DEVELOPMENT OF THE ALGORITHM OF SOlAR TURnKEY: SOLAR ELECTRICITY SOFTWARE FOR TURKEY

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
THE MIDDLE EAST TECHNICAL UNIVERSITY

BY

ABDULLAH BUĞRAHAN KARAVELİ

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF DOCTOR OF PHILOSOPHY
IN
EARTH SYSTEM SCIENCE

AUGUST 2018

Approval of the thesis:

DEVELOPMENT OF THE ALGORITHM OF SOlAR TURnKEY: SOLAR ELECTRICITY SOFTWARE FOR TURKEY

submitted by **ABDULLAH BUĞRAHAN KARAVELİ** in partial fulfillment of the requirements for the degree of **Doctor of Philosophy in Earth System Science (ESS), Middle East Technical University** by,

Prof. Dr. Halil Kalıpçılar ______________________
Dean, Graduate School of **Natural and Applied Sciences**

Prof. Dr. Cemal Can Bilgin ______________________
Head of Program, **Earth System Science**

Prof. Dr. Bülent Gültekin Akınoğlu ______________________
Supervisor, **Physics Dept., METU**

Prof. Dr. Uğur Soytaş ______________________
Co-Supervisor, **Bus. Adm. Dept., METU**

Examining Committee Members:

Prof. Dr. Raşit Turan ______________________
Physics Dept., METU

Prof. Dr. Bülent Gültekin Akınoğlu ______________________
Physics Dept., METU

Assoc. Prof. Dr. Merih Aydınalp Köksal ______________________
Env. Eng. Dept., Hacettepe University

Asst. Prof. Dr. Selçuk Yerci ______________________
Micro and Nanotechnology Prog., METU

Asst. Prof. Dr. Talat Özden ______________________
Energy Syst. Eng. Dept., Gumushane University

Date: ________________

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Last name : Abdullah Buğrahan Karaveli

Signature :

ABSTRACT

DEVELOPMENT OF THE ALGORITHM OF SOlAR TURnKEY: SOLAR ELECTRICITY SOFTWARE FOR TURKEY

Karaveli, Abdullah Buğrahan

Ph.D., Earth System Science (ESS)

Supervisor : Prof. Dr. Bülent Gültekin Akınoğlu

Co-Supervisor: Prof. Dr. Uğur Soytaş

August 2018, 121 pages

Together with the increase in population, consumption, environmental threats, social inclusion and poverty eradication needs, natural resource corruption and price, rapid electrification of the world necessitates to meet energy demand in the most efficient, economic, environmental and social way. At this point with the sharp decrease in prices, increase in efficiency and development in technology in addition to environmental friendliness and social inclusiveness, solar electricity has gained importance when compared to alternatives. On the other hand, today's highly advanced cyber technology enables the best, the most feasible and the highest efficient design ways to make for the investments owing to robust algorithm and infrastructure. As being solar belt country and having increase in population and consumption, Turkey has better to have solar electricity on the top of the agenda. However, there is a lack of experience, knowledge and technological sovereignty on the subject. This study by forming the infrastructure of a software program serving for making technical and economic feasibility analysis and preparing dynamic application projects for solar electricity fill the mentioned gaps on the sector. As the outcome of the study, an algorithm for the software program namely SOlAR TURnKEY has been formed. This algorithm is able to calculate total solar irradiation to be exposed, optimum design parameters, total electricity production, CO_2 emission reduction potential, total cost, payback time, total revenue, profit and other economic parameters of the project organized to be applied just with two inputs, which are latitude of the location and size of the power plant.

Key Words: Solar electricity, PV, LCOE, Feasibility software, CO_2

ÖZ

TÜRKİYE İÇİN GÜNEŞ ELEKTRİĞİ YAZILIMI SOlAR TURnKEY'İN ALGORİTMASININ GELİŞTİRİLMESİ

Karaveli, Abdullah Buğrahan
Doktora, Yer Sistem Bilimleri EABD
Tez Yöneticisi : Prof. Dr. Bülent Gültekin Akınoğlu
Ortak Tez Yöneticisi : Prof. Dr. Uğur Soytaş

Ağustos 2018, 121 sayfa

Hızla elektrikleşen dünyada, bir yandan da nüfusun, tüketimin, çevresel tehditlerin, sosyal içerme ve fakirliğin giderilmesi ihtiyacının, doğal kaynakların tüketiminin ve çıkarılma maliyetlerinin artışı yükselen enerji talebinin karşılanmasında ekonomik, çevresel ve sosyal açıdan en etkin yöntemlerin kullanılmasını gerektirmektedir. Tam da bu noktada, hızlı bir maliyet düşüşü, verimlilik artışı ve teknolojik gelişim yaşayan, çevre dostu olan ve sosyal içermeye katkı sunan güneş elektriği alternatiflerine karşı avantajlı konumdadır. Diğer yandan, güçlü algoritma ve altyapıya sahip olmak koşuluyla günümüz gelişmiş ileri bilgisayar tabanlı teknolojileri sayesinde yatırımın gerçekleştirilmesinde en iyi, en makul ve en verimli tasarımların yapılması sağlanabilmektedir. Güneş kuşağı ülkesi olması ve artan nüfusa ve tüketime sahip olması, Türkiye'nin de güneş elektriğini gündeminin başına koyması gerekliliğini doğurmaktadır. Fakat, Türkiye'de konu hakkında tecrübe, bilinç ve teknolojik hakimiyet eksikliği bulunmaktadır. Bu çalışma güneş elektriği projeleri için teknik ve ekonomik fizibilite analizi yapabilen ve dinamik uygulama projesi sunan bir yazılımın altyapısını oluşturarak sektörün bu alandaki ihtiyaçlarını karşılayacaktır. Çalışmanın çıktısı olarak, SOlAR TURnKEY adlı yazılımın algoritması oluşturulmuştur. Algoritma, yalnızca koordinat ve kapasite girdisi ile planlanabilecek bir proje için, sistemin maruz kalacağı güneş ışınımı miktarı, en uygun tasarım parametreleri, toplam elektrik üretimi, toplam maliyeti, CO_2 emisyon azaltım potansiyeli, yatırımın geri dönüş süresi, toplam gelir, kar ve diğer ekonomi parametreleri hakkında kapsamlı bilgiler sunmaktadır.

Anahtar Kelimeler: Güneş elektriği, Fotovoltaik, Fizilibilite yazılımı, SMA, CO_2

to all who read, think, imagine and work for goodness

ACKNOWLEDGEMENTS

The author desires to express his deepest gratitude to his supervisor Prof. Dr. Bülent Gültekin Akınoğlu and co-supervisor Prof. Dr. Uğur Soytaş for each respectful contributions for their not only guidance, advice, criticism, encouragements but also insight, tolerance and favor throughout the study.

The author dedicates the study to the ones who thinks on welfare of the humanity and the environment, flats over the troubles humanity and the environment faced with, endeavors to tackle global threats and imagines a better life.

The author represents his sincere gratitude to Thesis Monitoring Committee members, Prof. Dr. Raşit Turan and Asst. Prof. Dr. Selçuk Yerci and to Examining Committee members.

The author also extends his thanks to the distinguished contributors whose studies shed light to this study.

In addition, his gratitude's are for Earth System Science (ESS) Program of the Middle East Technical University (ODTÜ - METU) because of its providing an opportunity to bring about this thesis. He is also respectful to the former head of the ESS Program, Prof. Dr. Ayşen Yılmaz and her kindness and kind support.

The author also desires to express his gratitude to Turkish State Meteorological Service (TSMS) for its support by providing data for solar irradiation calculation part.

The last but not the least, the author would like to thank his wife, Şeyma Karaveli, for her inspirational-love and support and patience during preparation process of this thesis.

TABLE OF CONTENTS

LIST OF TABLES

TABLES

LIST OF FIGURES

FIGURES

LIST OF SYMBOLS AND ABBREVIATIONS

SYMBOLS

$\overline{H}_o$	Monthly average daily extraterrestrial solar irradiation
$\overline{H}$	Monthly average daily global solar irradiation on a horizontal surface
$\overline{H}_D$	Monthly average daily diffuse solar irradiation on horizontal surface
$\overline{H}_B$	Monthly average daily beam solar irradiation on horizontal surface
$\overline{H}_T$	Monthly average daily solar irradiation on tilted surface
G_{sc}	Solar constant
ϕ	Latitude
n_d	Mean day of the month
δ	Declination
ω_s	Sunset hour angle
T_s	Sun's temperature in Kelvin (K)
R	Radius of the Sun
σ	Stefan Boltzmann constant
D	Average distance between the Sun and the Earth
G	Instantaneous global solar irradiance
$\overline{n}$	Monthly average daily bright sunshine hours
$\overline{N}$	Monthly average day length
a , b	Coefficients of linear equation for global solar irradiation
a_o , a_1 , a_2	Coefficients of quadratic equation for global solar irradiation
a' , b'	Coefficients of linear equation for diffuse component
a'_o , a'_1 , a'_2	Coefficients of quadratic equation for diffuse component
τ_e	Monthly effective atmospheric transmission coefficient for clear sky
β	Optimum tilt angle of the photovoltaic (PV) modules
β_f	Optimum tilt angle for fixed system
β_t	Optimum tilt angle for tracking system

ω_s'	Sunset hour angle on a tilted surface for the mean day of the month
$\overline{R}_B$	Monthly average daily ratio of beam irradiation on tilted surface to that on horizontal surface
ρ_g	Constant for ground reflectance
$\overline{H}_{Tt}$	Monthly average daily solar irradiation on tilted surface for monthly tracking system
M_M	The amount of PV modules
P_T	Installed power of the power plant (PP)
P_M	Peak DC power of the PV module
X	Width of horizontally or length of vertically located modules
D_1	Depth of PV array with respect to ground
D_2	Minimum distance between two PV lines
δ_m	Obliqueness of the Earth
H	Height of PV line
h	Height of PV module
w	Width of PV module
M_{AL}	Total amount of aluminum
M_{ST}	Total amount of steel
M_{CONC}	Total amount of concrete
A_M	Area of PV modules
$M_{AL,unit}$	Amount of aluminum per m^2 of PV module
$M_{ST,unit}$	Amount of steel per m^2 of PV module
$M_{CONC,unit}$	Amount of concrete per m^2 of PV module
d	Cross sectional area of cable
I_{mpp}	Current at maximum power point (mpp)
l	Cable length
V	Maximum acceptable voltage drop
$V_{oc,ref}$	Reference open circuit voltage
$D_{L,C}$	Total cable length
$d_{L,C}$	Unit cable length per watt

$M_{i.m}$	Amount of micro inverter
$M_{i,s}$	Amount of string inverter
$M_{i,c}$	Amount of central inverter
M_{s}	Amount of string
$P_{i,s}$	Power of string inverter
P_{s}	Total power of PV modules in a string
$P_{i,c}$	Total power of the central inverter
E_{B}	Needed capacity of the battery
D_{d}	Depth of discharge of battery
n_{day}	Number of days of electricity production to store
E_{m}	Daily maximum electricity production in a year
N_{L}	Number of PV lines
W_{L}	Width of a PV line
A_{i}	Area for an inverter
$A_{i,c}$	Required area for central inverter
$A_{i,s}$	Total required area for string inverter
$W_{i,b}$	Width of the building for inverter
$L_{i,b}$	Length of the building for inverter
N_{i}	Amount of string inverter
A_{t}	Area for transformer
$W_{t,b}$	Width of the building for transformer
$L_{t,b}$	Length of the building for transformer
A_{T}	Total area of PV PP
A_{fs}	Free space between hedges and PV modules
A_{b}	Area for batteries
T_{c}	Cell temperature in ºC
$\overline{T}_{c}$	Monthly average daily cell temperature in ºC
$\overline{E}$	Monthly average daily electricity production of the system

