Review of the Electricity Tariffs for the Israel Electric Company

Prepared for:
The Public Utility Authority of Israel

Navigant Consulting, Inc.
30 South Wacker Drive
Suite 3100
Chicago, IL 60606

www.navigant.com

Project No. 166582
December 6, 2014

This report (the "report") was prepared for the Israel Public Utilities Authority ("PUA"), by Navigant Consulting, Inc. ("Navigant"). The report was prepared solely for the purposes of the PUA's evaluation of the electricity tariffs of the Israel Electric Company ("IEC") and may not be used for any other purpose. Use of this report by any third party outside of reviewing the tariffs of the IEC is prohibited. Use of this report should not, and does not, absolve the third party from using due diligence in verifying the report's contents. Any use which a third party makes of this report, or any reliance on it, is the responsibility of the third party. Navigant extends no warranty to any third party.

NAVIGANT

Table of Contents

List of Tables

List of Figures

Executive Summary

The Public Utility of Israel ("PUA") retained Navigant Consulting, Incorporated ('Navigant") to perform a review of the electric tariffs of the Israel Electric Company ("IEC" or "Company"). The PUA is charged with regulatory oversight of the electric power sector which includes the tariff levels charged by the Company. The IEC is a vertically integrated electric utility which serves the majority of the State of Israel. Virtually all equity of the IEC is held by the State of Israel.

1.1 Scope of Services

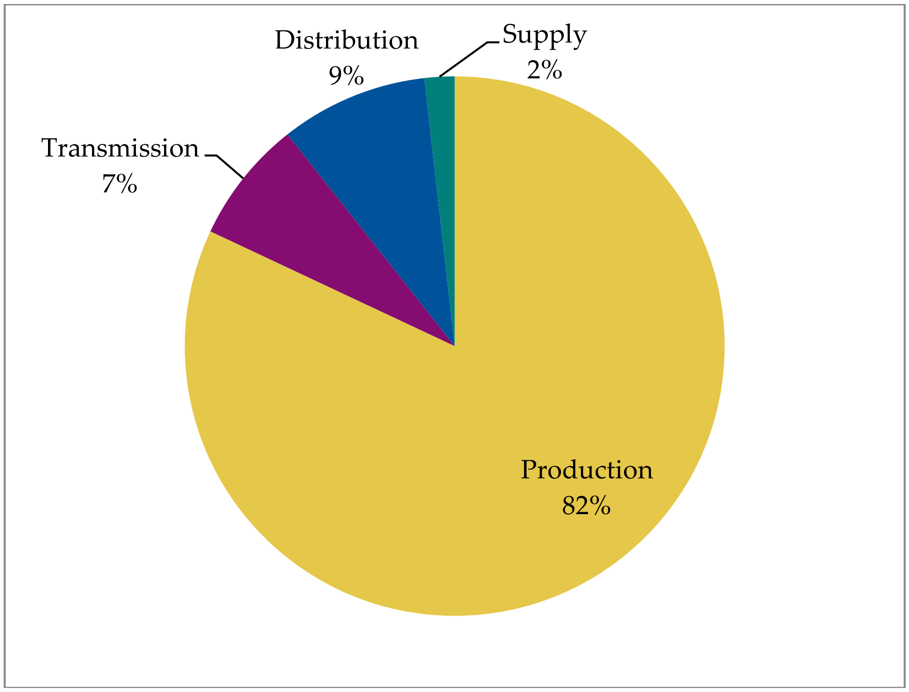
Navigant's review of the IEC's electric tariffs was confined to the transmission, distribution and supply functions. The generation function is not included in our scope of services. The scope of services for this project provides the PUA with the analyses typically in a rate review for a utility and required that Navigant perform a review of the level of costs of the IEC reviewing internal information and external benchmarks, the cost structure of the utility and the pricing design.

1.2 The Israel Electric Company

The IEC is a vertically integrated electric utility. Figure 1 below provides a pie chart illustrating the revenues by segment (i.e. generation, transmission, distribution and supply) for the year 2012.

NAVIGANT

Figure 1- Revenues by Segment – 2012



Source: IEC Billing Determinants

The transmission, distribution and supply segments of the IEC account for 18% of the revenues for the Company. The impact of the tariff adjustments for the transmission, distribution and supply functions will have a small impact on the financial conditions and operations of the Company as a whole.

1.3 Background

The PUA and Navigant initiated this project in July 2013. A one-week kick-off meeting was held in August 2013 with several days of meetings scheduled with the PUA and a one-day meeting with the IEC. A series of information requests and telephone calls were scheduled through the end of 2013 which included a one-week visit by Navigant representatives in October 2013 in order to facilitate the information request process from the IEC and seek clarifications for the requests. The information request process extended through the end of 2013. Only on February 5, 2014, Navigant received a copy of a report titled The Israel Electric Corporation Transmission and Distribution Segments Rate Case (hereafter referred to as the "IEC Report"). Navigant delayed completing our report until a review of the IEC Report was issued in order to include the most complete and detailed data as possible. Following the issuance of the IEC Report Navigant issued a number of information requests in order to clarify our understanding of that report. In early 2014 the IEC issued their report which was followed by a significant time period when information requests were issued. After the information request process was completed (unfortunately, with a lacking information from IEC) Navigant issued their report to the PUA.

1.3.1 Information Collection Challenges

Sound regulation requires that detailed information be provided to the regulator and interested parties regarding the utility's operations that can be used in analyses evaluating the cost structure of the utility and the design of the tariffs. **If less than complete cooperation is provided by the utility the regulatory review process will be frustrated.**

The support provided by the IEC to the PUA and Navigant in the information collection effort was inconsistent and overall unsatisfactory compared to other rate proceedings the Navigant Team has performed in the past. The information collection phase required several months and in the case of financial information did not produce satisfactory results.

The Navigant Team faced significant frustrations due to non-compliance associated with a number of Information Requests. As a result of the IEC's lack of cooperation the project faced significant delays in the delivery of the report. Navigant estimates that this report could have been delivered by January 1, 2014 if the IEC would have reasonably complied with our information requests and had announced early in the process that they were working on a separate report. The PUA Staff was required to assist or prepare several analyses which normally should have been provided by the utility.

Sound regulation requires robust data which is easily accessible. The lack of readily available and accurate data leads to poor decisions which adversely impact the utility, customers and other stakeholders. As a result of our challenging experiences Navigant recommends that a formal schedule of "compliance filings" be established requiring the IEC to provide the PUA and the other interested parties information and analyses required in the regulatory process on a regular basis. If the IEC fails to provide any of the components of the compliance filings to the PUA, or provides such filings in an unsatisfactory manner, the PUA would be provided the option of assessing significant financial penalties on the IEC and / or tariff reductions thus making the management of the IEC responsible for the penalties of non-compliance. Navigant further supports the PUA's work to design forms and detailed listing of information required for the compliance filings in order to avoid miscommunication and allow the IEC to fully understand what information is required. Additionally, in order to facilitate the analyses which are normally performed by regulators the PUA should be provided with the enforcement authority to receive information and / or material needed to complete investigations in a complete and efficient manner.

Non-compliance impacts the decisions of the IEC management and the leadership of the PUA which ultimately negatively impacts the owners and customers of the utility -- the citizens of the State of Israel. Navigant therefore strongly recommends that the compliance enforcement mechanisms be strengthened in cases where non-compliance occurs with the requests of the regulator.

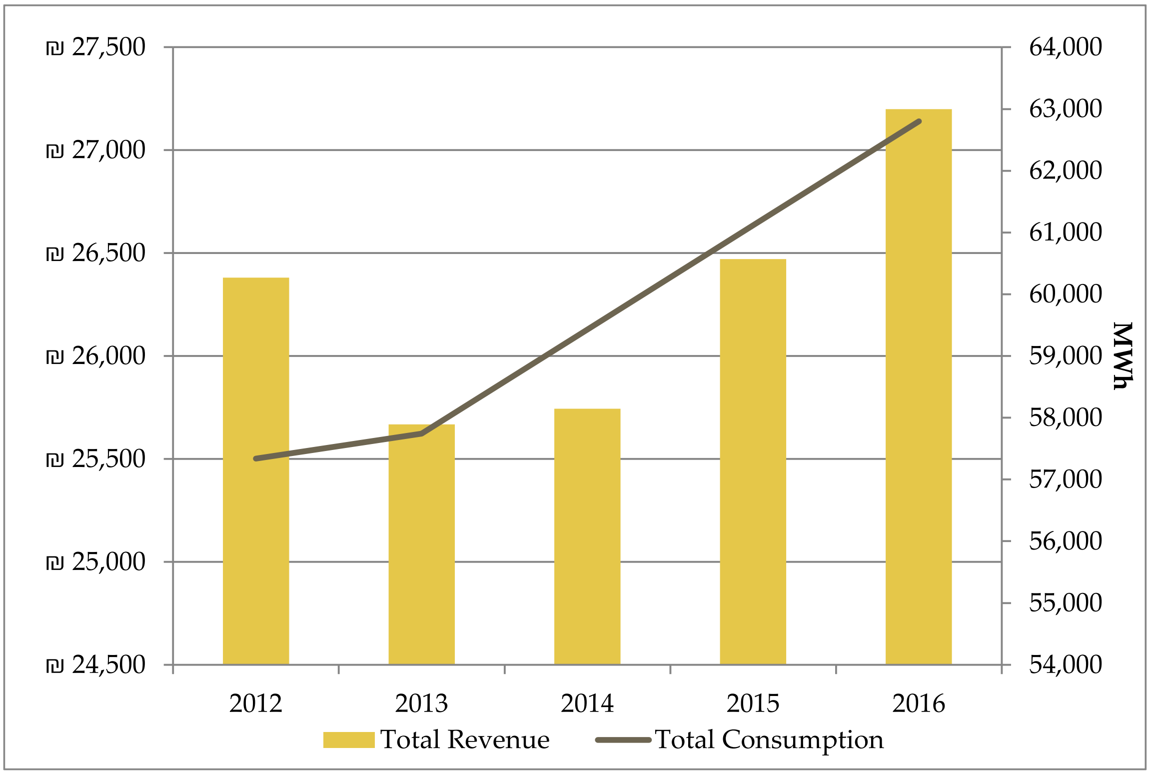
1.4 Findings

1.4.1 Revenue and Sales Projections

Navigant requested detailed revenue and sales forecasts from the IEC. After discussions with the company it was decided that the forecasts which the IEC prepared lacked the necessary detail required in for this project.

Based upon information provided by the IEC and publically available weather data Navigant prepared a sales forecast by customer class which was then used to produce revenue projections by tariff class and segment. The results of the Navigant forecast are provided in Figure 2 below.

Figure 2 - Revenue and Sales Projejctions for the IEC

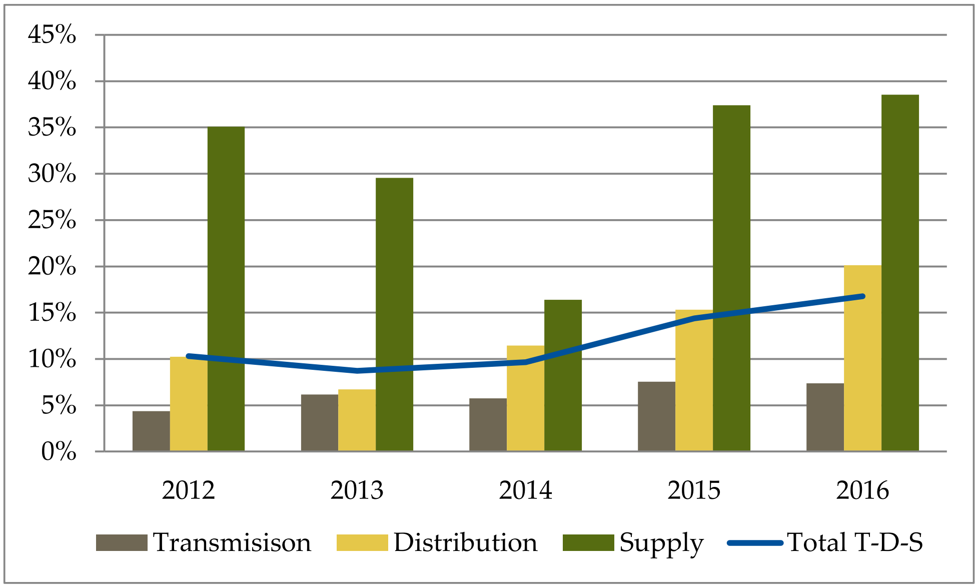


Navigant's revenue adjustments were predicated upon load and revenue forecasts prepared by Navigant during the course of this study.

1.4.2 Review of IEC Recognized Costs

Navigant reviewed the level of recognized costs detailed in the IEC Report which supported the Company's request. Our review resulted in adjustments to the Company's requested recognized costs which are illustrated in Figure 3 below.

Figure 3 –Forecast Rate Increase Requirements



The most significant adjustment to recognized costs made by Navigant was to reduce the salary costs which are captured in both O&M Expenses and CAPEX expenditures. Navigant's estimation of recognized costs is 8.1% to 9.9% below that of the IEC for the 2012-2016 time periods. Table 1 summarizes these calculations.

Table 1 – Comparison of IEC Requested Recognized Cost versus Proposed Recognized Cost

Transmission	Reference	2012	2013	2014	2015	2016
Navigant	Table 38	₪ 2,028	₪ 2,112	₪ 2,094	₪ 2,192	₪ 2,250
IEC	[1]	₪ 2,084	₪ 2,170	₪ 2,155	₪ 2,279	₪ 2,355
Percentage Difference		-2.6%	-2.7%	-2.9%	-3.9%	-4.5%
Distribution		**2012**	**2013**	**2014**	**2015**	**2016**
Navigant	Table 39	₪ 2,572	₪ 2,666	₪ 2,767	₪ 2,946	₪ 3,153
IEC	[2]	₪ 2,814	₪ 2,935	₪ 3,075	₪ 3,287	₪ 3,540
Percentage Difference		-8.6%	-9.2%	-10.0%	-10.4%	-10.9%
Supply	Table 40	2012	2013	2014	2015	2016
Navigant		₪ 639	₪ 625	₪ 570	₪ 681	₪ 695
IEC	[3]	₪ 803	₪ 786	₪ 713	₪ 858	₪ 876
Percentage Difference		-20.4%	-20.4%	-20.1%	-20.7%	-20.7%
Total T-D-S		2012	2013	2014	2015	2016
Navigant		₪ 5,240	₪ 5,403	₪ 5,430	₪ 5,818	₪ 6,097
IEC	[4]	₪ 5,700	₪ 5,890	₪ 5,943	₪ 6,424	₪ 6,771
Percentage Difference		-8.1%	-8.3%	-8.6%	-9.4%	-9.9%

The differences in recognized costs can be attributed to the following adjustments made by Navigant.

Labor Costs

As is discussed below, Navigant adjusted labor costs to market levels. Adjustments to labor costs impacted O&M Expenses and CAPEX which was included into rate base.

Income Taxes

Navigant included small adjustments in the level of income taxes.

---

[1] Response to Navigant Information Request Number 4, Question 25.

[2] Ibid

[3] Ibid

[4] Ibid

1.4.3 Proposed Rate Increases

Navigant recommends an increase in rates required to meet TD&S recognized cost for the years 2015-2016. Further, as is discussed later in this report Navigant does not recommend adjustments in recognized costs for the prior years (i.e. time period prior to 2012). Therefore, Navigant is recommending that rate increases be implemented in two steps. The first step of the rate increase would occur on January 1, 2015 and the second on January 1, 2016. The percentage adjustments to tariffs have been calculated exclusive of regulatory assets. Table 2 below provides the tariff adjustments by segment for each segment for the years 2015 and 2016.

Table 2 – Percentage Tariff Adjustments

	January 1, 2015	January 1, 2016
Transmission	5.1%	4.6%
Distribution	8.1%	7.1%
Supply	25.7%	19.7%
Total	11.5%	10.3%

Note: The tariff adjustment percentages provided above exclude regulatory assets.

Navigant has not addressed the recovery of deficiencies in recognized costs for the years 2012 through 2014. The PUA Staff informed Navigant that an offsetting regulatory liability exists which would partially or completely offset the deficiency for these time periods.

1.4.4 Benchmarking Analysis

Benchmarking is a valuable tool in utility regulation in that it provides a measure to compare the performance of one company to peers. Inasmuch as Israel is challenged by only operating one large electric utility Navigant believes that relevant information from other entities could be used in order to measure the performance of the company.

Benchmarking of IEC Wage Levels

Navigant compared the IEC wage levels to peers.
A comparison of utility sector-overall economy wage premiums in the US and Israel implies that IEC wages must be reduced by between 25.7% and 42.6% to attain relative wage levels consistent with those of the US electric utility sector. Navigant recommends reducing the wage component of IEC's recognized costs by the mean of this range, 34.2%.

The excessive labor costs are recommended to be denied recovery in recognized costs. These costs are considered part of the dividend foregone by the owner of the IEC, the State of Israel, as a result of their oversight of the labor cost issues at IEC.

Benchmarking of IEC CAPEX Levels (Australian Model)

Navigant reduced the level of CAPEX costs for the excess labor costs discussed above. The modeled CAPEX levels are above those modeled for the year 2012-2014 and below those forecasted by the IEC for 2015-2016 when excess labor costs are removed. . Therefore, Navigant cannot conclude that CAPEX, adjusted for excessive labor costs, are inappropriate. However, as is discussed below Navigant cannot conclude that the allocation of CAPEX to specific projects and initiatives is optimal.

1.4.5 Evaluation of the Distribution Investment Process

The IEC's Distribution Department described systems and methods it is now using based on asset management principles, including project prioritization. However, the spending forecast for asset renewal, particularly for distribution, appears to be based on historical trends. We also found a limited number of reports, analysis or guidelines documenting IEC's asset management practices, including how asset health is linked to condition assessment data derived from maintenance, testing or inspections records, and reliability cause codes; for example, age metrics for SAIFI and SAIDI. We also are not aware of cost benefit analysis of alternatives. Thus, we are unable to confirm the spending plan represents the least cost strategy for load growth and renewal spending.

Navigant recommends that the PUA require the IEC to provide a report which outlines a more efficient distribution planning process which is consistent with the current practices implemented in developed economies. Navigant is concerned that although the overall level of distribution CAPEX spending may be reasonable, the investments are not being made efficiently. Further, we will also echo our concerns about regarding inconsistent load forecast which are discussed above in the transmission investment process section.

1.4.6 Cost of Capital

Navigant proposes the adoption of IEC's requested Weighted Average Cost of Capital ("WACC") similar to the PUA's methodology. Navigant's analysis of the WACC relied upon the widely used and understood Capital Asset Pricing Model ("CAPM") to estimate return on equity ("ROE"), and two approaches for cost of debt. The first approach used to analyze cost of debt was a market approach using a comparable credit bond index. The second approach used an estimate of the IEC's historical embedded cost of debt to calculate WACC. Navigant's WACC analysis produced results that bound the IEC's requested amount, and thus we determined the amount to be reasonable and justifiable.

1.5 Tariff Adjustments

The IEC has traditionally been regulated by the PUA using a Consumer Price Index less an Efficiency Factor ("CPI-x") Regulatory approach. The PUA uses an approach which accounts for efficiency, economies of scale and technology advances. The CPI-x regulatory model is an alternative regulatory model where prices are allowed to increase at the rate of inflation less an efficiency adjustment. The objective of the CPI-x is to provide the utility with a revenue stream that is sufficient for a utility that is operated efficiently and provide management with the flexibility to operate the company without significant oversight of the regulator.

Navigant recommends that the CPI-x regulatory approach be suspended at least until 2016. During the time 2014-2016 time period annual rate increases for those years will be implemented. Deficiencies in recognized costs for the years 2012 through 2014 will be offset by the regulatory liability incurred by the IEC and treated separately by the PUA.

Navigant's rationale for implementing the stepwise regulatory approach is summarized below:

- The existing tariffs require adjustments to attain the proper level of revenues for each segment. The stepwise regulatory approach will provide for these adjustments to be phased-in over a number of years;
- The information reporting requirements and data available to the PUA from the IEC requires significant improvement. Jurisdictions that have implemented CPI-x mechanisms require especially detailed reporting requirements such as the Electricity Reporting and Record Keeping Requirements ("RRR") in Ontario, Canada. The time period between now and the end of 2016 will provide the opportunity to develop and implement the information reporting requirements;
- Navigant's benchmarking has indicated that certain inefficiencies exist in the IEC. The most notable inefficiency is high labor costs. The Navigant Team does not believe that a CPI-x mechanism will provide incentives which will encourage the IEC to address their cost structure challenges and stronger incentives are required;
- Navigant has developed an incentive mechanism identified a number of goals which we have suggested the PUA require to perform certain activities associated with a well-functioning utility in exchange for achieving their full allowed ROE.

1.5.1 Recommendations for Pricing Design Changes

The existing pricing design for distribution and transmission services is overly reliant on volumetric (i.e. KWH) pricing. Israel's reliance only on KWH pricing for distribution and transmission services should be reconsidered. In contrast, the fixed charges pricing design structure used for the supply function is reasonable and should be continued.

Near-Far Customer Pricing Design

Customers located near Independent Power Producers (IPP) are allowed to avoid certain transmission and distribution charges. At this time no customers are served under these tariffs. Navigant recommends that these tariffs be closed.

Lower Tariffs to Kibbutzim

Electricity tariffs to the Kibbutzim are lower than other consumers. Navigant recognizes that Kibbutzim have historically been electricity distributors in Israel. However, although IEC was asked to provide data regarding that this information was not fully given. Therefore, lacking cost of service analysis we cannot conclude if the prices paid by the Kibbutzim are justified. Navigant therefore recommends that unless the IEC be required to provide cost support quantifying the level of tariff no rate adjustment occurs.

IEC's Pricing Design and Installation of Photovoltaic Generation

Photovoltaic panel prices have decreased significantly in the last several years which has made these devices increasing popular with consumers. However, many electric utilities have expressed concern that existing tariff designs may be sending price signals to consumers which are triggering margin erosion to utilities and incenting the installation of photovoltaics which are not cost-based.

Navigant believes the change in pricing design proposed in this report (i.e. the introduction of fixed distribution charges and demand charges for customers with meters capable of providing demand readings) addresses the issue of non-economic photovoltaic generation. The gradual movement of prices away from volumetric (i.e. KWH) to fixed charges and demand charges should address concerns about the non-economic installation of photovoltaic technology.

1.6 Recommendations

1.6.1 Compliance Requirements

Effective regulation is predicated upon the utility supplying detailed and accurate data to the regulator. That standard is currently not being met. Further, as is discussed above Navigant's data collection efforts were often frustrated during the course of this study which significantly increased the effort required to complete this report and delayed the delivery by several months.

Navigant recommends that a number of compliance filings be required form the IEC in order to provide information required to monitor operations and facilitate future regulatory proceedings. Navigant further suggests that an incentive be provided to the IEC to ensure the compliance filings are provided to the PUA and at the same time penalties, for not providing full information. Therefore, reductions in the IEC's ROE will be made annually if the compliance filings are not provided to the PUA.

1.6.2 Suspension of the CPI-x Mechanism until 2017

Navigant has proposed an alternative to the CPI-x mechanism until 2017. Navigant further suggests that the when tariffs for 2017 and beyond are developed in 2016 that the design of regulatory mechanism be revisited.

1.6.3 The IEC Needs to Develop an Increased Customer Focus

The Navigant Team observed an under-developed customer focus in the IEC organization. A systematic theme in the analyses and proposals of the Company ignored what impact the actions would have on the customers of the company. Utility policies that do not examine the impacts and desires of customers are inappropriate for a modern electric utility and leads to inefficiency in the operations. Many of the goals Navigant has developed for the IEC will include customers' needs in the planning and decision-making of the Company.

1.6.4 Navigant Recommends Balancing Account Treatment for Projected CAPEX Investments

The level of recognized cost included in this report is predicated upon a significant level of CAPEX expenditures which will be implemented by the IEC. The PUA is concerned that the IEC will not attain the targeted level of CAPEX spending despite receive a level of recognized cost reflecting the targeted level of investments.

In response to the PUA concerns Navigant recommends that a CAPEX tracking mechanism be implemented, which would adjust tariff adjustments if CAPEX projects are not be completed as planned. A CAPEX tracking mechanism is recommended which ensures a matching of the actual recognized costs to the investments implemented by the IEC.

Compliance will be benchmarked to reported and verified investments. Failure to provide reports will be interpreted as failure to make investments and would be deducted from the recognized costs.
The IEC be required to periodically file information of CAPEX projected and percentage of completion to the PUA. The PUA will adjust the level of recognized costs to match the actual versus projected level of CAPEX. Undocumented CAPEX projects will not be included in the adjustment of the tariff.

1.6.5 Recovery of Pre-2012 Recognized Costs

The IEC requested recovery of costs associated with years prior to 2012. The request was predicated upon a claim that the IEC was denied the ability to update their tariffs. Navigant cannot opine on the legally of the IEC request, but from a regulatory policy standpoint recommends that the PUA reject the request for retroactive cost recovery before 2012 for the following reasons. In the same manner, Navigant didn’t adjusted Capex cost prior to 2012, despite excessive costs found by PUA during cost auditing for this period.

2. Revenue Analysis

At the core of any rate case is the estimated revenue of the utility. The objective of the revenue projection is to provide a basis for the utility's projected profitability and return founded on rate base and O&M Expense projections.

Navigant's analysis of the IEC revenue was more complex than a normal rate request for the following reasons:

- The base historical year of the analysis contained an interim rate increase;
- Weather normalized data for each rate class was unavailable;
- Sales forecasts by rate class were unavailable;
- There was lack of clarity on how rates should be functionalized for revenue allocation
- Historical load and demand data was provided under a different rate classification scheme than rates.

2.1 *Development of Historical Proof of Revenues*

A Proof of Revenues reconciles the actual sales of a utility with the billing determinants for a historical time period. At the inception of this project Navigant requested that IEC provide Navigant with the proof of revenues for 2012. IEC was unable to provide this analysis. Based upon data Navigant requested a historical proof of revenues was developed which was verified by the IEC. Table 3 below provides a summary result for the proof of revenues for the year 2012.

Table 3 – 2012 Actual Revenue by Rate Class and Segment (Million NIS)

Rate Class	Production	Transmission	Distribution	Supply	2012 Total
Residential	6,609.13	617.78	1,213.15	359.29	8,799.36
General	1,362.21	129.13	238.50	42.34	1,772.19
Street lighting	61.02	5.42	12.42	1.10	79.95
Low V TOU	3,710.32	350.92	670.92	59.07	4,791.23
Low V TOU / Collective Sale	53.42	4.89	4.90	-	63.21
Low V Bulk (PA)	33.79	3.12	6.24	-	43.14
Med V Bulk (PA)	931.34	86.93	24.63	-	1,042.90
Med V TOU	6,287.01	596.39	162.58	11.33	7,057.31
Med V TOU / Collective Sale	28.91	2.60	-	-	31.51
Med V Bulk TOU (PA)	670.86	61.88	-	-	732.74
High V TOU	1,881.67	84.73	-	0.15	1,966.55
Total	21,629.69	1,943.80	2,333.34	473.27	26,380.10

Source: Detail of Revenue Analysis

The IEC was granted an interim rate increase in April 1, 2012. Table 4 below provides the same sales results restated to reflect the end-of-year rates for the entire year.

Table 4 - 2012 Revenues Reflecting the End-of-Year Rates for the Entire Year (Million NIS)

Rate Class	Production	Transmission	Distribution	Supply	2012 Total
Residential	6,704.07	594.45	1,238.83	359.29	8,896.63
General	1,382.53	123.43	242.50	42.34	1,790.80
Street lighting	62.77	5.17	12.69	1.10	81.74
Low V TOU	3,773.66	335.70	681.22	59.07	4,849.64
Low V TOU / Collective Sale	54.64	4.68	4.99	-	64.32
Low V Bulk (PA)	34.67	2.99	6.35	-	44.01
Med V Bulk (PA)	944.82	83.08	24.94	-	1,052.84
Med V TOU	6,395.73	570.66	164.41	11.33	7,142.13
Med V TOU / Collective Sale	29.33	2.48	-	-	31.81
Med V Bulk TOU (PA)	686.65	59.23	-	-	745.88
High V TOU	1,913.09	76.61	-	0.15	1,989.84
Total	21,981.95	1,858.49	2,375.93	473.27	26,689.64

Source: Detail of Revenue Analysis

2.2 Sales and Revenue Forecasts

Navigant requested that sales and revenue forecasts be prepared by the IEC during the initial series of information requests in 2013. The response to Navigant's request indicated that the IEC prepared their forecasts using a "top-down" approach, starting with generation requirements and treating sales as a residual value. The top-down approach is not appropriate for preparing a rate case because it lacks the detailed sales forecast information for each rate class. Detailed sales forecasts by rate class are necessary in order estimate revenues for each rate class.

The level of detail for the billing determinants necessary to prepare a rate design was not available from IEC on a forecasted basis. Forecasts for sales, billing demand and number of customers by season and time-of-use for each rate class were also not available. These values should be weather normalized in order to eliminate any bias which would occur when estimating revenues which are produced by the billing determinants.

The information provided by the IEC was not differentiated by rate class which results in the following:

- Cost-of-service analysis estimating the cost attributable to each rate class is not possible;
- An accurate estimation of revenues requires that specific forecasts by rate class occur because different customer groups grow at different rates over time;
- The change in the number of customers by rate class is required in order to accurately estimate revenues for the Supply function.

2.2.1 Navigant Sales Forecast Approach

Navigant used a weather normalized regression approach to obtain weather normal values over the forecast period. The forecast used two regressions to establish the relationship between weather and aggregate consumption by customer segment. The first captures the relationship between average consumption per customer and weather, monthly seasonality and a linear annual trend. The second regression captures the annual linear trend in customer numbers by segment. This historical relationship was then fitted to obtain the forecast values over the forecast period, January 2013 – December 2016.

The details of the regression analysis, including formulas and data can be found in Section 10.2 Appendix B.

2.3 Revenue Projections by Rate Class

Based upon the sales forecasts described above Navigant prepared revenue projections for the years 2013 through 2016. These projections are summarized in Table 5 through Table 8 below.

Table 5 – IEC Forecasted Revenues by Rate Class for 2013 - Performed by Navigant (Million NIS)

Rate Class	Production	Transmission	Distribution	Supply	2013 Total
Residential	6,389.25	634.79	1,301.96	369.02	8,695.02
General	1,285.86	129.90	254.64	42.82	1,713.22
Street lighting	59.51	5.58	13.31	1.12	79.52
Low V TOU	3,540.15	359.62	718.97	58.53	4,677.28
Low V TOU / Collective Sale	51.75	5.02	5.28	-	62.06
Low V Bulk (PA)	33.57	3.30	6.93	-	43.80
Med V Bulk (PA)	949.28	93.83	27.06	-	1,070.17
Med V TOU	5,946.51	605.04	169.25	11.43	6,732.23
Med V TOU / Collective Sale	27.06	2.63	-	-	29.69
Med V Bulk TOU (PA)	662.89	65.79	-	-	728.68
High V TOU	1,751.94	84.10	-	0.15	1,836.19
Total	20,697.77	1,989.60	2,497.41	483.08	25,667.87

Source: Detail of Revenue Analysis

Table 6 – IEC Revenues by Rate Class for 2014 (Million NIS)

Rate Class	Production	Transmission	Distribution	Supply	2014 Total
Residential	6,346.01	629.00	1,288.30	374.52	8,637.83
General	1,280.51	129.39	255.10	43.66	1,708.65
Street lighting	58.35	5.56	13.20	1.14	78.25
Low V TOU	3,558.02	360.74	716.58	59.37	4,694.72
Low V TOU / Collective Sale	51.53	5.03	5.27	-	61.83
Low V Bulk (PA)	33.71	3.34	7.02	-	44.07
Med V Bulk (PA)	975.26	96.25	27.52	-	1,099.03
Med V TOU	5,925.18	602.40	169.62	11.64	6,708.83
Med V TOU / Collective Sale	27.17	2.61	-	-	29.79
Med V Bulk TOU (PA)	667.10	66.72	-	-	733.82
High V TOU	1,723.76	79.02	-	0.15	1,802.93
Total	20,646.61	1,980.06	2,482.62	490.47	25,599.76

Source: Detail of Revenue Analysis

Table 7 – IEC Revenues by Rate Class for 2015 (Million NIS)

Rate Class	Production	Transmission	Distribution	Supply	2015 Total
Residential	6,491.52	643.43	1,317.84	379.43	8,832.22
General	1,325.59	133.94	264.08	44.23	1,767.83
Street lighting	59.68	5.69	13.50	1.16	80.03
Low V TOU	3,683.26	373.44	741.81	60.15	4,858.66
Low V TOU / Collective Sale	53.34	5.21	5.46	-	64.01
Low V Bulk (PA)	35.26	3.49	7.34	-	46.09
Med V Bulk (PA)	1,019.91	100.66	28.78	-	1,149.35
Med V TOU	6,090.00	619.15	174.34	11.77	6,895.27
Med V TOU / Collective Sale	27.93	2.69	-	-	30.62
Med V Bulk TOU (PA)	697.64	69.77	-	-	767.41
High V TOU	1,750.99	80.27	-	0.15	1,831.41
Total	21,235.12	2,037.73	2,553.15	496.88	26,322.88

Source: Detail of Revenue Analysis

Table 8 – IEC Revenues by Rate Class for 2016 (Million NIS)

Rate Class	Production	Transmission	Distribution	Supply	2016 Total
Residential	6,637.03	657.85	1,347.38	384.46	9,026.72
General	1,370.66	138.49	273.06	44.77	1,826.98
Street lighting	61.02	5.81	13.81	1.17	81.81
Low V TOU	3,808.50	386.14	767.03	60.88	5,022.56
Low V TOU / Collective Sale	55.15	5.38	5.65	-	66.18
Low V Bulk (PA)	36.80	3.64	7.66	-	48.10
Med V Bulk (PA)	1,064.56	105.06	30.04	-	1,199.66
Med V TOU	6,254.83	635.91	179.06	11.90	7,081.70
Med V TOU / Collective Sale	28.68	2.76	-	-	31.44
Med V Bulk TOU (PA)	728.18	72.82	-	-	801.01
High V TOU	1,778.21	81.52	-	0.15	1,859.88
Total	21,823.63	2,095.40	2,623.68	503.33	27,046.05

Source: Detail of Revenue Analysis

2.1 Recommendations for the Development of Future Revenue Forecasts

Navigant has identified the following activities which should be required by the IEC for rate filings. These activities would facilitate an accuracy and efficiency in preparation of a rate request.

2.1.1 Annual Reconciliation of Revenue

Navigant recommends that the PUA require a Proof of Revenues be provided by the company for each year after the accounting period has closed. The Proof of Revenues reconciles actual revenues of the IEC with the billing determinants for each function and rate class. It should include detailed documentation of requisite calculations and assumptions made. . The IEC should be able to provide data to the PUA or an outside analyst that can be used to reconstruct their calculated revenues to a reasonable degree of accuracy for the functions presented in financial reports.

2.1.2 Revenue Forecast by Rate Class

Utilities in developed economies typically prepare a revenue forecast for each rate class. These forecasts are required in order to determine on a forward looking basis the potential rate increases required, capital investments and other operational issues.

The IEC's "top-down" approach to load forecasting does not provide the detail required to prepare a rate case. Navigant recommends that the IEC either adopt the forecast methodology prepared by Navigant or prepare their own approach to sales forecasting which can be applied to rate classes.

