million NIS over the time scope of the CBA (Nominal values). The costs are shown at the time of formation (i.e. not on a cash-flow basis):



10.2 Total benefit figures

The total benefits of enhanced smart metering are 9.447 billion NIS in Nominal value. Figure 11 displays a high level of these benefits divided into Operational Benefits and Demand Response Benefits. Total Operational Benefits of enhanced smart metering are 4.325 billion NIS, while Total Demand Response Benefits are 5.122 billion NIS. In this section we explore in detail (10.1.2.1) Total Operational benefits, (10.1.2.2) Total Demand Response Benefits and (10.1.2.3) Yearly benefit operations.

Figure 11: High level overview of Benefits in nominal values

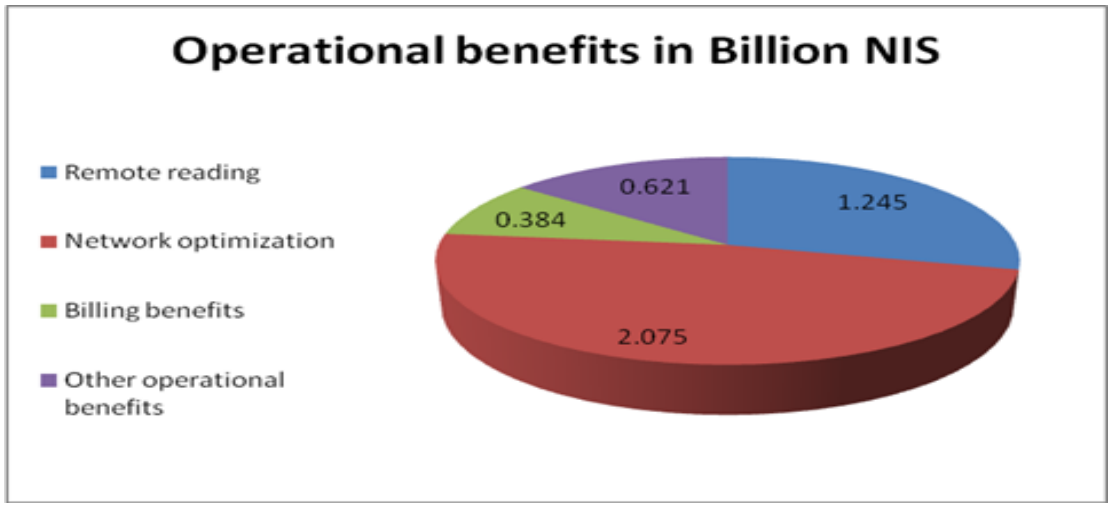


10.2.1 Operational benefits

Total operational benefits in the model horizon are 4.325 billion NIS in nominal value. Total operational benefits are divided into (1) Remote reading, (2) Information benefits, (3) Billing benefits and (4) Other operational benefits[95]. The division of operational benefits in nominal values is displayed in figure 12 Of the operational benefits considered, information benefits are the most significant sub-benefits (48%), mainly due to (a) reduction in network enforcement due to better planning and (b) reduction in network losses. Remote reading is the second largest post (29%), driven mainly by avoided regular- and special meter reading. Operational benefits alone cover 92% of the total capital expenditure (including re-investments in capital renewals, in nominal values). This is in line with what can be expected from the literature.

[95] For details on these categories see section 9.1

Figure 12: Division of total operational benefits in nominal values throughout the model (15 years):