$E_{T,a}$	Annual electricity production for the first year
L_{total}	Total loss
$E_{N,a}$	Net electricity leaving the PP
E_T	Life time net electricity production
T_a	Ambient temperature in ºC
$\tau\alpha$	Transmittance-absorptance product
η_c	Load efficiency
U_L	Overall heat loss coefficient
$T_{c,NOCT}$	Nominal operating cell temperature (NOCT) in ºC
$T_{a,NOCT}$	Ambient temperature at NOCT in ºC
G_{NOCT}	Solar irradiation at NOCT
η_{mpp}	Actual efficiency at mpp
$\eta_{mpp,ref}$	Reference efficiency at mpp
$\mu_{\eta mpp}$	Temperature coefficient of efficiency at mpp
$T_{c,ref}$	Reference cell temperature in ºC
V_{mpp}	Voltage at mpp
μ_{Voc}	Temperature coefficient of open-circuit voltage
$V_{mpp,ref}$	Reference voltage at mpp
$\overline{H}_{T,i}$	Value of monthly average daily solar irradiation on tilted surface in W m^{-2}
$\overline{T}_a$	Monthly average daily ambient temperature in ºC
n_i	Number of days for the *i*th month
$\overline{E}_i$	Monthly average daily electricity production of the *i*th month
L_s	Shading loss
l_1	Number of line coefficient
R_c	Resistance of cable
l_2	Length cable factor
ρ_c	Resistivity of material conductor
l_c	Length of the cable

s_c	Cross sectional area of the cable
L_c	Cabling loss
μ_{Isc}	Temperature coefficient of short circuit current
$I_{mpp,ref}$	Reference current at mpp
$E_{in,i}$	DC electricity entering the inverter
$E_{out,i}$	AC electricity leaving from the inverter
η_i	Efficiency of the inverter
$E_{used,i}$	Electricity consumed by the inverter
L_i	Loss of inverter
$E_{in,ACcable}$	Electricity leaving inverter
$E_{out,ACcable}$	Electricity transmitted by the cable
$\eta_{ACcable}$	Efficiency of the cable
L_B	Battery back-up loss
η_B	Efficiency of the battery
L_{Tr}	Loss from the electricity consumption by tracking system
EC_{Tr}	Electricity consumption of tracking system
d	Degradation rate
EF_{OM}	Operating margin emission factor
EF_{BM}	Built margin emission factor
EF_{CM}	Combined margin emission factor
ER_{CO_2}	Lifetime CO_2 emission reduction potential
R_{CO_2}	Revenue from carbon market
w_{OM}	Weighting of operating margin emission factor
w_{BM}	Weighting of built margin emission factor
U_{CO_2}	Unit price per ton CO_2 certificates
C_{CO_2}	Total expenditure for CO_2 certificates
C_p	Cost of unlicensed permission process
$C_{p,rooftop}$	Cost of permission for roof-top unlicensed power plants

$C_{p,ground}$	Cost of permission for ground mounted power plants
C_I	Initial investment for the cost of the PV power plant
C_L	Land cost for the PV power plant
C_M	PV module cost
U_M	Unit watt peak module cost
C_{BoS}	Cost of balance of system (BoS) components
C_w	Cost of cabling (wiring)
C_i	Inverter cost
C_e	Cost of earthing
C_r	Cost of remote monitoring
C_{lp}	Cost of land preparation
C_t	Cost of transformer
C_h	Cost for hedges
C_{nc}	Connection to grid expenditures
C_{BoSwb}	Cost of BoS with battery
C_b	Battery cost
C_{cc}	Charge controller cost
C_{mppt}	Maximum power point tracker cost
C_{ME}	Cost of mounting equipment
M_{ME}	Amount of mounting equipment
U_{ME}	Unit price of mounting equipment
r	Discount rate
$C_{i,c}$	Cost of central inverter
$C_{i,s}$	Cost of string inverter
$C_{i,m}$	Cost of micro inverter
$U_{i,c}$	Unit price of central inverter
$U_{i,s}$	Unit price of string inverter
$U_{i,m}$	Unit price of micro inverter
U_w	Unit price of cable

U_e Unit price for set of earthing equipment

M_e Amount of set of earthing equipment

U_b Unit price of battery

M_b Amount of battery

U_{cc} Unit price of charge controller

M_{cc} Amount of charge controller

M_{mppt} Amount maximum power point tracker (mppt)

U_{mppt} Unit price of mppt

M_{rm} Amount of the set of remote monitoring equipment

U_{rm} Unit price of the set of remote monitoring equipment

C_{tu} Truck usage cost

C_{gr} Grading cost

C_{rc} Road construction cost

C_{Cb} Cost of cabling for grid connection

C_{EP} Cost of electricity pylons

C_{Ex} Cost of expropriation

C_{Ser} Cost of servitude

C_{Lb} Labor cost

M_t Amount of time a labor is needed

U_{Lb} Unit price of labor

M_{Lb} Amount of labor needed

C_{sm} Cost of smart meter

U_{sm} Unit price of smart meter

M_{sm} Amount of smart meter

C_{cm} Cost of carbon market

C_{su} System usage cost

U_{su} Unit price of system usage

C_h Hedge cost

L_h Length of hedge

U_h	Unit cost of hedge
C_{sc}	Cost of security cameras
M_{sc}	Amount of security cameras
U_{sc}	Unit price of security cameras
C_{ins}	Insurance cost
r_{f-tr}	Cost ratio between fixed tilted and single-axis tracking PPs
C_V	Variable cost
C_{Vwb}	Variable cost of the PP with storage
C_{Vwtr}	Variable cost of the PP with tracking system
C_{su}	System usage cost
$C_{O\&M}$	Cost of operation and maintenance
$C_{i,r}$	Cost of replacement of inverters
$C_{T,tr}$	Cost of power plant with tracking system
p	Share of self-contribution to capital of investment
e	Annual interest rate for loan
t	Period of payment of installments
EoS	Coefficient for economic of scale (EoS)
$C_{T,EoS}$	Total cost of the power plant with EoS
E_n	Electricity production at the *n*th year
R_1	Total revenue of the PP from Scenario 1
$R_{2.1}$	Total revenue of the PP from Scenario 2.1
$R_{2.2}$	Total revenue of the PP from Scenario 2.2
$R_{2.3}$	Total revenue of the PP from Scenario 2.3
$R_{2.4}$	Total revenue of the PP from Scenario 2.4
$R_{3.1}$	Total revenue of the PP from Scenario 3.1
$R_{3.2}$	Total revenue of the PP from Scenario 3.2
$R_{4.1}$	Total revenue of the PP from Scenario 4.1
$R_{4.2}$	Total revenue of the PP from Scenario 4.2
$R_{4.3}$	Total revenue of the PP from Scenario 4.3

$R_{5.1}$	Total revenue of the PP from Scenario 5.1
$R_{5.2}$	Total revenue of the PP from Scenario 5.2
P_n	Profit of the *n*th year
C_{CF}	Highest acceptable contribution fee for tender
U_{CF}	Lowest acceptable tariff for electricity selling
E_{15}	Net present value (NPV) of the worth of net cumulative electricity production in the 15th year
$R_{NPV,15}$	NPV of the cumulative revenue in the 15th year
KPI_E	Electric key performance indicator
E_1	Electricity production of the 1st year
I_o	Extraterrestrial solar irradiation falling on horizontal surface during certain time interval
I	Global (total) irradiation on horizontal surface
I_B	Beam (direct) irradiation on horizontal surface
I_D	Diffuse irradiation on horizontal surface
I_{D1}	Diffuse irradiation on horizontal surface during clear-sky period
I_{D2}	Diffuse irradiation on horizontal surface during cloudy-sky period
I_{D3}	Diffuse irradiation on horizontal surface coming from the first reflection cycle between ground and the atmosphere
n_i	Fractional clear sky period
τ	Atmospheric transmission coefficient for clear sky
β'	Atmospheric forward scattering coefficient
τ'	Transmission coefficient for clouds
α	Ground albedo
β	Atmospheric back-scattering coefficient
α'	Cloud-base albedo
τ_e'	Monthly effective transmission coefficient for clouds
α_e	Monthly effective ground albedo
α_e'	Monthly effective daily cloud base albedo
β_e	Monthly effective atmospheric back-scattering coefficient

$\beta_e^{'}$	Monthly effective atmospheric forward-scattering coefficient

ABBREVIATONS

AC	Alternating Current
ANN	Artificial Neural Network
BM	Built Margin
BoS	Balance of System
CDM	Clean Development Mechanism
CdTe	Cadmium Telluride
CH_4	Methane
CIGS	Copper Indium Gallium Selenide
CO_2	Carbon dioxide
c-Si	Crystalline silicon
CSP	Concentrated Solar Power
DC	Direct Current
EBRD	European Bank on Reconstruction and Development
EDAM	Center for Economics and Foreign Policy Studies
EF	Emission Factor
EMRA	Energy Market Regulatory Authority
FiT	Feed-in-Tariff
GHG	Green House Gases
GÜNAM	The Center for Solar Energy Research and Applications
GW	Giga watt
GWh	Giga watt hours
IEC	International Electrotechnical Commission
IPARD	Instrument for Pre-accession Assisst. in Rural Development
IRR	Internal Rate of Return
K	Kelvin
KPI	Key Performance Indicator
KWh	Kilo watt hours
LCOE	Levelized Cost of Electricity
LROE	Levelized Revenue of Electricity
LPOE	Levelized Profitability of Electricity
MAE	Mean Absolute Error
MBE	Mean Bias Error

MCDL	Monthly Coefficient Diffuse Linear
MCDQ	Monthly Coefficient Diffuse Quadratic
MCGL	Monthly Coefficient Global Linear
MCGQ	Monthly Coefficient Global Quadratic
METU	Middle East Technical University
MJ	Mega Joule
MPPT	Maximum Power Point Tracking
MW	Mega Watt
NFM	Net Feasibility Measure
NOCT	Nominal Operating Cell Temperature
NPV	Net Present Value
NREL	National Renewable Energy Laboratories
N_2O	Nitrous Oxide
OM	Operating Margin
O&M	Operation and Maintenance
PP	Power Plant
PV	Photovoltaic
RMSE	Root Mean Square Error
SAM	System Advisory Model
SDGs	Sustainable Development Goals
TSE	Turkish Standards Institution
TSMS	Turkish State Meteorological Service
UNFCCC	United Nations Framework Convention on Climate Change
VAT	Value Added Tax

CHAPTER 1

INTRODUCTION

1.1 The Rationale of the Thesis Study

In many fundamental issues of global conjuncture and daily life needs and aspirations such as designing world agenda, meeting the needs of humanity, protection of natural resources and environmental degradation, energy sector seems to be the main actor due to both problem creation and problem solution aspects.

Furthermore, the World has been rapidly electrified day by day [1] with an ever increasing rate. In other words, the meaning of electricity in the daily life of humankind has been gaining more and more importance. In addition, due to actual and potential economic, environmental and social problems, a global effort is seeking for every alternatives of conventional electricity production ways, *mutatis mutandis*.

The marginal costs of renewables are interestingly but evidently decreasing [2]–[5] and efficiencies are increasing in accord with the technology [3], [5], [6]. Moreover, because of the Sun's energy being relatively homogenously distributed resource when compared to alternatives, the electricity production via photovoltaic power plant (PV PP) seems to be one of the most feasible alternative source within the renewables and to conventional sources/technologies [7].

Investments on photovoltaics (PV), a major technology for solar electricity production, have been gaining importance and its cumulative installed power has been rapidly increasing for the last two decades [4]. Global cumulative PV installed power has reached 385.7 GW at the end of 2017 [8]. This amount was just 8.7 GW a decade ago [8]. The main factors for above mentioned techno-economic feasibility are higher efficient PV modules [3], [6], high learning rate (24% [9]), low levelized cost of electricity (LCOE) [10], [11] and appealing incentives [12]. Moreover, contribution to tackle climate change and emission-free electricity production are the positive externalities of PV systems, *inter alia* [13].

Owing to all these benefits, PV technology serves for the sustainable development [14] and contributes to the achievement of sustainable development goals (SDGs) especially for SDG 7, that is affordable and clean energy and SDG 13, that is the climate action [15].

Moreover, developing/emerging countries (i.e. like Turkey) being in a development process together with increase in population and consumption are confronted with the increase in energy demand inevitably. Because of Turkish energy sector's having high share in the current deficit [16], [17] and strategic/vital importance in international politics and being essential for sustainable development, the investments to be made on energy sector should be evaluated in depth.

Similarly, having high potential for solar irradiation exposure [18], regulated sector with legal basis (i.e. regulations), incentive systems (i.e. feed-in-tariffs (FiT)), requirements to diversify its energy mix and to reduce foreign dependency on energy resources and being in a ratifying process of Paris Agreement (a legally binding agreement under the frame of United Nations Framework Convention on Climate Change (UNFCCC)) together with the rapidly reduced cost of solar electricity systems, Turkey has better to investigate the opportunities to produce solar electricity a lot more and work on solar electricity technologies intensely.

In parallel to these issues, by the end of June 2018 Turkey has had 4743.9 MWs of PV installed power [19]. This amount was 3420.7 MW at the end of 2017, that is just 7 months before, and it was just 832.5 MW at the beginning of 2017 [19].

At this point, it needs to be taken into account that even if the solar electricity investment is made with the lowest marginal cost and highest efficient technology, it may not reflect the exact potential unless the investment design and required analysis are properly made. In other words, soft costs need to be minimized and appropriate design for the maximum utilization should be applied.

Furthermore, in order to be able to give correct decisions to make an investment, technical availability and economic profitability needs to be known. In other words, technical and economic (techno-economic) feasibility of the investment should be determined prior to the construction [13].

Specific to PV PPs, techno-economic analysis consists of technical analysis parameters which are calculation of solar irradiation amount (that is the input of the system), design parameters (such as amount and type of components and total area needed), electricity production (that is the output of the system) and economic analysis parameters that are cost, revenue, profit and payback time. Moreover, LCOE is also essential for the comparison of PV investment with alternative sources. In addition to LCOE analysis, this study proposes a new concept entitled Economic Feasibility Concept (EFC) and enables a tool to estimate and analyze the levelized revenue of electricity (LROE), levelized profit of electricity (LPOE) and net feasibility measure (NFM) which are original metrics to the best of author's knowledge. On the other hand, positive/negative effect of the investment on the environment such as greenhouse gases (GHG) emission reduction potential is considered, *inter alia*.