Navigant recommends that IEC be required to provide a sales and revenue forecast of at least five (5) years. The forecast will be updated annually and provided to the PUA for their review. The forecast shall include the following detail:

- Revenues for each rate class for each year; and
- Sales, customers, and demand for each rate class for each year;
- Rates in effect for each season, time of use, and rate class for each year.

Furthermore, at the end of each year the IEC shall provide the PUA with a comparison of the most recent load forecast to the actual results for that year. The comparison should provide the estimated impact of weather, macroeconomic impacts and other variables on sales and the resulting changes in revenues.

3. Technical and Economic Assessment of the IEC Transmission and Distribution Functions

Navigant reviewed the investment strategy of the IEC transmission and distribution ("T&D") segment with the goal of determining if the investment strategy was efficient, safe and reliable. Our approach, analyses and results are detailed below in this chapter.

3.1 IEC Planning and Design Criteria

3.1.1 System Design

The IEC's T&D planning and design criteria is based on a philosophy of balancing risk versus cost, while conforming to generally accepted utility planning principles and practices. Increasingly, IEC is locating lines underground, particularly for distribution, despite higher costs. Reasons for the increasingly higher percentage of underground lines include policies and codes that effectively mandate undergrounding, including municipal codes, or other obligations imposed by the Electricity Law or federal requirements. These processes also are informed by public policy and security objectives such as minimizing environmental impacts, public health risks and resiliency to terrorist threats and attacks. Each of these factors invariably results in enhanced design standards and increased cost. Further, load density is extremely high in major urban centers, with access for electrical lines and facilities increasingly limited due to environmental, land use and availability.

3.1.1.1 Transmission

As a small nation with few interties to neighboring utilities, IEC relies almost entirely on the capability of its 400kV and 161kV transmission system to deliver bulk power supply to load centers while meeting a loss of load expectation ("LOLE") of one day in 10 years.[5] Similar to utilities in Europe, North America and other regions, the bulk transmission system is designed to an N-2 criterion, which enables the integrated system to withstand the loss of two major elements or components while not violating system stability, loading or voltage standards. The IEC's most recent transmission plan is presented in the IEC Report RE-1448[6], which describes the investment that will be required over the next five to ten years to meet IEC planning and design criteria. The 400kV transmission lines are located in central and northern Israel, forming a loop or semi-loop connecting to major load centers. To improve transmission deliverability, reliability and security; IEC proposes to expand the 400kV transmission system to a loop

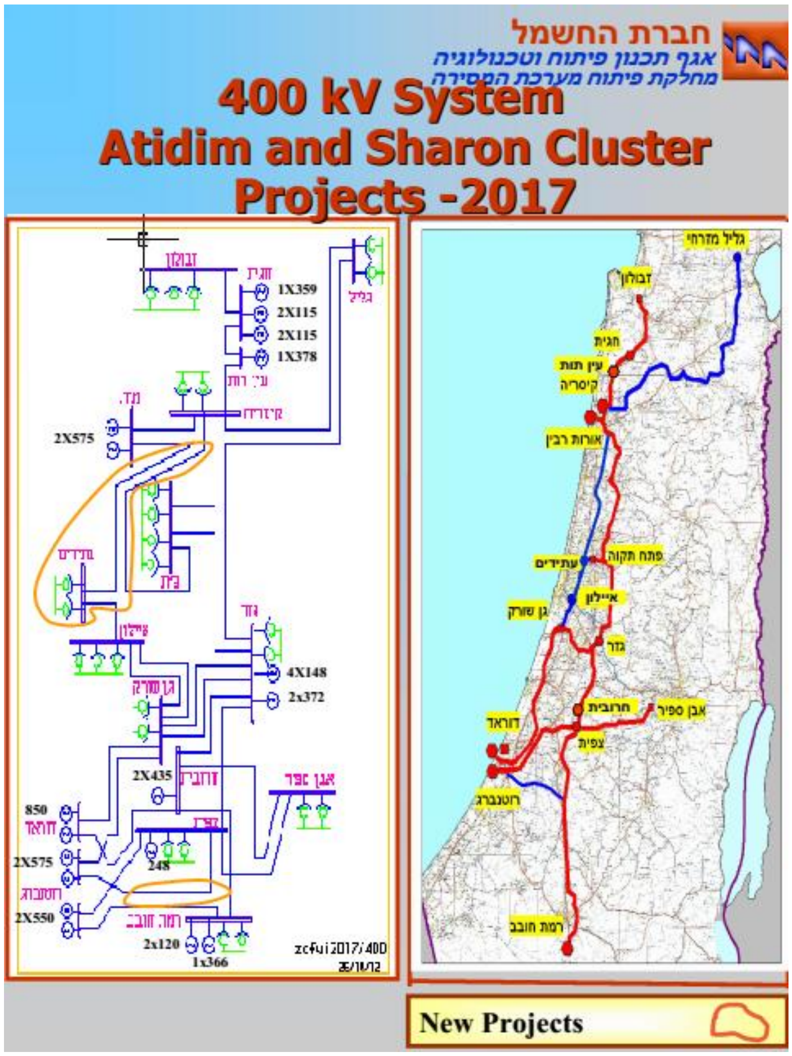
---

[5] IEC recently developed new analytical methods to identify the minimum generation capacity to meet bulk system reliability requirements. The new methodology incorporates with a greater degree of rigor both generation and transmission availability, which should determine to a greater degree of accuracy the capability of the integrated bulk power system to meet minimum reliability requirements.

[6] IEC Transmission Development Sector, *Transmission System Development Plan for the Years 2013-2017*, July 2013

(often referred to as a "ring") configuration. The 400kV expansion will be implemented in phases over the next ten years and beyond.

Figure 4 - 400kV Transmission Expansion Plan (2017)



Note: New 400kV lines circled on one-line and highlighted in blue on map.

With the completion of major sections of the 400kV loop (later this decade), IEC will no longer need to rely on 161kV lines to provide contingency support for a loss of portions of either the 400kV and 161kV loop. It also lessens the likelihood of a system-wide blackout due to the loss of critical 400kV lines or stations. This philosophy is consistent with common utility practices at it provides greater flexibility and reliability to the entire transmission network. The ring configuration also is consistent with the design of high-voltage transmission networks in urban areas in North America and worldwide. Lastly, the 400kV system will be needed to deliver output from new and existing generation, including over 1500 MW from IPP projects alone.

Increasingly, IEC's transmission system has been expanded and configured to deliver power from Independent Power Producers ("IPP") via IEC's Open Access Transmission tariff, some of which are in remote locations where high voltage lines were non-existent or incapable of reliably delivering IPP output. Current IPP forecasts will require addition transmission lines or upgrades to deliver this additional capacity.

The transmission planning criteria that IEC uses for the design of its 400kV and 161kV system includes the following:

- **Single Contingency (N-1):** Loss of a single component (line or transformer) on 161kV line with resulting loading at 120 percent or less of thermal rating for outages longer than 30 minutes.

- **Double Contingency (N-2):** Loss of two 400kV lines with on a common structure, with resulting loading at 120 percent or less of thermal rating.

The above criterion is comparable to design standards applied internationally, and are reasonable for the IEC system. Historical transmission system performance and reliability also supports use of the above criteria, as interruption statistics are within reasonable bounds. The N-2 criterion is generally consistent with North American and European standards including the North American Electric Reliability Council ("NERC") requirement for comparable lines. However, the standard could be revised (i.e., that is, made more stringent) if conditions or events in Israel resulted in a degradation of transmission system reliability or increase in the frequency widespread outages.

The IEC also includes in its budget funds to reduce or mitigate EMF for the design and siting of transmission lines. Adoption of formal EMF standards can significantly increase costs where EMF levels exceed threshold levels. The allowable or recommended level of EMF and Voltage Potential was initially prepared by the Ministry of Environmental Protection, and currently adopted by the ICNIRP for prolonged exposure to the general public appears in Table 9.

Table 9 - EMF Threshold

Electric field strength	Magnetic flux density
5 kV / m	1000 mG (milligauss)

The cost of meeting the EMF threshold is greatest in areas where overhead lines are the standard, but must be installed underground, significantly increases costs compared to equivalent overhead construction. Similarly, lines that must be increased in height or relocated to new or expanded rights-of-way also will result in higher costs. Several international utilities apply and IEC has adopted a "prudence avoidance" approach, which encourages utility planners to design or locate lines in areas where EMF is less of an issue or apply designs that produce lower EMF, when it is cost-effective and reasonable to do so.[7]

The practices IEC has adopted for EMF is possibly more stringent than many other utilities, most of which do not allocate or budget funds to reduce EMF levels. Further, IEC planning documents states the following: "The system is designed in a proper way having all IEC facilities and power lines complying with these limitations."[8] The statement suggests that all new transmission facilities will be designed to meet the recommended standard. Interviews held with IEC technical staff confirms this premise, as IEC's ability to obtain necessary permits from local municipalities or federal agencies is diminished if the standard is not met. Notably, utility regulators and health agencies in several other nations have been reluctant to adopt formal EMF standards due to inconsistencies in studies or lack of evidence that definitively shows a correlation of health effects and EMF levels. Navigant supports a position that upgrading the design to meet EMF thresholds should be considered when the additional cost is reasonable. For example, an acceptable increase in cost to meet the EMF standards should be no higher than 5 to 10 percent of the cost of a standard design. In addition, Navigant recommends that the IEC provide the PUA with a study discussing different approaches to meet the EMF thresholds, including independent evidence of the causality that such investments are required due to a correlation with health risks and an opinion from the IEC of which is the optimal approach to compliance.

3.1.1.2 Distribution Planning

Most IEC substations are designed to meet and N-1 criterion (i.e., the loss of a single power transformer or bus section does not cause loss of load for most contingency events). Current planning and design criteria now include mutual area support, with distribution feeder tie switches that enable distribution operators to transfer load from one substation to adjacent substations in the event of a contingency. At these substations, maximum normal feeder loadings is limited to approximately two-thirds of maximum current (250 amps on feeders set to trip at 400 amps) to enable load transfer. This practice is desirable and consistent with utility practices as it lengthens the time required to upgrade or add new substations to meet capacity increases caused by load growth.

Distribution feeders also are designed to meet an N-1 criterion, with open tie points between adjacent feeders. Because of the substation and feeder N-1 back-up planning criterion, maximum feeder loading, as noted above, is about 250 amps for 400 amp feeders.[9] Maximum distribution transformer loading is

---

[7] IEC estimates that if the Environmental Protection Ministry recommendation regarding exposure to 50Hz EM-fields were set at 4 milligauss (based on the preventive caution principle) for existing lines would dramatically increase costs. IEC estimates that 390 km of 161kV lines and 64 km of 400kV lines would need to be relocated underground. Also there are 10 km of underground cables that exceeds the limitation. The preliminary cost evaluation for the existing lines only is 8.5 Billion NIS (1.7 Billion EUR). Taking into consideration the 161-400kV lines planned to be established in the next 5 years and the need to install capacitive compensation systems, the cost would reach 24 Billion NIS (4.8 Billion EUR).

[8] IEC Transmission Plan, pg. 12.

[9] Continuous current trip settings at the substation breaker is 400 amps, which is low for some utilities, but does not materially impact feeder design and loading practices.

110 and 120 percent, respectively, for oil-filled indoor and outdoor transformers. Low voltage feeder voltages are +/- 10 percent of nominal, as measured at the customer counter.

3.1.1.3 Distribution Design Standards

Distribution planning and design standards apply to assets rated 33kV and below, including substations with low-side voltages 33kV and below. Low voltage (LV) distribution is 400 volt three-phase and 230 volts single-phase, also common for utilities worldwide. Distribution design standards include overhead lines or underground cables, the selection depending on geographical location. In urban and preserved areas the new distribution must be underground, and overhead or underground in open areas, depending on municipal siting requirements. In rural and less congested areas, most substations are above ground with typical utility design standards such as open air busses and circuit breakers. Substations located in areas subject to mortar shelling and sabotage is sometimes designed to a higher physical standard, with walls or enclosures capable of withstanding attacks.

Most new distribution lines are constructed aluminum wires and cables, with copper conductor used in specialized applications such as underground conduit with limited spacing or high capacity requirements. This is consistent with common utility practice. The size and type of distribution conductor, cable and transformers also is consistent with common utility practices.

Other than the higher physical requirement for substations, IEC distribution delivery voltages, overhead and underground design requirements, and equipment selection is mostly consistent with common utility practices.

One area where a higher design standard results in higher cost is substations in large cities. Substations in major cities use compact designs and equipment such as GIS; in a few cases in very high load density with physical constraints, IEC proposes to install underground substations. The cost of compact design can be higher by a factor of two, and much higher for underground facilities. IEC reports that new underground substations are required in larger cities such as Tel Aviv due to inability to obtain land or permits. Navigant is aware of only a relatively small number of completely underground stations similar to those planned by IEC. For example, in Canada, there are underground substations in Vancouver, British Columbia; Calgary, Canada; and one under construction in Toronto, Canada.

Navigant recommends that the IEC be held to a standard where they allowed to recover the costs of undergrounding facilities when they have made a concerted effort to obtain required permits to construct facilities of have produced studies and documentation that confirm major underground facilities are required.

3.1.2 Enhanced Design Standards

In addition to EMF, IEC has adopted more stringent design standards in urban areas and in areas susceptible to mortar attack. For areas with high load density and limited land availability (or physical barriers), IEC has adopted compact substation design based on use of Gas Insulated Switchgear ("GIS"), which is far more compact than conventional switchgear. However, the cost of GIS is twice the cost of conventional switchgear. An even greater cost differential exists in urban areas where proposed substation are located underground; costs for these stations can be twice as costly, or higher, than conventional substations. Congestion typically is addressed by installing conventional ground-based substations. The cost of ground-based substations is usually lower when suitable land is available to accommodate the substation.

Similarly, limited right of way availability for future 161kV lines in urban areas also is resulting in higher costs. Currently, IEC's transmission standard for 161 kV transmission lines is the overhead line construction. In very populated urban areas, XLPE underground cables are used, which is six to eight times more costly.

In a similar approach as is described above, Navigant recommends that the IEC be held to a standard where they allowed to recover the costs of undergrounding facilities when they have made a concerted effort to obtain required permits to construct facilities of have produced studies and documentation that confirm major underground facilities are required.

3.1.3 Reliability and Performance

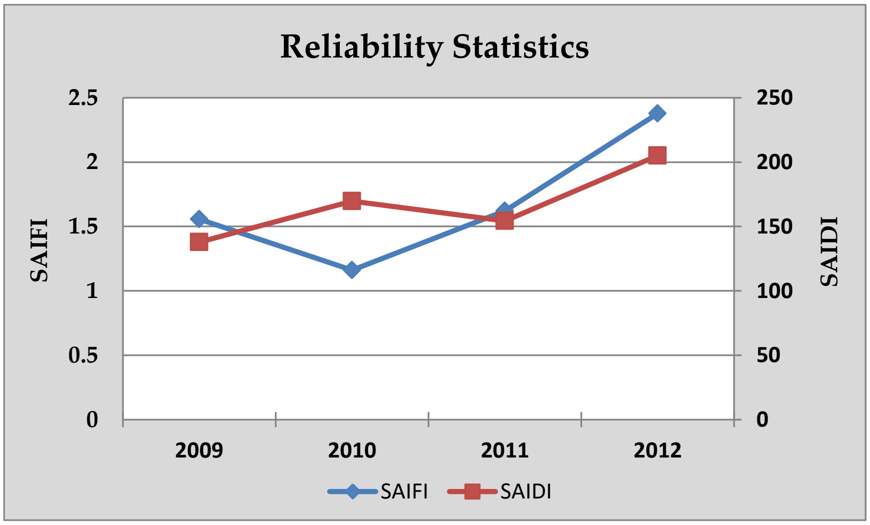
Distribution system reliability has remained steady over the past four years with an uptick in 2013. Figure 5 presents IEC reliability performance for 2009 through 2012, as measured by commonly applied reliability metrics.[10] These statistics appear to be in line with other utilities with comparable service territories, although duration as measured by SAIDI appears to be in the upper ranges. The increase in 2012 may be the result of weather or improved data collection methods from Outage Management Systems (OMS)[11], but if reliability declines, IEC likely will need to take action to mitigate underlying causes to the increase, IEC uses about 30 cause codes to classify interruptions, a very high number compared to other utilities.

---

[10] IEC has adopted reliability tracking and measurements consistent with IEEE P1366 guidelines, an industry standard that utilities worldwide commonly use to measure, track and benchmark reliability.

[11] Navigant's experience with OMS indicates that the accuracy of reliability metrics improves due to the improved data quality resulting from the installation of the DMS and associated business processes changes – the reliability of the system does not decline as a result of the installation of the DMS. It is not unusual to see a 25 to 35 percent worsening of reliability metrics once the DMS and related systems such as Outage Management Systems (OMS) are installed. The fact that reliability metrics have declined due to more accurate reporting does not itself support any increases (or decreases) in renewal spending.

Figure 5 - Reliability Trends



Source: IEC reliability metrics database

While this observation does not impact reliability or mitigation investment strategies, Navigant's experience suggests that fewer cause codes might provide a sufficient level of detail to evaluate performance and develop strategies and options to address reliability issues.[12]

Table 10 presents IEC annual SAIDI, with one or more individual cause codes combined into one of twelve categories. Aside from planned interruptions, the dominant cause code is aging, which typically is associated with equipment failure due to degradation. Notably, the aging category is one of the individual cause codes not combined with other cause codes. Age related failures typically are addressed through proactive replacement via the renewal investment category.[13]

[12] For example, Navigant often finds that field crews or operating personnel may assign different cause codes for similar events occurring at different times.

[13] Navigant does not suggest use of age alone should be used to support renewal replacement or to predict equipment failure. Current utility asset management practices strongly recommend that equipment should be replacement based on actual condition, measured based on field measurements, prior failure history and other data that indicates that the equipment has a higher likelihood of failure or decline in performance.

Table 10 - Annual SAIDI by Cause (Minutes)

Cause Code	2009	2010	2011	2012
Weather	11	25	6	10
Animals	1	1	1	1
Trees	5	8	4	10
Terrorism & Sabotage	3	5	7	11
Faulty Equipment	2	3	2	2
Aging	24	28	37	44
Protection & Systems	6	6	4	4
Lack of Supply	5	3	2	7
Faults in PA Area	1	2	1	1
Unknown	12	13	11	11
Planned	35	31	34	37
Other	15	21	23	33
Total	121	145	132	172

Source: IEC reliability metrics database

3.1.4 Energy Efficiency and Demand Management

Energy Efficiency programs are the responsibility of a separate entity (Ministry of National Infrastructure, Energy and Water Resources), while demand management programs, operationally, are the responsibility of IEC.[14] During interviews and some documents refer to efficiency and demand management as an alternative or considered in capacity planning decisions, mostly at the substation level. However, the documents Navigant was provided and reviewed did not specifically identify the impact and role demand management or efficiency initiatives in capacity planning decisions. Under the right circumstances, targeted efficiency and demand management programs have the potential to defer major capacity investments for one or more years. Accordingly, IEC should continue to explore and advance efficiency and demand management initiatives in areas where cost-effective capacity deferral (along with other ancillary benefits) may be achieved.

3.1.5 Asset Management and Renewal

Asset management practices at IEC include collection and assessment of equipment condition and health evaluation. IEC distribution staff also reported during interviews that it also prioritizes asset renewal based on prioritization methods. These are important elements of asset management and will improve spending efficiency by directing capital investments to assets that are at risk of failure and with the highest consequences in terms of reliability, safety and environmental impacts, among other factors.

---

[14] As noted in other sections, Navigant recommends that IEC assume greater responsibility for the planning and administration of energy efficiency programs in Israel, both to increase potential savings and to design programs to provide the greatest benefits to IEC's power delivery system, among other benefits.

During interviews and meetings, IEC's distribution department described systems and methods it is now using based on seven criteria, list below. These prioritization methods are designed to minimize risk and ensure compliance with energy law. They also correspond to priorities that have been established by the Energy Minister and the PUA; in addition to considering the criticality of each substation and line within the transmission network. At a high level, these generally are consistent with asset management principles and practices adopted by utilities worldwide.

The seven prioritization and risk criteria applied to transmission are listed and ranked below.[15]

1. The top priority is represented by programs planned to match the safety rules for IEC personal and the public (e.g., replacement of circuit breakers in order to accommodate the increased short currents);
2. Second priority: programs developed to meet laws and regulation requirement (e.g., fire prevention code, environmental regulations, etc.);
3. The third priority relates to programs in order to meet security requirements. (e.g., electronic fences, cyber related activities etc.);
4. The fourth priority relates to complementary programs for the IPP's connection to the network (in addition to the network developing plans);
5. The fifth relates to projects related to the transmission development plan;
6. The sixth priority: equipment upgrading in order to meet the increasing demands for the continuity of supply for the customers; and
7. The seventh priority: increasing the reliability of transmission system and especially in the main nodes of the transmission system (switching stations, substations transmission lines).

IEC provided a list of representative projects for each of the seven categories, including percent spending based on a five year forecast.

[15] The seven priorities and descriptions were provided by IEC in Data Request No. 27.

Table 11 - Transmission Renewal Spending

Priority	Projects Category	Examples	Transmission Capital Budget (2013-16) (*10^6 NIS)	Percent of Total Budget
1	Safety	"MASHABE SADE" substation: Install circuit breakers of higher rating to replace existing lower-rated breakers, to meet increased short circuit current	130	29%
2	Requirements of Relevant Code	"CURSI" substation: Modify water system in order to conform to firefighting & prevention code regulations	66	15%
3	Security	"KRAYOT" substation: Security fence around substation	54	12%
4	Projects Related to HV & EHV Private Substations	"GEZER" substation: Modify differential protection relay (currently suitable for two-terminal transmission line) in order to accommodate 3rd terminal to line	22	5%
5	Projects in the transmission development plan	"EILAT" substation: Install 3-phase voltage transformer at line terminals	6	1%
6	Equipment upgrading	"HERZLIYA" substation: Install relay for load shedding at underfrequency, undervoltage & overcurrent to replace existing relays	122	28%
7	Reliability	"YAVNE" switching substation(directly connected to power plant):Install 220VDC distribution panels in two rooms, in place of single existing panel	43	10%
		TOTAL	444	100%

Source: Navigant Data Request (No. 27) - 27. Renewal Program – Project Selection & Prioritization Methods

It is important to emphasize asset management includes practices, systems and tools that support selection of programs and project within each of the above seven criterion for both transmission and distribution. These include centralized data registries, and use of condition assessment and prioritization methods to identify equipment in need of upgrade or replacement; and use of optimization tools to compare alternative solutions to determine the least cost option. While these methods and tools are consistent with current practices, we were not provided information or clear and explicit examples of asset condition assessment and prioritization to confirm that IEC has used these methods have been used to develop their distribution investment plan. Further, it is not clear the extent to which IEC uses cost benefits approaches to help prioritize investments within these seven categories.

The recent IEC spending forecast for asset renewal, particularly for distribution, appears to be based on historical trends. We also found a limited number of reports, analysis or guidelines documenting IEC's asset management principles and practices, including how asset health is linked to condition assessment data derived from maintenance, testing or inspections records, and reliability cause codes; for example, age metrics for SAIFI and SAIDI. We also are not aware of cost benefit analysis of alternatives. To the extent these activities and approaches are in progress, IEC should advise the PUA of its status and results.

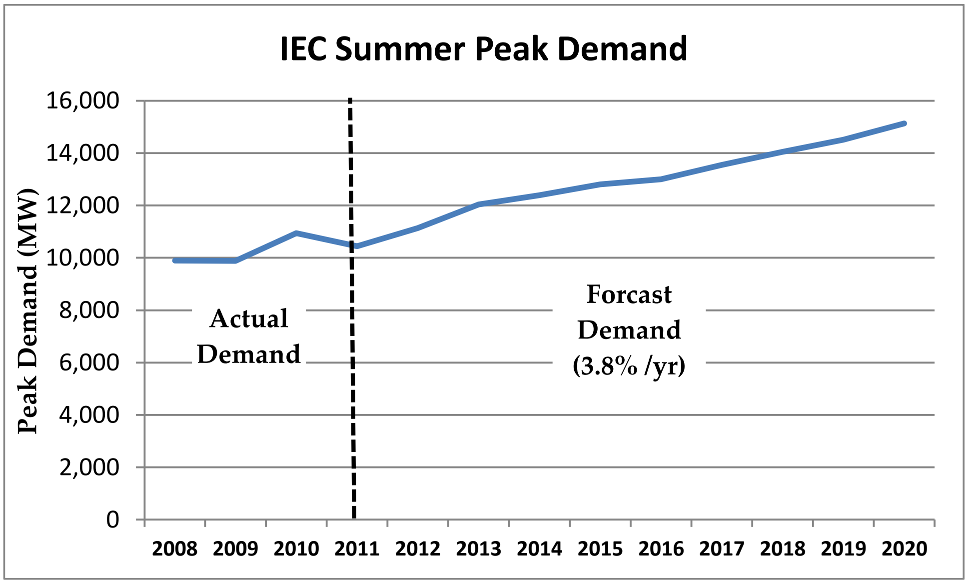
3.2 Transmission & Distribution Investment Plans

The IEC system includes five major districts or regions, from which development plans are prepared for each area. Because of the integrated nature of the UHV system (400kV and 161kV), planning is performed on an integrated basis for major segments of the bulk power delivery system; whereas distribution investment plans are prepared for each district. Further, IEC prepares independent load forecasts for each district for planning and budgeting.

3.2.1 Demand Forecasting

The IEC system peak for the past several years has occurred during the summer, and IEC expects this pattern to continue over the ten-year forecast. Forecast peak demand at the transmission level, presented in Figure 6, is expected to be robust, growing at an average rate of almost 4 percent annually. The forecast excludes the reduced demand resulting from IPP firm demand reduction. Prospectively, the transmission system must be capable of accommodating about 500 MW of addition load to its network annually to 2020.

Figure 6 - IEC System Peak Demand Forecast



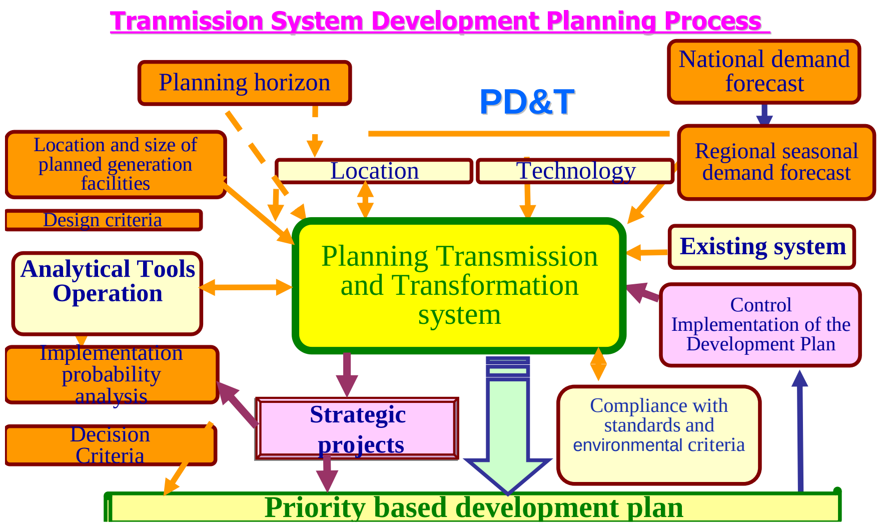
Source: IEC Peak Demand Forecast: IEC Transmission Development Plan for the years 2013 – 2017 (RE-1448).

Transmission Planning

3.2.1.1 Transmission Planning Process

IEC's transmission planning process is presented in Figure 7. The initial driver for transmission expansion is forecasted electric demand, which is developed by the IEC. Several other important inputs include committed or proposed IPP additions and other generation projects. As described earlier, IEC is seeking to expand the 400kV UHV transmission system to reduce reliance on the 161kV system to meet performance and reliability requirements. With the evolution of the 400kV system, the 161kV system increasingly will be used for power delivery to distribution substations.

Figure 7 - IEC Transmission Planning Process



Source: IEC Report RE-1448, *Transmission System Development Plan for the Years 2013-2017*, July 2013

IEC uses several commercially available or internally developed software simulation models to analyze transmission system performance and evaluated expansion alternatives or reinforcement options. These include the PSS/E network load flow simulation and internally-developed optimization models that use probabilistic algorithms for transmission system studies. Navigant views IEC's methodology and its use and application of simulation tools to be consistent with or above industry standards.

IEC is expanding the 400kV system incrementally over time, both due to local load growth and to enhance the reliability and security of the interconnected bulk system. The expansion of the 161kV system is largely driven by increases in demand at major load centers, which require new 161kV lines for new major substations to serve the new load. For most new substations and lines, IEC has prepared comprehensive studies of alternative supply options, choosing the lowest cost options that meets demand and reliability criterion. The transmission studies include use of sophisticated analytical tools and methods to test candidate expansion plans. Our review confirms the number of proposed alternatives and tools IEC applies to evaluate options are consistent with industry practices.

3.2.1.2 Transmission Investment Plan

The IEC updated its transmission investment plan in early 2014 in its proposed rate case submission document, with proposed spending highlighted.

Table 12 - 2014 – 2016 Investment Plan (M NIS in 2012 Prices)

Basic Investments	2012	2013	2014 Original	2014 Revised	2015	2016
National dispatch center	0	36	29	39	24	20
Switching stations	109	164	304	139	176	199
E.H.V lines (400 KV)	37	40	97	84	116	444
H.V. lines (161 KV)	437	257	1,030	349	750	563
Substations	291	235	654	142	478	627
Active switching & substations	0	0	0	109	0	0
Spare parts	0	2	2	4	2	2
Increase in the budget pending approval	0	0	0	5	0	0
Total planned investments	873	734	2,115	872	1,544	1,855

Source: IEC Report Table 22

The most recent transmission development plan includes the following project categories and is reflected in Table 11. Specific lines and substations that are proposed to 2017 are listed in the Appendix.

1. Construction of new 400 kV power lines and upgrading of existing power lines;
2. Construction of new 400/161 kV switching stations, expansions and various projects at the existing switching stations;
3. Construction of new 161 kV substations, expansions and various works at the existing substations;
4. Construction of new 161 kV power lines and upgrade of existing power lines;
5. "Prudent avoidance" projects of in order to reduce exposure to electromagnetic fields; and
6. Projects intended to connect Independent Power Providers (“IPP”) to the transmission system.

In the short-term, investments are mostly dedicated to completing 161kV build-out and lines to major substations and IPPs. Among other projects, transmission supply to the growing Eilat area in the far south is expanded and enhanced, increasing capacity and reliability of supply. It also includes 400kV lines and critical switching stations needed for bulk system security and reliability.

The investment plan also includes a substantial amount of reactive support in the form of capacitors, a cost-effective approach to improve power factor, increase capacity, and stabilize voltages. Table 13 lists the capacitor additions, by district.

Table 13 - Transmission Capacitor Additions

Year	2012	2017
Haifa District	282	348
North District	415	630
South District	801	1341
Dan District	335	819
Jerusalem District	200	424
Total (MVAR)	2033	3562

Source: Response to Information Request

3.2.1.3 Transmission Losses

Transmission losses are measured as a percent of total deliveries from generating sources (busses). For the end of 2012, IEC transmission losses were estimated at 1.2 percent. Table 14 presents the losses by component. All transmission losses are measured up to and including the high side of the distribution substation transformer. Transformer load and no load losses are included in distribution loss totals.

Table 14 - Transmission Losses

Description	Percent Losses
Lines and Tie Transformers	0.89%
Transformation system	0.31%
Total Losses	1.20%

From Navigant's experience and losses reported by other utilities, the 1.2 percent reported energy loss is consistent with utilities with comparable service territory characteristics, network configuration and delivery voltages. However, Navigant was unable to independently verify these values via review of IEC's analysis, including load flow studies or calculations.

3.2.2 Capacity Additions

Capacity additions include new or upgraded distribution substations and feeders. The planning approach and analysis for large new or upgraded substations is comprehensive, with several candidate options evaluated. These options typically include new substations, load transfer, reactive support or voltage upgrades, where applicable. Each report that Navigant reviewed for major substation additions appeared to thoroughly and rigorously evaluate each option, with a needs assessment based on predicted loads and equipment capability. Importantly, IEC includes area and regional planning criteria to assess capacity requirements, which ensure less costly options such as load transfer is included in the options analysis.

Notably, IEC personnel have developed innovative and sophisticated probabilistic-based methods to predict transformer capacity reserve requirements for medium and high voltage substations, whose applications exceeds industry practices. Based on our review of IEC planning criteria, methods and approach, the proposed substation additions appear warranted. One area where Navigant recommends additional rigor and analysis is use of life-cycle economics to evaluate options. In most studies, the preferred option often is the one that has the lowest up front capital cost. While the cost approach may produce accurate results for most plans, long-term economic analysis of options may produce a lower cost plan.

The amount directed to distribution feeders is largely based on historic trends as opposed to evaluation on a case-by-case basis.

3.2.3 Mandated Investments

Mandated investments include connections to new customers, environment or safety improvements, and other improvements required by local jurisdictions or Israeli agencies. It includes facility relocation or upgrades to comply with Electricity Law, Ministry of Environment, and other jurisdictional agencies.

3.2.4 Efficiency and Innovation

Several IEC documents and plans highlight innovation strategies designed to improve spending efficiency and reliability. These include installation of smart meters to reduce operating expenses and incentivize customers to conserve energy. The implementation of automation and enhanced distribution management systems are expected to improve reliability and performance.

3.2.5 Technical and Non-Technical Distribution Losses

Table 15 presents load and no load distribution losses, which collectively are 6.4%. The values generally are consistent with percent losses reported by other utilities with similar service territories. The methodology IEC uses to derive losses is based on a combination of measured and calculated losses. At the distribution level, calculated losses are determined by load flow simulation models or measurements that predict with reasonable accuracy the losses for a specific line or set of lines. To ensure accurate results, simulation studies must be conducted for a representative set of feeders under a range of loads and conditions.

Table 15 - Distribution Losses (TBC)

Description	Percent Losses
Load losses	5.4%
No load losses	1.0%
Total Losses	6.4%

The IEC reports that it expect to implement a continuous measuring system within the next few years as part of its Distribution Management System (DMS) that will enable engineering and operating personnel to derive more accurate losses for the distribution network. Once the DMS integration and measurement system is completed, IEC should update its loss analysis and report these results to PUA, including peak and average loss factors by voltage level. Because IEC's reported distribution losses do not appear high or inconsistent with industry benchmarks, and measures are proposed to improve determination and reporting of loss factors, Navigant determined that additional study or analysis is not needed at this time.

3.2.6 Non-Technical Losses

Non-technical losses include meter errors and energy diversion (i.e., theft). The amount of losses attributable to energy diversion is difficult to differentiate when measurement approaches are applied, as it is not possible to differentiate technical from non-technical losses. However, with the advent of smart meters, the level of read errors should decline. Additionally, smart meter data and post-processing software designed to detect theft should also reduce energy diversion over time. IEC reports that one of the primary goals of its smart meter program is better identification of non-technical losses. Similar to technical losses, IEC should report progress on non-technical loss reduction programs to PUA, including the status of smart meter program applications for detection of non-technical losses.