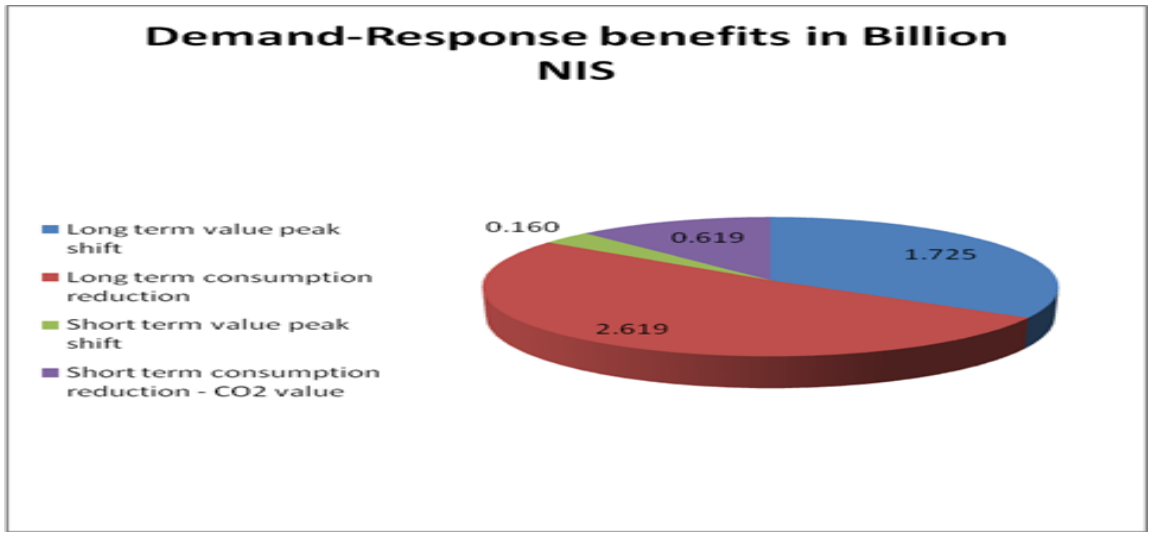


10.2.2. *Demand -response benefits*

Total demand-response benefits in the model horizon are 5.12 billion NIS in nominal value. . *From a macro level*, a distinction is deployed between short-term and long-term demand response benefits[96]. *From a micro level*, total demand-response benefits are divided into (1) Long term value of peak-shifts, (2) Long term value of consumption reduction, (3) Short term value of peak-shifts and (4) Short term value of consumption reduction[97]. Long term consumption reduction is the most significant of these, accounting for 51% of the total demand-response benefits. The second most important demand response benefit is the long term value of peak-shifts (34%), deriving from deferring one power-plant during the time scope of the CBA valued at 1.7 billion in nominal terms. Demand-Response benefits cover 109% of the total capital expenditure (including re-investments in capital renewals, in nominal values).

[96] We have, somewhat artificially, categorized Co2-reduction as a short term value of consumption reduction. It should be seen as a structural grip rather than a substantive categorization.
[97] For details on these categories see section 9.2

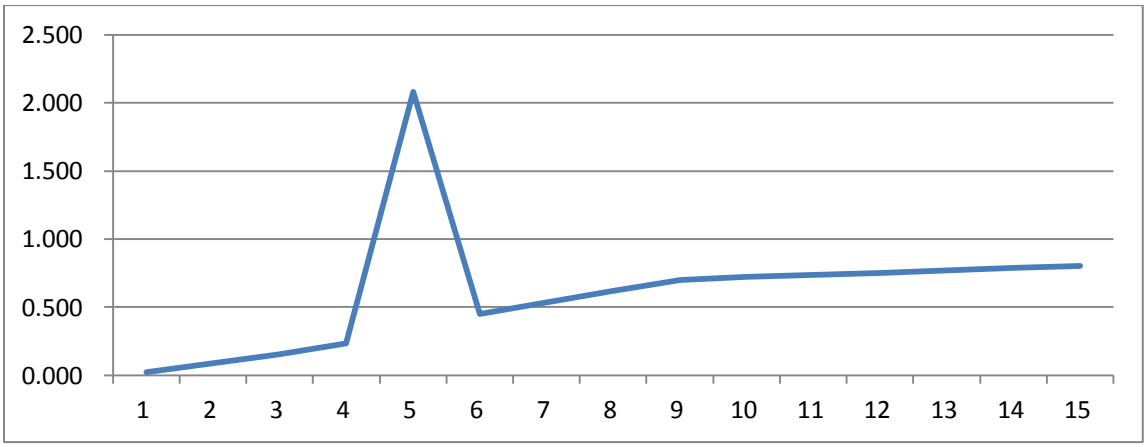
Figure 13: The division of total demand-response benefits in nominal values throughout the model (15 years):



10.2.3 Yearly operation of total benefits

Figure 14 shows how total benefits develop over the time scope of the CBA. There is a stable increase in benefits per smart meter deployed, with moderate reduction in the growth rate from the year of complete initial rollout (8.5 years). The dramatic demand response implication of deferring a power-plant can be seen in the fifth year.