The algorithm which is derived and whose details are given within this study is the basis of the software namely SOlAR TURnKEY that is potentially to be developed in pursuit of this research.

Today's cyber world puts the most efficient technologies into service to design and decide the best investments by using information and communication technologies, hardware, software and orgware. However, together with the lack of required academic information and gap on the methodological and empirical experience, insufficient usage of cyber technologies cause the infeasible investments. Moreover, Turkey is a country that has currently less developed advanced technologies [20] and is depended on foreign based software programs to make feasibility analysis for solar systems (i.e PV Sol [21], PV Syst [22], System Advisory Model (SAM) [23], EU PVGIS [24], Archelios [25], Bluesol [26], Helioscope [27], Polysun [28]). Accordingly, SOlAR TURnKEY, the software program whose algorithm is prepared by this study, will be able to make techno-economic feasibility analysis and to prepare dynamic application reports of the investment demanded to make by providing as much information as possible regarding the project with the least input possible in a user friendly way. Furthermore, it will create an opportunity for the selection of the most cost effective and technically efficient way of utilizing solar energy.

Together with the reduction of foreign dependency in the sector owing to this study, the feasibility studies in the solar electricity market that sharply extends its volume day by day will have chance to be realized in the fastest, most appropriate and least conventional source use, too. This algorithm and possible realized software will fill the gap in that rapidly emerging market in highly significant manner by providing access to many costumers in a widespread portfolio. Another point is that the algorithm can globally be used and can be adopted to be based on any pre-specified time intervals.

In accordance with the idea of living in a cyber-world, this study contributes to the improvement of technological knowledge and contributes to fill the gap of best accurate information, knowledge and data about PV PPs.

The last but not the least, the present algorithm that makes calculation with location specific coefficients and equations and market realities not only gives very accurate results but also embodies many original schemes of techno-economic approaches.

After making general introduction to the subject and defining the rationale of the study in the Introduction part, forming of an algorithm is conducted successively within Chapter 2 and 3. In Chapter 2, the elaboration of the part of the algorithm for technical analysis in an order of the subtitles of solar irradiation physics (for solar irradiation calculation, input), solar design (for the calculation of design parameters), solar electricity (for the computation of electricity production) and green solar (for the determination of GHG emission reduction potential) are given. Chapter 3 explains and elaborates economic analysis part of the algorithm, with the sub-sections the cost, the scenarios, LCOE and newly defined EFC and some new insights to economic analysis. The case study where the algorithm is trained for a specific case is explained in Chapter 4. Chapter 5 where the conclusions and discussions of the study are written also contains future prospects. There are also Appendices to show the details of calculation, derivation processes and give extra detailed data and information.

1.2 The System: PV System and PV Power Plant

According to the rules of thermodynamics, the inference can be made that energy is neither created nor destroyed and there is no system with 100% efficiency. Consequently, for all the systems, there is an input, output and loss (dissipated) the amount of which determines the efficiency. For instance, sun radiation reaches to the atmosphere penetrates through reaching the Earth’s surface. Some part of it is reflected back, and the Earth absorbs the remaining part. Heated Earth (atmosphere, lands and oceans) radiates energy in longer wavelength (infrared) to the space. The reflected solar irradiation by the Earth’s surface and Earth’s emitted infrared radiation energy should be equal to the solar input. If there is a difference between the input solar irradiation and the explained output, it results in global warming, so the global climate change.

Similarly, solar electricity production system, namely PV cells/modules has an input as solar irradiation and output as electricity. However, the amount of conversion of solar irradiation into electricity depends on the efficiency of the system. Consequently, the amount of input and efficiency of the system (PV modules) determines the output that is, the electrical energy. The difference between input and output is loss (dissipation).

The fundamental component of PV systems is PV modules that constitutes PV cells which are divided into major technologies such as silicon (in the form of mono- and poly-crystalline and, amorphous), cadmium telluride (CdTe) thin film, copper indium gallium selenide (CIGS) thin film etc. PV modules are directly exposed to sunlight and they directly convert photons of sunlight into direct current (DC) electricity [29]. The electricity produced by PV modules can be stored or converted into alternating current (AC) and can be given to the grid. In a PV PP the equipment such as inverters, cables, remote monitoring systems, batteries are embedded to the modules (PV systems) in large areas. The details of these components and PV PPs are given in the design part (Section 2.2).

1.3 Forming the Algorithm of SOlAR TURnKEY

The focus of this study is the identification of ways and potentials to utilize solar energy optimally and efficiently via the production of solar electricity by the conversion of photons directly into electricity owing to PV technology covering 99% of current global solar electricity market [8], [30], [31]. The algorithm is suitable for all the main sub-technologies of PV, namely crystalline silicon and thin films.

In order to perform the algorithm, initially the computations for the most accurate estimations of global solar irradiation falling on location of interest together with its components are determined to define the input potential correctly. Then, the optimum design parameters are defined by taking into account different techniques and methods to exploit solar energy. Total electricity production potential (an output potential) is then computed for the designed PP owing to the mathematical methodology developed in this study. The cost of the PV PP is calculated and revenue, profit, payback times are obtained depending on different original scenarios.

Moreover, together with LCOE, new metrics of the new EFC that are LROE, LPOE and NFM are calculated. Other economic parameters that are demanded by banks for loan or by the Government for tenders are computed as well. GHG emission reduction potential of the system is also computed. Then the algorithm is completed and made ready to be coded into software in order to apply for long-term feasibility analysis. As a final step, the check of accuracy of the algorithm in each step comparisons are carried out using the field measurements and data obtained from currently active technologies and from the literature.

The pillars and components of the algorithm is given in Figure 1.

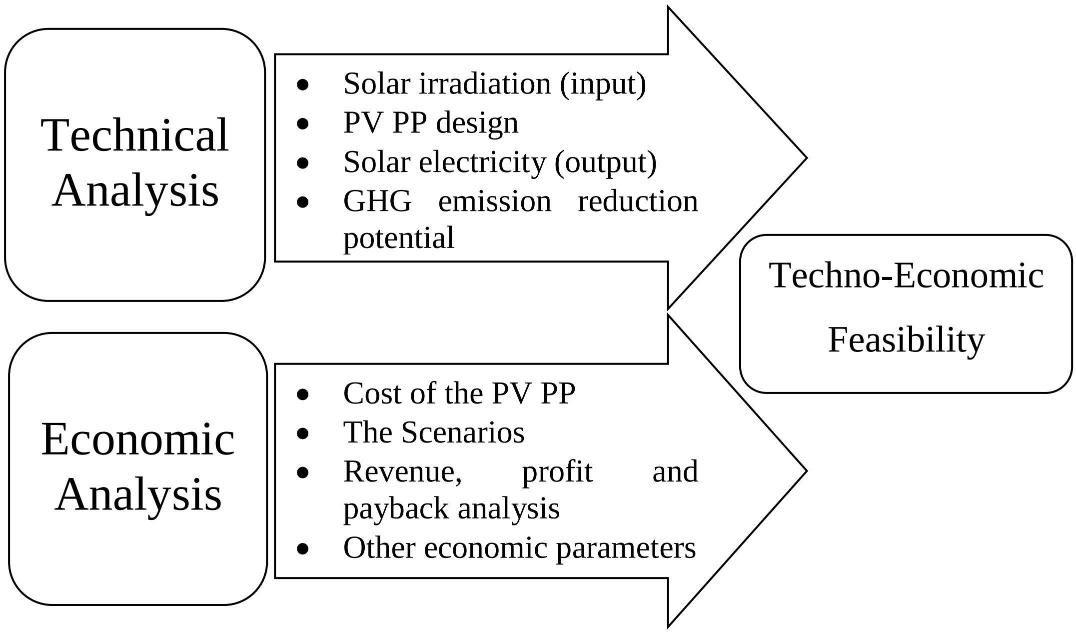

Figure 1 The pillars and components of the algorithm

1.4 Novelty of This Thesis

The algorithm by itself is an original product that contributes to the literature and presents a beneficial tool for the sector. This algorithm is able to give more accurate results with the least possible inputs than alternative algorithms/software programs that are globally accepted and in use. Furthermore, the pillars of this algorithm have major contributions to the literature.

In the solar irradiation calculation part of the algorithm, a method to be able to calculate solar irradiation exposure of any location within the territory of Turkey is developed. Its newly derived location specific equations with location specific monthly coefficients pave the way for highly accurate estimations for solar irradiation exposure.

In the solar electricity production part, cell temperature model is applied to monthly average daily cell temperature estimations for the first time to the best of author’s knowledge. Moreoever, a new method for monthly average electricity production of the PV PP has been developed.

In economic analysis part, a comprehensive cost analysis starting from the permission period till dismantling process has been taken into account for the first time for Turkey. The original scenarios for the estimation of options with which the PV PP investor will be faced are developed for the first time as well. Owing to the these scenarios, future feed-in-tariff amounts, day ahead mechanism (DAM) prices and end-user electricity prices are forecasted and future market conditions and incentives are estimated. New parameters such as the lowest acceptable feed-in-tariff price or the highest acceptable contribution fee for the tenders are developed, *inter alia*.

The last but not the least a new concept for feasibility determination of energy source/technology and its comparison with alternatives the new novel concept is developed.

CHAPTER 2

THE ALGORITHM: TECHNICAL

2.1 Input: Solar Irradiation

Solar irradiation the Earth is exposed is the resource of solar electricity of the Earth's surface based plants and so the input of solar electricity systems. Therefore, the starting point of the thesis is the calculation/prediction of the solar irradiation available for the planned PV system to produce electrical energy. In other words, the amount of the input of the system should be determined by this procedure.

Solar irradiation leaving the Sun reaches initially to the upper atmosphere, then to the Earth's surface after passing through the atmosphere. While passing through the atmosphere, part of the irradiation reaches directly to the surface without scattering. The remaining part arrives after being scattered by the atmospheric constituents mainly by clouds, aerosols, air molecules etc. A part of the solar irradiation reaching to the ground can be reflected to the point where the solar system is planned to be installed. Hence, there are two main components of the total solar irradiation reaching to the horizontal surface, which are the direct (*beam*) one and the scattered (*diffuse*) one. The sum of these components is called as the total (*global*) solar irradiation.

The knowledge of total amount of solar irradiation and the two components reaching to the horizontal surface are critically important to reach to the solar irradiation on inclined surfaces and so to carry out the calculations concerning the utilization of solar energy. In determining the solar irradiation on the inclined PV module (or any system that the solar energy is an input), estimation of the amount of these components as accurate as possible is necessary to reach truthful feasibilities. In other words, by knowing this data and analyzing the system, identification of the performance of solar energy application can be obtained and the best way/technology (the one seems the most feasible) to utilize solar energy can truthfully be obtained [32], [33], [42]–[44], [34]–[41].

Although the most accurate way of determination of solar irradiation is direct measurements with accurate instruments, installation of such measuring systems all over the country does not seem possible from both technical and economic aspects [33]. On the other hand, since the solar irradiation reaching Earth's surface varies year to year there is a need to have long-term measured data. Consequently, to use in the techno-economic analysis, it is required to develop methodologies to make estimations of solar irradiation as accurate as possible in all forms, from global solar irradiation on horizontal surface to its diffuse and beam components and in-plane solar irradiation on inclined solar energy systems.

In view of the above given facts, developed solar irradiation scheme that is used in the present thesis is based on monthly average daily calculations. The methodology of solar irradiation calculations as a part of the techno-economic algorithm is the computation/estimations of:

- Monthly average daily extraterrestrial solar irradiation on horizontal surface ($\bar{H}_o$),
- Total monthly average daily solar irradiation falling on a horizontal surface on Earth ($\bar{H}$),
- Monthly average daily beam ($\bar{H}_B$) and diffuse components ($\bar{H}_D$) of the total solar irradiation on a horizontal surface on Earth,
- Total monthly average daily solar irradiation falling on the tilted PV surfaces on Earth ($\bar{H}_T$).

The flowchart of the solar irradiation calculation is given in Figure 2.

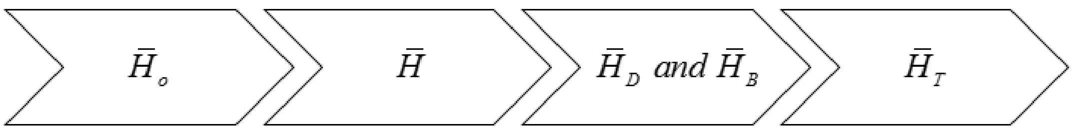

Figure 2 The flowchart of solar irradiation calculation part

As of this point, in order to calculate solar irradiation amounts as accurate as possible the mathematical methodology necessary for the structure of the algorithm are developed. The first sub-section 2.1.1 in the followings summarizes well-known calculation schemes, which were derived analytically, simply by using the solar constant, latitude of the location and geometrically computable Sun-Earth angles.