3.2.7 Distribution Investment Plan

Table 15 presents IEC's most recent five-year investment (rate) plan, which includes retroactive totals for 2013 and 2012. A substantial percentage of the investment plan is for the build out or replacement of distribution lines, in large part to meet new demand and connections. Substation investments, which are included in the transmission segment budget, are proposed for many new substations in several districts, which are needed to meet new demand. Additional 161kV transmission also is needed for many of these substations and is included in the transmission budget.

Table 16 - Distribution Investment Plan (M NIS)

Basic Investments MNIS, 12/2012 prices	2012	2013	2014 original	2014 budget	2015	2016
Transformers	289	0	511	0	390	385
M.V. lines	584	836	1,180	806	770	737
L.V. lines	318	282	591	283	385	383
DMS	18	28	12	26	12	12
Returning materials & connection to homes	-3	0	0	0	0	0
Retrospective implementation of IAS19	0	0	0	0	0	0
Increase in the budget, pending approval	0	0	0	111	0	0
Total (Basic investments)	1,206	1,146	2,295	1,226	1,557	1,517
Smart grid			136	39	903	907
Total (Basic + smart grid investments)	1,206	1,146	2,432	1,265	2,460	2,424
Grid Renewal					794	795
Connections to homes improvements	0	10	104	20	110	110
Total planned investments	1,206	1,156	2,535	1,285	3,364	3,329

Source: The Israel Electric Corporation Transmission and Distribution Segments Rate Case

Notably, the plan includes up to 1 billion for smart grid investments, which underscores IEC's commitment to innovation. Relatedly, there is over 50 million targeted for DMS enhancements, which often is used in automation and advanced outage detection systems. Due to the major cost commitment to smart grid, IEC should periodically report on the progress and benefits on smart grid and related investments to the PUA.

3.3 Summary Assessment

3.3.1 System Design and Planning

IEC's T&D planning and design criteria each are based on a philosophy of balancing risk versus cost, while conforming to generally accepted utility planning principles and practices. The high voltage bulk power system is designed consistent with industry practices and reliability criteria. The Israeli transmission system is designed to meet a double contingency (N-2) as it has few interties and effectively operates as an island. Distribution planning and design standards are consistent with current utility practices, with most lines and substations designed using first contingency criteria (N-1) in most areas. Increasingly, IEC is locating lines underground, particularly for distribution, despite higher costs. Reasons for the increasingly higher percentage of underground lines include policies and mandates that effectively mandate undergrounding, including municipal codes, or other obligations imposed by the Electricity Law or federal agency requirements. These processes also are informed by public policy and security objectives such as minimizing environmental impacts, public health risks and resiliency to terrorist threats and attacks. Each of these factors invariably results in increased cost.

System Reliability and Performance

System reliability as measured by commonly used metrics generally is in line with industry averages for utilities with similar service territories. However, reliability as measured by length of interruptions recently has increased. Further, there is not specific evidence that IEC has initiated investment strategies or maintenance programs to address the increase. Also, there was limited evidence of asset management practices that link spending to reliability at the distribution level. Transmission system performance reliability has consistently been good, as the lines appear to have been well maintained and designed to withstand contingencies without major loss of load.

3.3.2 Transmission Plan

The five and ten-year transmission development plans, while robust in terms of spending, appears warranted given the relatively high load growth, minimal interties with adjacent nations, and need for a high level of security and reliability. Expected increases in independent power production sources also are driving the need for additional transmission. The analytical tools and methods IEC uses to evaluate the transmission network are thorough and consistent with industry standards. The expansion of the 400kV system has been carefully analyzed for many years and the completion of network loops is a logical approach to reduce reliance on the 161kV system to provide back-up support, and enable lower voltage lines to be used primarily for delivery of bulk supply to distribution substations.

3.3.3 Distribution Plan

During interviews and meetings, IEC's distribution department described systems and methods it is now using based on asset management principles, including project prioritization. However, the spending forecast for asset renewal, particularly for distribution, appears to be based on historical trends. We also found a limited number of reports, analysis or guidelines documenting IEC's asset management practices, including how asset health is linked to condition assessment data derived from maintenance, testing or inspections records, and reliability cause codes; for example, age metrics for SAIFI and SAIDI. We also are not aware of cost benefit analysis of alternatives. Thus, we are unable to confirm the spending plan represents the least cost strategy for load growth and renewal spending.

3.3.4 System Losses

System losses at both the transmission and distribution level appear reasonable and consistent with those reported by utilities with comparable design and service territory characteristics. The methodology to calculate technical losses in the past has some limitations; however, IEC's proposed use of smart meter data and enhanced distribution management system capability should improve derivation of distribution system losses.

3.3.5 Recommendations

Based on the findings of our review and evaluation, Navigant recommends that IEC implement the following.

1. Implement life-cycle economic evaluation of transmission and distribution investment alternatives, including quantification and prioritization of investments based on cost, reliability, safety and other benefits;
2. Institute asset management programs and strategies, focusing on condition assessment and asset health. It includes prioritization of renewal investment programs for transmission and distribution, including refurbishment, where cost-effective;
3. Continue the development of smart metering data collection and distribution management enhancements for improved measurement and detection of technical and non-technical losses;
4. Conduct systematic and rigorous studies of the economic impact of enhanced transmission and distribution design standards, including the incremental costs of EMF prudence avoidance measures, environmental restrictions and major delays resulting from permitting authorities;
5. Investigate the potential benefits of proactive demand-side measures and other incentives that reduce T&D peak demand as an alternative to capacity investments; this includes recognition of the impact of demand charges on load forecast that Navigant recommends in other sections of this report; and
6. The timing of future transmission and distribution system expansion should be adjusted to reflect adjustments in load forecasts, including reductions achieved by demand management, rate policies and other innovative strategies.

4. Benchmarking Approach

The Navigant team undertook a benchmarking analysis to inform its views on appropriate recognized costs for IEC. More specifically, the Navigant team benchmarked: 1) the IEC wage premium relative to Israeli economy compared to the wage premium for US electric utilities relative to the US economy; and 2) IEC's capital expenditures (CAPEX) using a CAPEX econometric model developed and implemented in Australia. We describe these benchmarking analyses below.

4.1 Wage Benchmarking Analysis

The wages paid by IEC will have an impact on the Company's operating and capital expenditures. Wages for IEC personnel naturally comprise a substantial component of IEC's operating budget. The wages paid by IEC for construction labor will also be reflected in the cost of installing infrastructure to serve customers. These construction wages will be capitalized and therefore impact the magnitude of IEC's distribution and transmission regulatory asset base. Because IEC performs much of its own construction rather than contracting with outside parties, the wages IEC pays to its own construction workers will be reflected in the Company's past and projected capital expenditures.

Previous studies have found that IEC wages exceed international norms. For example, the World Bank estimated IEC's labor costs per employee were 38% higher than those of comparator power suppliers at nominal exchange rates.[16] KPMG found that while IEC's labor productivity was comparable to coal-fired power stations in Europe, a 40% reduction in its labor costs would be necessary to bring them in line with international benchmarks.[17]

Navigant compared data on IEC wages relative to wages in Israel's overall economy. Data indicate that the 2012 average wage for IEC's entire labor was 23,195 NIS per month. This is equivalent to 278,340NIS, or US $72,296, per year. This value for wages for IEC's entire labor force was taken as a proxy for IEC's average wages for distribution and supply employees as well.

The 2013 Central Bureau of Statistics ("CBS") Statistical Abstract of Israel reports that in 2012, wages for all Israeli workers were NIS 107,652. This is equivalent to US $27,962. IEC distribution wages of US $72,296 were therefore 158.6% above the average wage in Israel. The "wage premium" for IEC relative to the overall Israeli economy is 2.586, or 158.6% (i.e., 72,296/27,962 = 2.586).

Navigant compared IEC wages to those paid in the US electric utility sector. There are several sources of data on US electric utility wages, but two of the most prominent and authoritative measures are the Quarterly Census on Employment and Wages ("QCEW") and the Occupational Employment Statistics

---

[16] World Bank (May 2010), *Study of Israel Electric Corporation's Tariffs and Financial Situation*, p. 3. The World Bank estimated that IEC's labor cost per employee were 25% above comparable power suppliers at purchasing power parity exchange rates. It should be noted that IEC's normalized labor cost in 2012 exceeds the company's normalized labor cost in 2009 by 25% in nominal terms and 16.7% in real terms.

[17] KPMG (December 2005), *Reform of the Israeli Electricity Supply Industry*, p. 73.

("OES") Survey, both conducted by the US Bureau of Labor Statistics ("BLS"), a part of the US federal government's Department of Labor.

There are significant differences in how "wages" are defined in these two BLS sources. The QCEW measure in most States reports total compensation paid during the calendar year, regardless of when services were performed. Under most State laws, the QCEW measure of "wages" include bonuses, stock options, severance pay, the cash value of meals and lodging, tips and other gratuities, and in some States employer contributions to certain deferred compensation plans, including 401(k) plans. In contrast, the OES wage measure includes only the base rate of pay, tips, cost-of-living allowances, guaranteed, hazardous-duty, and on-call pay. OES wages exclude back pay, overtime, severance, jury duty, bonuses, non-production bonuses, and adjustments for shift differentials. Both wage measures exclude employer contributions for health insurance, old-age, survivors, and disability insurance, unemployment insurance, workers compensation, and private pensions not reported as wages.

It is instructive to consider how the QCEW and OES wage measures computed by the BLS compare with the wage measure calculated by the CBS in Israel. The CBS wage measure includes gross payments for all employee costs in a month, including basic wages, cost of living allowances, seniority payments, back pay, advance payments, overtime, premiums, various benefits, grants and supplements such as on-call, shift, 13-mong salary, transportation, vacation, education and proficiency allowances and car allowances. CBS wage measures exclude pension funds, insurance for employees, and employers' tax.

The CBS wage for the Israeli electric utility sector certainly includes elements of compensation that are excluded from the OES wage measure for the US electric utility sector. These components include back pay, overtime, on-call, shift, bonuses, and transportation and car allowances. All else equal, excluding these elements of compensation in the CBS wage measure will tend to decrease reported wage premium compared to those wage estimates presented in the OES.

However, the CBS wage for the Israeli electric utility sector excludes elements of compensation that are included in the QCEW wage measure the US electric utility sector. Sources of compensation excluded from CBS wages that are included in QCEW compensation include stock options, employer contributions to 401(k) retirement plans, and severance pay (*i.e.* payments made to workers whose jobs are eliminated). These elements of reported compensation can be sizable, given the large number of mergers in the US electric utility industry which lead to job losses and severance payments, and the prevalence of 401(k) retirement plans and stock options. All else equal, including these elements of compensation from the CBS wage measure will tend to *increase* reported CBS wages premium compared to those wage estimates presented in the QCEW.

While no BLS measure of US electric utility wages is defined identically with the CBS wage measure, the discussion in the preceding two paragraphs indicate that the OES and QCEW wage measures can provide a range of wages against which IEC wages can be benchmarked. Because the OES wage measure excludes elements of compensation reflected in IEC's reported wages, OES wage premium for the US electric utility sector represents the low end of this range. The QCEW measure of compensation for US electric utilities includes elements of compensation that are not included in IEC wages, so it represents the high end of this range.

In the May 2012 OES, the mean wages for US electric utilities are an estimated US $67,950. In contrast, the average wage in the overall US economy is $45,785. Using the OES wages, the wage premium for US electric utilities compared to the US economy as a whole is therefore 48.4% (i.e., 67,950/45,785 = 1.484). IEC wages ($72,296) exceed average wages for US electric utilities as calculated by the OES ($67,950[18]) by 6.4%. In part, this reflects the fact IEC wages include compensation that is not included in the OES wage. However, the IEC – overall Israeli wage premium of 158.6% is far greater than the US electric utility – overall US wage premium of 48.4% that is calculated using the OES wage measure for US utilities.

In 2012, the QCEW total compensation per worker for the electric utility industry (power generation and supply, NAICS 2211) was $94,762. The 2012 QCEW total compensation figure for all industries was $49,289. Using QCEW data, the wage premium for US electric utilities compared to the US economy as a whole is therefore 92.3% (i.e., 94,726/49,289 = 1.923). The QCEW-based 92.3% wage premium for electric utilities vis-à-vis the entire economy is far greater than the 48.4% wage premium that is estimated using OES wage data. This reflects the fact that the QCEW compensation measure is far more expansive and includes compensation including some contributions to retirement plans and stock options.

IEC wages can be benchmarked by comparing the wage premium between IEC and the overall Israeli economy to the wage premium between US electric utilities and the overall US economy. Navigant believes the US electric utilities wage premium QCEW is an appropriate benchmark for an electric utility wage premium since it reflects: 1) the experience of a large, mature, and diverse electric utility industry; and 2) an economy, and an electric utility industry, in which labor markets are largely competitive. The gap between US electric utility wages and overall US wages is therefore a reasonable estimate of the "equilibrium" wage premium electric utilities must pay (relative to other employers in the economy) to attract and retain workers with the skills necessary for electricity sector employment.

As discussed, the IEC-overall Israeli wage premium is 2.586. There are two measures for the US electric utility-overall US wage premium: this premium is 1.484 using OES wages, and it is 1.923 using QCEW compensation. For the IEC wage premium to be consistent with the OES-based US electric utility wage premium, IEC wages would have to be reduced by 42.6%. In other words, 2.586 * (1 - .426) = 1.484.
For the IEC wage premium to be consistent with the QCEW-based US electric utility wage premium, IEC wages would have to be reduced by 25.7%. In other words, 2.586 * (1 - .257) = 1.923. Thus, a comparison of utility sector-overall economy wage premiums in the US and Israel implies that IEC wages must be reduced by between 25.7% and 42.6% to attain relative wage levels consistent with those of the US electric utility sector. Navigant recommends reducing the wage component of IEC's recognized costs by the mean of this range, 34.2%.

---

[18] Navigant verified the U.S. direct salary data with information published in the Federal Energy Regulatory Commission Form 1 where information on direct salaries are published, and, data published by the utilities on the number of employees. We calculated the average wage rate as follows: We Energies - $66,083; El Paso Electric $65,669; Consolidated Edison of New York - $54,058; and, Southern Company - $35,845.

4.2 Benchmarking of CAPEX Levels

Navigant also used an econometric model developed in Australia to benchmark IEC's CAPEX, both historically and for the period 2014-2016. This econometric model was developed for the Australian Energy Regulator (AER) in its most recent review of electricity distribution prices for distributors in the Australian state of Victoria. This model was developed and estimated using data for the entire Australian electricity distribution industry.

The CAPEX model regressed data on each distributor's CAPEX per customer as a function of customers per km of distribution line. As previously discussed, benchmark of customers per kM of line (or miles of line) is also referred to as customer density, and customer density is known to be one of the most important drivers of electricity distributors' operating and capital expenditures. In the AER Decisions and Reports, the regression results were plotted and the actual econometric models, "fitted" with the estimated coefficients, were not published. However, Navigant personnel were able to obtain the CAPEX econometric model by contacting the relevant personnel who developed the model and requesting it.

The model can be easily implemented to develop 2012 benchmarks by inserting IEC's 2012 value for customers per km of distribution line into the fitted CAPEX econometric model; doing so yields predictions for 2012 CAPEX.[19] This model can also be used to project IEC CAPEX in subsequent years by taking the 2012 benchmarks and escalating them each year for the estimated growth in customer numbers. Navigant assumed 1.35% annual customer growth for IEC between 2012 and 2016, consistent with Navigant's forecast change in billing determinants (including customer numbers) over these years. These results can then be converted to NIS using the average NIS:A$ exchange rate for 2012 and compared to IEC's historical and projected OPEX and CAPEX values for the 2012-2016 period.

Navigant undertook this analysis. The results for the CAPEX benchmarking are presented in. in Table 21. It should be noted that, unlike the US benchmarking analyses, these comparisons do include IEC's allocated overhead costs for CAPEX, because the Australian utilities in the model are all stand-alone distributors, so the estimated model will reflect all of the Companies' overhead costs. We compared these model projections to IEC projections, less a 34.2% adjustment to the salary component of IEC investment costs.

[19] Because the CAPEX econometric model is calibrated to generate predictions in 2010$, it was necessary to apply a one-time adjustment in 2012 to update the prediction to reflect the expected growth in CAPEX input prices, net of OPEX partial factor productivity growth, between 2010 and 2012. Navigant assumed that CAPEX input price inflation minus OPEX productivity growth would lead to 1.5% changes in CAPEX each year between 2010 and 2012.

Table 17 – CAPEX Benchmarking Results for Distribution and Supply (2012 NIS)

Item	2012	2013	2014	2015	2016
CAPEX projection from Model (M NIS)	2,132	2,161	2,190	2,219	2,280
Revised CAPEX excluding excess labor costs (Table 25 and Table 26)	1.039	992	1,091	2,755	2,728
Difference (M NIS)	1,093	1,169	1,099	-536	-448

When the results of the model are compared to CAPEX projections adjusted to reduce the excessive labor costs captured in CAPEX we find that for the years 2012 through 2014 the CAPEX expenditures are below budget and for the years 2015 and 2016 the CAPEX budgets exceed those modeled. Navigant's explanation of the results for the model for the years 2012 through 2014 time period is that the results which are below that of the model due to decisions made by the management regarding the disposition of available liquid funds which may have reduced the amount of available cash flows for investments. The time period 2015 through 2016 reflect a period of expected financial health and normal operations of the company. Navigant is not recommending that any adjustments to the CAPEX budget, outside of the labor adjustment previously discussed, for 2015 and 2016 because the overall CAPEX expenditures are below that modeled.

NAVIGANT

5. Review of the IEC Capital Structure and Cost of Capital

Navigant conducted an independent analysis of the IEC's capital structure and cost of capital. We also reviewed the IEC's proposed capital structure and cost of capital detailed in the IEC Report. Navigant's independently prepared estimates of the cost of capital and capital structure are described in this chapter of the report. We found that the IEC's cost of capital estimates fall within the range of our analyses.

Our analysis of cost of capital took the following three approaches:

- Estimate WACC using a debt beta of zero, capital structure and tax rate of publicly-traded firms of comparable risk to IEC, and a market cost of debt based on a corporate bond index
- Estimate Weighted Average Cost of Capital (WACC) using a debt beta of zero and IEC's actual capital structure, tax rate and embedded cost of debt
- Estimate WACC with a non-zero debt beta assumption using IEC's actual capital structure, tax rate and embedded cost of debt

5.1 General Approach and Selection of Comparable Firms

In principle, investments of comparable risk will face comparable costs of capital. While IEC may be unique in many respects, its business, which in this case is power transmission, distribution and supply, confronts certain operational and financial risks that are similar to other firms engaged in such business. How certain non-diversifiable risks are translated into value (and hence discount rates) can vary among the firms, and we account for those by adjusting our basic results to reflect IEC's specific circumstances.

We began by identifying US firms that transmit and distribute electricity.[20] We selected US firms as the benchmark for comparison for the following reasons.

- The US firms that we considered share the same type of operational risk as IEC that is common to transmission and distribution of electricity;
- The regulatory process in the US is relatively transparent, which means data are reliable. Oftentimes testimony and orders or rulings are available online. The regulatory process itself is overseen by US courts that provide a check against arbitrary or capricious decision-making. In our view, the courts are relatively respectful of law and defining property rights;
- Although there are many differences associated with operating in the US versus Israel, there are understood methods of translating US experience to other countries by virtue of country risk-adders, which we employ; and
- There exists a relatively rich and reliable source of data on US utility operations and financing.

---

20 Some of our comparable firms also generate electricity.

Risks can be additively broken into component parts: (1) operational risks that are associated with the generation, transmission, and distribution of electricity; (2) financial risks that are associated with the requirement to service fixed debt obligations; and (3) risks associated with operating in a specific operating environment, namely, in Israel as opposed to the US

Our use of firms that are in the same business as IEC captures operating risks associated with transmitting and distributing electricity to wholesale and retail customers. We then make certain adjustments in our analysis to control for differences in risks associated with differences in the level of debt financing (i.e., to control for financial risk). Finally, to control for the fact that IEC does business in Israel and not the US, we make an adjustment for Country Risk, which is addressed in section 4.5 .

We identified publicly-traded firms with project risk characteristics similar to those of IEC's T&D operations using information from the SNL Financial ("SNL") group: Regulatory Research Associates ("RRA"). SNL/RRA aggregates regulatory information on both utility holding companies and their operating subsidiaries. We focused on the holding companies because they have publicly traded equity and more transparency in terms of data availability. Equity prices are critical in obtaining a cost-of-equity estimate.

We eliminated electric service provider companies that also had gas operations. We also eliminated the following companies:

- Hawaii Electric and Caribbean Utilities Company (sui generis);
- El Paso due to small size (load is < 2 GW); and
- Otter Tail and Westar due to classification as "diversified utilities" by CapIQ.

The remaining 12 companies are:

- AES Corporation;
- American Electric Power Company, Inc.;
- Edison International;
- FirstEnergy Corp.;
- Great Plains Energy Inc.;
- IDACORP, Inc.;
- ITC Holdings Corp.;
- NextEra Energy, Inc.;
- Pinnacle West Capital Corporation;
- PNM Resources, Inc.;
- Portland General Electric Company; and
- Southern Company.

5.2 Cost of Debt

Navigant examined debt costs in two ways: (1) looking at the marginal cost of debt in capital markets as faced by the comparable firms and (2) examining IEC's embedded cost of debt.

Table 18 shows that the ratings on long-term bonds for the comparable firms were approximately BBB. Firms of comparable risk classification have approximately the same likelihood of default and therefore should have about the same cost of debt, absent idiosyncratic features that might be associated with the debt issue itself (e.g., lack of liquidity). We found that IEC's senior secured debt issues under the global medium-term note programme has a Baa3 rating from Moody's[21] which is an investment-grade rating that is one notch above speculative grade. The long-term corporate credit rating opinion provided by S&P is a BB+ rating, which is a speculative-grade rating. The distinction between investment grade and non-investment grade can be a significant one in terms of debt costs. We concluded that a group of comparable companies with an approximate BBB rating is a reasonably close measure for the marginal cost of debt as applied to IEC.[22]

Table 18 - Ratings on Long-Term bonds of Selected Utility Firms

Name	Ticker	Issuer Rating
AES Corporation	AES	BB-
American Electric Power Company, Inc.	AEP	BBB
Edison International	EIX	BBB-
FirstEnergy Corp.	FE	BBB-
Great Plains Energy Inc.	GXP	BBB
IDACORP, Inc.	IDA	BBB
ITC Holdings Corp.	ITC	BBB+
NextEra Energy, Inc.	NEE	A-
Pinnacle West Capital Corporation	PNW	A-2
PNM Resources, Inc.	PNM	BBB
Portland General Electric Company	POR	BBB
Southern Company	SO	A

For the 12-month period ending November 2013, BBB corporate debt costs averaged 5.01 percent.[23] We used a 20-year index to match the duration of our risk free rate assumption, 20 year US Treasury Bond used in return on equity calculations and described in further detail in Section 4.3.1 . Because the PUA uses a "real" or inflation-adjusted discount rate, we adjusted this nominal value to real using the same

21 "Moody's changes outlook on Israel Electric's Baa3 ratings to stable; affirms ratings," December 11, 2013, at https://www.moodys.com/research/Moodys-changes-outlook-on-Israel-Electrics-Baa3-ratings-to-stable--PR_288828. The S&P BBB and Moody's Baa ratings are materially the same risk categories. See, e.g., "Moody's Ratings Symbols and Definitions," 2009, p. 8 (available at https://www.moodys.com/sites/products/AboutMoodysRatingsAttachments/MoodysRatingsSymbolsand%20Definitions.pdf) and "Standard & Poor's Ratings Definitions," June 22, 2012, p. 5 (available at http://www.standardandpoors.com/spf/general/RatingsDirect_Commentary_979212_06_22_2012_12_42_54.pdf).

22 Our conclusion is supported by the fact that we use the average capital structure of the comparable firms, which is less leveraged than is IEC's. This means that there is more of a weighting of equity costs (which are higher-cost than debt) in the WACC that is based on the comparable firm capital structure.

23 Bloomberg Fair Value 20-year BBB Composite bond index.

inflation factor discussed in Section 4.3.1 .[24] The resulting value for the real marginal cost of debt after adjustment is 2.66%.

We analyzed and rejected a country risk factor for debt. (See Section 5.5 for a discussion of the country risk factor applied to equity). The IEC international credit rating and dollar denominated debt yield reflects the country risk. Thus we conclude such an adjustment is unnecessary.

Our second approach analyzed the IEC's embedded cost of debt. We evaluated IEC's embedded cost of debt for the following reasons:

- Our analysis seeks to ensure that the resulting WACC produces sufficient cash flow for IEC to pay its existing obligations; and
- Our analysis of comparable firms utilizes a much higher equity-to-debt ratio than IEC. Since equity costs are greater than debt costs, our approach ensures that IEC is capable of making its interest payments.

We compute the embedded cost of debt before and after erosion. As used here, the term erosion is an adjustment made for the effects (if any) of changes in foreign exchange rates, hedging position values, adjustments to principal for CPI-linked bonds, and other factors that might affect the cost of debt when it is evaluated in local currency. The embedded cost of debt before erosion is a measure for interest payments received by creditors, whereas embedded cost of debt after erosion is a measure of interest payments paid by debtors. Since our analysis is concerned with the burden of debt from the debtor's perspective (IEC), we use interest cost after erosion in our calculations.

As shown in below, the final embedded cost we calculate is similar to the cost of debt presented in IEC rate case.

---

24 We did not adjust this yield for currency risk. IEC's bonds mostly are denominated in new shekels, which is the same currency as the firm's revenues. As of the date of the investigation, Israel and U.S. inflation were comparable, which means that there was no need to adjust the U.S. yields for an inflation differential.

Table 19 - IEC Embedded Debt Cost - 2011

Item	Average Loan Value	Interest Before Erosion	Interest After Erosion
Local currency loans (CPI linked & unlinked)	₪20,988	₪1,153	₪1,298
Interest % of Average Loan Value		5.49%	6.18%
Foreign currency loans	₪20,546	₪1,163	₪881
Interest % of Average Loan Value		5.66%	4.29%
Total	₪41,534	₪2,316	₪2,179
Interest % of Average Loan Value		5.58%	5.25%

Table 20 - IEC Embedded Debt Cost – 2012

Item	Average Loan Value	Interest Before Erosion	Interest After Erosion
Local currency loans (CPI linked & unlinked)	₪26,404	₪1,323	₪1,255
Interest % of Average Loan Value		5.01%	4.75%
Foreign currency loans	₪20,622	₪1,267	₪1,735
Interest % of Average Loan Value		6.14%	8.41%
Total	₪47,026	₪2,590	₪2,990
Interest % of Average Loan Value		5.51%	6.36%

Table 21 - IEC Embedded Debt Cost – 2013

Item	Average Loan Value	Interest Before Erosion	Interest After Erosion
Local currency loans (CPI linked & unlinked)	₪27,628	₪1,277	₪1,196
Interest % of Average Loan Value		4.62%	4.33%
Foreign currency loans	₪23,020	₪1,316	₪1,366
Interest % of Average Loan Value		5.72%	5.93%
Total	₪50,648	₪2,593	₪2,562
Interest % of Average Loan Value		5.12%	5.06%

As shown in Table 21, the 2013 embedded cost of debt before erosion is 5.12%, (local currency debt is 4.62% and foreign currency debt is 5.72%). The embedded cost of debt after erosion is 5.06%, (local currency debt is 4.33% and foreign currency debt is 5.93%).

The IEC presents its financial statements in real terms, so no adjustment from nominal to real was needed to the embedded cost of debt.

We note that the IEC's marginal cost of debt differs from its embedded cost is a result of a number of different factors, including differences in yield on debt issues with non-investment grade ratings, differences in comparable leverage and higher prevailing interest rates in past years. These factors should be analyzed and quantified by IEC in a compliance filing.

5.3 Cost of Equity

Equity costs cannot be viewed directly in capital markets. These costs must be computed indirectly from capital market information.[25] One approach to making these inferential computations, and the approach used here, is the Capital Asset Pricing Model (CAPM). This approach is based on the understanding that the investor's required returns on a particular investment will depend on the riskiness of that investment *relative to* the riskiness of other such investments. The CAPM approach is widely used in the EU, US, and Israel.

$$k_e = r_f + \beta[E(r_m) - r_r] \qquad \textbf{Equation 1}$$

Where:

k_e	is the cost of equity
r_f	is the risk-free rate
β	is the beta coefficient (a measure of association between the stock and the overall equity market, as described in section 4.3.2)
$E(r_m)$	is the expected return on the market. The term $E(r_m)$-r_f is called the equity risk premium (ERP).

The CAPM equation says that the cost of equity is a linear function of risk, where risk is measured by beta, as discussed more fully in section 4.3.2. If the security is risk-free (β=0), then the cost of equity is the risk-free rate, r_f. If the security has the same risk as the rest of the market (β=1.0), then the cost of equity will be the same cost as the rest of the market (that is, the expected return of the stock will be the same as the expected return of the market).

The following subsections describe the components of the CAPM and how we measure them for purposes of this analysis.

5.3.1 Risk-Free Rate and Inflation Adjustment

We measure the risk-free rate using the 3-month average yield to maturity on 20-year constant-maturity US Treasury bonds.[26] We use a 20-year *bond* because a long-term bond (rather than a Treasury *bill*) is indicated when estimating the cost of equity, which itself is long-term in nature. In addition, the 20-year term of this bond also is consistent with that used by Ibbotson-Morningstar in the computation of the equity risk premium (see section 4.3.3 below).

The risk-free rate is measured in nominal terms (i.e., including the effect of inflation). The PUA use a "real" or inflation-adjusted discount rate, so we adjust the real rate for inflation. We adjust this to a real risk-free rate using 20-year Treasury Inflation-Protected Securities (TIPS). The TIPS security is issued by the Treasury. It is indexed to inflation and thereby protects investors from the negative effects of inflation.[27] We make the adjustment using the formula:

---

[25] Roger Morin, NEW REGULATORY FINANCE, (2006)(Virginia: Public Utilities Reports) (hereafter *Morin*), p. 167.

[26] "10-Year Treasury Constant Maturity Rate," Federal Reserve Bank of St. Louis, at http://research.stlouisfed.org/fred2/series/DGS10/.

[27] "Treasury Inflation-Protected Securities (TIPS)," TreasuryDirect, at https://www.treasurydirect.gov/indiv/products/prod_tips_glance.htm.

$$\mathit{Inflation\ Adjustment} = \frac{1+\mathit{Nominal\ Rate}}{1+\mathit{TIPS\ Rate}} - 1 \qquad \textbf{Equation 2}$$

The result we obtain for the real risk-free rate is 2.65%. We use this same inflation adjustment factor on debt costs as well. The reason for removing inflation from both equity and debt cost is that inflation expectations are factored into both debt and equity cost rates. While debt and equity are different in many respects, in fundamental terms they comprise the same factors:

- Time value of money. This is the cost (in real terms) of consuming now or later;
- Inflation premium. This is the cost associated with the decrease in purchasing power of money that is saved; and
- Risk premiums. This is the additional increment to both debt and equity that captures the risks associated expected amounts, timing, and certainties of future cash flows.

The inflation premium is not included in the real cost, which in theory provides values and rates in terms that are unaffected by changes in price levels. Thus, in order to make an accurate comparison we removed the inflation premium from the nominal costs of debt and equity in order to obtain a real Weighted Average Cost of Capital.

5.3.2 Beta

Beta is the risk measure or index used by the CAPM, and in fact it is one of the fundamental insights of that financial theory. Beta is a measure of correlation with market and therefore measures what is called systemic risk. Beta measures the riskiness of an asset relative to a benchmark, which is often a major market index, rather than focusing on the total riskiness of the asset itself. Beta is defined as the ratio of the covariance of the return on a portfolio (or stock) to the market to (i.e., divided by) the variance of the market.

The covariance of a stock's return to the market will be affected by (1) operational characteristics of the firm (such as the ratio of fixed to total costs) and (2) the firm's capital structure (such as the ratio of debt to total capital). Because equity is the residual security, it shares in the firm's value only after senior obligations such as debt are satisfied. The greater the proportion of senior obligations, the more volatile will be the value to the residual claimant, all else held constant.

We adjust each firm's equity beta to reflect the capital structure of the model company (see section on Capital Structure). This places all of the betas on the same footing with regard to financial leverage. This is done by a process called de-leveraging and re-leveraging.[28] We calculate asset beta by unlevering the equity betas to remove the effect that different levels of leverage would have. We then relever the asset betas using three approaches: (1) the debt/market cap ratio of the average of the capital structures of the comparable firms and a debt beta of zero, (2) using IEC's debt / equity ratio and a debt beta of zero, and (3) using IEC's debt / equity ratio and a debt beta of 0.22. We adjust beta for taxes in all three cases with either the comparable company average tax rate or IEC's effective tax rate, as appropriate (see section 4.4 below).

The convention is to use a debt beta of 0.00, which implies that the returns on debt (less the risk-free rate) are uncorrelated with the expected return on the market. This does not mean that the debt is risk free (since the debt can still have default risk) but that the expected returns are not correlated with the

---

28 *Damodaran 1996*, p. 195.

market. The debt beta example of 0.22 is calculated by Fama and French (1993) via regression of Baa corporate bond excess returns on equity risk premium. [29]We believe that this is a prudent example to show the effect of a non-zero debt beta.

We obtained historical equity betas from a number of data sources and chose to use Value Line and Bloomberg values for our analysis. Value Line uses 5 years of NYSE Composite historical performance data, while Bloomberg uses 2 years of S&P 500 historical data, to calculate beta. The median asset beta we calculated using ValueLine data is 0.48 and Bloomberg is 0.49. We calculated a mean asset beta from these data sources of 0.48 using medians within each data set.

Using IEC leverage and tax rate, and a zero debt beta, we calculated an equity beta of 1.89, whereas substituting a debt beta of 0.22 into the same calculation resulted in a much lower value of 1.24 for equity beta. Using comparable company average tax rate and leverage, and using a debt beta of zero, we calculated a value of 0.77 for equity beta, Navigant compared these values to the value in the IEC Rate case of 0.80 for tax affected equity beta.
It should be noted that although the values are similar they are based on different parameters:

- The IEC beta value is based on reported betas from European utility regulator and consultant reports from a broad time period, rather than a point market estimate; and
- The IEC's beta value reflects only T&D operations while some of the comparable firms operations also include generation.

5.3.3 The Equity Risk Premium

The equity risk premium (ERP) is the increment of expected return of the equity market (r_m) over the risk free rate (r_f):

$$ERP = E(r_m) - r_f \qquad \text{Equation 3}$$

We use an historical ERP as total return on S&P 500 less the income return on 20-year treasury bonds[30] as computed by Ibbotson-Morningstar for the period 1926-2012. Ibbotson-Morningstar is said to be the most widely used estimation service.[31] We compute arithmetic mean returns.[32] This produces an ERP of 6.2%. This value is similar to the value presented in the in IEC rate case 6.4%.

5.4 Capital Structure

In our independent analysis of WACC, we use the average of the market-based capital structures of the comparable firms and IEC's actual debt / equity ratio provided by PUA. "Market based" means that we use capital market data rather than accounting book data. The equity weight is computed as the market capitalization (share price x number of shares outstanding) divided by enterprise value. We obtained the data from SNL/RRA December 4, 2013. The average weight of debt is computed as 1-Equity Weight.