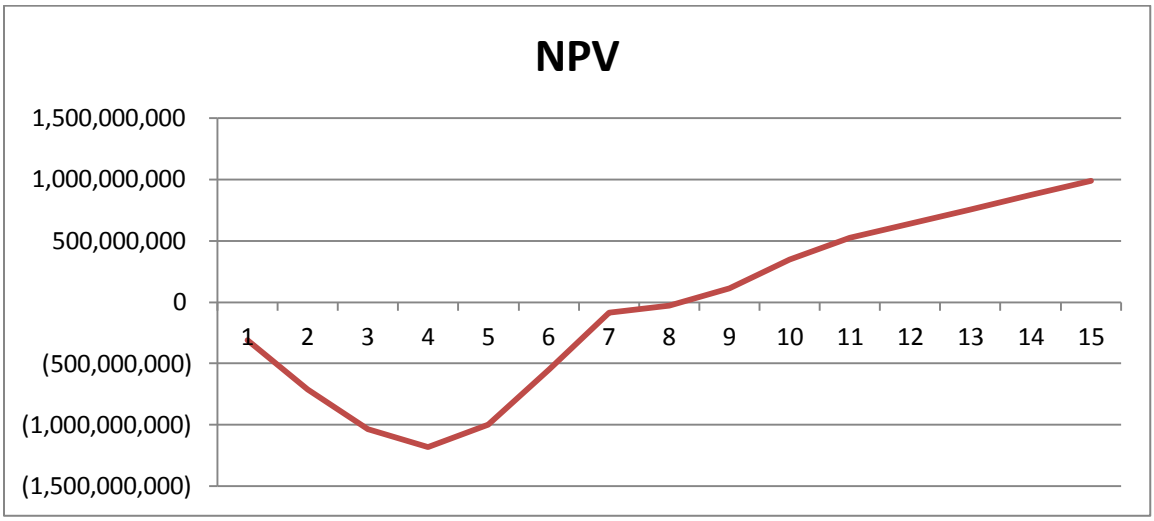
Figure 14: Development of total benefits in million NIS over the time scope of the CBA (Nominal values). The benefits are shown at the time of formation (i.e. not on a cash-flow basis):



10.3 Main results – an NPV assessment of the investment

Over the 15 years time horizon of this CBA, enhanced smart metering deployment in Israel has a net benefit of 986.73 million NIS. Figure 15 displays how this NPV develops in time given the discount rate of seven percent. After the Initial IT CAPEX (407 million NIS) is completed after three and a half years, NPV shows a constant positive slope. In the fifth year there is a kink in the graph resulting from the deferring investments of a new power plant[98]. In the ninth year we get the first positive NPV.

Figure 15: NPV 2015-2030 given discount rate of 7%



10.3.1 Sensitivity analysis

The sensitivity analysis is divided into (10.1.3.1) Standard sensitivity tests and (10.1.3.2) Cross-sensitivity tests. The main conclusion is that the positive NPV on enhanced smart metering is consistent and robust across a range of sensitivity tests.

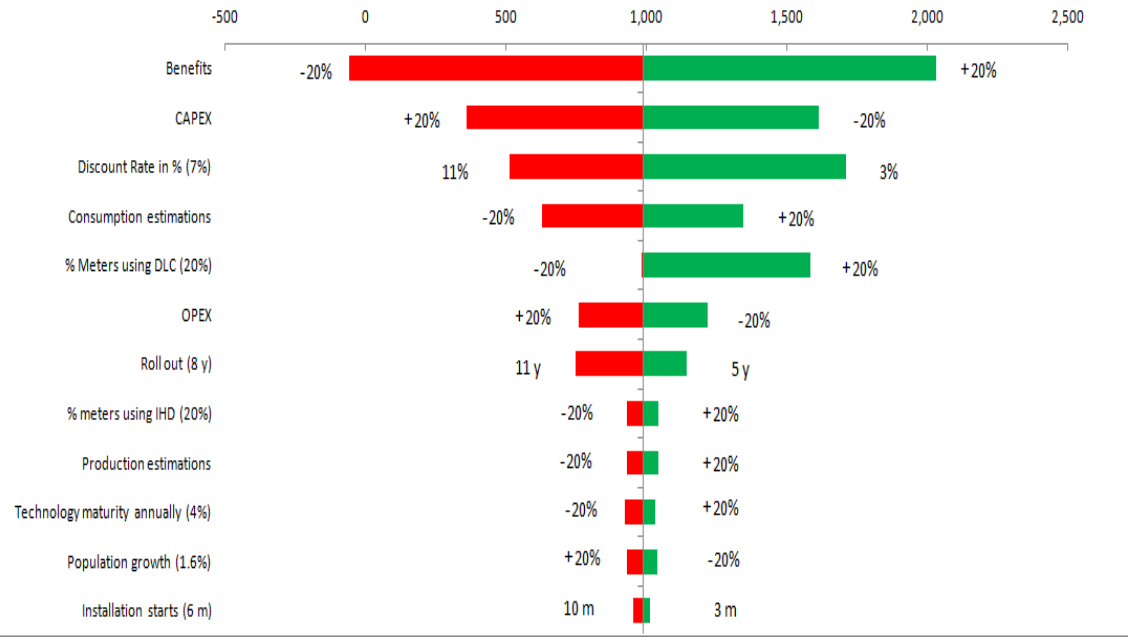
10.3.1.1 Standard sensitivity tests

From figure 16 we see that the NPV is most sensitive to changes in (1) benefits, (2) CAPEX, (3) discount rate and (4) consumption estimations. The positive NPV remains robust across a range of sensitivity tests carried out. A reduction in benefits of 20% is the single parameter with a potential of turning the NPV marginally negative. In is worth noting that