2.1.1 Extraterrestrial Solar Irradiation

The calculation of the present algorithm is based on monthly averages of daily values. Thus, $\bar{H}_o$ is the amount on a horizontal surface, outside the atmosphere directly above the location of interest, at the point that the irradiation enters the atmosphere [34]. $\bar{H}_0$ can be calculated using the expression:

$$\bar{H}_o = \frac{24 \times 3600}{\pi} G_{sc} \left(1 + 0.033 \cos \frac{360 \times n_d}{365} \right) \left(\cos \phi \cos \delta \sin \omega_s + \frac{\pi \omega_s}{180} \sin \phi \sin \delta \right). \quad (1)$$

The important quantity G_{sc} is named as the “Solar Constant” and defined as the solar irradiance outside the atmosphere at the mean Sun-Earth distance, incident on a surface perpendicular to sun rays. This value is very important both for simulative works as in the present, also for the climate change. It is measured and updated by different labs [42]. The other variables of this equation are:

- Latitude, the angular distance north or south of the equator, of the location of interest (ϕ) is the first input that will be entered by the algorithm user or is defined by the system when the software user selects the point where the project will be applied from the map.
- Mean days of the months (n_d) are considered to calculate the monthly average values of daily extraterrestrial solar irradiation on horizontal surface. The mean days of the month to calculate $\bar{H}_o$ are used as given in [36], [37] and tabulated in Table A.1 in Appendix A.
- Declination (δ) is the angular position of the sun at solar noon with respect to the plane of the equator and be computed from the related equation given in Eq. 2 below, by using n_d values. Declination values are also given in Table A.1 in Appendix A.
- Sunset hour angle (ω_s) is the angular span of the sun projected to the surface of horizon, from sunrise to sunset. It is computed by using Eq. 3 below [34].
- The recent value of the solar constant (G_{sc}), is taken to be 1367 W m^{-2}. (Note that it can be calculated by using Stephan Boltzmann Law as given in Eq. 4. However, 1367 W m^{-2} is a measured value).

The set of equations then to calculate $\overline{H}_o$ are given below [34], [35]:

$$\delta = 23.45 \sin\left(\frac{284 + n_d}{365}\right) \tag{2}$$

$$\omega_s = \cos^{-1}(-\tan\phi \tan\delta) \tag{3}$$

$$G_{sc} = \sigma T_s^4 \left(\frac{R}{D}\right)^2 \tag{4}$$

where T_s is the Sun's temperature (5777 K); R is the radius of the Sun (6.96×10^8 m); σ is the Stefan Boltzmann constant (5.67×10^{-8} W m^{-2} K^{-4}) and D is the average distance between the Sun and the earth (1.496×10^{11} m).

Computation steps for monthly mean daily and annual solar irradiation amounts starts with the calculation of $\overline{H}_o$ in the unit of MJ m^{-2} d^{-1}. The calculated amounts of energy are also given in kWh m^{-2} d^{-1} for comparisons (in fact, two units are alternatively used in the related literature). The resulting $\overline{H}_o$ equation to use directly in the software coding can then be stated as:

$$\overline{H}_0 = \frac{11810800}{\pi}\left(1 + 0.033\cos(0.9863013698630137 \times n_d)\right)\cos\phi\cos\left(23.45\sin\left(\frac{284 + n_d}{365}\right)\right)$$
$$\sin\left(\cos^{-1}\left(-\tan\phi\tan\left(23.45\sin\left(\frac{284 + n_d}{365}\right)\right)\right)\right) + \frac{\pi\left(\cos^{-1}\left(-\tan\phi\tan\left(23.45\sin\left(\frac{284 + n_d}{365}\right)\right)\right)\right)}{180} \cdot \tag{5}$$
$$\sin\phi\sin\left(23.45\sin\left(\frac{284 + n_d}{365}\right)\right)$$

Following sub-sections are the prediction/computation schemes for solar irradiation developed within the scope of the present studies.

2.1.2 Total Horizontal Solar Irradiation Reaching to the Surface

Monthly-based analysis for the solar irradiation on Earth's surface can be launched by calculating/predicting $\overline{H}$. In fact, measured solar irradiance on horizontal surface is the data that might also be reached at least for a limited number of locations all over the World.

The instantaneous global solar irradiance (W m^{-2}) on horizontal surface *G* is a parameter that is commonly measured, as mentioned above, in the measurement stations. However, installing measuring systems throughout Turkey or any other region is neither economically feasible nor technically possible [33], [45]–[47].

Therefore, there is a need to develop methodology to calculate/predict solar irradiation wherever the PV PP will be installed within the region of interest.

Additively, the diffuse and beam components of $\bar{H}$ are required to be estimated for the solar irradiation predictions on inclined surfaces (plane of the module). Unlike $\bar{H}$, on-plane measurements are not commonly recorded with sufficient accuracy to use for scientific purposes in most of the stations [33], [39]–[42], [47]. Consequently, there seems always a need for accurate estimation of $\bar{H}$ so that more precise diffuse and beam estimations would be possible and so the better estimation of the input to the systems (on tilted PV system in our case).

On the other hand, most of the stand-alone weather stations and the measuring systems that are installed in PV PPs have global solar irradiation-measuring photodiodes. The accuracy of these devices is insufficient to use in the scientific researches [33], [42]. The main reason is the fact that these devices' being simple pn junction solar cells and their spectral response's is dependent on a region of the spectrum of the solar irradiance. Consequently, in the measurements of global solar irradiation, more accurate black and white-type thermopile pyranometers must be used [33], [47].

Global solar irradiation estimation models use various meteorological data, but the models which use the monthly average daily bright sunshine hours $\bar{n}$ (sunshine duration) seem the most appropriate, in terms of its easiness and its accuracy [33], [43], [44], [47], [48]. Bright sunshine hours data are available and reliable almost in all regions of Turkey; therefore, the present work is mainly based on the measurements of monthly average daily global solar irradiation on horizontal surface $\bar{H}$ and bright sunshine hours $\bar{n}$. Not all but eight locations in Turkey have also the monthly average daily diffuse component $\bar{H}_D$ .The methodology developed in this study for the estimation of global and diffuse solar irradiation on horizontal surface using $\bar{n}$ is based on a physical modeling approach [44], [47], [49]. This approach uses all three measurements: $\bar{H}$, $\bar{H}_D$ and $\bar{n}$. It is referenced to recorded data of 40 locations that is measured by Turkish State Meteorological Service (TSMS).

Within this approach, it is possible to reach monthly-based estimation schemes both for global and diffuse components of monthly average daily irradiation values.

There are 57 locations in Turkey where TSMS has stations [33] measuring solar irradiation with accurate pyranometers. The measurements are on the basis of $\overline{H}$, $\overline{H}_D$ and $\overline{n}$. However, after working on the data, we reached a result that 40 of them can be useable for the measurements of $\overline{H}$ and $\overline{n}$ and only 8 (measurement stations in Ankara, Eskisehir, Istanbul, Tekirdag, Amasra, Sinop, Mugla, Aydin) of them have reliable $\overline{H}_D$ data. These eight stations with three measured data are fortunately quite evenly located at different latitudes and climates of the country. This provides the opportunity to use them to produce countrywide estimations schemes.

In the light of this information, we have an opportunity to make land- and climate-based regional groupings of the stations with closer locations and similar climates, by taking one of the eight stations as a reference of a corresponding range. So, the linear and quadratic equations (Eqs. 6 and 7 below) derived for the mentioned eight locations to estimate $\overline{H}$ are applied to all the points and compared to find the one that fits best to the measured values. The rationale behind this idea is as follows: (i) these equations are derived with a physical modeling; (ii) the approach has geographical parameters (for example, latitude through $\overline{H}_0$ and $\overline{N}$) and also an important measured parameter, bright sunshine hour $\overline{n}$; (iii) some atmospheric information are regarded such as the transmissivity, absorptivity, and scattering and reflection coefficients of ground, cloud, and sky (calculated by the formalism or obtained from the literature); and (iv) the equations and the coefficients within are on monthly basis [33].

If these equations below (Eqs. 6 and 7) match and give better results for a region than alternatives such as other correlations or databases, then this would be an acceptable method to make estimations. Accordingly, linear and quadratic equations for the above mentioned eight reference locations are derived on a monthly base.

Consequently, the methodology giving the highest accurate results can only be created by using above-mentioned locations as references to all other locations in Turkey. In that vein, we initially derived equations calculating $\overline{H}$ by benefiting from $\overline{H}$, $\overline{H}_D$ and $\overline{n}$ measurements.

As the first step, minute by minute W m^{-2} measurements from the period as of the first day of 2011 till the last day of 2015 of 8 abovementioned locations were taken. They were used to obtain monthly mean daily values with the unit of MJ m^{-2} day^{-1} by sorting them out in order to get rid of unreliable data record values .

The equations with monthly coefficients to calculate $\overline{H}$ are developed in the form of:

$$\overline{H} / \overline{H}_0 = a + b(\overline{n} / \overline{N}) \tag{6}$$

$$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2 \quad . \tag{7}$$

The models derived from abovementioned Eqs. 9 and 10 are called as MCGL (Monthly Coefficient Global Linear) and MCGQ (Monthly Coefficient Global Quadratic), respectively. The derivation steps of them are given in Appendix B.

The monthly coefficients of a ,b ,a_0 ,a_1 ,a_2 are determined for 8 reference locations and are applied to other 32 locations to find the most decent equation by comparing them with the measured values of these 32 locations. Then, this method is applied to all the locations covering all the territories of Turkey. Equation match-up for each locations depending on calculated statistical error values of MBE and RMSE are tabulated in Table C.1 of Appendix C. Consequently, the best matching coefficients of the reference location to be used in predictions for a location in a specified region can be determined.

2.1.3 Diffuse and Beam Components

Diffuse irradiation consists of the components: the sky-diffuse, ground-reflected diffuse and the amount reaching to the system after multiple reflections between the ground, the clouds, and the atmosphere. Because of its complexity, raw data to calculate $\overline{H}_D$ are usually missing in most meteorological stations in Turkey except eight of them as mentioned previously. Nevertheless, despite to this fact the accuracy of diffuse component is crucial to estimate the input to the systems. The estimation of the beam component (global − diffuse) is rather uncomplicated, and the accuracy of these estimations is considerably better than the estimations of diffuse components [33], [47].

The diffuse data of the eight locations were used to obtain linear and quadratic forms using the physical modeling approach. The derived equations for the calculation of $\overline{H}_D$ values were as follows:

$$\overline{H}_D / \overline{H}_0 = a' + b'(\overline{n} / \overline{N}) \tag{8}$$

$$\overline{H}_D / \overline{H}_0 = a_0' + a_1'(\overline{n} / \overline{N}) + a_2' (\overline{n} / \overline{N})^2 \quad . \tag{9}$$

The method using Eq. 8 is called as MCDL (Monthly Coefficient Diffuse Linear) and the method for Eq. 9 is called as MCDQ (Monthly Coefficient Diffuse Quadratic). The derivation steps of MCDL and MCDQ are given in Appendix B, as well.

Moreover, a new model estimating diffuse component in relation to not only the monthly average sunshine duration over monthly average day length ($\overline{n} / \overline{N}$) but also additionally to the monthly clearness index ($\overline{H} / \overline{H}_0$) are derived and integrated into the estimation calculations. Eq. 10 symbolizes this new method, namely MCGD (Monthly Coefficient Global Depended Diffuse).

$$\overline{H}_D / \overline{H}_0 = \overline{H} / \overline{H}_0 + \tau_e(\overline{n} / \overline{N}) \quad . \tag{10}$$

The derivation steps of Eq. 10 is also given in Appendix B.

For the locations nearby within a few tens of km zone of a station where the measured data of global solar irradiation is available, the measured data of that station should be preferred [50] for that location.

After predicting $\overline{H}_D$, calculation of $\overline{H}_B$ is simply as:

$$\overline{H}_B = \overline{H} - \overline{H}_D \quad . \tag{11}$$

2.1.4 Solar Irradiation on Tilted Surface

The input of the system is the solar irradiation falling on the tilted surfaces of the modules. This value is called as monthly mean daily solar irradiation on tilted surface and symbolized as $\overline{H}_T$. Using the results of $\overline{H}$, $\overline{H}_D$ and $\overline{H}_B$, $\overline{H}_T$ can be calculated by different modeling approaches. In this thesis study, $\overline{H}_T$ is estimated by the isotropic sky model [34], [51] and [52]:

$$\overline{H}_T = \overline{H}_B \overline{R}_B + \overline{H} \rho_g \left(\frac{1 - \cos\beta}{2} \right) + \overline{H}_D \left(\frac{1 + \cos\beta}{2} \right) \quad . \tag{12}$$

The steps to follow and parameters to define for the calculation of $\overline{H}_T$ are as hereinafter:

- Optimum tilt angle β is the optimum angle between the plane of the surface in question and the horizontal, for an optimal solar irradiation exposure. β is computed through the equations determined previously in [53], [54]. This tilt angle varies depending whether a system is fixed (β_f) or tracking (β_t) (Eq.13 and 16 below).

- ω_s' is the sunset hour angle on a tilted surface for the mean day of the month (that is, the total time in hours of the day starting from sunrise to the tilted surface to sunset) (Eq. 14 below).
- $\overline{R}_B$ is the ratio of beam radiation on tilted surface to that on horizontal surface (Eq. 15 below).
- ρ_g is the constant for ground reflectance ρ_g and typically can be taken as 0.2 [55]–[58] (It might be much higher for green grass or snow coverage of the land).