---

29 Fama, E. F.; French, K. R. (1993). "Common risk factors in the returns on stocks and bonds". Journal of Financial Economics

30 We use the income return rather than total return on bonds because the income return on treasury bonds is risk free but the total return (which includes capital gains or losses) is not.

31 Aswath Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2012 Edition, white paper, p. 22, at http://people.stern.nyu.edu/adamodar/pdfiles/papers/ERP2012.pdf.

32 Ibbotson SBBI Valuation Yearbook (2012), p. 56.

Accordingly, for our market cost analysis we compute the equity weight is 53% and the debt weight is 47%.

We use the average of the comparables as our capital structure rather than IEC's capital structure for our market cost analysis, and use the IEC's capital structure of 19% equity and 81% debt for our embedded cost analysis. Our use of the comparables' capital structure is justified for at least two reasons.

- First, the end-product WACC should be relatively unchanged whether we use one debt ratio or another, with small changes attributable to the deductibility of interest from corporate income taxes[33] The intuition for this invariance is that the value of the firm is determined by the net present value of its expected future net cash flows, not its financial structure.[34] Expected cash flows depend upon the fundamental drivers of demand and technology. The firm's value can be divided between lenders and shareholders (and taxing authorities), but the way the value is divided neither creates nor destroys value. Accordingly, and absent further analysis, changing from the modeled capital structure using our comparables to IEC's actual capital structure would not be expected to change our estimate of the overall WACC; and
- We have not performed the type of interest/coverage analysis that would be required to estimate what the rating agencies might arrive at for higher debt ratios. Accordingly, to maintain coherence with the market data that are available to us, we maintain the use of the comparables' capital structure with the confidence that our resulting pre-tax WACC would not change much (if at all) even though the components of debt and equity costs may do so.

5.5 Country Risk

The firms that we have selected as being comparably risky to IEC operate primarily in the US The IEC operates in Israel, not the US We investigated and concluded that there should be an adjustment to equity costs to account for risk differences associated with social institutions for otherwise comparable investments.[35]

We consider two methods of computing a country risk adder. The first is the difference in sovereign yields and the second involves credit default swaps.

- In the sovereign yield approach, we subtract the yield on 10-year US Treasury bonds from the yield on dollar-denominated Israeli 10-year sovereign bonds for the 12-months and 36-months ending November 2013; and
- In the credit default swap analysis, we examined data on credit default swaps for Israel and the US A CDS is an insurance policy against credit default. The buyer of the insurance policy pays a premium to the seller. If a credit issue defaults, the seller of the policy must pay off the buyer in full.[36] The yield spread on a CDS describes how much one has to pay for a risk-free investment. For example, if an Israeli treasury bond is yielding 4.00%, then one would pay to the insurer 1.21% out of that 4.00% for the insurance. The spread is 121 basis points. The 121

---

33 Modigliani, F.; Miller, M. (1958), "The Cost of Capital, Corporation Finance and the Theory of Investment," American Economic Review 48 (3): 261–297. See also, Modigliani, F.; Miller, M. (1963), "Corporate Income Taxes and the Cost of Capital: a Correction," American Economic Review 53 (3): 433–443.

34 *Morin*, p. 456.

35 The idea of country risk is detailed in Aswath Damodaran, Investment Valuation: Tools and Techniques for Determining the Value of Any Asset, (1996) (New Jersey: John Wiley) (hereafter *Damodaran 1996*), pp. 166-176.

36 See, e.g., Aswath Damodaran, "The Credit Default Swap (CDS) Market," February 12, 2010, at http://aswathdamodaran.blogspot.com/2010/02/credit-default-swap-cds-market.html

basis points may include counterparty risk as well as country risk. Accordingly, we compute the CDS spread relative to the US and without (therefore the range 90 to 121 basis points).

The average of the four figures in Table 18 is 145 basis points. The average of the 3 figures in Table 18 (using the midpoint of the CDS method) is 158 basis points, so we conclude that 150 basis points is a reasonable figure for country risk adder for equity.

Table 22 - Country Risk Premia

	5-year CDS Spreads (bps) [A]	10-Year Bond YTMs [B]	10-Year Bond YTMs [C]
Israel	121	3.84%	4.40%
US	33	2.24%	2.31%
Implied CRP (basis points)	90 to 121	160	210

[A] Bloomberg / Deutsche Bank (12 months ending 12/13/13).
[B] Bloomberg (12 months ending November 2013).
[C] Bloomberg (36 months November 2013).

5.6 Results of the Analysis

Table 19 shows the real pre-tax WACC estimates provided by IEC in their rate case, and Navigant's estimates based on: (1) market/marginal cost of debt with zero debt beta; (2) IEC's embedded cost of debt with zero debt beta, and (3) IEC's embedded cost of debt with non-zero debt beta. Navigant concludes that because IEC's request lies within the bounds of our estimates and for reasons discussed earlier, the request is reasonable.

Table 23 - Weighted Average Cost of Capital Computation and Results

Item	Rate				Notes
Cost of Equity	**IEC**		**Navigant**		
Nominal Risk Free Rate			3.47%		[A]
- Inflation Adjustment			2.29%		[B]
Real Risk Free Rate	2.64%		1.15%		[C]
+ CRP			1.50%		[D]
ERP	6.40%		6.20%		[E]
Asset Beta	0.32		0.48		[F]
Equity Beta	0.80	0.77	1.98	1.29	[G]
Real Cost of Equity	7.77%	7.40%	14.95%	10.68%	
Capital / Asset Ratio	33%	53%	19%	19%	[H]
Cost of Debt		Market ßd = 0	Embedded ßd > 0	Embedded ßd = 0	
Implied Debt Beta			0.63	0.63	[I]
Debt Beta Input Assumption			0.22		
Real Cost of Debt	4.90%	2.66%	5.06%	5.06%	
Debt / Asset Ratio	67%	47%	81%	81%	1-[H]
Tax	26.5%	32.9%	26.5%	26.5%	
Real WACC	4.99%	4.76%	5.04%	5.81%	

[A] 3-month average yield on 20-year US treasury bonds.
[B] Computed from 20-year TIPs as [1+Nominal]/[1+TIPS]-1
[C] 3-month average yield on 20-year TIPs.
[D] Average of YTM spread and CDS spread methods.
[E] Ibbotson-Morningstar 1926-2012 arithmetic average.
[F] Average of Bloomberg and ValueLine comparables median asset beta
[G] Asset beta relevered to equity beta at target capital structure and tax rate
[H] Target capital structure: Median of comparable companies / IEC level
[I] Calculated as cost of debt minus risk free rate divided by ERP

We recommend that the Israel PUA initially rely on the cost of equity and embedded cost of debt as provided by IEC until a more complete analysis and forecast is performed. We recommend that the PUA request that IEC complete a comprehensive analysis of their cost of capital. The analysis should include the approaches used in this chapter, examination and explanation of the difference between embedded cost of debt and marginal cost of debt, and a capital plan to ensure an efficient financial strategy going forward. Navigant recommends that the PUA re-examine the cost of capital during and at the conclusion of IEC's study to ensure proper compliance.

6. Review of the Recognized Cost of the Israel Electric Company

6.1 Overview and Summary of Results

Navigant reviewed the projected recognized cost for the years 2012 -2016 which was detailed in the IEC Report. In this section, we provide the recommended recognized cost for IEC for its Transmission, Distribution and Supply business segments. The description of the work performed is provided and the approach taken in developing Navigant's recommended recognized cost is described, along with the results.

6.2 General Approach to Calculation of Recognized Cost

Navigant applied a standard approach to development of recognized cost which included the development of a rate base for electric plant in use, applying a rate of return to that rate base, and using either historical or forecasted operating expenses, depreciation and taxes to calculate a revenue requirement that is at a sufficient level to generate a reasonable return on equity.

To accomplish this task, Navigant first reviewed the Annual Financial Reports of IEC for the years ended December 31, 2010, 2011, and 2012. Because many of the financial statements are primarily focused on the consolidated operations of IEC, Navigant was required to rely upon a number of the footnotes within the Financial Statements to segment assets, liabilities and operating income and expense. As part of this effort, the annual operating expenses for each year were reviewed for any anomalies that may have occurred in those years to gain a better understanding of the operations and accounting of IEC as it related to the Transmission and Distribution assets and expenses. Navigant also reviewed the accounting practices concerning cost assignment and allocations between segments, and verified segmented costs back to total company reporting as shown in the Annual Report.

Based upon this review, Navigant then developed a "test year" income statement (using 2012 financial statements), rate base, cost of capital, and revenue requirement, including identifying shortfalls for the test year for both Transmission and Distribution. As part of developing this initial Test Year Revenue Requirement, Navigant was able to review in some detail the components of costs, assess depreciation practices, and other relevant matters.

Subsequent to this effort, IEC provided the IEC Report which included forecasts for all components that are typically used to develop revenue requirements. Based upon this updated information, Navigant then developed its recommended recognized costs.

6.3 Rate Base

Provided below is a table that shows the Rate Base as developed by Navigant. As used by IEC, Navigant accepted Average Plant Investment, Net of Accumulated Depreciation as its starting point for each of the historical and forecasted years. However, Navigant did make two additional adjustments to IEC's proposed basis for developing their rate of return

Adjustments for Excess Labor Costs

A reduction of forecasted Average Plant Investment to reflect a reduction in salary levels charged to plant during the forecasted years by 34.2% to reflect salary levels supported by Navigant's benchmarking review of costs and staffing. No attempt was made to adjust rate bases for excess wages which were capitalized before 2012. The calculations detailing the reduction in investment for the years 2012 through 2016 in provided by segment in Table 24, Table 25 and Table 26 below:

Table 24 – Revised Transmission Investment (M NIS)

Item	Reference	2012	2013	2014	2015	2016
Transmission Investment per IEC	IEC Report Table 22	₪ 873	₪ 734	₪ 872	₪ 1,544	₪ 1,855
Percent Salaries		42%	42%	42%	42%	42%
Salaries in Investments		370	311	370	655	787
Salary Reduction	Section 4.1	34.2%	34.2%	34.2%	34.2%	34.2%
Adjusted Salary Cost		244	205	243	431	518
Adjustment to Transmission Plant Additions		127	106	126	224	269
Revised Transmission Investments		₪ 746	₪ 628	₪ 746	₪ 1,320	₪ 1,586

Table 25 – Revised Distribution Investment (M NIS)

Item	References	2012	2013	2014	2015	2016
Distribution Investment per IEC	IEC Report Table 23	₪ 1,206	₪ 1,156	₪ 1,285	₪ 3,364	₪ 3,329
Percent Salaries		58%	58%	58%	58%	58%
Salaries in Investments		698	669	744	1,947	1,926
Salary Reduction	Section 4.1	34.2%	34.2%	34.2%	34.2%	34.2%
Adjusted Salary Cost		459	440	489	1,281	1,268
Adjustment to Distribution Plant Additions		239	229	254	666	659
Revised Distribution Investments		₪ 967	₪ 927	₪ 1,031	₪ 2,698	₪ 2,670

Table 26 – Revised Supply Investment (M NIS)

Item	Reference	2012	2013	2014	2015	2016
Supply Investment per IEC	IEC Report Table 24	₪ 88	₪ 80	₪ 75	₪ 71	₪ 71
Percent Salaries		55%	55%	55%	55%	55%
Salaries in Investments		49	44	42	39	40
Salary Reduction	Section 4.1	34.2%	34.2%	34.2%	34.2%	34.2%
Adjusted Salary Cost		32	29	27	26	26
Adjustment to Supply Plant Additions		17	15	14	13	14
Revised Supply Investments		₪ 71	₪ 65	₪ 61	₪ 57	₪ 58

The resulting Plant in Service values are provided below in Table 27, Table 28 and Table 29 below.

Table 27 – Calculation of Plant in Service for the Transmission Segment (M NIS)

Item	2012	2013	2014	2015	2016
Assets (end of the year)	₪ 14,127	₪ 13,832	₪ 13,642	₪ 13,979	₪ 14,562
Capex	873	734	872	1,544	1,855
Less Salary Adjustment	(127)	(106)	(126)	(224)	(269)
Depreciation	907	926	940	990	1,012
Less Salary Adj. to Depreciation	-	4	4	7	9
Assets (average)	₪ 12,906	₪ 13,980	₪ 13,737	₪ 13,810	₪ 14,271

Table 28 - Calculation of Plant in Service for the Distribution Segment (M NIS)

Item	2012	2013	2014	2015	2016
Assets (end of the year)	₪ 18,181	₪ 18,035	₪ 17,948	₪ 19,341	₪ 20,579
Capex	1,206	1,156	1,285	3,364	3,329
Less Salary Adjustment	(239)	(229)	(254)	(666)	(659)
Depreciation	1,054	1,082	1,129	1,332	1,460
Less Salary Adj. to Depreciation	-	10	11	28	27
Assets (average)	₪ 17,361	₪ 18,108	₪ 17,992	₪ 18,644	₪ 19,960

Table 29 - Calculation of Plant in Service for the Supply Segment (M NIS)

Supply Plant	2012	2013	2014	2015	2016
Assets (end of the year)	₪ 515	₪ 500	₪ 478	₪ 450	₪ 419
Capex	88	80	75	71	71
Less Salary Adjustment	(17)	(15)	(14)	(13)	(14)
Depreciation	77	81	84	87	90
Less Salary Adj. to Depreciation	-	1	1	1	1
Assets (average)	₪ 512	₪ 508	₪ 489	₪ 464	₪ 435

Adjustment for Deferred Taxes

Navigant reduced Rate Base for Accumulated Deferred Income Taxes equal to approximately 9.37% of plant, which represents the year end 12/31/2012 relationship.

Table 30 – Calculation of Rate Base for Transmission (M NIS)

Transmission	2012	2013	2014	2015	2016
Average Plant Investment, Net of Acc. Depreciation	₪ 12,906	₪ 13,980	₪ 13,737	₪ 13,810	₪ 14,271
Less: Accumulated Deferred Income Taxes	1,207	1,308	1,285	1,292	1,335
Total Rate Base	₪ 11,699	₪ 12,672	₪ 12,452	₪ 12,519	₪ 12,936

Table 31 – Calculation of Rate Base for Distribution (M NIS)

Distribution	2012	2013	2014	2015	2016
Average Plant Investment, Net of Acc. Depreciation	₪ 17,361	₪ 18,108	₪ 17,992	₪ 18,644	₪ 19,960
Less: Accumulated Deferred Income Taxes	1,631	1,701	1,690	1,751	1,875
Total Rate Base	₪ 15,730	₪ 16,407	₪ 16,301	₪ 16,893	₪ 18,085

Table 32 – Calculation of Rate Base for Supply (M NIS)

Supply	2012	2013	2014	2015	2016
Average Plant Investment, Net of Acc. Depreciation	₪ 512	₪ 508	₪ 489	₪ 464	₪ 435
Less Accumulated Deferred Income Taxes	48	48	46	44	41
Total Rate Base	₪ 464	₪ 460	₪ 443	₪ 420	₪ 394

6.4 Calculation of Return

Navigant recommended the PUA rely on the debt equity structure and costs of capital requested and provided by IEC. Navigant calculated pre-tax WACC to be used for the recognized cost calculation based on the capital structure and costs of capital provided by IEC. The values used in this calculation are shown below.

Table 33 – Real Cost of Capital

Capital Component	2012	2013	2014	2015	2016
Debt	5.11%	4.96%	4.90%	4.88%	4.86%
Equity	7.77%	7.70%	7.70%	7.70%	7.70%
Weights					
Debt	66.67%	66.67%	66.67%	66.67%	66.67%
Equity	33.33%	33.33%	33.33%	33.33%	33.33%
Weighted Costs					
Debt	3.41%	3.31%	3.27%	3.25%	3.24%
Equity	2.59%	2.57%	2.57%	2.57%	2.57%
WACC	**6.00%**	**5.87%**	**5.83%**	**5.82%**	**5.81%**

Source: IEC Rate Case and WACC calculation, Navigant

This overall Cost of Capital was then applied to the Forecasted Rate Base for each year to produce the Return component of the recognized cost as shown below in Table 34, Table 35 and Table 36.

Table 34 - Calculation of Return – Transmission Segment

	Reference	2012	2013	2014	2015	2016
Total Rate Base	Table 30	₪ 11,699	₪ 12,672	₪ 12,452	₪ 12,519	₪ 12,936
Weighted Average Cost of Capital	Table 33	6.00%	5.87%	5.83%	5.82%	5.81%
Total Return		₪ 702	₪ 744	₪ 726	₪ 729	₪ 751

Table 35 - Calculation of Return – Distribution Segment

	References	2012	2013	2014	2015	2016
Total Rate Base	Table 31	₪ 15,730	₪ 16,407	₪ 16,301	₪ 16,893	₪ 18,085
Weighted Average Cost of Capital	Table 33	6.00%	5.87%	5.83%	5.82%	5.81%
Total Return		₪ 943	₪ 964	₪ 951	₪ 983	₪ 1,050

Table 36 - Calculation of Return – Supply Segment

Supply	References	2012	2013	2014	2015	2016
Total Rate Base	Table 32	₪ 464	₪ 460	₪ 443	₪ 420	₪ 394
Weighted Average Cost of Capital	Table 33	6.00%	5.87%	5.83%	5.82%	5.81%
Total Return		₪ 28	₪ 27	₪ 26	₪ 24	₪ 23

Table 37 - Calculation of Return – Transmission, Distribution and Supply Segments

Total Transmission, Distribution and Supply	References	2012	2013	2014	2015	2016
Total Rate Base	Table 34, Table 35 and Table 36	₪ 27,893	₪ 29,539	₪ 29,197	₪ 29,832	₪ 31,414
Weighted Average Cost of Capital	Table 33	6.00%	5.87%	5.83%	5.82%	5.81%
Total Return		₪ 1,673	₪ 1,735	₪ 1,703	₪ 1,736	₪ 1,824

6.5 *Overall Recognized Cost*

Navigant then developed overall recognized cost for each of the business segments as presented below. Navigant's approach to this calculation varies from that adopted by IEC in two major ways.

Labor Costs

Based upon the observations and recommendations from Chapter 5, Benchmarking, Navigant indicated that IEC salaries are considerably above the norm and recommended that wages should be reduced by 34.2%, and reflected at 65.8% of their current level. This adjustment has been reflected in the Navigant calculation reflected below. A corresponding adjustment for salary costs was also made to plant investments for the years 2013 through 2016 in the calculation of the rate base, using the four year average relationship of capitalized wages to total investment in both the Transmission and Distribution segments.

Income Taxes

Navigant adjusted the level of recognized cost to reflect deferred income taxes.

Working Capital

Navigant further notes that most utilities request a working capital component which is included in rate bases. The working capital is the level of available cash or liquid investments required to operate the utility on a day-to-day basis. Navigant did not have access to information required to make a working capital calculation and thus did not include this component.

Accordingly, Navigant made these adjustments to IEC's forecasted Revenue Requirements.

Table 38 - Summary of Transmission Recognized Cost

Item	2012	2013	2014	2015	2016
Operating Expenses	₪ 405	₪ 417	₪ 401	₪ 463	₪ 477
Less: Salary Adjustment	(86)	(89)	(85)	(98)	(101)
Depreciation Expense	907	922	936	983	1,003
Income Taxes	101	117	115	116	120
Return	702	744	726	729	751
Total Recognized Costs	₪ 2,028	₪ 2,112	₪ 2,094	₪ 2,192	₪ 2,250
Revenues Under Current Rates	₪ 1,944	₪ 1,990	₪ 1,980	₪ 2,038	₪ 2,095
Percentage Increase / (Decrease)	4.4%	6.1%	5.7%	7.6%	7.4%

Table 39 - Summary of Distribution Recognized Cost

Item	2012	2013	2014	2015	2016
Operating Expenses	₪ 713	₪ 777	₪ 868	₪ 811	₪ 821
Less: Salary Adjustment	(185)	(201)	(225)	(210)	(213)
Depreciation Expense	1,054	1,073	1,118	1,305	1,433
Income Taxes	46	54	55	57	62
Return	943	964	951	983	1,050
Total Recognized Costs	₪ 2,572	₪ 2,666	₪ 2,767	₪ 2,946	₪ 3,153
Revenues Under Current Rates	₪ 2,333	₪ 2,497	₪ 2,483	₪ 2,553	₪ 2,624
Percentage Increase / (Decrease)	10.2%	6.7%	11.5%	15.4%	20.2%

Table 40 - Summary of Supply Recognized Cost

Item	2012	2013	2014	2015	2016
Operating Expenses	₪ 695	₪ 674	₪ 599	₪ 742	₪ 758
Less: Salary Adjustment	(162)	(157)	(140)	(173)	(177)
Depreciation Expense	77	80	83	86	89
Income Taxes	1	2	1	1	1
Return	28	27	26	24	23
Total Recognized Costs	₪ 639	₪ 625	₪ 570	₪ 681	₪ 695
Revenues Under Current Rates	₪ 473	₪ 483	₪ 490	₪ 497	₪ 503
Percentage Increase / (Decrease)	35.1%	29.5%	16.1%	37.0%	38.0%

Table 41 - Summary of Transmission, Distribution and Supply Recognized Cost

Item	2012	2013	2014	2015	2016
Operating Expenses	₪ 1,813	₪ 1,868	₪ 1,868	₪ 2,015	₪ 2,056
Less: Salary Adjustment	(433)	(447)	(450)	(481)	(491)
Depreciation Expense	2,038	2,075	2,137	2,373	2,525
Income Taxes	149	173	172	175	183
Return	1,673	1,735	1,703	1,736	1,824
Total Recognized Costs	₪ 5,240	₪ 5,403	₪ 5,430	₪ 5,818	₪ 6,097
Revenues Under Current Rates	₪ 4,750	₪ 4,970	₪ 4,953	₪ 5,088	₪ 5,222
Percentage Increase / Decrease	10.3%	8.7%	9.6%	14.4%	16.7%

6.6 Recommendations for Future Recognized Cost Calculations

Israel has traditionally used an approach to calculating recognized costs based upon real (i.e., adjusted for inflation) costs. Navigant has been informed that the real cost approach was implemented because the IEC maintains its accounting records on an inflation adjusted basis. The accounting policies dated back to a time in Israel's history when hyper-inflation challenged the macro economy.

Navigant suggests that the PUA and the IEC evaluate abandoning the real cost approach to calculating recognized cost and adopt the more conventional approach of performing the calculation in nominal terms. Navigant is suggesting the methodology change for the following reasons:

- The IEC is in the process of moving from US GAAP to IFRS accounting standards. The IFRS standards do not allow the indexation of balance sheet accounts for inflation.
- The rate of inflation in Israel in recent years has been moderate and relatively similar to other developed nations. Adoption of procedures to account for inflationary changes is no longer necessary.
- Navigant is concerned that the calculation of forecasted income taxes in real terms may introduce potential inaccuracies that are subtle and difficult to correct.

Implementation of the recommended adoption of the calculation of recognized costs in nominal terms should be documented in advance by the PUA outlining the processes, procedures and calculations in order to avoid ambiguity as the new approach is implemented.

6.7 Implementation of Functional Separation Rules

Traditionally, the IEC has operated as a vertically integrated utility with all operations reviewed by the PUA. Recently, the IEC has created a subsidiary offering unregulated communications services to consumers. The movement from a purely regulated company to an organization which offers both regulated and unregulated services requires that rules be established that ensure that no cross-subsidization occur between the two different set of services. These rules were unnecessary in the past because all operations of the IEC were under the jurisdiction of the PUA.

Navigant did not feel that it was necessary to adjust the recognized costs examined in this report for potential impacts of unregulated operations because these businesses are in their infancy and not yet operational. However, it is important that rules be established in order to allow the IEC and the PUA to have a common understanding of under what circumstances transactions can occur and how will goods and services be priced when transactions occur. Otherwise the Israeli electricity consumers will cross subsidize other markets. Several examples of documents exists which provide the rules and regulations under which utilities may operate. Navigant suggests that a good example of such a document is the Ontario Energy Board (OEB) Affiliates Relations Code[37]. The OEB's document is straightforward and clearly written and captures all important policies which exist for this issues related to affiliate transactions and behavior.

[37] http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2007-0662/Attachment_C_20080516.pdf

7. Proposed Pricing Design

Pricing design is important to an electric utility because it provides customers with information on the efficient use of the various functions of the electric power system. Pricing electric service introduces complexities because in Israel service has been separated into four functions (i.e. generation, transmission, distribution and supply).

Navigant scope of work limits our involvement to the transmission, distribution and supply functions. The generation function excluded in our analysis. However, information about generation prices have been included in calculating the impacts of proposed tariff changes for customers.

Navigant believes that the distribution and transmission tariffs can be significantly improved and have recommended a number of changes based upon the following analyses. The pricing design chapter is organized as follows:

- Establishment of underlying pricing design principles;
- A discussion of the attributes of natural monopolies;
- Estimations of marginal costs; and
- Development of proposed electricity tariffs.

7.1 Underlying Principles (Bonbright's Criteria)

The pricing strategy proposed by Navigant is based upon a set of principles established to meet the needs of the utility and the customers with the objective of providing service in a safe and reliable manner in the most efficient style possible. Navigant met with the PUA and the IEC at this kick-off of this project to: (1) Develop a working knowledge of the electric power sector in Israel; (2) Identify the goals of the pricing design change or known shortcomings. Furthermore, guidance was sought from industry accepted sources such as Bonbiright[38] in developing the guiding principles. Based upon these meetings and the research of the team the following goals were identified.

Provide the Level of Revenue Required to Preserve the Financial Integrity of the Utility

If the financial integrity of the utility is threatened the organization will not be able to operate efficiently and in the extreme case will fail. An electric utility is capital intensive and therefore any action that increases the cost for the utility to attract capital will also increase the rates faced by customers. Therefore it is critical that the tariffs that are developed and offered by the utility produce the level of revenues necessary to sustain the operations and prudent capital investment necessary to sustain the day-to-day business of the enterprise.

NCI proposes that the tariffs that result from this effort should provide the IEC with the level of revenues required to maintain the strong financial position of the organization in a stable and predictable manner. The tariffs should therefore:

- Design tariffs that realistically will provide the utility with the identified level of recognized revenues;

---

[38] Bonbright, James C., Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Public Utilities Report, 1988

- Establish pricing designs and rate adjustment mechanisms that will minimize the probability of cash flow volatility;
- Establish and maintain the relationship between changes in revenues and costs.

Avoid Undue Price Fluctuations

Customers prefer price stability versus volatility if all else is held equal. It therefore follows that one of the critical goals of a utility's tariffs is to provide the acceptable level of price stability desired by customers.

Allocate Costs to Specific Tariff / Customer Classes in a Reasonable, Equitable and Defendable Manner

Cost allocation is a complex and contentious issue. The utility often finds themselves in the middle of a debate between various customer groups regarding what is the "fair" cost allocation. Arguments by specific customer classes are often driven by what allocation approach will provide them with the most favorable (i.e. lowest) allocation of costs.

It is the opinion of Navigant that no single "correct" approach to the cost allocation issue exists. A number of approaches are generally accepted by the industry. Various approaches may or may not be appropriate given the specific circumstances of the utility.

In performing a cost allocation study, the following conditions are required to be met:

- Transparency – any reasonably informed party could audit and reproduce the results. All work papers, supporting calculations and source data are either supplied or reasonably accessible to interested parties;
- Relevant Test Period Interval– the data used for the test year will match or be reasonably similar to the test year used to estimate the level of the recognized revenues. Furthermore, if a historical test year is chosen the situation and circumstances associated with the test year for the level of recognized revenue will be reasonably similar that of the cost of service analysis. For example, if the recognized revenue includes a major new investment which was not included in the historical test year for the cost of service analysis the test year for the cost of service analysis would be considered irrelevant and the results from such an analysis could be criticized or rejected; and
- Accurate – all input data must be from a defendable source. Where assumptions or forecasts have been used, the assumptions or forecasts must be defendable.

Develop Electricity Tariffs that Encourage Customers to Use Electricity in an Efficient Manner

Optimally electric power tariffs should be designed so that the change in a specific customer's usage – either an increase or a decrease – will have little or no economic impact on other customers of the utility or the financial performance of the utility. If a change in a specific customer's behavior is triggering an increase or decrease in another customer's tariff a cross-subsidy exists and the utility tariff should be reviewed. Further, if a change in customer usage triggers a significant change in the financial performance of the utility (either positive or negative).

An ideal situation would exist if the utility tariff was established at marginal cost. However, the following problems exist even if marginal cost pricing is applied: (a) prices established at marginal cost will not necessarily produce the recognized revenue; (b) even if prices are set at marginal cost the price of electricity is sometimes volatile and it is not always practical to establish tariffs that change with the volatile nature of electricity costs. In these situations Demand Side Management (DSM) and utility sponsored energy efficiency programs can be very valuable and when properly implemented can reduce the long-run average prices of electric power to the customer.

Maintain a System of Tariffs that is Understandable to Customers and not Unduly Burdensome to Administer by the Utility

One of the primary goals of pricing is to provide information to the customer on the cost of consuming that commodity at a specific point in time. A tariff that a customer does not understand or is difficult for the utility to explain to the customer fails to provide the customer information about the cost of the commodity. The customers will not react properly to the price signal in the tariff and could potentially increase the average system cost to all customers by over- or under-consuming the commodity. It is, therefore, critical that electric tariffs be designed in a manner that is clearly understandable to the customers.

Tariffs that are easier for customers to understand often have the following attributes:

- They have as few elements as possible that send the correct price signal to the customer;
- Inter-relationships between tariff elements are minimized. For example, the pricing of one tariff elements (e.g. the energy charge) is unrelated to another tariff element (e.g. the demand charge). An example of a tariff that is overly-complex is a load factor tariff with multiple blocks of usage;
- Cost components that have similar characteristics (e.g. generation and transmission capacity costs) are bundled together and cost components that are dissimilar (e.g. distribution capacity costs) are captured in a separate tariff element;
- The presentation of tariffs to customers is clearly stated in the tariff sheets but more importantly simple explanations are readily available through customer service literature or over the internet.

The utility must recognize that customer education programs are required on an ongoing basis. If a significant change in tariffs is planned a special emphasis must be made to provide customers with the information they require to understand and utilize the tariff efficiently.

Tariffs must also be reasonably easy for the utility to administer. Criteria that a Pricing Department should consider before administering a change or adding a new tariff design would include the following:

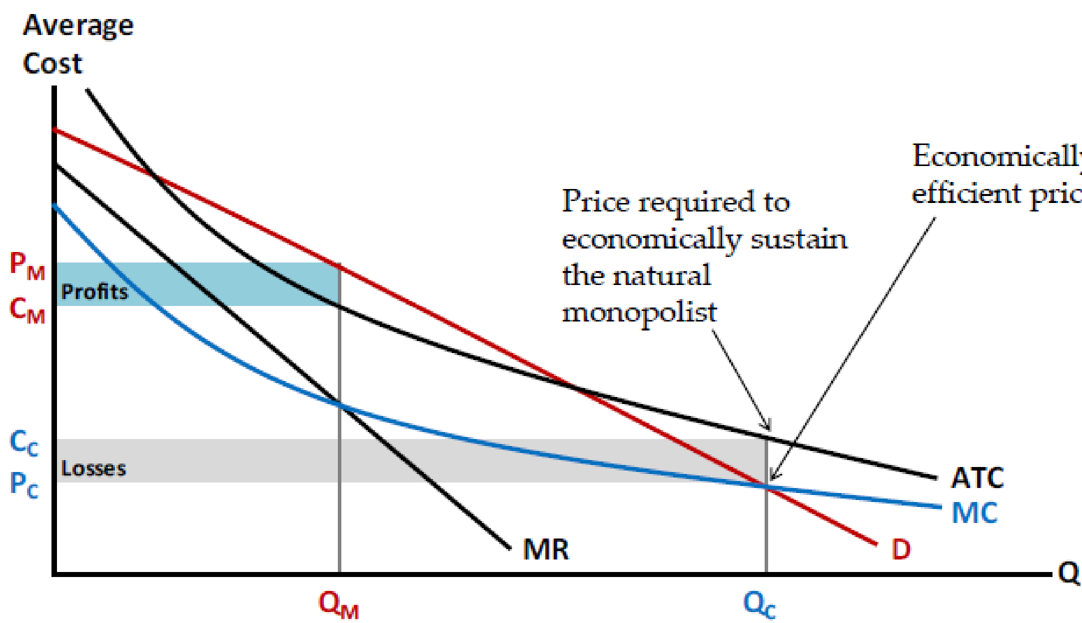
- Can the existing Billing and Customer Service Systems accommodate the proposed tariff design;
- Are any new Customer Service resources or tools required to support the proposed tariff change; and
- Finally, recognize that customer education is required and may require implementing a formal customer education program.

7.2 *Theory of Natural Monopolies*

Any examination of electric distribution and transmission systems should start with the recognition that these systems are "Natural Monopolies". A natural monopoly is defined as an industry where the economies of scale are so important that only one firm can survive. Examples of natural monopolies outside of the electric power industry include water distribution systems, natural gas distribution systems and public transit systems.

An attribute of natural monopolies is that the ratio of fixed to variable costs is very high. The high ratio of fixed to variable costs triggers significant economies of scale as the average cost per unit decreases. Further, natural monopolies introduce special challenges when establishing prices because of the firm cannot simultaneously set prices at marginal and average.

Figure 8 – Cost Behavior of a Natural Monopoly



If prices are established at marginal cost for a natural monopoly the firm cannot be economically sustained. However, if prices are established at average cost an inefficient price signal is being sent to customers because prices are too high and customers would presumably under-consume services.

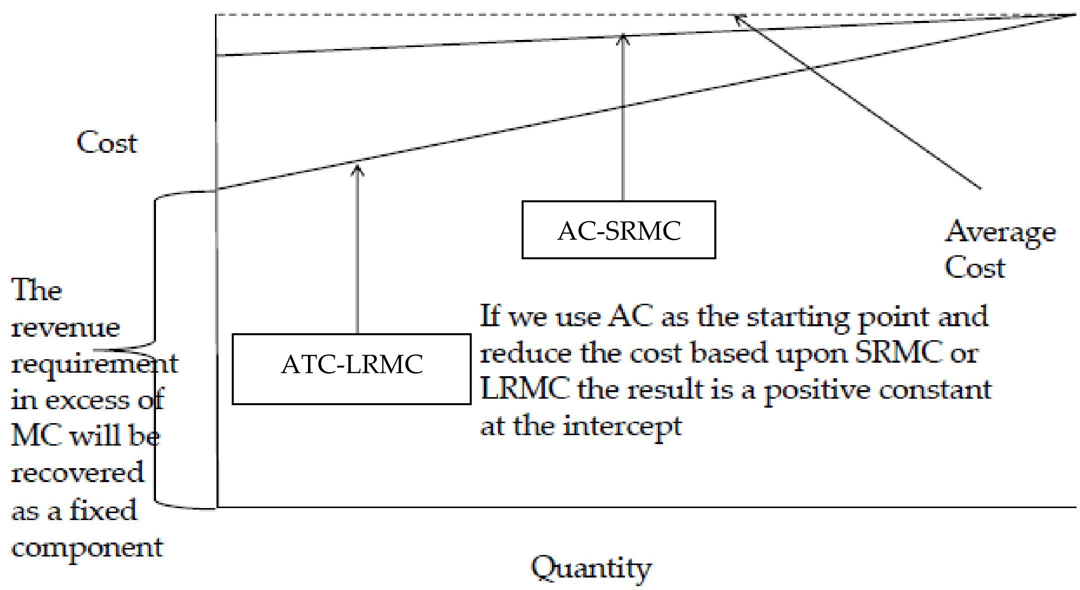
Baumol and Bradford[39] suggested a solution to this problem which is referred to as "Second Best Pricing". Second best pricing suggests that a two-part pricing approach is adopted. The strategy for the two-part pricing is as follows:

- The price for the commodity is established at marginal cost; and
- The remainder of the cost of production is recovered through a price inelastic component such as a fixed charge[40].