[98] The benefit is spread over three years with a 20%, 40% and 40% distribution respectively.

the NPV would still be highly positive (360 million NIS) should the CAPEX of enhanced smart metering be 20% higher than what we assumed. The same is true for the discount rate and our estimations for future consumption. The skewed result of DLC displays that a 20% increase in opt-in, due to its effect on peak-consumption, will defer an additional power-plant over the relevant time horizon.

Figure 16: Sensitivity Analysis, changes in NPV



10.3.1.2 Cross sensitivity tests

We use cross-sensitivity to identify the NPV-effect of simultaneous changes in our assumptions. We perform cross-sensitivity of the three most crucial variables - i.e. benefits, CAPEX and discount rate. *Firstly, figure 17* shows the sensitivity of total NPV to simultaneous changes in benefits and CAPEX. In one extreme scenario, 20% increase in CAPEX and 20% decrease in benefits would produce a negative NPV of 686 million NIS. In the first figure, this is the only combination of simultaneous changes that results in a negative NPV. *Secondly, figure 18* displays how NPV varies with simultaneous changes in benefits and discount rate. Again the extreme case, this time 20% lower benefits at a discount rate of 11%, displays a negative NPV (-269 million NIS). At a social discount rate of 3%, approximately the discount rate recommended for the European CBAs (JRC, 2011),

even a 20% reduction in benefits gives a highly positive NPV of 276 million NIS. In total, we conclude that a highly positive business case for enhanced smart metering deployment in Israel is consistent and robust across a range of sensitivity tests.

Figure 18: Simultaneous changes in Benefits and CAPEX

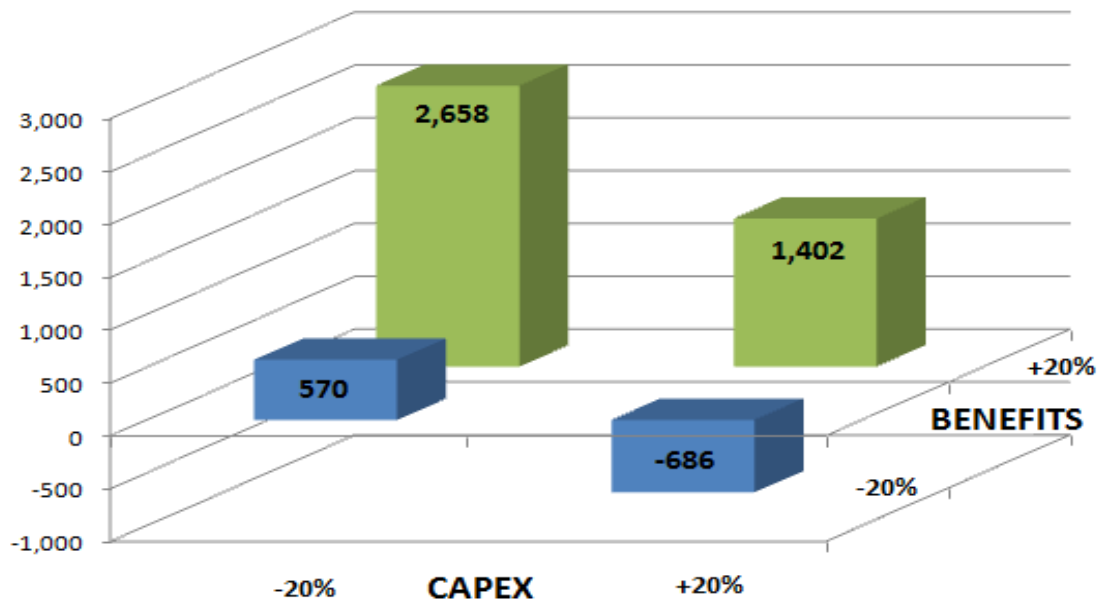


Figure 19: Simultaneous changes in Benefits and discount rate

11. Appendices

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