The set of equations to calculate $\overline{H}_T$ are as follows:

$$\beta_f = 0.764 \times \phi + 2.14 \tag{13}$$

$$\omega_s' = \min \begin{Bmatrix} \cos^{-1}(-\tan\phi \tan\delta) \\ \cos^{-1}(-\tan(\phi-\beta)\tan\delta) \end{Bmatrix} \tag{14}$$

$$\overline{R}_B = \frac{\cos(\phi-\beta)\times\cos(\delta)\times\sin\omega_s' + \frac{\pi}{180}\times\omega_s'\times\sin(\phi-\beta)\times\sin\delta}{\cos\phi\times\cos\delta\times\sin\omega_s + \frac{\pi}{180}\times\omega_s\times\sin\phi\times\sin\delta} . \tag{15}$$

Eq. 13 is from [53] and Eqs. 14 and 15 are from [34]. δ and ω_s are calculated by using Eq. 2 and 3, respectively.

β_f is optimum tilt angle for fixed systems. Notwithstanding, in addition to fixed tilted systems the system can also be single-axis tracking whose tilt is changed monthly. For a plane rotated on a horizontal east-west axis about north-south axis with a single monthly adjustment so that the beam irradiation is normal to the surface at noon each monthly mean day [54], β_t, angle of modules for average days of each month, is calculated by using equation $\beta_t = |\phi - \delta|$ [54]. Inserting the declination equation (Eq. 2), we get:

$$\beta_t = \left| \phi - 23.45 \sin\left(\frac{284 + n_d}{365}\right) \right| . \tag{16}$$

n_d values for each month are known (Table A.1), so β_t values can easily be computed. Consequently, β_f is replaced with β_t in Eq. 12 and $\overline{H}_{Tt}$ that is solar irradiation on tilted surface for monthly tracking system is calculated.

2.1.5 Validation of the Solar Irradiation Calculation Methodology

A model, methodology or an algorithm to predict performance and economic feasibility can only be approved through comparisons of its results with measured values. There are some statistical approaches such as mean bias error (MBE) and root-mean-square error (RMSE) to make the comparisons and to reach the accuracy.

The values for MBE (Eq. 17) and RMSE (Eq. 18) are two of the most common metrics used to measure accuracy and they are equations that have been used in the references [45]–[47] (and also in many similar works) for the validation of the solar irradiation predictions of the algorithm within the scope of the thesis. The equations are:

$$MBE = \frac{1}{s} \sum_{i=1}^{s} \left(X_{i,calc.} - X_{i,msrd.} \right) \tag{17}$$

$$RMSE = \sqrt{\frac{1}{s} \sum_{i=1}^{s} \left(X_{i,calc.} - X_{i,msrd.} \right)^2} . \tag{18}$$

In these equations X corresponds to any parameter to compare the predicted and measured values.

The performance of the solar irradiation calculation part of the algorithm of this thesis was verified on the basis of $\overline{H}_D$, $\overline{H}$ and $\overline{H}_T$ by applying above mentioned statistical methods [33], [45], [46], [52]. Comparison of solar irradiation calculation methodology with its main alternatives were carried out. These alternatives cover the equations/methods that are widely accepted in the literature [44], [49], [67], [68], [59]–[66] and prove their accuracy in the recent researches [69], [70] from the literature and a widely used software, EU PVGIS developed by European Commission [24] and a database used by many software programs namely Meteonorm [71].

These comparisons to check the accuracy of the algorithm of this study were made by using MBE and RMSE statistical methods, as mentioned above. The comparisons are carried out via the data of solar radiation measurements of TSMS.

For validation and comparison of $\overline{H}$ calculations of above mentioned methodology, $\overline{H}$ was calculated for 40 locations in Turkey and the results are compared with alternatives by using the measured value. For the validation and comparisons of $\overline{H}_D$, 8 locations having $\overline{H}_D$ are separated as 4 pairs. The equations (monthly coefficients for diffuse estimation) obtained for one of the locations of the pair is used to predict diffuse component of the other. The results are compared with alternative diffuse estimation methodologies from literature ([35], [62], [65], [72] for $\overline{H}$ and [34], [59], [60], [67], [73], [74] for $\overline{H}_D$).

These validation and comparison studies were discussed in [33], [47]. Briefly, in 32 of 40 locations the algorithm outlined in this thesis (of SOlAR TURnKEY) has given the most accurate results for the global solar irradiation predictions. For the remaining 8 locations the algorithm has given quite close results with the other best alternatives. Therefore, the results have shown that the present procedure derived gives reliable results. For the pairs for diffuse calculation, 3 of the 4 pairs SOlAR TURnKEY has given results that is the closest to the measured data.

2.2 Design of the PV System and the PV Power Plant

The second step is the identification and calculation of design parameters. That is, how much total area needed for the system, what is the distance between PV lines to avoid shading effect, how many equipment are needed to make optimum design should be known. This part constitutes three main outputs: determination of system equipment, numbering and sizing of these equipment and calculation of total area needed.

2.2.1 Components and Parameters for Optimum Design

All the components of the PV PP and the equations for numbering/sizing them are identified and determined in this section.

The PV PP fundamentally consists of PV modules, mounting equipment (junction pieces, concrete structures), AC and DC cables, inverters (central/string/micro), charge controllers, batteries, transformers, remote monitoring units, hedges, earthing equipment and miscellaneous equipment (DC/AC disconnects, breakers and switches, combiner/junction boxes, bus-bar/distribution panel) [54], [75].

The solar irradiation (input) reaches the PV system (modules) and cells in the modules directly convert photons into DC electricity. This DC electricity produced by the system is transferred to inverters via cables that converts DC electricity into AC electricity. This AC electricity is fed into the grid after the adjustment made in the transformers to supply energy to the end users. On the other hand, the electrical energy may be stored for later use, that is batteries must be used for this purpose. The energy production of PV PP and also the safety and security can be followed by remote control units. Others are ancillary equipment for the above mentioned progressions.

2.2.1.1 Parameters concerning the system

PV Modules are placed together and are connected to form arrays. The main reason to connect modules in order to form arrays is to raise voltage or current [76]. Arrays are connected to each other to structure PV lines.

The amount of PV modules (M_M) required for the system is calculated by dividing total size of the system by peak DC power of the module:

$$M_M = {P_T}/{P_M} \tag{19}$$

where P_T is the pre-specified installed power of the system and P_M is the peak DC power given in datasheets of the modules.

PV modules are placed on the mounting equipment, which are adjusted to an optimal tilt angle. PV modules can be placed either horizontally or vertically. Moreover, the amount of the modules on the same column or row do not have any limit and depends on the construction design details of the system. Present algorithm has the options for array design for PV module placement as 2-3 modules on the same column both for vertically and horizontally.

These preferences have an effect on the distance between the PV lines which is important to avoid shading. The calculation method for the minimum distance between the module lines are developed as given in Fig. 3 [37], [77], [78].

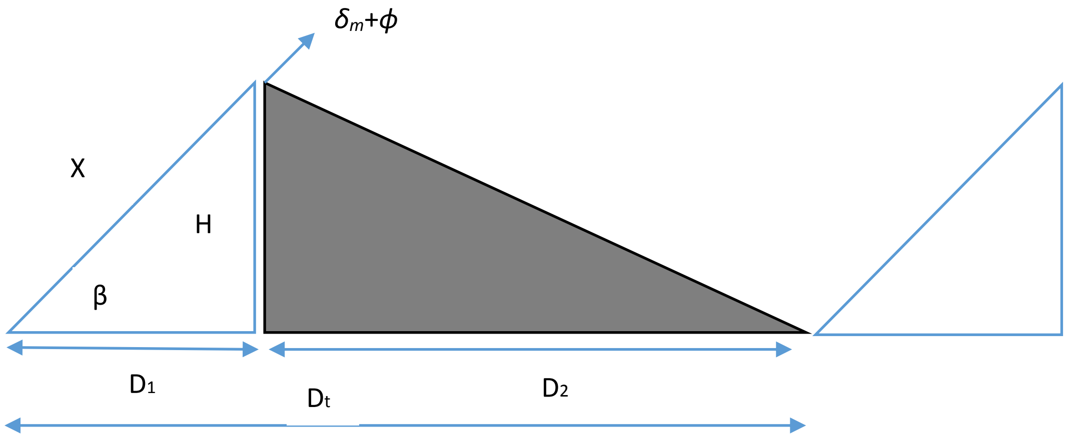

Figure 3 Triangle shadow method for the computation of the PV line spacing

The various parameters in this design given in Fig. 3 can be calculated as follows:

$$D_1 = X \times \cos \beta \tag{20}$$

$$H = X \times \sin \beta \tag{21}$$

$$D_2 = H \times \tan(\delta_m + \phi) \tag{22}$$

$$D_T = D_1 + D_2 \tag{23}$$

where X is the width of horizontally or length of vertically located modules. β is the optimum tilt angle as determined in Eq. 13. D_1 is the depth of PV array with respect to ground. D_2 is the minimum distance between the two PV lines that is left to avoid the negative effect of shadowing. δ_m is the obliqueness of Earth, 23.45° and ϕ is the latitude of the location.

The greater tilt angle requires more distance between lines to avoid from shading effect that decreases the productivity in a considerable amount according to our calculations. Consequently, for the tracking option the greatest monthly average daily tilt angle of a year is taken by applying Eq. 16 to every month.

In the placement of PV modules to a location of interest with different options, the only variable is X in the above-mentioned expressions. The options are classified as followings:

- Option 1: 2 modules horizontally located

The width and height information of PV modules can be taken from the datasheets of them that are officially released/announced by the producers. For this option, X matches with 2 times the width of the PV module. Consequently,

$$X = 2 \times w \tag{24}$$

where w is the width of PV module.

- Option 2: 3 modules horizontally located

For this option, X equals to 3 times width of PV module. Consequently,

$$X = 3 \times w \ . \tag{25}$$

- Option 3: 2 modules vertically located

X is now 2 times of the height of PV module. So,

$$X = 2 \times h \tag{26}$$

where h is the height of PV module.

- Option 4: 3 modules vertically located

X for this option is 2 times the height of PV module. So,

$$X = 3 \times h \ . \tag{27}$$

The software needs to compare the results of these options and select the option that requires the smallest PV PP area in total. The remaining parameters for the calculation of area of PV modules are given in the area calculation part.

2.2.1.2 Mounting systems

The construction materials are divided into 3 main components that are junction equipment like screw, tire rod, cement for concrete works and aluminum/steel frames for bearing elements [79], [80].

The amount of mounting materials can be calculated by utilizing unit amount required as determined in [79], [80]. For each m^2 of module system, 3.98 kg aluminum, 5.74×10^{-4} m^3 concrete, 6.15 kg steel [79], [80] is required.

The equations to estimate required amounts of aluminum (M_{AL}), steel (M_{ST}) and concrete (M_{CONC}) are given in Eqs. 28, 29 and 30, respectively.

$$M_{AL} = M_{AL,unit} \times A_M \tag{28}$$

$$M_{ST} = M_{ST,unit} \times A_M \tag{29}$$

$$M_{CONC} = M_{CONC,unit} \times A_M \tag{30}$$

where $M_{AL,unit}$, $M_{ST,unit}$ and $M_{CONC,unit}$ are amount per m^2 and A_M is area of modules.

2.2.1.3 AC/DC Cables

The electricity is in the form of direct current (DC) from PV modules to inverters then it is converted into alternating current (AC). Consequently, cable sizing and cable type selecting of the PV PP is another important step for design analysis. Sizing cable means determining required diameter and length of the cable. Thicker cables are required for distribution at low voltages because currents are higher and the voltage drop along the cable must be lower [81].

For cable selection, cross sectional area and the length of the route for the cable from the battery to last appliance are calculated [81].

While length of the cable is project specific, however there can be some general acceptations from literature. On the other hand, cross sectional area of a cable (d) can be calculated with Eq. 31.

$$d = I_{mp} \times l \times {}^{0.04}\!/_{V} \tag{31}$$

where I_{mp} is maximum current, l is cable length, V is maximum acceptable voltage drop. 0.04 has unit of V mm^2 A^{-1} m^{-1}.

According to related standard and Turkish Energy Distribution Company specification [82] maximum acceptable voltage is calculated by multiplying $V_{oc,ref}$ with number of modules and 1.15.

The equation for total cable length ($D_{L,C}$) that is calculated by multiplying unit length per watt ($d_{L,C}$) with total power (P_T) is as follows:

$$D_{L,C} = P_T \times d_{L,C} \quad . \tag{32}$$

2.2.1.4 Inverter

Inverters used to convert DC electricity into AC has three sub technologies that are micro, string and central ones [83] depending on their size. In this study, all are taken into account and calculated separately.

The software owing to the algorithm can decide which option is the best by checking their price, efficiency and land coverage.

Micro inverters do not require any additional space because they are located under the PV modules [83]. On the other hand, string and central inverters occupy additional places. The area calculation for inverters are made in area calculation part.