[39] Baumol, William J. and David F. Bradford, Optimal Departures from Marginal Cost Pricing, The American Economic Review, June, 1970, p. 265-83.

[40] In the case of public transit the difference is often provided through a lump-sum subsidy from general revenues.

Figure 9 – Illustration of Two Part Pricing



The conflicting goals of setting prices equal to marginal cost and providing the sustainable level of revenues are able to be achieved simultaneously.

7.3 Proposed Tariff Design for the IEC

Navigant reviewed the existing tariff design of the IEC. Our review included limited cost-of-service data and therefore we have not included any comment of the cost basis of tariffs. However, we were able to comment about the overall structure and suggest some changes to the overall tariff design.

7.4 Existing Tariff Design

The existing tariff design is summarized in Table 42, Table 43 and Table 44 below.

Table 42 - IEC Transmission Function Consumption Tariff as of April 1, 2012

	Winter			Spring/Autumn			Summer		
Rate Class	Off Peak	Shoulder	Peak	Off Peak	Shoulder	Peak	Off Peak	Shoulder	Peak
Residential	0.0346	0.0346	0.0346	0.0346	0.0346	0.0346	0.0346	0.0346	0.0346
General	0.0373	0.0373	0.0373	0.0373	0.0373	0.0373	0.0373	0.0373	0.0373
Street lighting	0.0283	0.0283	0.0283	0.0283	0.0283	0.0283	0.0283	0.0283	0.0283
Low V TOU	0.0238	0.0278	0.0564	0.0216	0.0302	0.0361	0.0304	0.0492	0.1000
Low V TOU / Collective Sale	0.0235	0.0275	0.0555	0.0214	0.0299	0.0356	0.0301	0.0485	0.0983
Low V Bulk (PA)	0.0337	0.0337	0.0337	0.0337	0.0337	0.0337	0.0337	0.0337	0.0337
Med V Bulk (PA)	0.0317	0.0317	0.0317	0.0317	0.0317	0.0317	0.0317	0.0317	0.0317
Med V TOU	0.0231	0.0269	0.0540	0.0211	0.0293	0.0349	0.0295	0.0473	0.0957
Med V TOU / Collective Sale	0.0230	0.0266	0.0535	0.0210	0.0290	0.0346	0.0293	0.0468	0.0946
Med V Bulk TOU (PA)	0.0230	0.0266	0.0535	0.0210	0.0290	0.0346	0.0293	0.0468	0.0946
High V TOU	0.0083	0.0102	0.0257	0.0075	0.0125	0.0165	0.0131	0.0239	0.0559

Table 43 - IEC Distribution Function Consumption Tariff as of April 1, 2012

Rate Class	Winter			Spring/Autumn			Summer		
	Off Peak	Shoulder	Peak	Off Peak	Shoulder	Peak	Off Peak	Shoulder	Peak
Residential	0.0722	0.0722	0.0722	0.0722	0.0722	0.0722	0.0722	0.0722	0.0722
General	0.0733	0.0733	0.0733	0.0733	0.0733	0.0733	0.0733	0.0733	0.0733
Street lighting	0.0695	0.0695	0.0695	0.0695	0.0695	0.0695	0.0695	0.0695	0.0695
Low V TOU	0.0674	0.0695	0.0865	0.0660	0.0698	0.0719	0.0697	0.0789	0.1025
Low V TOU / Collective Sale	0.0314	0.0334	0.0500	0.0301	0.0338	0.0358	0.0336	0.0426	0.0658
Low V Bulk (PA)	0.0717	0.0717	0.0717	0.0717	0.0717	0.0717	0.0717	0.0717	0.0717
Med V Bulk (PA)	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
Med V TOU	0.0088	0.0091	0.0126	0.0086	0.0092	0.0096	0.0092	0.0110	0.0159
Med V TOU / Collective Sale	-	-	-	-	-	-	-	-	-
Med V Bulk TOU (PA)	-	-	-	-	-	-	-	-	-
High V TOU	-	-	-	-	-	-	-	-	-

Table 44 - IEC Supply Function Fixed Tariff as of April 1, 2012

Rate Class	Monthly Customers	Bi-Monthly Customers
Residential	13.49	13.49
General	56.96	13.49
Street lighting	56.96	13.49
Low V TOU	157.60	56.96
Low V TOU / Collective Sale	-	-
Low V Bulk (PA)	-	-
Med V Bulk (PA)	-	-
Med V TOU	292.77	-
Med V TOU / Collective Sale	-	-
Med V Bulk TOU (PA)	-	-
High V TOU	294.30	-

Navigant's offers the following comments regarding the existing tariff design:

Overly Reliant on Volumetric Pricing

The existing tariff design is overly reliant on volumetric pricing, which tends to send incomplete price signal to customers when used as the dominant tariff type. Over reliance on volumetric pricing can cause volatility in revenue and peak demand growth. Transmission and distribution tariff structures should be more heavily weighted to fixed and demand tariffs such that customers are sent the proper price incentives and the cost of service is fairly distributed.

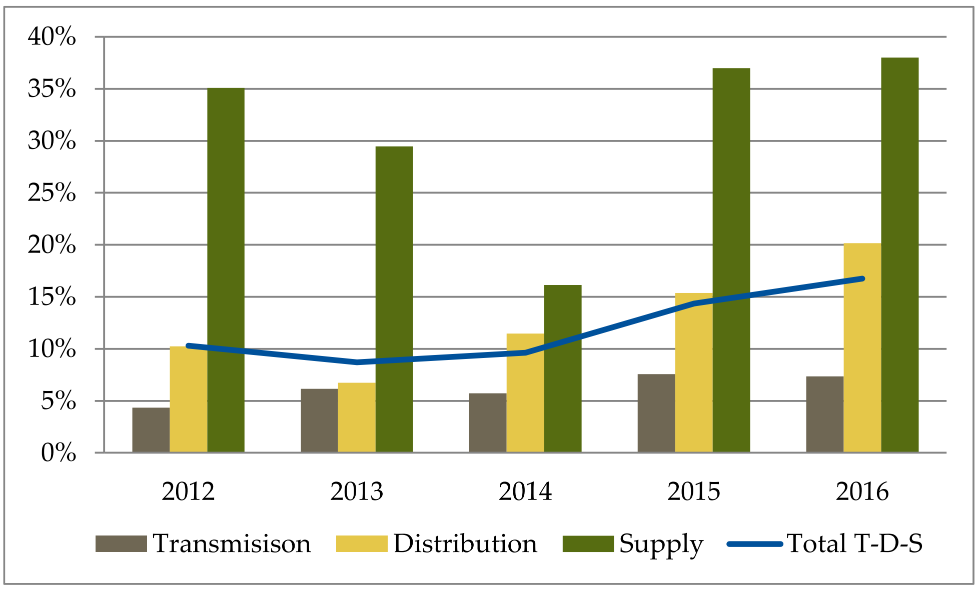
Prices are Reflecting Average Cost Analysis

The existing tariffs overly rely upon volumetric pricing which essentially becomes average cost pricing. From a theoretical standpoint prices should be established at marginal costs, preferably short-run marginal cost.

7.5 Targeted Level of Recognized Costs

Navigant has previously discussed the deficiencies which occurred since 2012 for the IEC tariffs. Rebilling of customers for previous time periods is impractical and not recommended. Navigant has designed tariffs which will recover the estimated revenue deficiencies for the years 2015 and 2016. The PUA has informed Navigant that a regulatory liability exists for the years 2012 through 2014 which will offset the deficiencies for those time periods and will be treated outside of this report. The annual rate increase required to cover recognized cost is provided in Figure 10 below.

Figure 10 – Projected Rate Increases Required

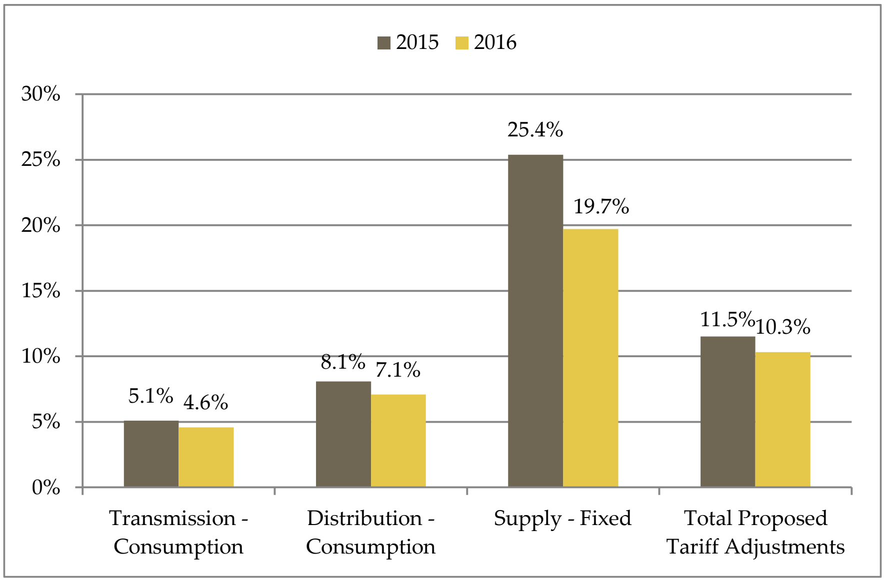


7.6 Proposed Tariff Designs

7.6.1 Implementation of Tariff Adjustments for the Time Period 2012 through 2016

Navigant proposes that tariffs adjustments be implemented on January 1, 2015 and January 1, 2016. The two year adjustment period incorporates levelized recovery of total TD&S deficiency or surplus relative to actual tariff recognized cost for the years 2012 (excluding regulatory assets). The proposed rate increases are shown in Figure 11

Figure 11 – Proposed Rate Increases for January 1, 2015 and January 1, 2016 (Excluding Generation)



7.7 Proposed Tariff Designs – Scenario 1

Navigant's status quo case is to retain the existing volumetric tariff design for transmission and distribution, and the fixed monthly tariff for supply. Under this scenario, all tariffs are adjusted to recover segment recognized cost such that the transmission segment, distribution and supply functions experience a rate increase. Pro Forma rate adjustments and revenue are depicted in below.

The advantages of the status quo tariff design are that customers have familiarity with the current tariff design and any changes to the company's Customer Information System (CIS) system will be minimal and IEC did not provide the cost of service study for a different tariff structure. These tariffs were developed by PUA based on TOU models. The disadvantage is that the tariff design would not accurately reflect cost of service and sends poor price signals to customers. The customer impacts are not uniform in this scenario, as illustrated in Figure 12 below.

Figure 12 – Overall Customer Bill Impacts by Tariff Class for Scenario 1 – Production Component Not Included in the Bill Impacts

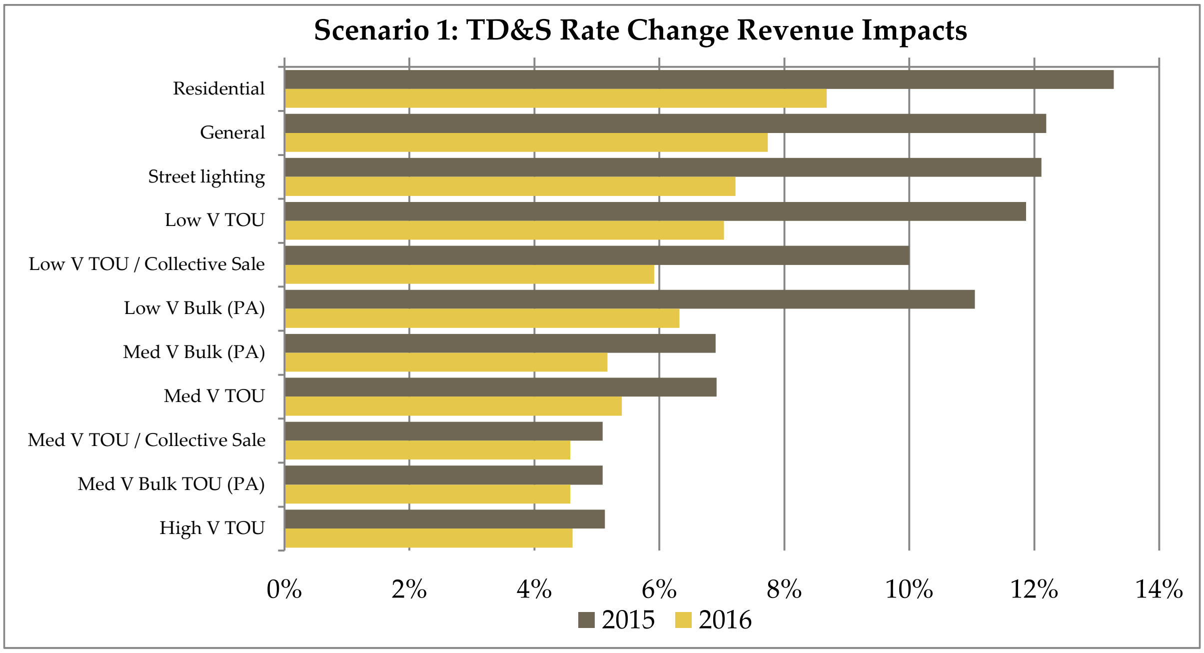
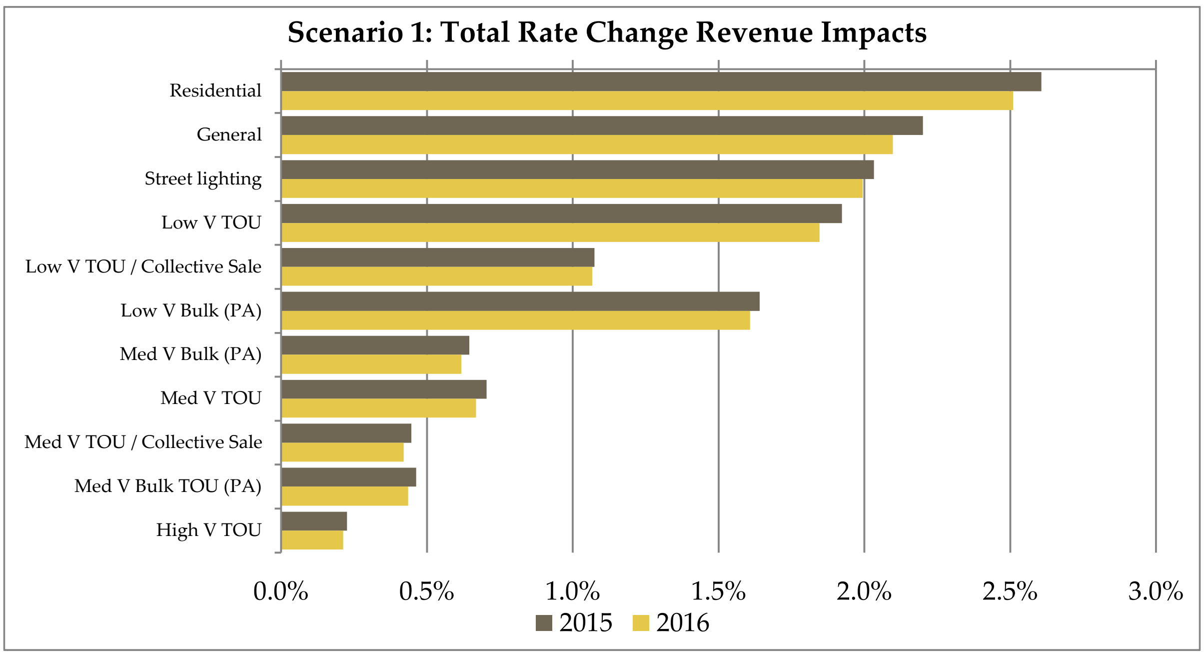


Figure 13 – Overall Customer Bill Impacts by Tariff Class for Scenario 1 – Production Included



The rate increases were allocated equally across all tariff classes by segment. However, the impact of the increases differed because not all tariff classes equally use each segment in a proportionate manner. For example, the supply charge is a larger percentage of the total bill for residential customers than medium and high voltage customers. Navigant analyzed bill impacts on actual meter data for each customer class and found the impacts were roughly in line with our expectations based on billing determinants. Because scenario 1 does introduce any new tariffs, but rather adjusts existing tariffs, the impacts were consistent with the impacts we calculated from billing determinants.

7.8 Proposed Tariff Designs – Scenario 2

Navigant prepared an alternative tariff design based upon the following principles:

- The allocation of recognized costs remained identical to Scenario 1. Therefore, the impacts on tariff classes as a whole were unchanged;
- The supply recognized costs were allocated based upon information provided by the IEC;
- A distribution fixed charge was implemented based upon 25% of the distribution recognized costs for tariff classes without demand meters. Tariff classes with demand meters received distribution charges equal to 10% of the distribution recognized cost;
- Customers with meters capable of registering demand readings will receive distribution demand charges equal to 15% of recognized cost; and
- Customers with meters capable of registering demand readings will receive transmission demand charges equal to 25% of recognized cost.

Navigant chose these allocation levels to illustrate the effect of introducing new charge types and recommends that PUA and IEC use this type of analysis and approach to setting rates in the future.

Table 45 – Allocation of Recognized Revenue by Tariff Element

Rate Class	Type	Transmission Revenue %			Distribution Revenue %		
		Volume	Fixed	Demand	Volume	Fixed	Demand
Residential	Non-TOU	100.00%	0.00%	0.00%	75.00%	25.00%	0.00%
General	Non-TOU	100.00%	0.00%	0.00%	75.00%	25.00%	0.00%
Street lighting	Non-TOU	100.00%	0.00%	0.00%	75.00%	25.00%	0.00%
Low V TOU	TOU	75.00%	0.00%	25.00%	75.00%	10.00%	15.00%
LV TOU Collective	TOU	100.00%			100.00%		
Low V Bulk (PA)	Non-TOU	100.00%			100.00%		
Med V Bulk (PA)	Non-TOU	100.00%			100.00%		
Med V TOU	TOU	75.00%	0.00%	25.00%	75.00%	10.00%	15.00%
MV TOU Collective	TOU	100.00%			100.00%		
MV Bulk TOU (PA)	TOU	100.00%			100.00%		
High V TOU	TOU	75.00%	0.00%	25.00%	0.00%	0.00%	0.00%

7.8.1 Implementation of Demand Charges

Demand charges are used globally for sending price signals to customers for the distribution and transmission segments. The advantages of using demand charges included:

- Cost causality related to the distribution and transmission segments are related to peak and non-peak demand and not energy consumption.
- The implementation of demand charges reduces cross-subsidies which are transferred from low-load factor to high-load factor customers.

- The price signal to customers is muted which triggers increased load growth which further increases the level of CAPEX required by the company.

Navigant believes the current volumetric rate design for the customers with demand meters can be improved if a demand charges are gradually introduced. Relying upon a volumetric tariff design for distribution and transmission has the following shortcomings:

- The pure volumetric charge is set at average cost which exceeds the marginal cost;
- A pure volumetric charge introduces volatility to the revenue stream of the company; and
- The bills faced by consumers are also very volatile.

Another question which arose during the tariff design is what is relevant measure for demand for a tariff with an explicit demand charge? Generally, lower voltage investment, such as distribution, do not have the opportunity to use diversity of customer load to reduce investment. In other words, the utility must serve the peak load for the customer regardless of when in occurs. In the case an annual peak demand (i.e. maximum demand measured in the previous year) is justified. However, in developing a tariff other considerations (i.e. Bonbright's Criteria) should be considered. For example, would such a tariff design considerations should be evaluated such as customer understanding of the tariff and administrative considerations such as such as billing system capabilities and availability of data. As a result, Navigant recommends that monthly demand reading be used for determination of billing demands for T&D services.

An impediment to implementing demand charges is the negative impact on customers with low load factors relative to high load factor customers. Navigant therefore suggests that the movement to demand charges occur gradually to avoid adverse customer impacts. Navigant also suggests that demand charges be implemented only in rate classes with higher load in order to send the proper price signal to the appropriate customers. The potential demand charges per kW-month calculated based on non-coincident peak load can be reviewed in the appendices.

7.9 Scenario 2 Bill Impacts

The following graphs illustrate overall bill impacts based on IEC billing determinants with and without the production function.

Figure 14 - Overall Customer Bill Impacts by Tariff Class for Scenario 2– Production Not Included

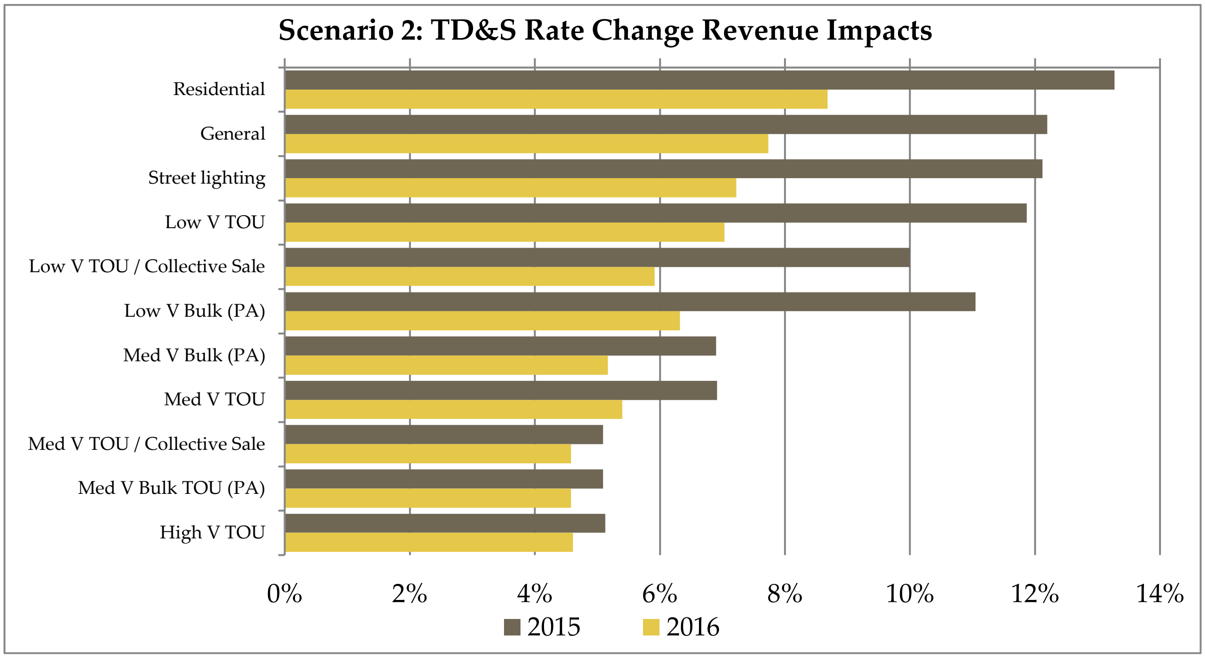
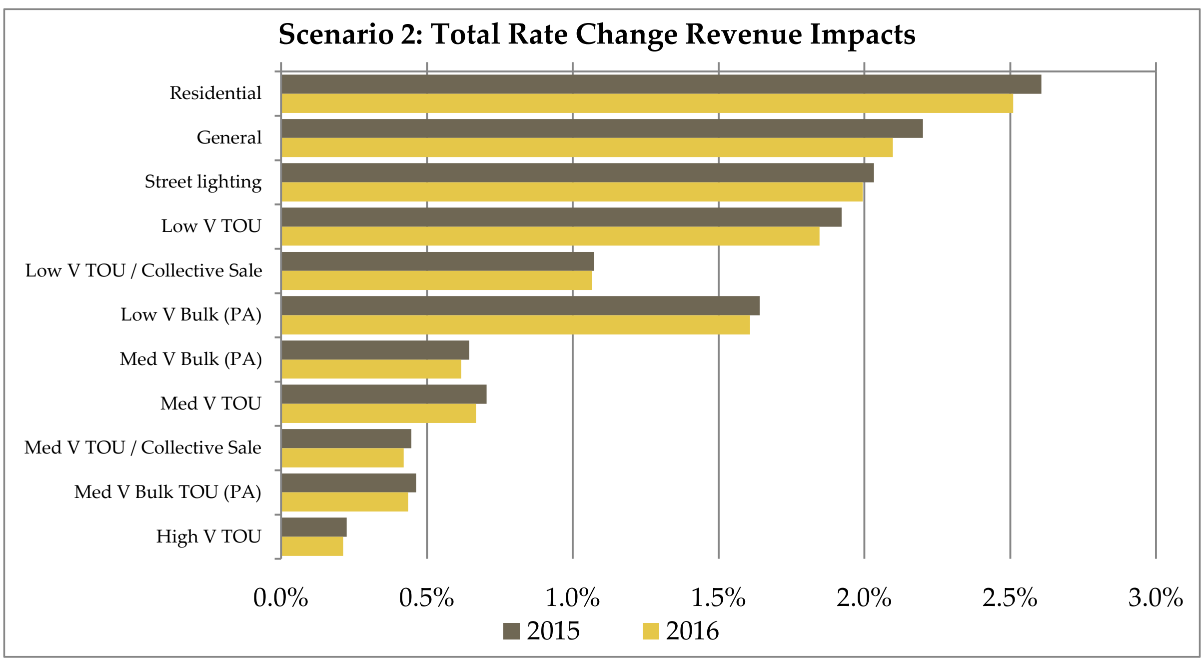


Figure 15 - Overall Customer Bill Impacts by Tariff Class for Scenario 2– Production Included



Given the changes in pricing design for Scenario 2, Navigant performed a detailed customer impact analysis on actual meter data samples for various tariff classes. The objective of the analysis was to ascertain if any specific subgroup of customers were adversely impacted. The meter data provided by IEC was limited with respect to the amount of data available relative to the number of total customers in each rate class, as illustrated in the table below.

Table 46 – 2012 Meter Data and Total Customer Count by Rate Class

Rate Class	Type	Number of Meters in IEC Demand Data	Number of Meters in Customer Impact Analysis	Year End 2012 Customer Count
Residential	Non-TOU	1,841	1,770	2,227,138
General	Non-TOU	2,161	1,974	243,594
Street lighting	Non-TOU			5,980
Low V TOU	TOU	28,825	26,565	62,762
LV TOU Collective	TOU	106	87	
Low V Bulk (PA)	Non-TOU			
Med V Bulk (PA)	Non-TOU			
Med V TOU	TOU	1,147	1,139	3,282
MV TOU Collective	TOU	29	29	
MV Bulk TOU (PA)	TOU			
High V TOU	TOU	75	72	42
Total		34,184	31,636	2,542,798

The meter data provided by IEC was unrefined and required revision before the customer impact analysis could be performed. Data points were removed from the set if determined to be erroneous or unrepresentative. Any meters with negative electricity consumption values or zero consumption for the entire period of record were removed from the analysis. Customers with very low but non-zero consumption in at least a few months of the year were left in the sample set. These customers appear to have very large bill impacts on a percentage basis, but on an absolute basis are not severely impacted.

The graphs below illustrate bill impacts for Scenario 2 using the meter data provided relative to the T&D portion of the bill only, and for the total bill including production. A brief discussion is included below each set of graphs.

Figure 16 - Residential Customer Bill Impacts for Scenario 2 – Transmission, Distribution & Supply

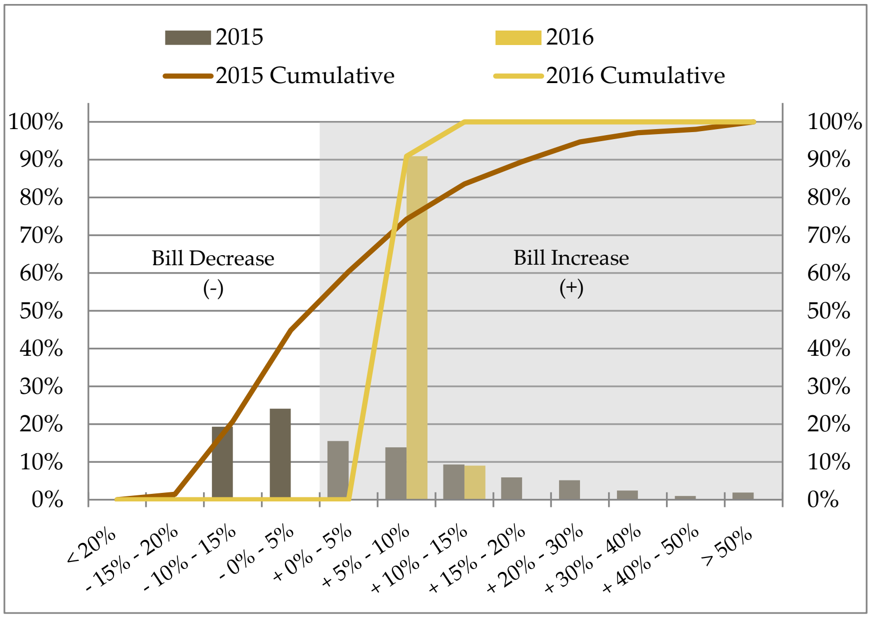
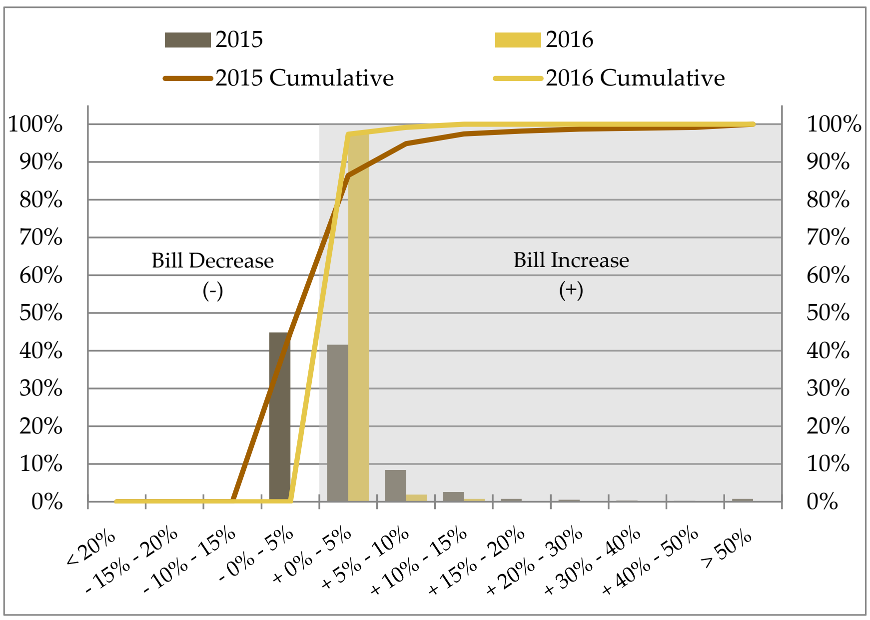


Figure 17 - Residential Customer Bill Impacts for Scenario 2 – Total Including Production



Navigant included 1,770 residential meters with 2012 usage data in its customer impact analysis. Including production, 95% of this sample would see a bill increase in 2015 of 10% or less with a mean increase of 2.4% and 99% would experience an increase of 10% or less with a mean increase of 2.4% for 2016. The most significant increases occurred for smaller customers due to the introduction of the distribution fixed charge.

Figure 18 - General Customer Bill Impacts for Scenario 2 – Transmission, Distribution & Supply

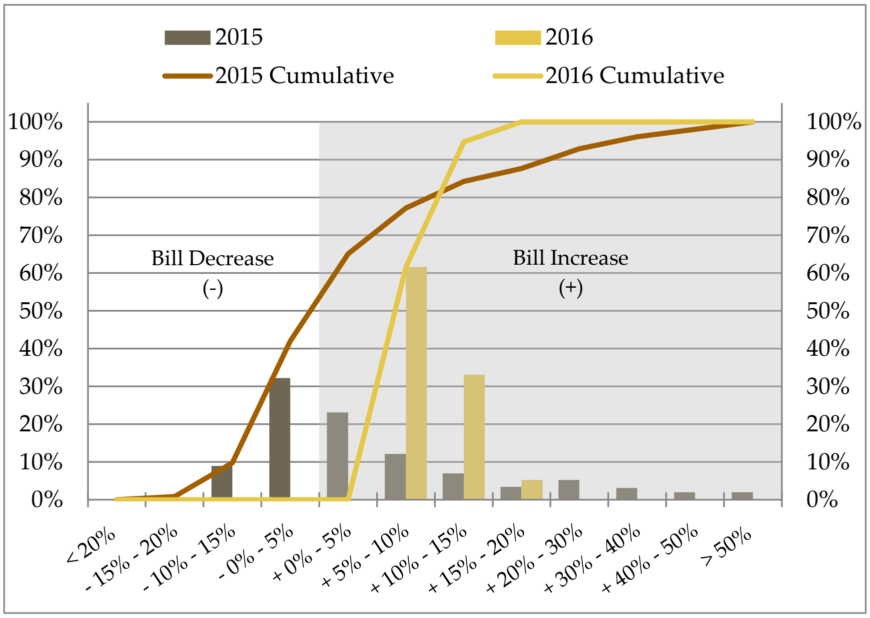
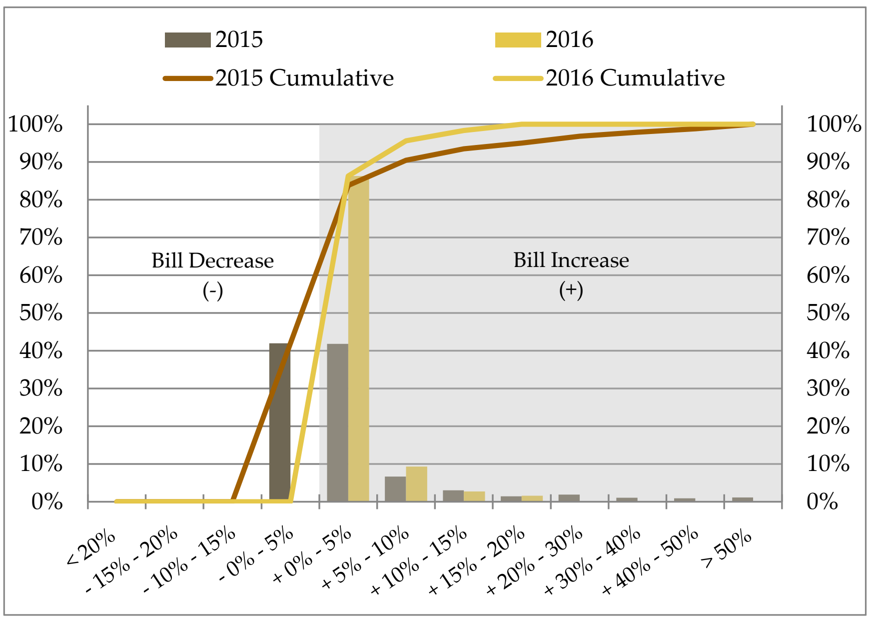


Figure 19 - General Customer Bill Impacts for Scenario 2 – Total Including Production



Navigant included 1,974 general tariff meters with 2012 usage data in its customer impact analysis. Including production, 94% of this sample would see a bill increase in 2015 of 10% or less with a mean increase of 3.3% and 98% would experience an increase of 10% or less with a mean increase of 3.6% for 2016. The most significant increases occurred for smaller customers due to the introduction of the distribution fixed charge.