For micro inverter, the amount ($M_{i,m}$) equals to the amount of module (M_M). So,

$$M_{i,m} = M_M \quad . \tag{33}$$

For string inverter, the amount of inverter ($M_{i,s}$) equals to the number of strings (PV lines) (M_s). Unit power of string inverters ($P_{i,s}$) equals to total power of modules in one string (PV line) (P_s). That is:

$$M_{i,s} = M_s \tag{34}$$

$$P_{i,s} = P_s \quad . \tag{35}$$

For central inverter the amount ($M_{i,c}$) is 1 and the size ($P_{i,c}$) equals to total installed power (P_T):

$$M_{i,c} = 1 \tag{36}$$

$$P_{i,c} = P_T \quad . \tag{37}$$

2.2.1.5 Battery

In case of storage instead of grid feeding or real-time consuming, batteries are operationalized. The battery size calculation part of the algorithm has the assumptions of a battery need for 1/2/3 days. The size of the battery also affects the cost of the system, as well.

The needed capacity of the battery (E_B) is calculated as the summation of 1/2/3 days electricity production. The equation is:

$$E_B = \left(n_{day} \times E_m\right) \times D_d \tag{38}$$

where D_d is the depth of discharge of battery, n_{day} is number of days of electricity production to store (options are 1/2/3) and E_m is the daily maximum electricity production in a year [84].

2.2.1.6 Controls, Charge Controller and Maximum Power Point Trackers

Charge controller is used in systems having battery backup. Their main duties are to keep battery from overcharging and overvoltage and provide one way flow of electricity to avoid reverse electricity flow from battery through array when the battery is fully charged [85]–[87]. Controls are used to maximize the output of arrays and protect electrical components from damage [34].

PV systems with batteries need protection of battery from overcharge or deep discharge [88]. Charge controller regulates the electricity that battery fed and protects battery from overcharging.

Maximum Power Point Trackers are devices that keep the impedance of the circuit of to the best operation level and also convert the resulting power from the PV array to the voltage that is required by the load [34].

These components do not cover extra land and can be placed within the allocated area of PV PP. Therefore, they are not included in the area calculation part; however, they are included in the cost analysis.

2.2.1.7 Transformer

Since electricity generated by PV PPs has to be transmitted to the areas of consumption, transformer is required to increase the voltage of the generated electricity to usually about 110 kV or 220 kV to transfer electricity efficiently [89]. For transformers, the precise requirements vary depending on the condition of each project. That is why each transformer should be almost as unique as a fingerprint when it comes to voltage, power, climate, network, topology, permissible noise level, and other factors.

2.2.1.8 Earthing and Lightning Protection

The Turkish Standards Institution (TSE) (International Electrotechnical Commission - IEC) 62305-numbered standard instructs to have 4-step shield. They are external lightening system, internal lightening system, equipotential system and earthing. The earthing is made with respect to Regulation on Earthing of Electricity Systems published in Official Journal (No 24500) on 21/08/2001.

2.2.1.9 Miscancellenous Components

Other components optionally required for PV PPs are remote monitoring units, hedge/fence, smart meter, security cameras and artificial intelligence units.

2.2.1.10 Lifetime of the System

PV modules, the key component of PV systems, are warranted for a duration in the range of 25–30 years by many producers [90]–[93]. The practical lifetime of the silicon-made PV modules is expected to be at least 30 years [94], [95]. In parallel with the mentioned information, the lifetime assumption for this study is 30 years.

2.2.2 Total Area Needed

The total area needed for the PP is an important parameter that should be known in order to arrange appropriate field. The total area calculation model developed in this study is given step by step below:

- Area for PV modules (A_m)

The area of PV modules are the functions of width and length of the area between the beginning of the first PV line and end of the last PV line. In order to get rid of shading effect as mentioned, empty places are left between PV lines. Consequently, the area needed for PV modules are calculated by using Eq. 39:

$$A_m = (N_L \times D_1 + (N_L - 1) \times D_2) \times W_L \tag{39}$$

where N_L is the number of PV lines and W_L is width of each line. D_1 and D_2 are calculated by using Eqs. 20 and 22.

- Area for an inverter (A_i):

String and central inverters are located in concrete buildings; however, there is no extra area requirement for micro inverters since they are placed under the PV module.

Required area for central inverter is symbolized as $A_{i,c}$ and for string inverters it is symbolized as $A_{i,s}$. Depending on the option selected in the design part the related parameter is taken into account.

Because inverters are placed in concrete buildings, the area of these buildings equal to the area needed for inverter. Thus, the area for central inverter is found by using Eq. 40 and total area for string inverters is calculated with Eq. 41:

$$A_{i,c} = W_{i,b} \times L_{i,b} \tag{40}$$

$$A_{i,s} = (W_{i,b} \times L_{i,b}) \times N_i \tag{41}$$

where N_i is an amount of string inverter. $W_{i,b}$ and $L_{i,b}$ are width and length of the building.

- Area for transformer (A_t)

Like inverters transformer is also placed into concrete buildings. Then, the area of transformer corresponds to the area of a building structured for transformer in Eq. 42 as:

$$A_t = W_{t,b} \times L_{t,b} \quad . \tag{42}$$

$W_{t,b}$ and $L_{t,b}$ are width and length of the building.

2.2.2.1 Total area needed for the PV power plant

Total area required for the PV PP (A_T) includes total area of modules (A_m), free space between hedges and modules left for security reasons (A_{fs}), area of the buildings for inverter(s) (A_i), batteries (A_b) and transformers (A_t). Consequently, Eq. 43 gives the total area needed:

$$A_T = A_m + A_{fs} + A_b + A_i + A_t \quad . \tag{43}$$

2.3 Output: Solar Electricity

For the PV PP whose input is known as calculated in Section 2.1 and whose design has been made as in Section 2.2 the output that is, solar electricity production can be calculated.

This part initially calculates DC electricity production of PV system (PV modules) that is called as gross electricity in this thesis. Then, net electricity remaining after all losses of cable, inverter etc. and provided to the grid and/or consumer by the PP is computed.

The flow chart of the electricity calculation part is given in Figure 4.

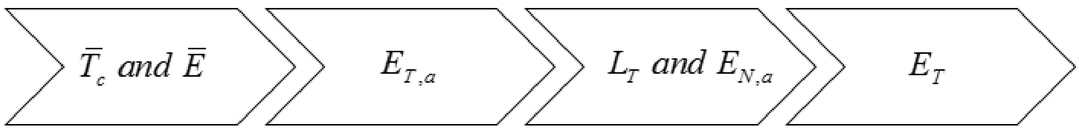

Figure 4 The flow chart of the electricity production part

$\overline{T_c}$ is monthly average cell temperature and $\overline{E}$ is monthly average daily electricity production of the PV PP. $E_{T,a}$ is gross annual DC electricity production of the PV PP. L_T is the total losses from BoS components and $E_{N,a}$ is annual net AC electricity that is provided to the grid or given to the end user by the PV PP. E_T is lifetime net electricity production of the PV PP.

For the validation of electricity calculation methodology as part of the algorithm, methodologies of current software programs and previous studies in literature were analyzed and compared.

2.3.1 Gross Electricity Production of the PV System

The electricity production performance of a module mainly depends on the solar irradiation exposure whose calculation methodology is defined in Section 2.1 and on the efficiency. Efficiency is basically depended on the static (i.e. capacity of manufacturing materials) and dynamic (i.e cell Temperature) parameters. The information of static parameters can be taken from the official datasheets of PV modules that manufacturers release. Nevertheless, we need to calculate cell temperature varying depending on ambient temperature change and its negative effect on performance.

Therefore, this part mainly deals with the models to calculate the cell temperature and PV electricity production of a PV module.

2.3.1.1 Cell temperature model

Cell temperature, thus the temperature of PV module surface has considerable effect on the performance of PV cells. We can assume cell temperature (T_c) as having the same value with ambient temperature (T_a) by night; however, in full sun it can exceed ambient temperature with more than 30°C [96].

Following procedure determines an equation to calculate T_c at certain time by using some other parameters like T_a that are measured or calculated.

Initially the energy balance is defined by utilizing the methodology of [34] as in the followings:

$$\tau\alpha G = \eta_c G + U_L (T_c - T_a) \tag{44}$$

where $\tau\alpha$ is transmittance-absorptance product, G is solar irradiance, η_c is load efficiency and U_L is overall heat loss coefficient.

Solving preceding equation (Eq. 44) for T_c, we acquire:

$T_c = \frac{G}{U_L}(\tau\alpha - \eta_c) + T_a$ and then $T_c = G\left(\frac{\tau\alpha}{U_L}\right)(1 - \frac{\eta_c}{\tau\alpha}) + T_a$.

Since the measurement of $\tau\alpha / U_L$ is hard [34], it is replaced with the following equation that is based on nominal operating cell temperature (NOCT) that is, the cell temperature at certain condition: 0.8 kW m^{-2}, 20°C and no load operation so η_c is 0 [34]:

$$\frac{\tau\alpha}{U_L} = \frac{T_{c,NOCT} - T_{a,NOCT}}{G_{NOCT}} \tag{45}$$

where $T_{c,NOCT}$ is nominal operating cell temperature – NOCT, $T_{a,NOCT}$ is ambient temperature at which NOCT is defined (20 ºC) and G_{NOCT} is solar irradiation at which NOCT is defined (0.8 kWh m^{-2}). Then, the equation takes the form:

$$T_c = G\left(\frac{T_{c,NOCT} - 20}{800}\right) + T_a \quad . \tag{46}$$

While $T_{c,NOCT}$ information can be taken from the official datasheet of a PV module, T_a is compiled from the measured values of the TSMS or another reliable data source and G is obtained using the solar irradiation calculation methodology given in Section 2.1.

T_a is measured continously by the TSMS and for SOlAR TURnKEY the database for ambient temperature of TSMS values should be embedded into the software. Moreover, the T_a data during daytime must be extracted as PV system is able to produce electricity should be taken into account.

2.3.1.2 PV System (PV module) electricity production:

5-parameter model [34] generally paves the way for the electricity production methodology of a PV module. The models used by alternative software (i.e PV Sol, SAM, PV F-Chart etc.) are generally based on this model with small variances.

However, in the present thesis, the method is considerably modified and formed to use in SOlAR TURnKEY algorithm.

The equations are given below. The references for them are Eq. 47, 48, 49 [34], Eq. 50 [97], [98] and Eq. 51 [34]:

$$\eta_{mpp} = \eta_{mpp,ref} + \mu_{\eta,mpp}(T_c - T_{c,ref}) \tag{47}$$

$$\eta_{mpp} = \frac{I_{mpp}V_{mpp}}{A_c G} \tag{48}$$

$$\mu_{\eta,mpp} = \eta_{mpp,ref}\frac{\mu_{Voc}}{V_{mpp}} \tag{49}$$

$$V_{mpp} = V_{mpp,ref} + \mu_{V_{oc}}\left(T_c - T_{c,ref}\right) \tag{50}$$

$$E = \eta_{mpp} G A_C \quad . \tag{51}$$

So the equation to calculate monthly mean daily electricity production of the PV system (PV module) ($\overline{E}$) is derived as:

$$\overline{E} = \eta_{mpp,ref}\left(1 + \frac{\mu_{V_{oc}}(\overline{T}_c - T_{c,ref})}{V_{mpp,ref} + \mu_{V_{oc}}\left(\overline{T}_c - T_{c,ref}\right)}\right)\overline{H}_T A_C \tag{52}$$

where

$$\overline{T}_c = \overline{H}_{t,i}\left(\frac{T_{c,NOCT} - 20}{800}\right) + \overline{T}_a \quad . \tag{53}$$

$\overline{H}_{t,i}$ is the value of the monthly average daily solar irradiation in W m^{-2}, $\eta_{mpp,ref}$ is the reference efficiency of a PV module/cell and the value is taken from the official datasheet of a module, $\mu_{V_{oc}}$ is the temperature coefficient of open-circuit voltage, $V_{mpp,ref}$ is reference voltage at maximum–point, $\overline{T}_c$ is the monthly average daily cell temperature, $T_{c,ref}$ is the reference cell temperature and the value is taken from the datasheet and A_c is the total PV cell area/module area of the PP. Annual electricity production ($E_{T,a}$) can be calculated by

$$E_{T,a} = \sum_{i=1}^{12} \overline{E}_i \times n_i \tag{54}$$

where n_t is the number of days for the *i*th month and $\overline{E}_i$ is monthly mean daily electricity production of the *i*th month that is $\overline{E}$ from Eq. 52 above for each month in a year.

The calculations in this part count in the losses stemming from modules. There are also some other climatic factors that affect the efficiency of the system such as dust, snow etc. [66], [99]–[105]. And losses from BoS components [106], all are taken into account in the next section.

2.3.2 Net Electricity Production of the Power Plant

There is a difference between the exit of the PV modules (gross electricity) and the entrance of smart meter (net electricity) because of some resistances throughout the PP.

The main aim is certainly to design and install systems with minimum possible losses. In other words, the main effort of the algorithm is to keep net electricity production amount as close as possible to gross electricity production. To do so, eliminating all the possible shading losses is one of the main targets of SOlAR TURnKEY; so, shading loss should be minimized as much as possible and be wiped out if possible. Therefore, shading loss is added to the algorithm with parameter L_s.

L_s is commonly assumed as 2% [107]. As a reference, this value can also be used within this algorithm while this assumption is in the control of the software.