Figure 20 - Low Voltage TOU Bill Impacts for Scenario 2 – Transmission, Distribution & Supply

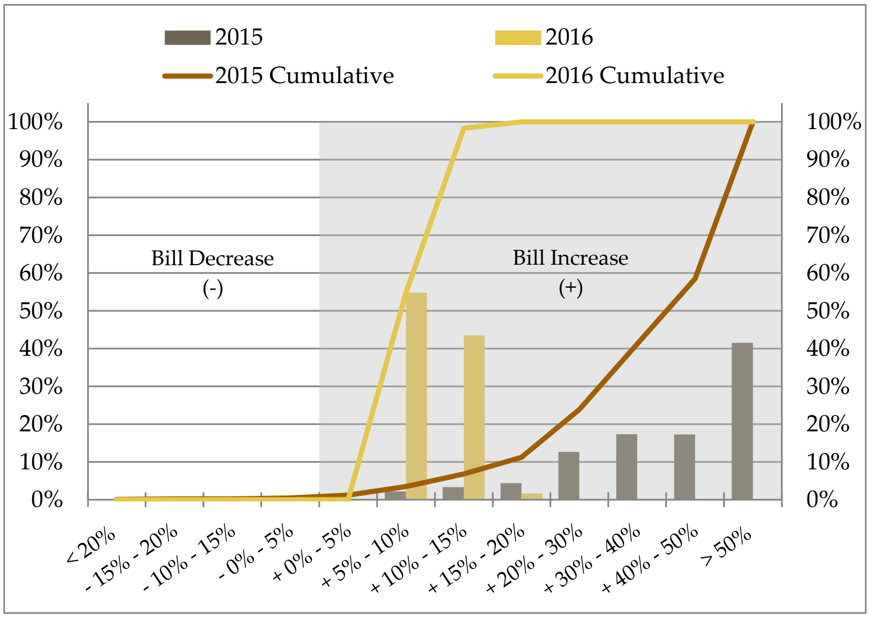
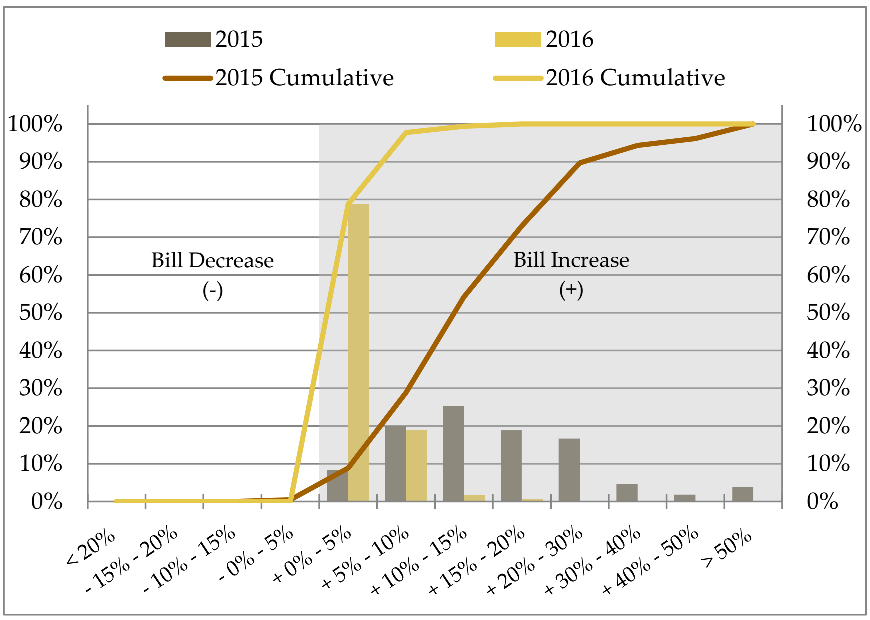


Figure 21 - Low Voltage TOU Bill Impacts for Scenario 2 – Total Including Production



Navigant analyzed rate impacts for 26,565 of the 28,825 Low Voltage TOU meters for which IEC provided data. The results of the analysis indicated severe rate impacts on these customers for Scenario 2 rate changes, which is not consistent with our results from analysis of billing determinants. The load factor for revised average meter data is 38% versus 59% based on billing determinants. We believe this discrepancy between the meter data and billing determinants should be reexamined and analyzed by IEC.

Figure 22 - Low V TOU Collective Sale Bill Impacts for Scenario 2 – Transmission, Distribution & Supply

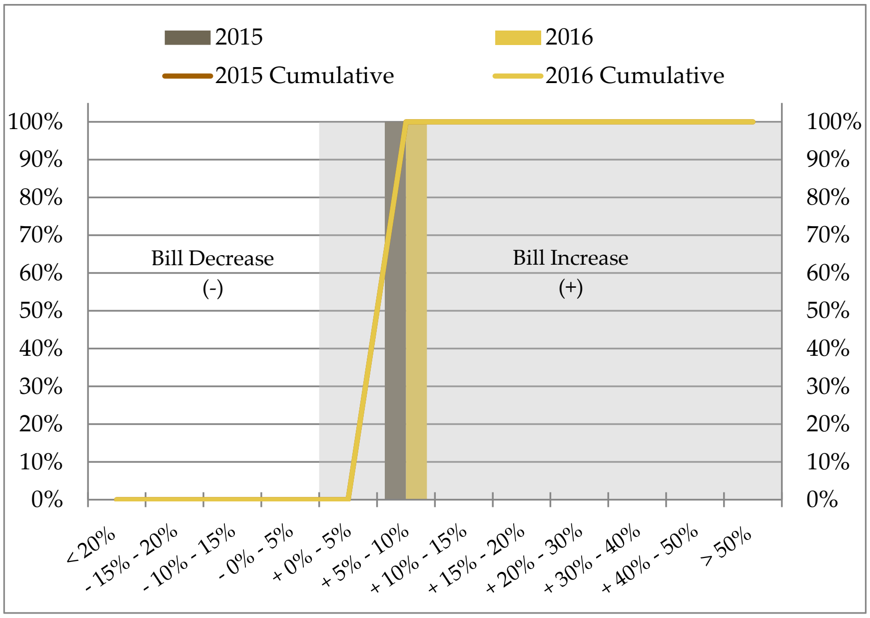
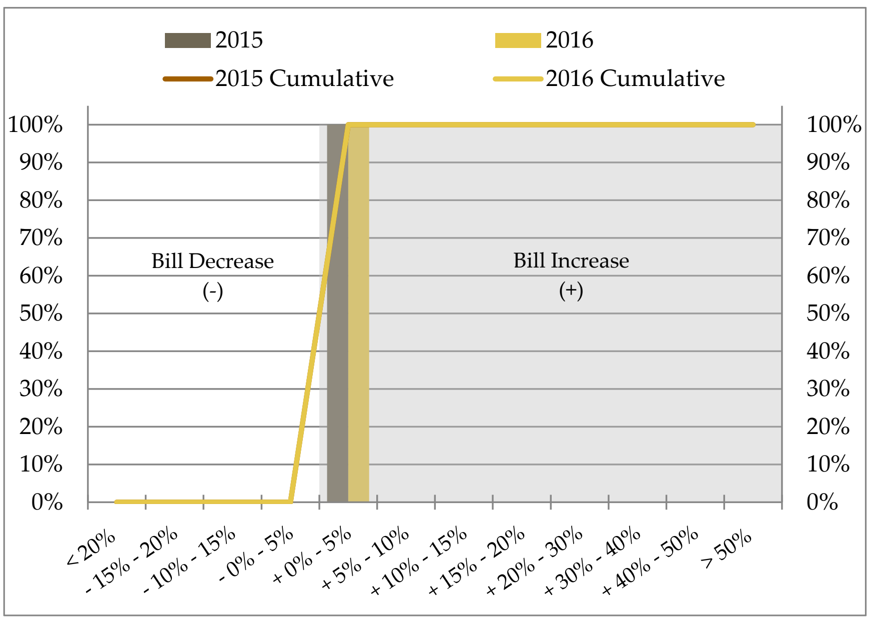


Figure 23 - Low V TOU Collective Sale Bill Impacts for Scenario 2 – Total Including Production



Navigant analyzed rate impacts for 87 of the 106 Low Voltage TOU Collective Sale meters for which IEC provided data. The result of the analysis is in line with our expectation for rate impacts on these customers for Scenario 2 rate changes. We did not receive customer count data for this rate class in the billing determinants and thus were unable to calculate per customer averages for comparison.

Figure 24 - Medium V. TOU Bill Impacts for Scenario 2 – Transmission, Distribution & Supply

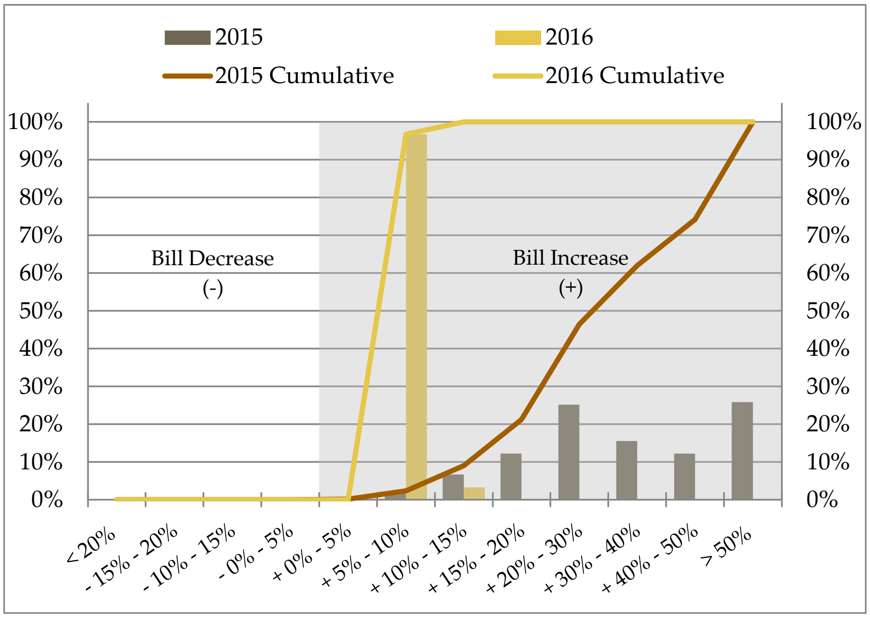
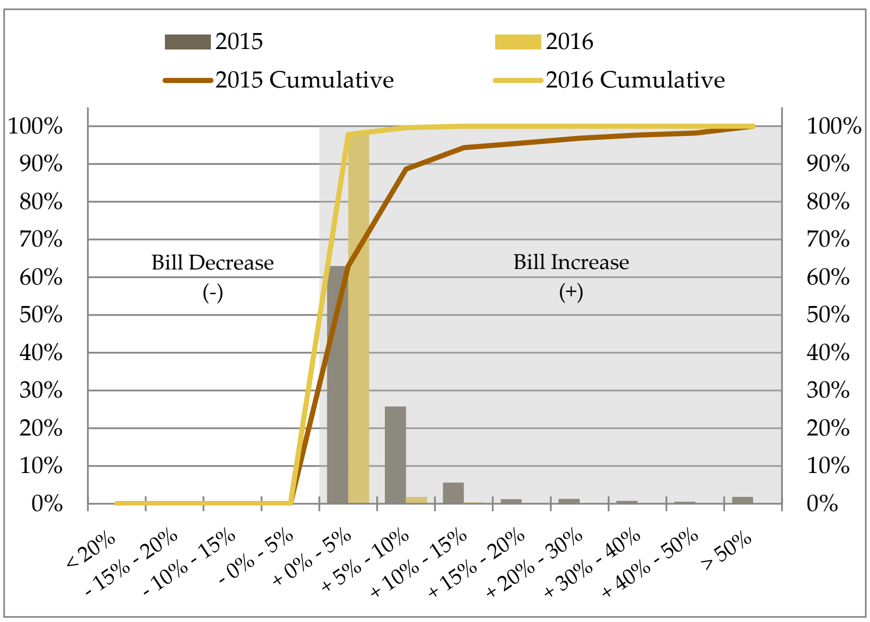


Figure 25 - Medium V. TOU Bill Impacts for Scenario 2 – Total Including Production



Navigant analyzed rate impacts for 1,137 of the 1,149 High Voltage TOU meters for which IEC provided data. The results of the analysis indicated severe rate impacts on these customers for Scenario 2 rate changes, which is not consistent with our results from analysis of billing determinants. The load factor for average meter data is 53% versus 69% based on billing determinants. We believe this discrepancy between the meter data and billing determinants should be reexamined and analyzed by IEC.

Figure 26 - Med V. TOU Collective Sale Bill Impacts for Scenario 2 – Transmission, Distribution & Supply

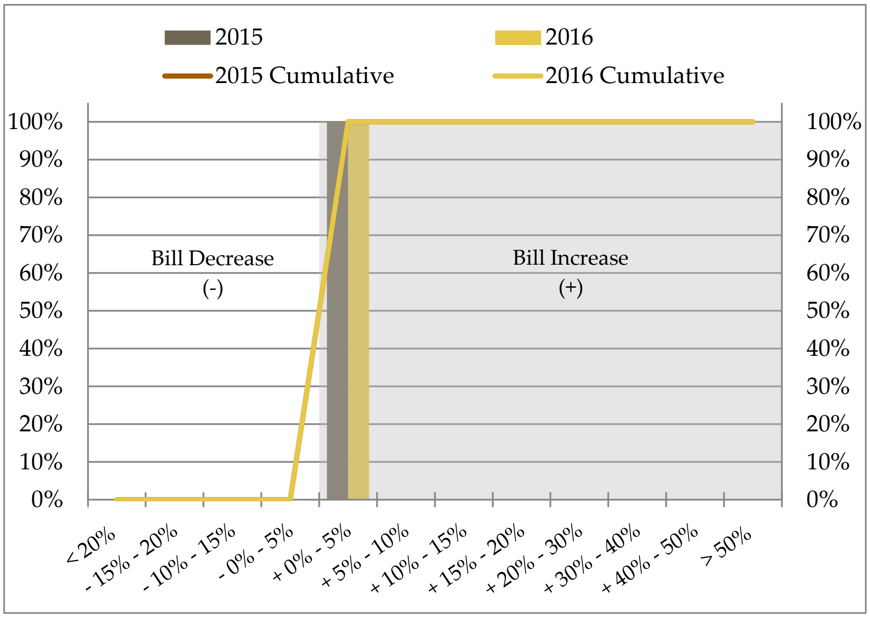
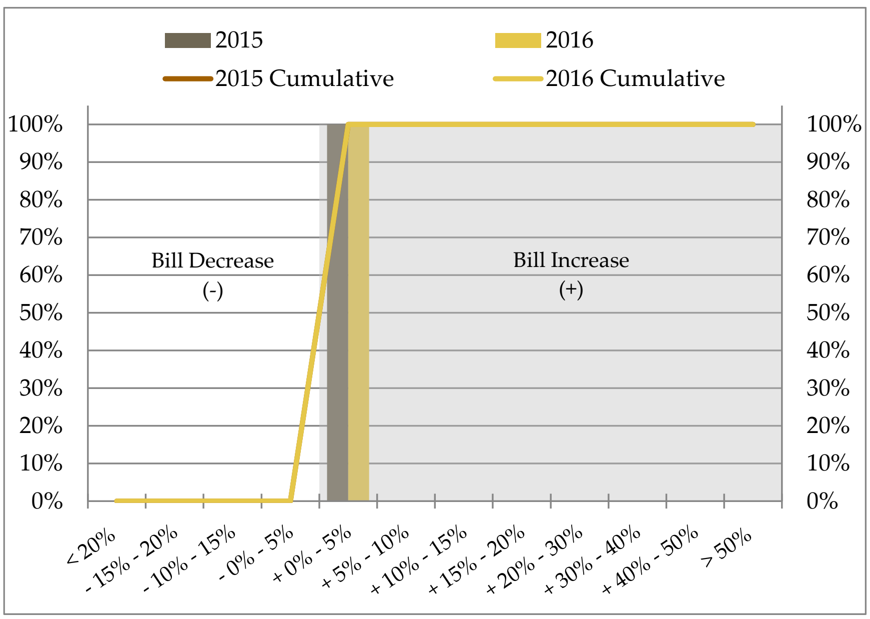


Figure 27 - Med V. TOU Collective Sale Bill Impacts for Scenario 2 – Total Including Production



Navigant analyzed rate impacts for the 29 Medium Voltage TOU Collective Sale meters for which IEC provided data. The result of the analysis is in line with our expectation for rate impacts on these customers for Scenario 2 rate changes. We did not receive customer count data for this rate class in the billing determinants and thus were unable to calculate per customer averages for comparison.

Figure 28 - High V. TOU Bill Impacts for Scenario 2 – Transmission, Distribution & Supply

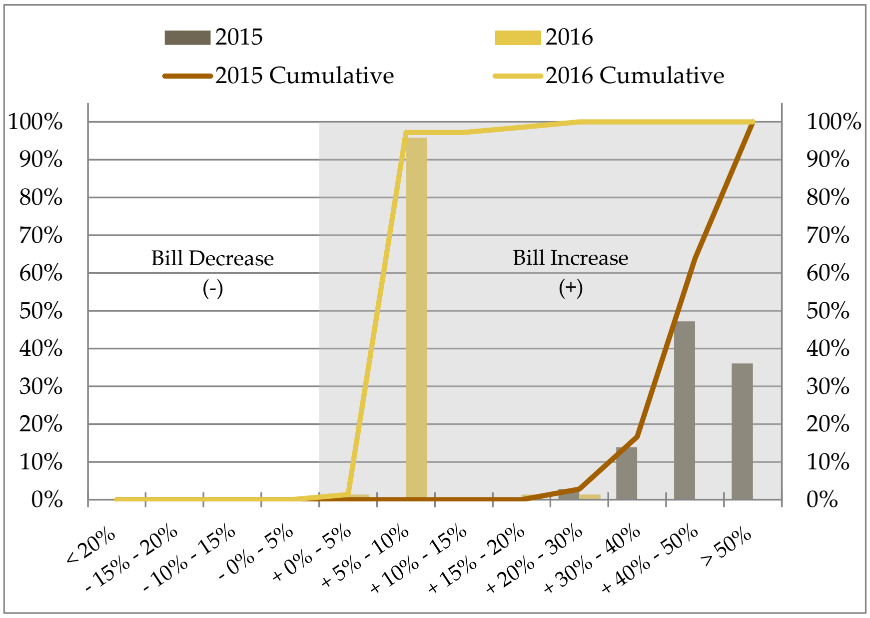
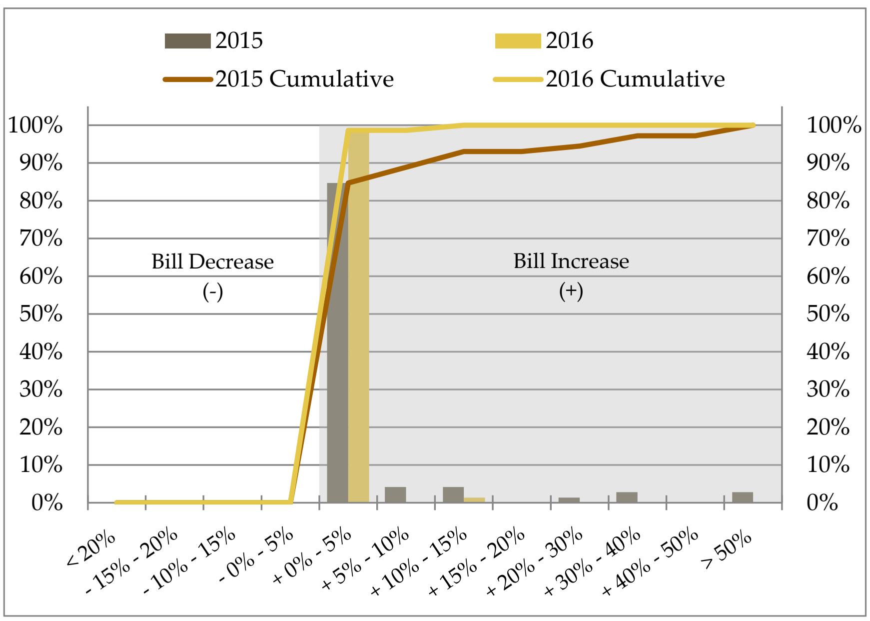


Figure 29 - High V. TOU Bill Impacts for Scenario 2 – Total Including Production



Navigant analyzed rate impacts for 72 of the 75 High Voltage TOU meters for which IEC provided data. The results of the analysis indicated severe rate impacts on these customers for Scenario 2 rate changes, which is not consistent with our results from analysis of billing determinants. We note the number of meters for which data was provided, 75, is higher than the number of customers indicated in the billing determinants. The load factor for revised average meter data is 38% versus 68% based on billing determinants. We believe this discrepancy should be analyzed by IEC.

7.9.1 Analysis of Customer Impacts and the Scenario Two Tariff design

Navigant prepared the customer impact analysis with the understanding that customer specific bill impacts have not previously been used in Israel. In the past, tariff design changes proposed by the IEC have not included this type of analysis.

In preparing the customer impact analyses, Navigant identified customer impacts which triggered concerns due to the large percentage increases individual customers experienced. In general these impacts were occurring for a small percentage of the customers. Further examination leads Navigant to believe that many of the impacts may have been triggered by anomalous data in the sample files. Further, some large percentage impacts are small in total bill impacts (i.e. number of NIS) and appear to be associated with homes owned by customers that are resident in other countries for the majority of the year. These customers have very low average electric consumption and are triggering large percentage increases due to the implementation of the fixed charges.

Further, the level of revenues could change based upon tariff design changes. Given the uncertainty stemming from the customer data used to calculate the impact analysis discussed above Navigant suggests that the PUA and the IEC may consider delaying the tariff design changes detailed in Scenario 2 until January 1, 2016. In the interim time period both parties can examine the customer data questions and ensure that the impacts are acceptable and reasonable.

7.10 *Other Pricing Design Changes*

"Near-Far" Tariffs

The IEC currently offers tariffs to customers located in close proximity (i.e. interconnected to the same substation as the generator) to independent generation resources using a discounted tariff. The rationale behind these tariffs is the customer is using a portion of distribution facilities. It is Navigant understands that no customers are currently receiving service under this tariff.

Navigant recommends that the "Near-Far" tariff be closed. Further, an argument can be made that all customers interconnected to substations interconnected to any generator, including those owned by the IEC, could make a cogent argument for similar treatment. The tariff design further ignores the fact that other transmission and distribution facilities are used to serve the customer when the generator is not operating due to maintenance and outage. However, a locational/congestion tariff might be considered under the relevant market circumstances.

Service to the Kibbutz

Kibbutz in Israel generally operate their own distribution systems. The IEC serves the Kibbutz at a single metering point. Therefore, the IEC avoids a portion of the distribution costs and the supply costs. The IEC has requested in their report that the discounted service be eliminated.

Navigant recommends that the IEC be required to provide detailed cost support which will quantify the costs to serve the Kibbutz. At this time we do not feel that satisfactory information exists to support the elimination of this tariff and therefore recommend that the IEC be required to provide a detailed and complete cost-of-service for the entire IEC system including detailed analysis of the service to the Kibbutz.

Congestion Pricing

Congestion pricing is a mechanism which differentiates the price of electric power based upon a locational price triggered by constraints in the transmission system. Congestion pricing can be applied to generators interconnected to the transmission systems impacting the level of compensation which they are paid or to end-users in which the price they are charged is impacted by the level of congestion.

Navigant does not recommend that congestion pricing be implemented for end-users. First, the electric power system which serves the majority of customers in Israel (i.e. the system excluding the Negev Desert) is relatively compact. Navigant's understanding of the transmission system indicates that congestion is not a significant concern. Further, even if congestion existed the PUA would need to consider the administrative problems associated with congestion pricing such as customer discontent, billing complexities and overall administration.

Navigant believes that it is reasonable to implement congestion pricing for electric generators. Generators should be sent a price signal to interconnect to the transmission system in locations where the output of the system is most valuable. Navigant suggests that the issue be addressed in the interconnection process.

8. Response to the Israel Electric Corporation Report

Several months after the project initiation the IEC informed the PUA they were preparing a report outlining their recommendations of the rate adjustments. On February 5, 2014, Navigant received a copy of a report titled The Israel Electric Corporation Transmission and Distribution Segments Rate Case (hereafter referred to as the "IEC Report").

Navigant began information collection activities in August 2013, which continued for several months. After the IEC Report was provided to Navigant and the PUA in February a new round of information requests occurred which was intended to facilitate Navigant's understanding of the IEC Report.

In summary, Navigant supports some of the recommendations in the IEC Report and in other cases reject the other recommendations. Outlined below is a listing of the IEC Report recommendations and Navigant's responses to these proposals.

8.1 Summary of the IEC Report Findings

The IEC Report addresses the time period of 2012 through 2016 which is consistent with the Navigant analysis. The Company requested the following recognized revenue for the years 2012 through 2016.

Table 47 – Recognized Revenues Requested by the Israel Electric Company (2012 Prices M NIS)

Segment	2012	2013	2014	2015	2016
Transmission	2,084	2,170	2,155	2,279	2,355
Distribution	2,814	2,935	3,075	3,287	3,540
Supply	803	786	713	858	876
Total	5,700	5,890	5,943	6,424	6,771

Source: Response to Navigant Information Request 4, Question 25.

The recognized revenues listed in Table 47 will produce significant rate increases for customers. Navigant calculated the following rate increases using two approaches. The first approach calculates the rate increase for each function (i.e. Transmission, Distribution and Supply) and the second approach calculates the rate increase based upon the total bill, including the generation component. This information is summarized in Table 48 and Table 49 below.

Table 48 – Rate Increase Requirement Each Function Separately

	2012	2013	2014	2015	2016
Transmission	4.4%	6.1%	5.7%	7.6%	7.4%
Distribution	10.2%	6.7%	11.5%	15.4%	20.2%
Supply	35.1%	29.5%	16.1%	37.0%	38.0%
Total	10.3%	8.7%	9.6%	14.4%	16.7%

8.1.1 Recovery of Pre-2012 Recognized Costs

The IEC requested recovery of costs associated with years prior to 2012. The request was predicated upon a claim that the IEC was denied the ability to update their tariffs. Navigant cannot opine on the legally of the IEC request, but from a regulatory policy standpoint recommends that the PUA reject the request for retroactive cost recovery before 2012 for the following reasons.

- Award of retroactive rate adjustments for a time period several years in the past is uncommon and, from a practical matter, extremely difficult is not impossible to estimate. Award of rate adjustments from previous time periods would be coupled with different CAPEX and OPEX expenditures that would impact the current system and proposed budgets.
- The benchmarking analysis performed in this study identified costs which appear to exceed the level that would reasonably be incurred by other efficiently operated electric utilities which would imply retroactive disallowance of these costs.

Navigant has not made any adjustments in the recognized costs to account for alleged under-recovery of costs from time periods prior to 2012.

8.1.2 Proposed Recovery of 2012-2013 Recognized Costs

On page 5 of the IEC Report the Company states, "As 2012 and 2013 costs have already been incurred, the Company demands that the PUA recognizes the full actual costs of the Company for these years in the tariff setting process." Navigant rejects this request on the basis that costs associated with salaries, significantly exceed the normative cost analysis and therefore are not reasonably included in the recognized cost of the company.

8.1.3 Proposed Recovery of 2014-2016 Recognized Costs

The Company requested that "The recognized costs of the Company in the Transmission, Distribution and Supply segments should be set according to projected operating and capital costs of the Company, rather than increase with the electricity consumption level growth rate (as is currently the case)."

Navigant analyzed the IEC budgets and in some cases made changes to adjust costs to a normative level, where appropriate. Navigant accepted all other figures in the Company's proposed budgets.

8.1.4 Appropriateness of International Benchmarking

The IEC Report provides the following commentary regarding benchmarking:

"Most countries where tariffs are set compare the utility to its peers. However, this option is not feasible in Israel, and any international comparison is very problematic. This situation makes it difficult to establish any proper comparative benchmarks"[41]

Inasmuch as Navigant believes that international benchmarking involves an additional level of complexity compared to benchmarking with a single economic system, we believe that benchmarking provides useful information regarding the overall efficiency of the operations of the utility.

Navigant used benchmarking in tandem with other analyses before accepting or rejecting the IEC proposals. Examples are provided below.

---

[41] IEC Report page 27.

- Detailed reviews of the IEC's operations and planning activities (e.g. questions and interviews about how CAPEX budgets were prepared). Reviewing the processes followed by the IEC in tandem with the benchmarking results was able to confirm our findings.
- In the case of the benchmarking of the level of wages Navigant was able to confirm the findings of other consulting looking at different time periods (i.e. KPMG and the World Bank).

Navigant acknowledges that a shortcoming of the benchmarking analyses is that in some cases it was able to identify an efficient level of budgetary activity (e.g. the distribution CAPEX budgets) but was unable to determine if the CAPEX budget was targeted to the proper activities.

8.1.5 Abandonment of the CPI-x Approach to Adjusting Tariffs

Navigant recommends the PUA to suspend the use of an efficiency factor to adjust tariffs for the next several years. Therefore, in its place Navigant recommends the use of an alternative "Stair-Step" approach based upon the budgets of the Company, an analysis of normative costs and other supporting analyses. Further, Navigant identified a number of "Milestones" activities that IEC will be required to achieve in order to attain the full recognized cost. The milestones are activities which are commonly performed in the electric power industry and should be reasonably attainable by the IEC. Failure to attain any of the milestones carries with it a penalty.

Navigant believes that the proposed stair-step proposal provides the proper balance between providing incentives to the IEC to operate efficiently and rewarding the Company for their investments. Furthermore, specific identifiable actions will provide the Company rewards for performing activities that are the norm in other electric utilities in the developed world.

- Navigant believes that CPI-x regulation might be reconsidered in Israel for the next base tariff at 2017, taking into consideration the different problems at IEC at the moment: CPI-x is appropriate in a situation where a transparent relationship exists with the utility and the current environment does not support that conclusion;
- The Company is not achieving cost savings and ignores the incentives; and
- Navigant's opinion is the Company overall management is not innovative – operations are characterized as similar to utilities in North America in the 1980s/1990s.

The IEC's movement to IFRS from US GAAP triggers changes to the accounting systems of the company will change and no longer be inflation indexed thus requiring an overhaul in the regulatory systems. Possibly include positive incentives which would increase the IEC's ROE if certain goal are exceeded. Navigant suggests a stronger regulatory policy with greater oversight.
Due to the current situation, Navigant recommends an incentive based mechanism that is closer to cost of service and after 2016 the PUA may return to CPI-x.

8.1.6 Cost of Capital

As was previously discussed the cost of capital as proposed by the IEC and calculated in this report were relatively similar. Navigant has adopted the IEC's requested cost of equity and embedded cost of debt in calculating the recognized cost.

8.1.7 Proposed Tariff Design Changes

IEC requested a number of changes to the electric tariff design. These changes can be summarized as movement away from the existing volumetric tariff design toward implementation of demand and fixed charges.

Navigant is generally supportive of the tariff design changes requested by the IEC but have identified a number of analyses that would need to be completed to properly design new tariffs. The analyses include:

- Marginal Cost Analyses for Distribution and Transmission;
- Fully Distributed Cost Analyses for Transmission, Distribution and Supply;
- Tools which would enable to calculation of bill impacts on a customer-by-customer basis;
- A detailed plan for customer education on the tariff design changes;
- Updates to the Company's Rating Period Analyses.

The above-mentioned studies are regularly prepared and updated by electric utilities in developed economies when making request for tariff adjustments. These studies are even more essential when changes in the tariff structure are requested. Navigant believes the information required to prepare these studies exists within the IEC. Navigant has therefore identified each of the above studies as a milestone activity by the Company which would need to be filed with the PUA for their review before any further rate design changes are allowed.

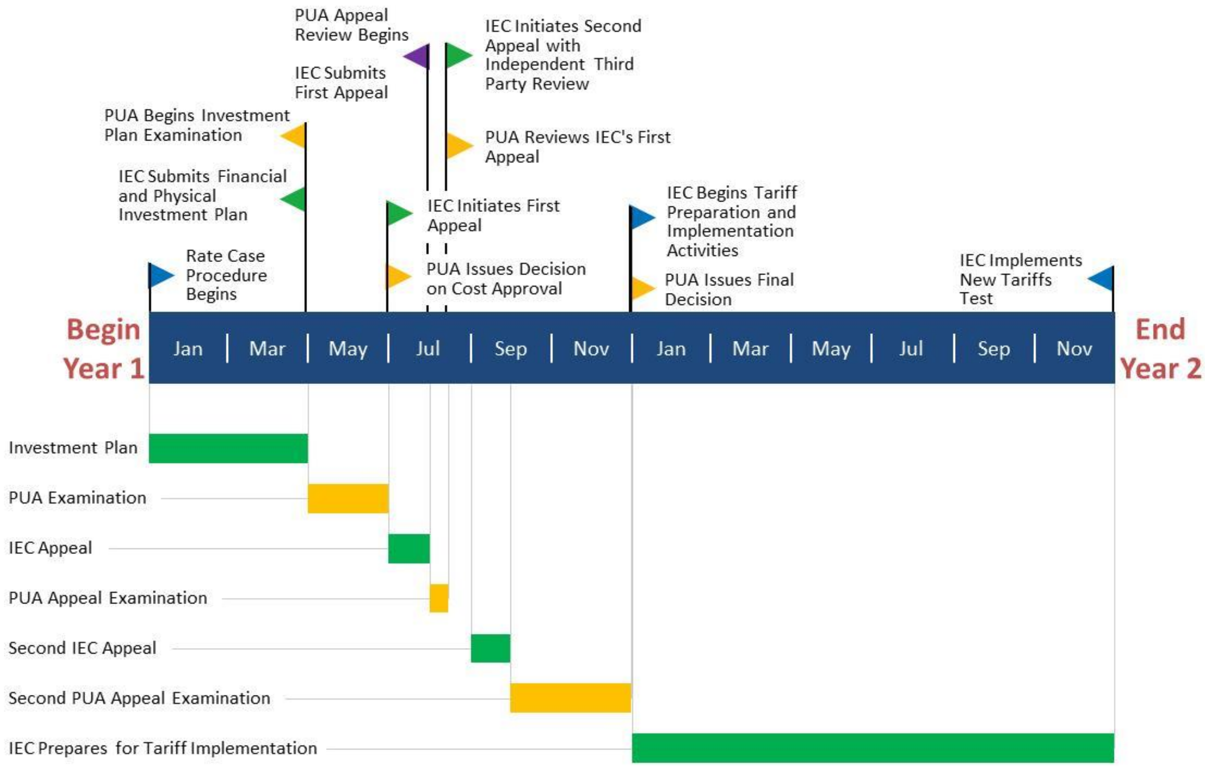
Navigant has included proposals to begin movement away from volumetric tariffs towards the implementation of fixed monthly charges and demand-based charges for customers with the appropriate metering equipment. However, a significant concern exist regarding customer impacts, cost allocation between classes, detailed marginal cost analysis and customer education programs.