Following sub-sections cover the methodology consisting of losses because of BoS components and their subtraction from gross electricity amount.

2.3.2.1 DC Electricity transmission (DC Cabling loss)

DC cabling loss includes all the losses occurring during electricity transfer from PV system (PV modules) to inverter. This algorithm is designed to be able to calculate project specific DC cabling losses. Energy losses in a cable is mainly due to resistive heating of the cable [108].

The equation of energy losses in wires depends on a number of line coefficient (l_1) (l_1=1 for single line and 3 for 3-phase circuit), resistance, current (I_{mpp}). The resistance is also depended to length cable factor (l_2) (l_2 is 2 for single phase wiring and 1 for three-phased wiring), resistivity of material conductor (ρ_c) (ρ_c is 0.017 Ω mm^2 m^{-1} for copper and 0.0265 Ω mm^2 m^{-1} for aluminum at 20°C), length of the cable (l_c) and cross sectional area of the cable (s_c)[108]. Thus, the equation to calculate cable loss can be defined as follows:

$$L_c = l_1 l_2 l_3 \rho_c I_{mpp}^2 \tag{55}$$

where l_3 is the ratio between the length (l_c) and cross section of the cable (s_c).

I_{mpp} can be calculated by using the below as developed in [97]:

$$I_{mpp} = \frac{\overline{H}_T}{\overline{H}_{T,ref}} \left(I_{mpp,ref} \times \mu_{I_{sc}} \left(\overline{T}_c - T_{c,ref} \right) \right) \tag{56}$$

where $\mu_{I_{sc}}$ is temperature coefficient of short circuit current.

2.3.2.2 DC/AC Conversion (Inverter Loss)

Inverter throughout the conversion process of DC electricity into AC results in some losses. The loss depends on the inverter efficiency and electricity consumption. Therefore, the AC electricity from the inverter ($E_{out,i}$) is calculated as:

$$E_{out,i} = E_{in,i} \times \eta_i - E_{used,i} \tag{57}$$

where η_i is the efficiency of inverter, $E_{used,i}$ is the electricity consumed by the inverter and $E_{in,i}$ is the DC electricity entering to inverter.

Likewise, the loss of inverter (L_i) is calculated as:

$$L_i = \frac{E_{in,i} - E_{out,i}}{E_{in,i}} \times 100 \tag{58}$$

Efficiency and energy consumption of inverters can be taken from the official datasheets of inverters.

2.3.2.3 AC Electricity Transmission – AC Cabling Loss

The AC cables are laid between the inverter and smart meter/load/grid. The concept for AC cabling losses are exactly the same as DC cabling losses part [109].

$$E_{out,ACcable} = E_{in,ACcable} \times \eta_{ACcable} \tag{59}$$

$E_{out,ACcable}$ is the electricity that is transmitted by the cable, $\eta_{ACcable}$ is the efficiency of the cable and $E_{in,ACcable}$ is the electricity leaving the inverter.

2.3.2.4 DC Electricity Storage – Battery back-up Loss

If the system is designed as off-grid with battery back-up, the loss because of the battery should be taken into account. Battery back-up loss (L_B) is calculated by examining the difference between charging and discharging amounts of electricity, so the efficiency. Consequently, the equation for loss is

$$L_B = (1 - \eta_B) \tag{60}$$

where η_B is efficiency of battery. As a reference, efficiency of lithium-ion batteries is generally assumed to vary between 0.85-0.95 [6][110].

2.3.2.5 Tracking system electricity consumption

The loss because of electricity consumption by tracking system (L_{Tr}) can be calculated by

$$L_{Tr} = EC_{Tr} \tag{61}$$

where EC_{Tr} is electricity consumption of tracking system.

This parameter is taken into account for PV PP's with tracking systems. The tracking system is assumed to consume 0.05 % of electricity production of PV PP [111].

2.3.2.6 Total Loss and Net Electricity Production Calculation

The total loss (L_{total}) is calculated by applying Eq. 62.

$$L_{total}\ (\%) = 100\left[1 - \prod_t 1 - \frac{L_t}{100}\right] \tag{62}$$

where $L_{total} = L_c + L_i + L_s$ and L_B and L_{Tr} are added optionally. Then the net electricity available to use ($E_{N,a}$) is calculated by subtracting losses from gross electricity production ($E_{T,a}$) as given in below equation:

$$E_{N,a} = E_{T,a} \times (1 - L_{total})\ . \tag{63}$$

2.3.3 Degredation of the System

Above-mentioned electricity production methodology gives the values for the first year of operation. However, the system cannot produce same amount of electricity sustainably and is degraded over time. This situation affects the productivity of the system [112]. Generally accepted value of degradation per year is around 0.5% [112], [113]. Location specific degradations can also be used as given in [42]. Then, the lifetime net electricity production (E_T) is calculated by using below equation

$$E_T = E_{N,a} + \sum_{n=1}^{N} E_{N,a} \times (1-d)^n \tag{64}$$

where d is the degradation rate, n is determined year and N is lifetime of the system.

2.3.4 Validation of Electricity Production Calculation Methodology

In addition to MBE and RMSE, there are some other statistical methods used: Mean Absolute Error (MAE), R-square etc. MAE which measures the average magnitude of the errors in a set of predictions without considering their direction [114] among them seems to be the one that gives the most realistic results together with RMSE [114].

In the literature, many studies acknowledges RMSE as a standard metric for accuracy testing [115]–[117], while a few others prefers only MAE [114], [118]–[121]. Therefore, MAE test is also applied in addition to the comparisons previously carried out (i.e. [45]–[47]). MAE is found by using below Eq. 65.

$$MAE = \frac{1}{s} \sum_{i=1}^{s} \left| X_{i,calc.} - X_{i,msrd.} \right| . \tag{65}$$

Consequently, MAE is added to the comparison methods in this part of the study.

This study initially develops monthly mean daily solar cell temperature calculation methodology depending on monthly mean solar irradiation values. When the methodology is applied for a simulated solar cell in the location whose details are given in Chapter 4 by using yearlong T_a measurements of a closer field, the results for the estimation of cell temperature are quite close to the measured cell temperature values. The results of MBE, RMSE and MAE analysis, which are -0.43, 0.15 and 0.45 respectively, have shown that cell temperature model of this algorithm is highly acceptable.

On the other hand, the yield estimations of the methodology are compared using the measured electricity production of 4 different modules installed on the roof of Middle East Technical University Center of Solar Energy Research and Applications (METU GÜNAM) [122] The estimations of widespread global software EU PVGIS and PV WATTS developed by National Renewable Energy Laboratories

(NREL) are also calculated and compared. For 3 of the 4 modules the algorithm of this study has made the best estimations according to the MBE, RMSE and MAE values [122]. The results showed the algorithm developed in this thesis has the most accurate estimations compared to EU PVGIS and PV WATTS [122].

2.4 CO_2 Emission Reduction Potential

Greenhouse effect is the fundamental reason why the globe has a serious threat namely abrupt climate change [123]. It is also accepted to be mainly anthropogenic [123]. The major actor of the formation of greenhouse effect is CO_2 emission [124], [125]. Therefore, calculation of CO_2 emissions is very important in any technology/activity. Furthermore, since solar electricity is under the coverage of carbon trading mechanisms, the calculations in this part of the study also enables necessary steps for carbon trading part. Solar electricity technologies are assumed to be clean energy technologies. Consequently, by replacing some other technology to meet the same demand of energy, they reduce the CO_2 emission potential.

In order to calculate the potential of PV PP to reduce GHG emissions in Turkey, international methodology in conformity with the related guidance of the UNFCCC [126] is applied. UNFCCC’s latest methodological tool namely “Tool to Calculate the Emission Factor for an Electricity System” is a reference document to compute Turkey’s emission factor for electricity generation [126]. In order to follow the process shed light by UNFCCC tools, initial step is the calculation of the national emission factor[1]. The calculation of national emission factor necessitates to determine build margin[2] (BM) and operating margin[3] (OM) and integrate them with certain formula [126]. Then, unit amount of CO_2 reduction per kWh can be determined. The order of calculation is given in Figure 5.

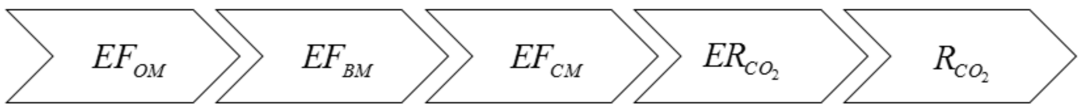

Figure 5 The order of the calculation steps of CO_2 emission reduction potential

[1] The amount emission per unit electricity generation
[2] BM is the emission factor that refers to the group of prospective power plants whose construction and future operation would be affected by the proposed Clean Development Mechanism (CDM) project activity.
[3] OM is the emission factor that refers to the group of existing power plants whose current electricity generation would be affected by the project activity.

EF_{OM} is operating margin emission factor and EF_{BM} is built margin emission factor while EF_{CM} is combined margin emission factor. ER_{CO_2} is emission reduction potential of the PV PP. R_{CO_2} is revenue from carbon markets.

Since the level of greenhouse gas emissions other than CO_2, such as CH_4 and N_2O, is negligibly small [127] computations are focused on CO_2 emission reduction.

Incidentally, during methodology development process for the calculation of the reduction amount, this study has benefited from UNFCCC's tool [126] and EDAM's study [128] which did the relevant work concerning nuclear energy.

As determined depending on the base year 2011, Turkey's OM emission factor (EF_{OM}) will be taken as 0.6603 tCO_2 MWh^{-1} [37], [38], [128]. Besides, BM emission factor (EF_{BM}) will be designated as 0.4315 tCO_2 MWh^{-1} [37], [38], [128].

After calculating OM and BM, the combined margin emission factor (EF_{CM}) is calculated by using the below equation:

$$EF_{CM} = EF_{OM} \times w_{OM} + EF_{BM} \times w_{BM} \quad . \tag{66}$$

The UNFCCC's tool suggests to take weighting of operating margin emission factor (w_{OM}) as 0.75 and weighting of built margin emission factor (w_{BM}) as 0.25 [126]. Consequently, the emission factor for PV in Turkey is calculated as:

$$EF_{CM} = 0.6603 \times 0.75 + 0.4315 \times 0.25 = 0.6031 \quad tCO_2 / MWh \quad .$$

Lifetime CO_2 emission reduction potential (ER_{CO_2}) of the PV system planned to be installed is computed by multiplying total electricity production with emission factor for solar electricity.

$$ER_{CO_2} = 0.6031\, tCO_2 / MWh \times E_T \tag{67}$$

where E_T is the electricity production of the system in MWhs.

This emission reduction potential can be monetized in carbon markets; however, the certification period needs some expenses. Consequently, the difference between the revenue in carbon market ($ER_{CO_2} \times U_{CO_2}$) and expenditure for certification (C_{CO_2}) is added to the revenue of the investment. Hence, the revenue from the carbon market is as follows:

$$R_{CO_2} = ER_{CO_2} \times U_{CO_2} - C_{CO_2} \quad . \tag{68}$$

CHAPTER 3

THE ALGORITHM: ECONOMICS

Economic analysis has utmost importance to decide on making any investment. It is also vital for energy sector and solar electricity, as well.

This chapter develops the economics part of the algorithm. It is *sine qua non* that these kind of algorithms cover all the related activities from cost to revenue, profit, payback etc.

In this part of the study, all procedures of the system installation period that have expenses are defined initially. Then, all the costs of the system from zero to turnkey are determined. Not limited to this, the costs after installation such as operation and maintenance costs until dismantling are taken into account. Economies of scale is also considered with newly developed equations. In almost all the steps from cost to revenue, calculations are using results of technical analysis part. The permission period of the system to install is also a part of a process that needs some expenditures. Hence, it is also taken into consideration.

As the second part of this subject, intuitive and novel scenarios for the determination of revenue options of the PV PP are developed first with respect to market realities, legal provisions and projections. Then, revenue, profit and payback analysis is made abiding by these new, original scenarios including various electricity selling options, price projections and governmental decision scenarios on feed-in-tariff system. The end-user price and day-ahead mechanism (DAM) price estimations were made as elaborated in Appendix D. Revenue part also consists of gain from carbon trading mechanism that is left after its expenditures to get required certificate are subtracted however in the algorithm this parameter was taken into account in Cost section.

Net worth of the system including LCOE, LROE, LPOE and NFM metrics is defined in order to give investor an opportunity to see economic feasibility of the investment and compare solar electricity investment option with its counterparts.

Moreover, some extra analysis like internal rate of return (IRR), annual electricity production per each unit cost of investment is studied because of their being demanded by some grant/support/loan programs (like Turseff, Midseff, IPARD, EBRD etc.) available for solar electricity investments. Furthermore, capital providing models such as own capital, loaning etc. are also other subjects of this part of the study.

To sum up, economic analysis consists of cost, revenue, profit, payback calculation together with LCOE, and the newly defined metrics LROE, LPOE, NFM calculations and other related parameters like IRR, Electric Key Performance Indicator (KPI) etc.

The flowchart of economics part of the algorithm is given in Figure 6.