The Company has proposed that the current system of "Nearby Customer Mechanisms" be discontinued. Navigant has not addressed this issue because it would require a change in the market design of the electric power system in Israel. Navigant proposes that changes to the Nearby Customer Program not be addressed until such time as market design changes are addressed in Israel.

8.2 Proposed Revisions to the Regulatory Mechanisms

The IEC proposed several changes to the regulatory rate process under which each party must abide by new processes and time limits. The process is illustrated in Figure 18

Figure 30 – IEC Proposed Regulatory Methodology



The process proposed by the Company is a variant of "formula ratemaking" where a company is allowed cost recovery based upon actual performance. Such mechanisms have been introduced in other developed economies.

Navigant recommends that the PUA reject the proposed changes in the regulatory mechanism by the IEC for the following reasons.

Formula Ratemaking is Inappropriate for the Current Environment in Israel

Formula ratemaking is generally introduced as a substitute for cost-of-service regulation when frequent changes to tariffs are requested and a prolonged history of efficient operations by the utility exists. The IEC does not meet either of these criteria. Further, the regulatory structure in the country is relatively immature (i.e. the PUA was only created in 1996).

Navigant's assessment of IEC operations finds a significant level of overall efficiency improvements can occur. Specifically, the distribution planning function and overall company staffing are two areas where significant operational efficiencies can be captured. Conversely, a reasonable level of operational efficiency exists in the transmission planning function for system planning and CAPEX.

The IEC Proposal Lacks Performance Measurement Standards

Formula ratemaking typically includes performance standards that the utility must attain or face a penalty. For example, the RIIO (Revenue = Incentives + Innovation + Outputs) regulatory programs in the UK and formula ratemaking mechanisms specify goals for reliability, customer satisfaction, employee safety and other key metrics associated with an efficiently operated utility. The IEC proposals do not include performance standards or associated penalties.

The Proposed Mechanism Ignores the Role of the Customer

The proposed mechanism completely ignores the role of the customer in the regulatory review process. Nowhere in the proposed mechanism is time allotted for customer groups to review the Company's proposals. Regulatory mechanisms in developed economies such as the UK, Canada and the United States always provide mechanisms for customers to voice concerns in reviews of utility rates and performance.

Israel Lacks the Information Infrastructure Required for Formula Rates

Detailed reporting mechanisms for utility financial and operating performance currently do not exist in Israel. Inasmuch as the PUA is currently designing reporting mechanisms that will facilitate the reporting of routine operational and financial information such mechanisms currently do not exist in Israel. The level of data required for the implementation of formula ratemaking is significant and may not be attainable in the current environment.

8.3 Lack of Customer Focus

An issue that Navigant has found to be particularly troublesome to the IEC is what appears to be the complete lack of customer focus in the decision-making of the IEC. Ignoring customers and the specific needs and desires of customers is uncharacteristic of a utility in a developing economy. Further, Navigant questions if the investment and operational decisions of the utility can truly be optimized if the company does not understand what is desired by customers.

Examples of the IEC lack of customer focus is provided below:

- The IEC has proposed a pricing design but has provided no cost-of-service or customer impact analysis. Therefore, the company appears to be advocating the designing tariffs that could trigger severe adverse impacts on specific customers or customer subgroups;
- The IEC's proposed regulatory process involves only the IEC and the PUA. Navigant could not find any avenue in which interested customer groups or third parties could participate in the proceeding. This is contrary to the process followed in most developed countries;
- During Navigant's discussions with the IEC nowhere did the company share any market research programs. Load research is currently being performed, but the load research program is currently in its infancy;

Customers need to be part of the process of an efficiently run utility if for no other reason to provide the utility management with information on what is desired from the company in terms of goods and services. Navigant therefore suggests the follows actions be implemented.

- The IEC should be required to operate market research programs aimed at determining what goods and services are desired by customers;
- Tariff design studies should include detailed customer impact analyses;
- Intervention in tariff adjustments should be open to the interested parties. Navigant recognizes that these proceedings require an investment in specialized services and thus recommend that intervener financing be provided to qualified parties in a proceeding; AND

- The IEC should be required to submit to the IEC on a periodic basis (e.g. annually) customer satisfaction surveys. The surveys should be performed by an independent third party and the results made publically available.

9. Compliance Filings

Navigant's efforts to review the operations and financial conditions of the IEC has been frustrated by the general unavailability of data and lack of uniformity in presentation. We believe that all stakeholders in the rate setting process, the IEC, customers and the PUA, would benefit from a uniform and robust data and information collection process.

As a result of our recommendations Navigant is recommending that the following studies be provided by the IEC on either a one-time or periodic basis as described below. Further, prescribed penalties for non-compliance are included if information is not provided.

Transmission & Distribution Development Plans

The IEC shall be required to provide, on an annual basis, descriptive summaries and costs for all major T&D projects and for all other major spending categories. Major T&D projects include those with costs above 10 million (NIS). The report should compare: actual versus budget expenditures; major changes in scope, schedule, cost or budget; and reasons for any changes. For projects in the planning or evaluation stage, IEC should provide a description of alternatives evaluated, including how life-cycle economic evaluation methods have been applied to each transmission and distribution investment alternatives. The annual report for each project should include quantification and prioritization of investments based on cost, reliability, safety and other benefits.

Asset Management and Reliability

On an annual basis the IEC shall be required to provide an annual summary of asset management programs and strategies, emphasizing those focusing on condition assessment, asset health and performance. The annual report should describe each major asset management initiative or program, including the prioritization of renewal investment programs for transmission and distribution, including refurbishment and upgrades. The annual report should present reliability metrics, by cause code, indicating where reliability has improved or degraded and programs IEC proposes to address emergent reliability issues. It also should quantify and present any inspection and maintenance cost savings achieved by asset management strategies and programs IEC has implemented.

Smart Grid & Losses

Prior to smart grid investments, IEC must do a comprehensive cost benefit analysis and deliver it to the PUA examination and decision. If these investment are to be authorized, the company shall be required to report on an annual basis the smart metering data collection and distribution management enhancements for improved measurement and detection of technical and non-technical losses. The report should include the results of annual calculation of peak demand and energy loss factors, and the methods and measurement used to derive the loss factors. IEC also should report on the status of smart grid related programs and expenditures, including actual spending versus budget, program schedule, and reasons for changes in costs or status. The report should include the status of automation and Distribution Management System (DMS) upgrades, and the benefits achieved such as improved reliability, cost efficiency and reduced inspection and maintenance, among other factors.

Energy Efficiency and Demand Management

On an annual basis the IEC should report annually on the amount of demand savings resulting from energy efficiency and demand management programs. The report should quantify and describe the benefits achieved from proactive demand-side measures and other incentives that reduce T&D peak demand as an alternative to capacity investments; this includes recognition of the impact of demand charges on load forecast that Navigant recommends in other compliance requirements. The report should describe how energy efficiency have been incorporated into T&D planning, and where future transmission and distribution system expansion have been adjusted to reflect adjustments in load forecasts, including reductions achieved by demand management, rate policies and other innovative strategies. IEC should also report on the savings resulting from the deferrals.

Peak Demand and Sales Forecast

The Company will provide on an annual basis a forecast of peak demand, electric sales and generation requirements. The structure of the forecasts should provide models for at least each tariff class. Further, a detailed weather normalization procedure should be specified for those classes which are weather sensitive. The detail and all supporting models and data used to develop estimates. All historical information used to derive forecasts are required to be provided to the PUA. The peak demand and energy forecast should recognize energy efficiency (EE) savings and demand response (DR) programs. The IEC should report on the methods it will use to capture EE and DR savings, and report forecasted demand and energy, pre- and post-EE/DR.

The company should provide quarterly a comparison of the forecasted versus actual sales including an explanation of the differences between actual and forecasted sales.

Sales Statistics / Billing Determinants

Annually the company shall provide detailed billing determinants which reasonably reconcile the revenues of the company to the tariff elements. The billing determinants should also be provided as weather normalized with estimates of the total revenue reflecting normal weather. The billing determinants data shall be provided on a monthly basis for at the tariff class level.

Load Research Data

Annually, the company should submit load research studies for the previous year. The load research information should at a minimum include information for Coincident Peak, Non-Coincident peak, sales and load factor by tariff class. It should include any adjustments for EE and DR programs.

Allocated Cost of Service Analysis

IEC shall annually provide the PUA with an allocated cost of service study for the transmission, distribution and supply functions. The study should differentiate distribution service by voltage level and provide allocated cost by tariff class. The study shall be performed on an actual and weather-normalized actual basis for the historical year.

Marginal Cost Study

IEC shall annually provide the PUA with a marginal cost study for the transmission and distribution functions. The study should differentiate distribution service by voltage level.

Distribution Reliability Information

Quarterly the IEC should provide the PUA with information about the SAIDI and SAIFI for each district, including reliability metrics by cause code. The quarterly report should highlight major initiatives undertaken to improve reliability, and expected benefits.

Employee Safety

The IEC shall on a quarterly basis provide information on lost time accidents to the PUA.

Call Center Response Time

The IEC shall on a monthly basis provide the IEC with data on average response time for inquiries to the call center.

Reporting of Quarterly and Annual Results of Operations

The IEC shall provide on a quarterly and annual basis the financial results of the supply, distribution and transmission segments of their business. The financial reporting should provide the net income / loss, RoR and RoE for each segment. Further, the company shall provide a comparison of the projected versus actual O&M Expenses and budget versus actual CAPEX expenditures. The company shall provide an explanation of the variation between forecasted and actual earning.

Employee Statistics

The IEC shall provide on an annual basis the number of employees and direct salaries by segment. In the case of the construction segment the number of employees and salaries shall be allocated to activities associated with the production, transmission, distribution and customer segments as well as overhead functions.

A. Major Projects for Transmission Development Plan: 2013-2017

Projects listed are included in IEC's most recent Transmission Development Plan. The timing of projects is contingent on the receipt of all of the required approvals and permits, which are described in the Plan.

1. 400 kV system – new lines and switching stations

Project name & description	Date of operation	Project objective
Zevulun third 400/161 kV transformer	2013	Meeting of design criteria, compliance of generation capacity connected to 400 kv grid to this grid capacity – load growth
Dorad connection – 4 km long	*2013	Connection of Dorad private producer
Moving of transformer from Zafit to Petach Tikva	2014	Meeting of planning criteria in the center area by increasing of 400/161 kv capacity– load growth
Haruvit (Dalia) connection – 2 km long	*2014	Connection of Dorad private producer
Ayalon switching station 3x650 MW; connection 11km	2015	Meeting of planning criteria in the center area by increasing of 400/161 kv capacity– load growth Meeting of design criteria, compliance of generation capacity connected to 400 kv grid to this grid capacity
Trans-Dan region line; 15.5 km long	2015	Meeting of design criteria, compliance of generation capacity connected to 400 kv grid to this grid capacity– load growth
Ruttenberg-Ahuzam line; 30 km long	2015	Reliability of energy transfer from the Rutenberg/Dorad generation compound
Galilee switching station 2x575 MW; connection 80 km long	2016	Meeting of planning criteria in the north area by increasing of 400/161 kv capacity– load growth
Gezer-Kassem line; 28 km long	2016	Planning only, security of system Meeting of design criteria, compliance of generation capacity connected to 400 kv grid to this grid capacity
Caseria-Hefer-Petach Tikva; 62 km long	2017	Meeting of design criteria, compliance of generation capacity connected to 400 kv grid to this grid capacity
Atidim switching station 2x650 MW; connection 1 km	2017	Meeting of design criteria, compliance of generation capacity connected to 400 kv grid to this grid capacity
Zafit-Ramat Hovav-Rotem Plain line; 30 km long	*2017	Connection of future private producers in the southern region

**contingent on completion of the production project*

2. New permanent substations

Haifa District

Name of substation	Year	Power in MVA	Project objective
Bikkurim	2016	2x50	Power supply to Haifa area according to load growth forecast
Atlit	2017	2x33	Power supply to Atlit area according to load growth forecast

Northern District

Name of substation	Year	Power in MVA	Type
Nahariya	2017	2x50	Power supply to Naharija area according to load growth forecast
Harish	2017	2x50	Power supply to new town according to load growth forecast

Dan District

Name of substation	Year	Power in MVA	Type
Atidim	2013	4x50	Power supply to Dan according to load growth forecast
Ayalon	2015	3x75	Power supply to Dan according to load growth forecast
Tel-Aviv University	2016	2x75	Power supply to Dan according to load growth forecast
Givatayim	2017	2x75	Power supply to Dan according to load growth forecast. Dismantle of temporary substation

Jerusalem District

Name of substation	Year	Power in MVA	Type
Givat Sha'ul	2013	2x50	Power supply to Jerusalem according to load growth forecast. Dismantle of temporary substation
Adumim Industry	2015	3x50	Power supply to Jerusalem according to load growth forecast. Dismantle of temporary substation
Nahal Tzufim	2017	2x56	Power supply to Jerusalem according to load growth forecast. Dismantle of temporary substation

Southern District

Name of substation	Year	Power in MVA	Type
Yahalom	2013	2x50	Power supply to Natania according to load growth forecast.
Lahavim	2015	2x50	Power supply to Beer Sheva according to load growth forecast. Dismantle of temporary substation
Tnuvot	2016	3x50	Power supply according to load growth forecast. Dismantle of temporary substation
Rishon East	2016	3x50	Power supply to Rishon le zion according to load growth forecast. Dismantle of temporary substation
Sderot	2016	2x50	Power supply to Sderot according to load growth forecast. Dismantle of temporary substation
Eyal	2016	2x50	Power supply according to load growth forecast. Dismantle of temporary substation
Ganim	2017	2x75	Power supply to Petach Tikva according to load growth forecast. Dismantle of temporary substation

9.1 3.161 kv overhead lines

Northern District

Name of line	Line km	Circuit km	Project objective
Alon Tavor – combined cycle conn.	0.2	0.3	Connection of new generation
Barkai – junction for mobile	0.1	0.1	Connection of new mobile substation
Harish – junction	7	14	Connection of new permanent substation – load growth
Mukeible – junction (Jenin)	9.3	18.6	Connection of new permanent substation – load growth
Ma'ale Gilboa – junction	6.5	13	Connection of new generation
Nahariya – junction	5.2	10.4	Connection of new permanent substation – load growth
Atlit – junction	0.5	1	Connection of new permanent substation – load growth
Galilee – junctions	24	48	Connection of new switching station– load growth
Manara – junctions	0.25	0.5	Connection of new generation
Total northern district	**53.05**	**105.9**	

Jerusalem District

Name of line	Line km	Circuit km	
Ariel (Immanuel) – junction	25	50	Power supply to Shomron area– load growth
Givat Sha'ul – junction	0.3	0.6	Connection of new permanent substation – load growth
Ramallah – junction	0.5	1	Connection of new permanent substation– load growth
Nablus – junction (Jenin)	8	16	Connection of new permanent substation– load growth
Tarkumiyeh – junction	5	10	Connection of new permanent substation – load growth
Total northern district	**38.8**	**77.6**	

Southern District

Name of line	Line km	
Tnuvot – inlets	2.5	Connection of new permanent substation
Eyal – junction	1	Connection of new permanent substation– load growth
Ashdod Energy private – junction	0.1	Connection of new generation
Ganim – junction	0.5	Connection of new permanent substation – load growth
Ashdod desal. private – junction	3	Connection of new permanent substation
Zmurot solar – junction	0.5	Connection of new generation
Teva-tech private – junction	2.5	Connection of new permanent substation
Yahalom – junction	1	Connection of new permanent substation – load growth
Kfar Uriah private – junction	0.23	Connection of new permanent substation – load growth
Lahavim – junction	1.5	Connection of new permanent substation – load growth
Nesher Ramle – junction	0.5	Connection of new generation
Sderot – junction	0.3	Connection of new permanent substation – load growth
TA North – junction	1	Powers supply to Tel Aviv area– load growth
Eitan Beersheba North line	35	Connection of new generation
Beersheba North Beersheba line	7	Connection of new generation
Be'erot Yitzhak-Or Yehuda-Ayalon line	0.5	Connection of new generation
Yotvata-Timna line	23	Power supply to Eilat area and new generation connection
Rotem-Dimona comb. cycle line	16	Connection of new generation
Masada-Arad line	30	Power supply to Dead Sea area and new generation connection – load growth
Ramon-Faran line	48	Power supply to Eilat area and new generation connection
Faran-Yotvata line	46	Power supply to Eilat area and new generation connection
Ramat Hovav-Ashalim line	13.5	Connection of new generation
Timna-Eilat line	22	Power supply to Eilat area and new generation connection
Rotem-Priklas line	1.5	Power supply to Eilat area and new generation connection
Eshkol comb. cycle absorption	4.5	Connection of new generation
Total Southern District	**261.63**	

**Provisionally connected with a T for the absorption of the PV at Ashalim*

B. Regression Details

Estimation Techniques

This chapter of the report will discuss the method for estimating the weather normal inputs for forecasting consumption, and the methods for forecasting consumption.
This chapter is divided into the following sub-sections:

1. **Data Used:** A description of the data provided and used for the analysis.
2. **Weather Normal Estimation:** A description of the method used to create the weather normal inputs to the forecasts.
3. **Forecast Method:** A description of the method used to develop the forecasts.

Two forecast methods were employed for this analysis**:**

- The "total consumption" method forecasts total consumption by sector; and
- The "total average" method first forecasts average consumption per customer by sector, then forecasts the number of customers by sector. The product of these two forecasts is the forecast of total consumption by sector.

9.2 Data Used

The following types of data were used in this analysis:

- Monthly Israel PUC usage data per customer by sector (residential, commercial, agriculture, industry, and water); and
- Daily weather data.

Usage by Customer Data

Navigant estimated weather normal inputs for the forecast and the estimated equations for the forecasts using the following consumption data:

- Monthly electricity energy (kWh) consumption for the five sectors for the Israel PUC; and
- This data was converted to MWh.

The Israel PUC provided Navigant with monthly electricity consumption data for customers in its five sectors from January 2002 to December 2012. The PUC also provided consumer data on the number of customers from January 2002 to December 2012 for the five sectors.

Weather Data

Navigant obtained daily weather data series for Tel Aviv to model the weather normal inputs.[42]
Weather data included a daily high and low temperature. A temperature mid-point was also calculated. Weather data was converted to a monthly series.

9.3 Normalization Method

The purpose of normalization is to estimate weather normal inputs for the forecasts.
This method of producing weather normal inputs proceeds in the following steps:

1. Estimate the relationship between average energy consumption per customer and:
    a. Weather

[42] Weather for Tel Aviv is recorded at the Ben Gurion Airport.

b. Calendar and trend variables
2. Apply historical weather for the past 31 years to the estimated relationship between weather and energy consumption.
3. The combination of weather variables that produces the median weather-induced energy consumption becomes the "normal" weather input for the given period.

There were a total of ten regressions estimated for this analysis. One for each sector, and one for each of the two model types: total consumption and total average consumption. The model specification was the same for each of the 10 models. Equation (1) below specifies the equation.

For ease of understanding Equation (1), it is helpful to have an illustration. For example, if one was modelling total consumption for the residential sector, the dependent variable (Y_m) would be total residential consumption for month m. The estimated coefficients (the betas) would be parameter estimates for residential total consumption. Note that heating and cooling degree days do not vary by sector; therefore these variables are consistent across all 10 models.

The model employed was:

$$Y_{m,} = \beta_0 + \beta_1\, HDD_m + \beta_2 CDD_m + \boldsymbol{\beta Z_m} + \varepsilon_m \tag{1}$$

Where:

$Y_m = Consumption$ (MWh)

$\beta_0 = Intercept\ coefficient$

$\beta_1 = Coeffient\ for\ HDD$

$\beta_2 = Coeffient\ for\ CDD$

$HDD_m = Heating\ Degree\ Days\ for\ month\ m$

$CDD_m = Cooling\ Degree\ Days\ for\ month\ m$

$\beta = A\ 14x1\ vector\ of\ coefficients\ for\ the\ 14\ explanatory\ variables$[43]

$Z_m = a\ 1x14\ matrix\ of\ additional\ explanatory\ variables\ in\ month\ m$

$\varepsilon_m = Error\ terms\ for\ month\ m$

The heating and cooling degree days were calculated as:[44]

$$HDD_m = Max(18 - MID_{POINT}, 0) \tag{2}$$

$$CDD_m = Max(MID_{POINT} - 18{,}0) \tag{3}$$

Where:

$HDD_m = Heating\ degree\ days\ for\ month\ m$

$CDD_m = Cooling\ degree\ days\ for\ month\ m$

$MID_{POINT} = The\ mid\ point\ between\ the\ daily\ low\ and\ daily\ high\ temperature$

[43] Explanatory variables include: An annual trend and 11 monthly dummy variables. Note that while there are 12 months in a year, only 11 dummies are required. This is because the 12 month is reflected in the intercept.

[44] By definition, heating and cooling degree days are calculated relative to a base temperature. This base temperature is generally an indoor temperature that is adequate for human comfort. In this analysis, 18 °C was used.

$at\ Ben\ Gurion, averaged\ by\ month$

It is important that the reader bear in mind that the historical weather data used to estimate normal weather inputs are drawn from the past 31 years of data. This and the fact that "normal weather" is the weather that delivers the median level of weather-driven consumption means that within this IESO-consistent weather normalization there *is an implicit assumption that the weather in any given year has a uniform probability of being like any of the weather experienced in the last 31 years*.
This last point especially should be borne in mind. If the reader has some a priori knowledge that recent weather is structurally different (for example, warmer on average) than earlier weather, then he or she may conclude that the weather normals derived in this fashion may not accurately reflect the true "normal" weather.

The first step to finding weather normals is to obtain parameter estimates for the regression equation. In particular, the estimates of $\beta_1$andβ_2: $\hat{\beta}_1$and $\hat{\beta}_2$. These two parameter estimates represent the estimated relationship between monthly electricity consumption and the cooling and heating days.
For the second step, the weather normal values are calculated by multiplying the estimated parameters for heating and cooling degree days, by the monthly heating and cooling degree variables observed in the historical period being used to generate the weather normal (i.e., the past 31 years):

$$Weathernorm_m = \hat{\beta}_1 \cdot HDD_m + \hat{\beta}_2 \cdot CDD_m \quad (3)$$

The sum of these two values, all else equal, is the expected consumption in each month that is directly attributable to the weather. This operation is performed for all 31 years and delivers a series of 31 observations of predicted weather-dependent consumption in each month.
From this series, the median weather-attributable consumption value in each month is selected. The heating and cooling degree days corresponding to this value then becomes the "normal weather" input for this sector in the given month.

9.4 Forecast Method

After estimating the weather normal inputs for the forecast, Navigant forecasts total and total average consumption from 2013 to 2019, assuming normal weather.
The total consumption model uses a single regression (see Equation (1) above) to establish the relationship between weather and aggregate consumption by customer segment. Also included are monthly dummy variables and a linear annual trend. This historical relationship was then fitted to obtain the forecast values over the forecast period, January 2013 – December 2019.

The total average consumption model uses two regressions to establish the relationship between weather and aggregate consumption by customer segment. One that captures the relationship between average consumption per customer and weather, monthly seasonality and a linear annual trend, and another that captures the annual linear trend in customer numbers by segment. This historical relationship was then fitted to obtain the forecast values over the forecast period, January 2013 – December 2019.

9.5 Model Results

Table 49 - Average Consumption – Agriculture

Variable	Estimate	Standard Error	t Value	p value
Intercept	9.1539	0.3919	23.36	<.0001
Trend	0.4566	0.0204	22.34	<.0001
HDD_mid	0.6065	0.1115	5.44	<.0001
CDD_mid	0.2621	0.0975	2.69	0.0083
Jan	-0.6364	0.3672	-1.73	0.0857
Feb	-1.5896	0.3354	-4.74	<.0001
Mar	-0.6283	0.3177	-1.98	0.0503
Apr	-1.3931	0.4048	-3.44	0.0008
May	-0.2933	0.5503	-0.53	0.5951
Jun	0.3164	0.7665	0.41	0.6805
Jul	1.6303	0.9473	1.72	0.0879
Aug	2.0102	0.9910	2.03	0.0448
Sep	0.3657	0.8693	0.42	0.6748
Oct	0.0817	0.6684	0.12	0.9029
Nov	-0.5498	0.4088	-1.34	0.1813

Table 50 - Average Consumption – Commercial

Variable	Estimate	Standard Error	t Value	p value
Intercept	3.6248	0.077	47.07	<.0001
Trend	0.1307	0.004	32.54	<.0001
HDD_mid	0.0767	0.022	3.5	0.0007
CDD_mid	0.1542	0.019	8.05	<.0001
Jan	-0.1469	0.072	-2.04	0.044
Feb	-0.5751	0.066	-8.73	<.0001
Mar	-0.3111	0.062	-4.98	<.0001
Apr	-0.5860	0.080	-7.37	<.0001
May	-0.1155	0.108	-1.07	0.2877
Jun	0.0102	0.151	0.07	0.9463
Jul	0.3261	0.186	1.75	0.0824
Aug	0.3023	0.195	1.55	0.1232
Sep	-0.0044	0.171	-0.03	0.9797
Oct	0.0999	0.131	0.76	0.4485
Nov	-0.0747	0.080	-0.93	0.3545

Table 51 - Average Consumption – Industrial

Variable	Estimate	Standard Error	t Value	p value
Intercept	22.2863	0.5960	37.39	<.0001
Trend	0.4699	0.0311	15.11	<.0001
HDD_mid	0.2835	0.1695	1.67	0.0971
CDD_mid	0.0824	0.1483	0.56	0.5794
Jan	-1.7407	0.5584	-3.12	0.0023
Feb	-3.6696	0.5101	-7.19	<.0001
Mar	-0.7725	0.4831	-1.60	0.1125
Apr	-2.3877	0.6156	-3.88	0.0002
May	1.2608	0.8369	1.51	0.1346
Jun	1.8573	1.1655	1.59	0.1137
Jul	3.5332	1.4405	2.45	0.0157
Aug	3.7361	1.5070	2.48	0.0146
Sep	1.1868	1.3219	0.90	0.3711
Oct	1.2962	1.0163	1.28	0.2047
Nov	0.0470	0.6217	0.08	0.9398

Table 52 - Average Consumption – Residential

Variable	Estimate	Standard Error	t Value	p value
Intercept	0.460	0.0216	21.27	<.0001
Trend	0.008	0.0011	6.93	<.0001
HDD_mid	0.048	0.0062	7.74	<.0001
CDD_mid	0.014	0.0054	2.67	0.0086
Jan	-0.003	0.0203	-0.15	0.8848
Feb	-0.078	0.0185	-4.19	<.0001
Mar	-0.063	0.0175	-3.61	0.0005
Apr	-0.100	0.0224	-4.48	<.0001
May	-0.107	0.0304	-3.53	0.0006
Jun	-0.069	0.0423	-1.63	0.1055
Jul	0.059	0.0523	1.13	0.2603
Aug	0.060	0.0547	1.10	0.2735
Sep	-0.015	0.0480	-0.31	0.7598
Oct	-0.073	0.0369	-1.99	0.0491
Nov	-0.070	0.0226	-3.08	0.0026

Table 53 - Average Consumption – Water

Variable	Estimate	Standard Error	t Value	p value
Intercept	36.544	2.826	12.93	<.0001
Trend	1.794	0.147	12.17	<.0001

HDD_mid	-0.098	0.804	-0.12	0.903
CDD_mid	0.910	0.703	1.29	0.1983
Jan	-6.551	2.648	-2.47	0.0148
Feb	-10.470	2.419	-4.33	<.0001
Mar	-2.529	2.291	-1.10	0.272
Apr	0.791	2.919	0.27	0.7869
May	10.242	3.969	2.58	0.0111
Jun	11.551	5.527	2.09	0.0388
Jul	14.015	6.831	2.05	0.0424
Aug	13.716	7.146	1.92	0.0574
Sep	8.743	6.268	1.39	0.1657
Oct	5.703	4.820	1.18	0.2391
Nov	1.780	2.948	0.60	0.5472

C. Detail of Revenue Analysis

Table 54 - Calculated Revenues for 2012 Actual Rates in Effect (Million NIS)

Rate Class	Function	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Total
Residential	Production	659.01	671.32	539.24	403.84	400.77	532.25	706.51	681.55	603.14	481.58	413.45	516.48	6,609.13
	Transmission	61.56	62.72	50.38	37.76	37.47	49.76	66.06	63.72	56.39	45.03	38.66	48.29	617.78
	Distribution	117.54	119.74	96.18	74.95	74.39	98.79	131.13	126.50	111.95	89.38	76.74	95.86	1,213.15
	Supply	29.99	30.02	30.06	29.78	29.81	29.85	29.88	29.91	29.95	29.98	30.01	30.04	359.29
General	Production	111.73	106.08	100.77	92.64	105.30	122.15	142.26	133.65	127.63	123.32	97.06	99.62	1,362.21
	Transmission	10.84	10.30	9.78	8.72	9.91	11.49	13.39	12.58	12.01	11.60	9.13	9.38	129.13
	Distribution	19.16	18.19	17.28	16.32	18.55	21.52	25.06	23.55	22.49	21.73	17.10	17.55	238.50
	Supply	3.57	3.57	3.57	3.53	3.52	3.52	3.52	3.51	3.51	3.51	3.50	3.50	42.34
Street lighting	Production	5.81	5.84	6.24	5.13	5.27	4.92	4.52	4.54	4.24	4.86	5.00	4.65	61.02
	Transmission	0.54	0.54	0.58	0.45	0.46	0.43	0.39	0.40	0.37	0.42	0.44	0.41	5.42
	Distribution	1.19	1.19	1.28	1.04	1.07	1.00	0.92	0.92	0.86	0.99	1.02	0.94	12.42
	Supply	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	1.10
Low V TOU	Production	320.62	291.16	212.58	207.56	261.99	290.87	511.90	489.65	276.52	275.07	244.09	328.30	3,710.32
	Transmission	24.01	21.83	20.92	19.76	24.88	27.66	57.31	55.10	26.41	26.17	23.21	23.66	350.92
	Distribution	49.13	44.82	43.92	43.93	54.21	60.23	79.36	77.66	59.22	57.47	50.58	50.39	670.92
	Supply	4.87	4.91	4.94	4.94	4.81	4.84	4.87	4.91	4.93	4.98	5.01	5.06	59.07
Low V TOU / Collective Sale	Production	7.28	6.27	3.81	2.62	2.92	3.43	6.04	5.78	3.30	3.02	3.22	5.69	53.42
	Transmission	0.53	0.46	0.38	0.25	0.28	0.33	0.69	0.66	0.32	0.29	0.31	0.40	4.89
	Distribution	0.55	0.47	0.40	0.28	0.30	0.36	0.56	0.55	0.35	0.32	0.34	0.43	4.90
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Low V Bulk (PA)	Production	2.98	2.68	2.73	2.41	2.56	2.82	3.33	3.29	2.94	2.91	2.46	2.67	33.79
	Transmission	0.29	0.26	0.26	0.22	0.23	0.26	0.30	0.30	0.27	0.27	0.22	0.24	3.12

Rate Class	Function	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Total
	Distribution	0.55	0.50	0.51	0.44	0.47	0.52	0.61	0.61	0.54	0.54	0.45	0.49	6.24
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V Bulk (PA)	Production	81.26	78.59	82.96	69.35	76.76	72.33	86.35	96.19	72.55	78.09	61.94	74.98	931.34
	Transmission	7.72	7.47	7.88	6.43	7.12	6.71	8.01	8.92	6.73	7.24	5.75	6.95	86.93
	Distribution	2.13	2.06	2.18	1.84	2.04	1.92	2.29	2.55	1.92	2.07	1.64	1.99	24.63
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V TOU	Production	543.44	496.45	381.16	381.45	458.98	487.86	839.37	810.77	450.00	462.68	424.38	550.48	6,287.01
	Transmission	40.91	37.41	37.52	36.31	43.61	46.41	94.84	92.05	42.99	44.05	40.36	39.94	596.39
	Distribution	11.99	10.98	11.05	11.07	13.10	13.96	19.99	19.65	13.30	13.35	12.13	12.01	162.58
	Supply	0.93	0.94	0.94	0.93	0.94	0.94	0.94	0.95	0.95	0.95	0.96	0.96	11.33
Med V TOU / Collective Sale	Production	1.95	1.83	1.32	1.35	1.62	1.66	2.53	3.06	1.72	1.79	1.87	8.23	28.91
	Transmission	0.15	0.14	0.13	0.13	0.15	0.16	0.29	0.35	0.16	0.17	0.18	0.59	2.60
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V Bulk TOU (PA)	Production	91.31	81.39	52.00	36.79	38.35	41.19	65.38	67.22	40.70	40.89	39.98	75.66	670.86
	Transmission	6.74	6.07	5.12	3.51	3.66	3.93	7.57	7.74	3.90	3.90	3.81	5.93	61.88
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
High V TOU	Production	142.52	139.54	122.06	136.12	153.31	148.77	200.02	208.07	142.09	151.47	143.51	194.18	1,881.67
	Transmission	4.80	4.69	5.47	5.88	6.65	6.44	12.57	13.07	6.07	6.55	6.24	6.30	84.73
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.15
Total		2,367.72	2,270.53	1,855.68	1,647.81	1,845.58	2,099.36	3,128.91	3,050.02	2,130.54	1,996.75	1,764.85	2,222.36	26,380.10

Table 55 - Calculated Revenues for 2012 Year-End Rates in Effect (Million NIS)

Rate Class	Function	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Total
Residential	Production	685.07	697.87	560.56	405.63	402.55	534.61	709.64	684.57	605.82	483.71	415.28	518.77	6,704.07
	Transmission	60.74	61.88	49.71	35.97	35.69	47.40	62.92	60.70	53.72	42.89	36.82	46.00	594.45
	Distribution	126.59	128.96	103.58	74.95	74.39	98.79	131.13	126.50	111.95	89.38	76.74	95.86	1,238.83
	Supply	29.68	29.72	29.75	29.78	29.81	29.85	29.88	29.91	29.95	29.98	30.01	30.04	358.36
General	Production	117.24	111.31	105.73	93.05	105.77	122.69	142.89	134.24	128.20	123.86	97.49	100.06	1,382.53
	Transmission	10.47	9.94	9.44	8.31	9.44	10.95	12.76	11.99	11.45	11.06	8.70	8.93	123.43
	Distribution	20.56	19.52	18.55	16.32	18.55	21.52	25.06	23.55	22.49	21.73	17.10	17.55	242.50
	Supply	3.54	3.53	3.53	3.53	3.52	3.52	3.52	3.51	3.51	3.51	3.50	3.50	42.23
Street lighting	Production	6.32	6.35	6.78	5.15	5.30	4.94	4.54	4.56	4.26	4.88	5.03	4.67	62.77
	Transmission	0.52	0.52	0.56	0.42	0.44	0.41	0.37	0.38	0.35	0.40	0.41	0.38	5.17
	Distribution	1.28	1.28	1.37	1.04	1.07	1.00	0.92	0.92	0.86	0.99	1.02	0.94	12.69
	Supply	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	1.09
Low V TOU	Production	340.34	309.07	225.50	208.48	263.15	292.16	514.17	491.82	277.75	276.29	245.17	329.75	3,773.66
	Transmission	23.03	20.94	20.36	18.84	23.72	26.37	55.05	52.93	25.18	24.95	22.13	22.21	335.70
	Distribution	52.79	48.16	47.21	43.93	54.21	60.23	79.36	77.66	59.22	57.47	50.58	50.39	681.22
	Supply	4.82	4.86	4.90	4.94	4.81	4.84	4.87	4.91	4.93	4.98	5.01	5.06	58.94
Low V TOU / Collective Sale	Production	7.73	6.66	4.05	2.64	2.94	3.45	6.07	5.81	3.32	3.04	3.24	5.72	54.64
	Transmission	0.51	0.44	0.37	0.24	0.27	0.31	0.66	0.64	0.30	0.28	0.29	0.38	4.68
	Distribution	0.58	0.50	0.43	0.28	0.30	0.36	0.56	0.55	0.35	0.32	0.34	0.43	4.99
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Low V Bulk (PA)	Production	3.25	2.92	2.98	2.42	2.57	2.83	3.35	3.30	2.96	2.92	2.47	2.69	34.67
	Transmission	0.28	0.25	0.26	0.21	0.22	0.24	0.29	0.29	0.26	0.25	0.21	0.23	2.99
	Distribution	0.60	0.54	0.55	0.44	0.47	0.52	0.61	0.61	0.54	0.54	0.45	0.49	6.35
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-

Rate Class	Function	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Total
Med V Bulk (PA)	Production	84.75	81.97	86.52	69.66	77.10	72.65	86.73	96.61	72.87	78.44	62.21	75.31	944.82
	Transmission	7.45	7.21	7.61	6.13	6.78	6.39	7.63	8.50	6.41	6.90	5.47	6.62	83.08
	Distribution	2.24	2.16	2.28	1.84	2.04	1.92	2.29	2.55	1.92	2.07	1.64	1.99	24.94
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V TOU	Production	576.84	526.95	404.40	383.14	461.01	490.02	843.09	814.37	452.00	464.74	426.26	552.92	6,395.73
	Transmission	39.26	35.90	36.52	34.62	41.58	44.25	91.12	88.45	41.00	42.00	38.48	37.50	570.66
	Distribution	12.63	11.57	11.64	11.07	13.10	13.96	19.99	19.65	13.30	13.35	12.13	12.01	164.41
	Supply	0.92	0.93	0.93	0.93	0.94	0.94	0.94	0.95	0.95	0.95	0.96	0.96	11.30
Med V TOU / Collective Sale	Production	2.07	1.95	1.40	1.35	1.62	1.66	2.54	3.08	1.72	1.79	1.88	8.27	29.33
	Transmission	0.14	0.13	0.13	0.12	0.15	0.15	0.28	0.34	0.16	0.16	0.17	0.55	2.48
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V Bulk TOU (PA)	Production	96.93	86.39	55.19	36.95	38.52	41.37	65.67	67.52	40.88	41.07	40.16	76.00	686.65
	Transmission	6.45	5.82	4.99	3.35	3.49	3.75	7.28	7.44	3.72	3.72	3.63	5.60	59.23
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
High V TOU	Production	151.27	148.11	129.61	136.72	153.99	149.43	200.90	208.99	142.72	152.15	144.15	195.04	1,913.09
	Transmission	4.24	4.14	5.01	5.28	5.97	5.78	11.69	12.15	5.44	5.88	5.60	5.44	76.61
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.15
Total		2,481.23	2,378.55	1,942.48	1,647.81	1,845.58	2,099.36	3,128.91	3,050.02	2,130.54	1,996.75	1,764.85	2,222.36	26,688.44

Table 56 - Calculated Revenues for 2013 Year-End Rates in Effect (Million NIS)

Rate Class	Function	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total
Residential	Production	688.03	700.89	562.99	407.38	387.13	492.74	654.06	630.95	558.37	445.82	382.76	478.14	6,389.25
	Transmission	64.65	65.86	52.90	38.28	38.08	50.73	67.33	64.95	57.48	45.90	39.40	49.22	634.79
	Distribution	127.76	130.14	104.54	75.65	77.65	106.35	141.16	136.18	120.51	96.22	82.61	103.19	1,301.96
	Supply	30.28	30.32	30.35	30.39	30.64	30.90	30.94	30.97	31.01	31.04	31.07	31.11	369.02
General	Production	117.80	111.84	106.24	93.50	100.04	109.25	127.25	119.54	114.16	110.30	86.82	89.11	1,285.86
	Transmission	11.14	10.58	10.05	8.84	9.96	11.46	13.35	12.54	11.97	11.57	9.11	9.35	129.90
	Distribution	20.76	19.71	18.73	16.48	19.32	23.06	26.86	25.23	24.09	23.28	18.32	18.81	254.64
	Supply	3.55	3.55	3.55	3.54	3.57	3.59	3.59	3.58	3.58	3.58	3.57	3.57	42.82
Street lighting	Production	6.35	6.37	6.81	5.17	5.05	4.47	4.11	4.12	3.86	4.42	4.55	4.23	59.51
	Transmission	0.56	0.56	0.60	0.45	0.47	0.44	0.41	0.41	0.38	0.44	0.45	0.42	5.58
	Distribution	1.29	1.30	1.38	1.05	1.12	1.08	0.99	0.99	0.93	1.06	1.10	1.02	13.31
	Supply	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	1.12
Low V TOU	Production	341.98	310.56	226.59	209.49	251.07	264.83	466.27	446.03	251.85	250.47	222.24	298.78	3,540.15
	Transmission	24.92	22.66	21.66	20.04	25.31	28.23	58.86	56.58	26.95	26.71	23.69	24.03	359.62
	Distribution	53.31	48.63	47.66	44.36	56.60	64.81	85.60	83.75	63.72	61.85	54.44	54.25	718.97
	Supply	4.66	4.70	4.74	4.78	4.82	4.86	4.90	4.94	4.98	5.01	5.05	5.09	58.53
Low V TOU / Collective Sale	Production	7.77	6.69	4.07	2.65	2.80	3.13	5.50	5.27	3.01	2.75	2.94	5.18	51.75
	Transmission	0.55	0.48	0.39	0.25	0.28	0.33	0.71	0.68	0.32	0.29	0.31	0.41	5.02
	Distribution	0.59	0.51	0.43	0.28	0.32	0.39	0.61	0.60	0.39	0.35	0.37	0.47	5.28
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Low V Bulk (PA)	Production	3.39	3.05	3.11	2.52	2.52	2.62	3.10	3.06	2.73	2.70	2.29	2.48	33.57
	Transmission	0.31	0.28	0.28	0.23	0.24	0.27	0.32	0.31	0.28	0.28	0.23	0.26	3.30
	Distribution	0.62	0.56	0.57	0.46	0.51	0.58	0.69	0.68	0.60	0.60	0.51	0.55	6.93
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-

Rate Class	Function	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total
Med V Bulk (PA)	Production	88.33	85.44	90.18	72.60	77.95	71.31	85.13	94.83	71.53	76.99	61.06	73.92	949.28
	Transmission	8.23	7.96	8.41	6.77	7.63	7.31	8.73	9.72	7.33	7.89	6.26	7.58	93.83
	Distribution	2.34	2.27	2.39	1.93	2.20	2.13	2.54	2.83	2.13	2.29	1.82	2.20	27.06
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V TOU	Production	573.83	524.21	402.30	381.15	435.48	439.81	757.00	731.25	405.81	417.15	382.57	495.98	5,946.51
	Transmission	42.03	38.44	38.46	36.46	43.92	46.89	96.41	93.57	43.43	44.50	40.78	40.15	605.04
	Distribution	12.63	11.57	11.64	11.06	13.39	14.57	20.87	20.51	13.88	13.94	12.66	12.53	169.25
	Supply	0.92	0.93	0.93	0.93	0.95	0.96	0.96	0.96	0.97	0.97	0.97	0.98	11.43
Med V TOU / Collective Sale	Production	2.05	1.94	1.40	1.34	1.53	1.49	2.28	2.76	1.55	1.61	1.68	7.42	27.06
	Transmission	0.15	0.14	0.13	0.13	0.15	0.16	0.30	0.36	0.17	0.17	0.18	0.59	2.63
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V Bulk TOU (PA)	Production	94.40	83.64	57.52	38.51	38.13	38.92	61.80	63.54	38.47	38.64	37.77	71.54	662.89
	Transmission	7.22	6.50	5.50	3.69	3.86	4.16	8.06	8.24	4.13	4.13	4.03	6.26	65.79
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
High V TOU	Production	148.13	145.03	126.91	133.87	143.21	132.08	177.65	184.80	126.18	134.48	127.40	172.22	1,751.94
	Transmission	4.89	4.78	5.55	5.84	6.56	6.32	12.53	13.03	5.95	6.43	6.12	6.11	84.10
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.15
Total		2,495.55	2,392.17	1,959.06	1,660.20	1,792.58	1,970.32	2,930.95	2,857.86	2,002.79	1,873.93	1,655.24	2,077.21	25,667.87

Table 57 - Calculated Revenues for 2014 Year-End Rates in Effect (Million NIS)

Rate Class	Function	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total
Residential	Production	648.48	660.59	530.62	383.96	381.05	506.06	671.74	648.01	573.46	457.88	393.10	491.06	6,346.01
	Transmission	64.28	65.48	52.59	38.06	37.77	50.16	66.58	64.23	56.84	45.38	38.96	48.67	629.00
	Distribution	139.47	133.20	106.99	77.42	76.83	102.04	135.45	130.66	115.63	92.32	79.26	99.02	1,288.30
	Supply	31.02	31.06	31.09	31.12	31.16	31.19	31.23	31.26	31.30	31.33	31.36	31.40	374.52
General	Production	108.59	103.09	97.93	86.18	97.96	113.63	132.35	124.34	118.74	114.72	90.30	92.68	1,280.51
	Transmission	10.97	10.42	9.90	8.71	9.90	11.48	13.37	12.56	12.00	11.59	9.12	9.36	129.39
	Distribution	22.84	20.43	19.41	17.08	19.41	22.52	26.23	24.64	23.53	22.74	17.90	18.37	255.10
	Supply	3.66	3.65	3.65	3.65	3.64	3.64	3.64	3.63	3.63	3.63	3.62	3.62	43.66
Street lighting	Production	5.88	5.90	6.30	4.78	4.92	4.59	4.22	4.23	3.96	4.54	4.67	4.34	58.35
	Transmission	0.56	0.56	0.60	0.46	0.47	0.44	0.40	0.40	0.38	0.43	0.45	0.41	5.56
	Distribution	1.41	1.33	1.42	1.08	1.11	1.03	0.95	0.95	0.89	1.02	1.05	0.98	13.20
	Supply	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.14
Low V TOU	Production	320.73	291.27	212.63	196.60	248.10	275.45	484.96	463.91	261.94	260.51	231.15	310.76	3,558.02
	Transmission	24.71	22.47	21.85	20.22	25.46	28.30	59.32	57.04	27.02	26.78	23.75	23.83	360.74
	Distribution	58.91	50.40	49.40	45.98	56.73	63.03	83.06	81.27	61.98	60.15	52.94	52.73	716.58
	Supply	4.74	4.77	4.81	4.85	4.89	4.93	4.97	5.01	5.04	5.08	5.12	5.16	59.37
Low V TOU / Collective Sale	Production	7.29	6.27	3.82	2.49	2.77	3.25	5.72	5.48	3.13	2.86	3.05	5.39	51.53
	Transmission	0.55	0.47	0.39	0.26	0.29	0.34	0.71	0.69	0.32	0.30	0.32	0.40	5.03
	Distribution	0.65	0.53	0.45	0.29	0.32	0.37	0.59	0.57	0.37	0.33	0.35	0.45	5.27
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Low V Bulk (PA)	Production	3.16	2.84	2.90	2.35	2.50	2.75	3.26	3.21	2.88	2.84	2.40	2.61	33.71
	Transmission	0.31	0.28	0.29	0.23	0.25	0.27	0.32	0.32	0.28	0.28	0.24	0.26	3.34
	Distribution	0.70	0.59	0.60	0.49	0.52	0.57	0.67	0.66	0.60	0.59	0.50	0.54	7.02
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-

Rate Class	Function	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total
Med V Bulk (PA)	Production	87.48	84.61	89.31	71.90	79.59	74.99	89.53	99.73	75.22	80.96	64.22	77.74	975.26
	Transmission	8.63	8.35	8.81	7.10	7.85	7.40	8.84	9.84	7.42	7.99	6.34	7.67	96.25
	Distribution	2.60	2.38	2.51	2.02	2.23	2.11	2.51	2.80	2.11	2.27	1.80	2.18	27.52
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V TOU	Production	534.10	487.91	374.69	355.00	427.08	453.97	781.37	754.79	418.87	430.58	394.89	511.95	5,925.18
	Transmission	41.37	37.84	38.50	36.50	43.84	46.66	96.46	93.62	43.22	44.28	40.58	39.52	602.40
	Distribution	13.56	11.90	11.97	11.38	13.47	14.35	20.56	20.21	13.67	13.73	12.47	12.35	169.62
	Supply	0.95	0.95	0.96	0.96	0.96	0.97	0.97	0.98	0.98	0.98	0.99	0.99	11.64
Med V TOU / Collective Sale	Production	1.91	1.80	1.30	1.25	1.50	1.54	2.36	2.85	1.60	1.66	1.74	7.65	27.17
	Transmission	0.15	0.14	0.13	0.13	0.15	0.16	0.30	0.36	0.17	0.17	0.18	0.58	2.61
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V Bulk TOU (PA)	Production	89.64	79.43	54.59	36.56	38.10	40.93	64.99	66.82	40.46	40.63	39.72	75.23	667.10
	Transmission	7.26	6.54	5.61	3.77	3.92	4.21	8.22	8.40	4.19	4.19	4.09	6.30	66.72
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
High V TOU	Production	136.19	133.34	116.80	123.21	138.77	134.67	181.13	188.42	128.65	137.11	129.89	175.59	1,723.76
	Transmission	4.36	4.26	5.16	5.43	6.15	5.95	12.10	12.58	5.60	6.06	5.77	5.60	79.02
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.15
Total		2,387.20	2,275.16	1,868.09	1,581.56	1,769.80	2,014.07	2,999.18	2,924.59	2,046.17	1,916.04	1,692.41	2,125.49	25,599.76

Table 58 - Calculated Revenues for 2015 Year-End Rates in Effect (Million NIS)

Rate Class	Function	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
Residential	Production	663.35	675.74	542.79	392.77	389.79	517.66	687.14	662.86	586.61	468.37	402.12	502.32	6,491.52
	Transmission	65.75	66.98	53.80	38.93	38.63	51.31	68.11	65.70	58.14	46.42	39.86	49.79	643.43
	Distribution	142.67	136.25	109.45	79.20	78.59	104.38	138.55	133.66	118.28	94.44	81.08	101.29	1,317.84
	Supply	31.43	31.46	31.50	31.53	31.57	31.60	31.64	31.67	31.71	31.74	31.78	31.81	379.43
General	Production	112.41	106.72	101.38	89.21	101.41	117.63	137.01	128.71	122.92	118.76	93.48	95.94	1,325.59
	Transmission	11.36	10.78	10.24	9.01	10.25	11.89	13.84	13.01	12.42	12.00	9.45	9.69	133.94
	Distribution	23.64	21.15	20.09	17.68	20.10	23.31	27.15	25.51	24.36	23.54	18.53	19.01	264.08
	Supply	3.70	3.70	3.70	3.69	3.69	3.69	3.68	3.68	3.68	3.67	3.67	3.67	44.23
Street lighting	Production	6.01	6.03	6.45	4.89	5.04	4.70	4.32	4.33	4.05	4.64	4.78	4.44	59.68
	Transmission	0.57	0.57	0.61	0.47	0.48	0.45	0.41	0.41	0.39	0.44	0.46	0.42	5.69
	Distribution	1.44	1.36	1.45	1.10	1.13	1.06	0.97	0.97	0.91	1.04	1.07	1.00	13.50
	Supply	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.16
Low V TOU	Production	332.02	301.52	220.12	203.52	256.83	285.15	502.03	480.24	271.16	269.68	239.29	321.70	3,683.26
	Transmission	25.58	23.26	22.62	20.93	26.36	29.30	61.41	59.04	27.97	27.72	24.59	24.66	373.44
	Distribution	60.98	52.18	51.14	47.60	58.73	65.25	85.98	84.14	64.16	62.26	54.80	54.59	741.81
	Supply	4.80	4.84	4.88	4.91	4.95	4.99	5.03	5.07	5.11	5.15	5.19	5.23	60.15
Low V TOU / Collective Sale	Production	7.54	6.49	3.95	2.57	2.87	3.37	5.93	5.67	3.24	2.96	3.16	5.58	53.34
	Transmission	0.57	0.49	0.41	0.27	0.30	0.35	0.74	0.71	0.34	0.31	0.33	0.42	5.21
	Distribution	0.68	0.55	0.46	0.30	0.33	0.39	0.61	0.59	0.38	0.34	0.36	0.46	5.46
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Low V Bulk (PA)	Production	3.30	2.97	3.03	2.46	2.62	2.88	3.41	3.36	3.01	2.97	2.51	2.73	35.26
	Transmission	0.33	0.29	0.30	0.24	0.26	0.29	0.34	0.33	0.30	0.29	0.25	0.27	3.49
	Distribution	0.73	0.62	0.63	0.51	0.54	0.60	0.70	0.70	0.62	0.62	0.52	0.57	7.34
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-

Rate Class	Function	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
Med V Bulk (PA)	Production	91.48	88.48	93.40	75.19	83.23	78.42	93.63	104.29	78.66	84.67	67.16	81.30	1,019.91
	Transmission	9.03	8.73	9.22	7.42	8.21	7.74	9.24	10.29	7.76	8.36	6.63	8.02	100.66
	Distribution	2.72	2.48	2.62	2.11	2.34	2.20	2.63	2.93	2.21	2.38	1.89	2.28	28.78
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V TOU	Production	548.95	501.48	385.11	364.88	438.96	466.59	803.10	775.79	430.52	442.55	405.88	526.19	6,090.00
	Transmission	42.52	38.89	39.57	37.51	45.06	47.96	99.14	96.23	44.42	45.51	41.70	40.62	619.15
	Distribution	13.94	12.23	12.30	11.70	13.84	14.75	21.13	20.77	14.05	14.11	12.82	12.69	174.34
	Supply	0.96	0.96	0.97	0.97	0.98	0.98	0.98	0.99	0.99	0.99	1.00	1.00	11.77
Med V TOU / Collective Sale	Production	1.97	1.85	1.34	1.29	1.55	1.59	2.42	2.93	1.64	1.71	1.79	7.87	27.93
	Transmission	0.15	0.14	0.14	0.13	0.16	0.16	0.30	0.37	0.17	0.18	0.18	0.60	2.69
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V Bulk TOU (PA)	Production	93.74	83.06	57.09	38.23	39.85	42.80	67.97	69.88	42.31	42.50	41.54	78.67	697.64
	Transmission	7.60	6.84	5.87	3.94	4.10	4.41	8.60	8.79	4.38	4.38	4.28	6.59	69.77
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
High V TOU	Production	138.34	135.44	118.64	125.16	140.96	136.79	183.99	191.40	130.68	139.28	131.95	178.36	1,750.99
	Transmission	4.43	4.33	5.24	5.52	6.25	6.04	12.29	12.78	5.68	6.15	5.86	5.69	80.27
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.15
Total		2,454.80	2,339.01	1,920.61	1,625.96	1,820.06	2,070.78	3,084.55	3,007.91	2,103.35	1,970.27	1,740.02	2,185.57	26,322.88

Table 59 - Calculated Revenues for 2016 Year-End Rates in Effect (Million NIS)

Rate Class	Function	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Residential	Production	678.22	690.89	554.96	401.57	398.52	529.27	702.55	677.72	599.76	478.87	411.13	513.58	6,637.03
	Transmission	67.22	68.48	55.01	39.80	39.50	52.46	69.64	67.17	59.45	47.47	40.75	50.91	657.85
	Distribution	145.87	139.31	111.90	80.97	80.36	106.72	141.66	136.65	120.93	96.56	82.90	103.56	1,347.38
	Supply	31.84	31.88	31.92	31.95	31.99	32.02	32.06	32.09	32.13	32.16	32.20	32.23	384.46
General	Production	116.23	110.35	104.83	92.25	104.86	121.63	141.67	133.09	127.10	122.80	96.66	99.20	1,370.66
	Transmission	11.74	11.15	10.59	9.32	10.60	12.29	14.31	13.45	12.84	12.41	9.77	10.02	138.49
	Distribution	24.44	21.87	20.78	18.28	20.78	24.11	28.08	26.38	25.19	24.34	19.16	19.66	273.06
	Supply	3.75	3.75	3.74	3.74	3.74	3.73	3.73	3.73	3.72	3.72	3.71	3.71	44.77
Street lighting	Production	6.15	6.17	6.59	5.00	5.15	4.80	4.42	4.43	4.14	4.75	4.89	4.54	61.02
	Transmission	0.59	0.59	0.63	0.48	0.49	0.46	0.42	0.42	0.39	0.45	0.47	0.43	5.81
	Distribution	1.48	1.39	1.48	1.12	1.16	1.08	0.99	1.00	0.93	1.07	1.10	1.02	13.81
	Supply	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.17
Low V TOU	Production	343.31	311.77	227.60	210.44	265.57	294.84	519.10	496.57	280.38	278.85	247.43	332.64	3,808.50
	Transmission	26.45	24.05	23.39	21.64	27.25	30.30	63.50	61.05	28.92	28.67	25.42	25.50	386.14
	Distribution	63.06	53.95	52.88	49.21	60.73	67.47	88.90	87.00	66.34	64.38	56.67	56.45	767.03
	Supply	4.86	4.90	4.94	4.97	5.01	5.05	5.09	5.13	5.17	5.21	5.25	5.29	60.88
Low V TOU / Collective Sale	Production	7.80	6.72	4.09	2.66	2.97	3.48	6.13	5.87	3.35	3.07	3.27	5.77	55.15
	Transmission	0.59	0.51	0.42	0.27	0.31	0.36	0.76	0.73	0.35	0.32	0.34	0.43	5.38
	Distribution	0.70	0.56	0.48	0.31	0.34	0.40	0.63	0.61	0.40	0.36	0.38	0.48	5.65
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Low V Bulk (PA)	Production	3.45	3.10	3.16	2.57	2.73	3.01	3.55	3.51	3.14	3.10	2.62	2.85	36.80
	Transmission	0.34	0.31	0.31	0.25	0.27	0.30	0.35	0.35	0.31	0.31	0.26	0.28	3.64
	Distribution	0.76	0.64	0.65	0.53	0.56	0.62	0.74	0.73	0.65	0.64	0.54	0.59	7.66
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-

Rate Class	Function	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Med V Bulk (PA)	Production	95.49	92.36	97.48	78.48	86.87	81.86	97.72	108.86	82.11	88.38	70.10	84.85	1,064.56
	Transmission	9.42	9.11	9.62	7.75	8.57	8.08	9.64	10.74	8.10	8.72	6.92	8.37	105.06
	Distribution	2.84	2.59	2.74	2.20	2.44	2.30	2.74	3.06	2.30	2.48	1.97	2.38	30.04
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V TOU	Production	563.81	515.05	395.53	374.75	450.84	479.22	824.84	796.78	442.18	454.53	416.86	540.43	6,254.83
	Transmission	43.68	39.94	40.64	38.53	46.28	49.25	101.83	98.83	45.62	46.74	42.83	41.72	635.91
	Distribution	14.32	12.56	12.64	12.01	14.22	15.15	21.70	21.33	14.43	14.49	13.16	13.03	179.06
	Supply	0.97	0.97	0.98	0.98	0.99	0.99	0.99	1.00	1.00	1.00	1.01	1.01	11.90
Med V TOU / Collective Sale	Production	2.02	1.90	1.37	1.32	1.59	1.63	2.49	3.01	1.69	1.75	1.83	8.08	28.68
	Transmission	0.16	0.15	0.14	0.14	0.16	0.17	0.31	0.38	0.17	0.18	0.19	0.62	2.76
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Med V Bulk TOU (PA)	Production	97.84	86.70	59.59	39.90	41.59	44.68	70.95	72.94	44.16	44.36	43.36	82.12	728.18
	Transmission	7.93	7.14	6.13	4.11	4.28	4.60	8.98	9.17	4.57	4.57	4.46	6.87	72.82
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
High V TOU	Production	140.49	137.55	120.49	127.11	143.15	138.92	186.85	194.37	132.71	141.44	134.00	181.14	1,778.21
	Transmission	4.50	4.40	5.32	5.60	6.35	6.14	12.48	12.98	5.77	6.25	5.95	5.78	81.52
	Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-
	Supply	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.15
Total		2,522.41	2,402.87	1,973.12	1,670.36	1,870.32	2,127.49	3,169.91	3,091.23	2,160.53	2,024.50	1,787.65	2,245.66	27,046.05

D. Rate Design

Table 60 – Residential Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	13.69	17.17	20.55	15.82	18.93
Distribution - Volumetric	0.0770	0.0832	0.0891	0.0624	0.0669
Distribution - Fixed Charge	-	-	-	13.52	14.61
Distribution - Demand Charge	-	-	-	-	-
Transmission - Volumetric	0.0355	0.0373	0.0390	0.0373	0.0390
Transmission - Demand Charge	-	-	-	-	-

Table 61 – General Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	57.83	72.51	86.81	63.18	75.70
Distribution - Volumetric	0.0778	0.0841	0.0900	0.0631	0.0675
Distribution - Fixed Charge	-	-	-	24.82	27.15
Distribution - Demand Charge	-	-	-	-	-
Transmission - Volumetric	0.0374	0.0393	0.0411	0.0393	0.0411
Transmission - Demand Charge	-	-	-	-	-

Table 62 – Street Lighting Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	57.83	72.51	86.81	59.23	70.89
Distribution - Volumetric	0.0743	0.0803	0.0860	0.0602	0.0645
Distribution - Fixed Charge	-	-	-	51.38	55.52
Distribution - Demand Charge	-	-	-	-	-
Transmission - Volumetric	0.0295	0.0310	0.0324	0.0310	0.0324
Transmission - Demand Charge	-	-	-	-	-

Table 63 – Low Voltage TOU Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	**2016**	**2015**	**2016**
Supply	151.2	189.6	227.0	307.7	368.7
Distribution - Volumetric					
Winter - Low	0.0718	0.0776	0.0831	0.0582	0.0623
Winter - Shoulder	0.0741	0.0801	0.0858	0.0601	0.0643
Winter - Peak	0.0924	0.0999	0.1070	0.0749	0.0803
Spring/Autumn - Low	0.0703	0.0760	0.0814	0.0570	0.0611
Spring/Autumn - Shoulder	0.0744		0.0862	0.0604	0.0646
Spring/Autumn - Peak	0.0767	0.0829	0.0888	0.0622	0.0666
Summer - Low	0.0742	0.0803	0.0859	0.0602	0.0645
Summer - Shoulder	0.0843	0.0911	0.0976	0.0683	0.0732
Summer - Peak	0.1098	0.1187	0.1271	0.0890	0.0953
Distribution - Fixed Charge	-	-	-	116.12	127.02
Distribution - Demand Charge	-	-	-	5.33	5.72
Transmission - Volumetric					
Winter - Low	0.0243	0.0256	0.0267	0.0192	0.0200
Winter - Shoulder	0.0285	0.0300	0.0313	0.0225	0.0235
Winter - Peak	0.0580	0.0609	0.0637	0.0457	0.0478
Spring/Autumn - Low	0.0221	0.0232	0.0243	0.0174	0.0182
Spring/Autumn - Shoulder	0.0310	0.0326	0.0341	0.0244	0.0256
Spring/Autumn - Peak	0.0371	0.0390	0.0408	0.0292	0.0306
Summer - Low	0.0312	0.0328	0.0343	0.0246	0.0257
Summer - Shoulder	0.0506	0.0531	0.0556	0.0399	0.0417
Summer - Peak	0.1031	0.1084	0.1134	0.0813	0.0850
Transmission - Demand Charge	-	-	-	4.12	4.32

Table 64 – Low Voltage TOU Collective Sale Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	-	-	-	-	-
Distribution - Volumetric					
Winter - Low	0.0339	0.0366	0.0392	0.0366	0.0392
Winter - Shoulder	0.0360	0.0389	0.0417	0.0389	0.0417
Winter - Peak	0.0540	0.0584	0.0625	0.0584	0.0625
Spring/Autumn - Low	0.0325	0.0351	0.0376	0.0351	0.0376
Spring/Autumn - Shoulder	0.0364	0.0394	0.0421	0.0394	0.0421
Spring/Autumn - Peak	0.0386	0.0417	0.0447	0.0417	0.0447
Summer - Low	0.0363	0.0392	0.0420	0.0392	0.0420
Summer - Shoulder	0.0460	0.0497	0.0533	0.0497	0.0533
Summer - Peak	0.0710	0.0768	0.0822	0.0768	0.0822
Distribution - Fixed Charge	-	-	-	-	-
Distribution - Demand Charge	-	-	-	-	-
Transmission - Volumetric					
Winter - Low	0.0241	0.0253	0.0265	0.0253	0.0265
Winter - Shoulder	0.0281	0.0296	0.0309	0.0296	0.0309
Winter - Peak	0.0570	0.0599	0.0627	0.0599	0.0627
Spring/Autumn - Low	0.0219	0.0230	0.0241	0.0230	0.0241
Spring/Autumn - Shoulder	0.0306	0.0322	0.0337	0.0322	0.0337
Spring/Autumn - Peak	0.0366	0.0385	0.0402	0.0385	0.0402
Summer - Low	0.0309	0.0324	0.0339	0.0324	0.0339
Summer - Shoulder	0.0498	0.0524	0.0548	0.0524	0.0548
Summer - Peak	0.1015	0.1066	0.1115	0.1066	0.1115
Transmission - Demand Charge	-	-	-	-	-

Table 65 – Low Voltage Bulk (PA) Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	-	-	-	-	-
Distribution - Volumetric	0.0764	0.0826	0.0884	0.0826	0.0884
Distribution - Fixed Charge	-	-	-	-	-
Distribution - Demand Charge	-	-	-	-	-
Transmission - Volumetric	0.0343	0.0361	0.0377	0.0361	0.0377
Transmission - Demand Charge	-	-	-	-	-

Table 66 – Medium Voltage Bulk (PA) Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	-	-	-	-	-
Distribution - Volumetric	0.0101	0.0109	0.0117	0.0109	0.0117
Distribution - Fixed Charge	-	-	-	-	-
Distribution - Demand Charge	-	-	-	-	-
Transmission - Volumetric	0.0335	0.0352	0.0368	0.0352	0.0368
Transmission - Demand Charge	-	-	-	-	-

Table 67 – Medium Voltage TOU Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	297.1	372.51	445.97	314.71	377.56
Distribution - Volumetric					
Winter - Low	0.0092	0.0099	0.0106	0.0074	0.0080
Winter - Shoulder	0.0095	0.0102	0.0109	0.0077	0.0082
Winter - Peak	0.0131	0.0142	0.0152	0.0106	0.0114
Spring/Autumn - Low	0.0090	0.0097	0.0104	0.0073	0.0078
Spring/Autumn - Shoulder	0.0096	0.0104	0.0111	0.0078	0.0083
Spring/Autumn - Peak	0.0100	0.0108	0.0116	0.0081	0.0087
Summer - Low	0.0097	0.0104	0.0112	0.0078	0.0084
Summer - Shoulder	0.0115	0.0124	0.0133	0.0093	0.0099
Summer - Peak	0.0166	0.0180	0.0193	0.0135	0.0144
Distribution - Fixed Charge	-	-	-	493.47	536.91
Distribution - Demand Charge	-	-	-	0.813	0.872
Transmission - Volumetric					
Winter - Low	0.0237	0.0249	0.0260	0.0186	0.0195
Winter - Shoulder	0.0275	0.0289	0.0302	0.0217	0.0227
Winter - Peak	0.0556	0.0584	0.0611	0.0438	0.0458
Spring/Autumn - Low	0.0216	0.0227	0.0237	0.0170	0.0178
Spring/Autumn - Shoulder	0.0300	0.0316	0.0330	0.0237	0.0248
Spring/Autumn - Peak	0.0358	0.0376	0.0394	0.0282	0.0295
Summer - Low	0.0303	0.0318	0.0333	0.0239	0.0250
Summer - Shoulder	0.0487	0.0511	0.0535	0.0383	0.0401
Summer - Peak	0.0987	0.1037	0.1085	0.0778	0.0814
Transmission - Demand Charge	-	-	-	4.507	4.724

Table 68 – Medium Voltage TOU Collective Sale Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	-	-	-	-	-
Distribution - Volumetric					
Winter - Low	-	-	-	-	-
Winter - Shoulder	-	-	-	-	-
Winter - Peak	-	-	-	-	-
Spring/Autumn - Low	-	-	-	-	-
Spring/Autumn - Shoulder	-	-	-	-	-
Spring/Autumn - Peak	-	-	-	-	-
Summer - Low	-	-	-	-	-
Summer - Shoulder	-	-	-	-	-
Summer - Peak	-	-	-	-	-
Distribution - Fixed Charge	-	-	-	-	-
Distribution - Demand Charge	-	-	-	-	-
Transmission - Volumetric					
Winter - Low	0.0235	0.0247	0.0258	0.0247	0.0258
Winter - Shoulder	0.0273	0.0287	0.0300	0.0287	0.0300
Winter - Peak	0.0550	0.0578	0.0605	0.0578	0.0605
Spring/Autumn - Low	0.0214	0.0225	0.0236	0.0225	0.0236
Spring/Autumn - Shoulder	0.0298	0.0313	0.0327	0.0313	0.0327
Spring/Autumn - Peak	0.0355	0.0373	0.0390	0.0373	0.0390
Summer - Low	0.0300	0.0316	0.0330	0.0316	0.0330
Summer - Shoulder	0.0482	0.0506	0.0529	0.0506	0.0529
Summer - Peak	0.0976	0.1026	0.1072	0.1026	0.1072
Transmission - Demand Charge	-	-	-	-	-

Table 69 – High Voltage TOU Tariff Rate Change Scenarios

	Existing Tariff	Scenario 1		Scenario 2	
		2015	2016	2015	2016
Supply	298.66	374.49	448.34	460.30	558.32
Distribution - Volumetric					
Winter - Low	-	-	-	-	-
Winter - Shoulder	-	-	-	-	-
Winter - Peak	-	-	-	-	-
Spring/Autumn - Low	-	-	-	-	-
Spring/Autumn - Shoulder	-	-	-	-	-
Spring/Autumn - Peak	-	-	-	-	-
Summer - Low	-	-	-	-	-
Summer - Shoulder	-	-	-	-	-
Summer - Peak	-	-	-	-	-
Distribution - Fixed Charge	-	-	-	-	-
Distribution - Demand Charge	-	-	-	-	-
Transmission - Volumetric					
Winter - Low	0.0085	0.0090	0.0094	0.0067	0.0070
Winter - Shoulder	0.0105	0.0110	0.0115	0.0083	0.0086
Winter - Peak	0.0266	0.0280	0.0293	0.0210	0.0219
Spring/Autumn - Low	0.0077	0.0081	0.0085	0.0061	0.0063
Spring/Autumn - Shoulder	0.0129	0.0136	0.0142	0.0102	0.0107
Spring/Autumn - Peak	0.0170	0.0179	0.0187	0.0134	0.0140
Summer - Low	0.0135	0.0142	0.0148	0.0106	0.0111
Summer - Shoulder	0.0247	0.0260	0.0272	0.0195	0.0204
Summer - Peak	0.0581	0.0611	0.0639	0.0458	0.0479
Transmission - Demand Charge	-	-	-	1.79	1.88