Figure 6 The flowchart of economics part of the algorithm

3.1 Cost

This part of the study calculates the cost of the PV PP by taking into account all types of fixed and variable costs.

To make cost analysis in the most accurate way, the unit price and usage amount of every component used for the system should be known with all options that are applicable. Because of its being a very dynamic issue, defining the unit prices is a work under the software creation and operation process. Consequently, in this part the structure of the methodology is formed and equations are developed.

The cost analysis is separated into two main parts as initial investments and annual dynamic variable costs. Initial investment is also separated into two main parts, namely documentation and permission/application process and system installation.

These costs are given in the following sub-topics subsequently.

3.1.1 Initial Investments

3.1.2.1 Documentation and Permission Process

There are three main ways to get permission for PV PP to feed electricity to grid and sell it to the authorities, namely licensing process and un-licensing one and tenders for YEKA (Renewable Energy Resource Zones - Re-ZONE).

The PPs, whose installed power is smaller than one MW, are subjected to un-licensed process according to the Directive on Unlicensed Electricity Production in Electricity Market. Those whose installed power are bigger than one MW are liable to licensing process. Moreover, government periodically announces tendering process at a scale of 1000 MW for YEKAs. There are, of course, always off-grid self-consumption option too.

In order to be able to be updated and follow the recent processes this study deals with all the options for permission.

The last but not the least, if an investor wants to install a rooftop system up to 10 kW and sells excess electricity as a prosumer, he/she is liable to special circumstances as mentioned in Council Decision of Energy Market Regulatory Authority (EMRA) dated 27 December 2017.

The cost of un-licensed permission includes application fees and other soft costs. This amount is added to the algorithm as a parameter and the amount must be updated real time in software. The details of permission process are given in Appendix E and permission steps are listed in Table E.1 in Appendix E.

Licensing tenders included contribution fee in the first example that were realized in 2014-2015 period. However, it is foreseen that these kind of tendering conditions may no longer be applicable. Consequently, if the size of the system planned to install is bigger than one MW the algorithm look for the both ways to add additional cost for the permission process and to query the smallest acceptable amount of price the investor accept to sell electricity to the government as is done todays tenders such as YEKA tender. This part is separately given in the algorithm as showing the smallest acceptable price for tender and highest acceptable contribution fee as mentioned above.

Documentation and permission process differs depending on the size of the PV PP planned to install. If the size of the PV PP is equal to or less than one MW, this part is directed to un-licensing permission process. Then, all the costs for un-licensing process are added to analysis. Un-licensing process is also separated into two as roof top systems up to 10 kW and ground mounted utility scale systems up to one MW.

The equations defining total permission costs for rooftop systems up to 10 kW, $C_{p,rooftop}$ and un-licensed process for the systems up to one MW, $C_{p,ground}$ are as follows:

$$C_{p,rooftop} = U_1 \tag{69}$$

$$C_{p,ground} = U_2 \tag{70}$$

U_1 and U_2 shall be given and updated in the software.

In order to simplify the process, the cost of documentation and permission process (C_p) is embedded to initial investment (C_I).

3.1.2.2 System Installation

Initial investment C_I constitutes the cost of the PV PP and the cost of the required land, C_L. However, because it differs from location to location and time to time, C_L is left out of scope.

Cost of the PV PP mainly constitutes from the module costs and BoS costs. BoS costs part consist of all the costs of the system excluding PV module cost.

❖ *Module Cost*

The module cost (C_M) is basically computed by multiplying unit cost (U_M) in \$ Wp^{-1} with the total installed power (P_T).

$$C_M = U_M \times P_T \tag{71}$$

With the intention of avoidance from duplication, the costs caused by mounting systems, erection of PV modules and installation of PV modules are considered separately.

❖ *Balance of System (BoS) Costs*

Cost of BoS components (C_{BoS}) include all non-module costs of a solar PV installation, including mainly wiring (cabling) (C_w), inverter (C_i), earthing (C_e), remote monitoring (C_r), transformer (C_t), hedges (C_h), and land preparation (C_{lp}) and connection to the grid expenditures (C_{nc}) [129]. Moreover, optional equipment like battery, charge controller, transformer etc. are added to BoS costs. Additively, cost of construction equipment is also added to BoS costs.

$$C_{BoS} = C_w + C_i + C_e + C_r + C_t + C_h + C_{lp} + C_{nc}. \tag{72}$$

However, the invester nets off C_{nc} with the distribution company.

Moreover, for the battery system;

$$C_{BoSwB} = C_{BoS} + C_b + C_{cc} + C_{mppt} \tag{73}$$

where C_b is battery cost, C_{cc} is charge controller cost and C_{mppt} is the cost for maximum power point tracker (mppt).

- Cost of Mounting Equipment (C_{ME})

Mounting equipment is used to erect PV modules to optimum degree that maximizes utilization of the system. It generally consists of galvanized steel and aluminum differing with respect to the project features [79]. For this parameter unit prices and required amount are determined and multiplied with each other. Unit prices (U_{ME}) can be added to software while required amount is determined in the algorithm as shown in Section 2.2.1.2.

$$C_{ME} = M_{ME} \times U_{ME} \tag{74}$$

where M_{ME} is the amount of mounting equipment used.

- Inverter Costs (C_i)

Depending on the technology and insurance period, inverters may be replaced with the new one in certain period. This time is foreseen around 10 years in literature [129]. While replacement is calculated, discount rate (r) is imposed to the prices in order to find net present value.

All the three options which can be selected, namely string ($C_{i,s}$), micro ($C_{i,m}$) and central inverters ($C_{i,c}$) are calculated separately. Consequently, investor has chance to compare these options and select whichever preferred. Moreover, the software can compare them by taking into account cost, required field and technical availability and suggests the best option.

$$C_{i,s} = M_{i,s} \times U_{i,s} \tag{75}$$

$$C_{i,m} = M_{M} \times U_{i,m} \tag{76}$$

$$C_{i,c} = U_{i,c} \tag{77}$$

where $U_{i,s}$, $U_{i,m}$ and $U_{i,c}$ are unit price of string inverter, micro inverter and central inverter respectively.

- Wiring (Cabling) Costs (C_w)

Cabling costs are calculated simply by multiplying length (l_c) defined at the cabling design part of this study with unit price of the cable (U_w) as shown in Eq. 78.

$$C_w = U_w \times l_c \tag{78}$$

- Earthing Costs (C_e)

Earthing equipment is defined as sets, so the cost is defined with the required amount of sets (M_e) and their prices (U_e), as in Eq. 79.

$$C_e = U_e \times M_e \tag{79}$$

- Battery Costs (C_b)

Battery prices should be in the software as a database, which constitutes all brands and their all products differing with demanded storage capacity. The amount of battery that is required to meet needed capacity defined at the battery design part of this study (M_b) is multiplied with unit price of the battery (U_b) in order to define battery cost (C_b), as given in Eq. 80.

$$C_b = U_b \times M_b \tag{80}$$

- Charge Controller Costs (C_{cc})

The amount to be calculated in this part will be taken into account for the system with back-up batteries. Required scale of charge controller (M_{cc}) is multiplied with unit cost price (U_{cc}) for the calculation of charge controller costs (C_{cc}), as in Eq. 81.

$$C_{cc} = U_{cc} \times M_{cc}\,. \tag{81}$$

- Maximum Power Point Tracker Costs (C_{mppt})

This equipment is also generally used with back-up systems. The procedure for the previous sub-title is valid exactly in here too.

$$C_{mppt} = U_{mppt} \times M_{mppt} \quad (82)$$

where U_{mppt} is the unit price of mppt and M_{mppt} is the amount of mppt.

- Remote Monitoring Systems (C_{rm})

Remote monitoring system prices are sold as sets; so calculation is made by multiplying size of the set (M_{rm}) and unit price of the monitoring system (U_{rm}), as given in Eq. 83.

$$C_{rm} = U_{rm} \times M_{rm} . \quad (83)$$

- Land Preparation (C_{lp})

This part of system installation is project specific. That’s why the algorithm can only apply general information to projects with some options. However, in general formation truck usage prices (C_{tu}), grading (C_{gr}) and road construction (C_{rc}) is part of this subtitle. So the cost of land preparation (C_{lp}) is calculated from Eq. 84.

$$C_{lp} = C_{tu} + C_{gr} + C_{rc} . \quad (84)$$

- Grid Connection (C_{nc})

Grid connection activities target to transmit net electricity to grid. The investor initially covers the expense of grid connection. Then, the investor and distribution company net off.

This part of the study also differs specific to each project because of all projects having sui-generis features at the position to connect the PP to grid. For instance, while one project can be near to connection point, the other may have 3 more neighbor lands owned by some other between the installed system and connection point, let’s say in 1 km. Consequently, together with cabling (C_{Cb}), transformer (C_t), electricity pylons (C_{EP}), expropriation (C_{Ex}), servitude (C_{Ser}) of the land owners where cables are passing or pylons are located is paid. That results in extra costs. That’s why the algorithm at this point gives the reasonable equation with some assumptions, as in Eq. 85.

$$C_{nc} = C_{Cb} + C_t + C_{EP} + C_{Ex} + C_{Ser} . \quad (85)$$

❖ Labor (C_{Lb})

Direct labor requirement in the site is needed for construction and installation process from adjusting the land to assembling the PP. Land adjustments, mounting construction equipment, module mounting and BoS system installation from transformers to cables are main activities requiring labor. Eq. 86 is developed to calculate labor cost (C_{Lb}).

$$C_{Lb} = (M_t \times U_{Lb}) \times M_{Lb} \tag{86}$$

where M_t is amount of time a labor is needed, U_{Lb} is unit price of labor and M_{Lb} is the amount of labor needed.

❖ Smart Meter (C_{sm})

Smart meter measures not only the amount of electricity production but also the difference between consumed and produced. By using Eq. 87 the cost of a smart meter is added to cost calculation, as well.

$$C_{sm} = M_{sm} \times U_{sm} \tag{87}$$

where U_{sm} is the unit price and M_{sm} is the required amount.

❖ Carbon Market (C_{CM})

The GHG emission reduction potential of the system can be monetized by utilizing voluntary carbon market via carbon certificates; however, there are expenditures to acquire these certificates. This process is added to cost side. If the revenue is more than the cost of the certificates this part is taken into effect as minus cost for the system. The equation is:

$$C_{CM} = C_{CO_2} - R_{CO_2} \tag{88}$$

where R_{CM} is revenue from carbon certificates and C_{CO_2} is expenditure to acquire carbon certificates.

❖ System Usage Cost (C_{su})

System usage cost is a cost paid because generated electricity is using transmission/distribution lines. This cost is adjusted as 10.25 krş kWh^{-1} for unlicensed projects as of January 1st, 2018. However, this cost is 0.8969 krş kWh^{-1} for licensed projects. Total electricity produced is multiplied with above-mentioned price and it is added to the cost.

Unit price (U_{su}) is taken from EMRA decisions and is multiplied with electricity usage of the mentioned time. Then *NPV* is defined in pursuant to discount rate (r). The equation is:

$$C_{su} = \sum_{n=0}^{N} \frac{U_{su} \times E_n}{(1+r)^n} \tag{89}$$

where T is the total years electricity is fed into grid and r is discount rate.

- ❖ Hedge (C_h)

The amount of hedge required and the equation to calculate total cost of hedge/fence is given by the algorithm. However, the software will give the unit price of hedge (U_h). The equation for C_h is:

$$C_h = L_h \times U_h \tag{90}$$

where L_h is total length of hedge required.

- ❖ Security Cameras (C_{sc})

If the investor prefers to provide the security of the plant via security cameras giving chance to remote control instead of warden/guard employment, this part is considered. Thus, the cost of security cameras is found by using Eq. 91:

$$C_{sc} = M_{sc} \times U_{sc} \quad . \tag{91}$$

where M_{sc} and U_{sc} are unit price and amount of the security cameras respectively.

3.1.2 Annual Variable Costs

- ❖ Insurance Costs (C_{ins})

Owing to the relatively high technological risks associated with PV system, in contrast with conventional ones, an insurance policy should be adopted. The annual insurance rate for PV systems is foreseen as 0.25% [130] of C_I.

- ❖ Operation and Maintenance Costs, O&M

Operation and maintenance costs of PV PP (O&M) are comparatively low owing to its not consuming fuel, which is a major item for O&M.

For the parts of the study where tracking part by the system is not taken into account, O&M only consists of regular cleaning, monitoring of performance and inverter replacement approximately every 10 years [130]–[132]. In addition, batteries generally have 10-year warranty so it should also be replaced for every 10 years. However, the situation differs for the systems having tracking parts.

The parts dealing with fixed PV systems, based on the average of reported values, are considered to have annual O&M cost as 1.5% of C_I [90], [133]–[136].

On the other hand, according to the calculations of NREL [137], annual O&M cost per kW is 15.4 $ for fixed tilted system, while it is 18.5 $ kW^{-1} for single-axis tracking system. The amount for fixed tilted system also matches with above mentioned ratio. Therefore, for PV PP with tracking system the annual O&M cost is 20% higher than the one with fixed tilted system.

The investment cost ratio between fixed tilted and single-axis tracking (r_{f-tr}) is defined as 1.09 which means tracking system is 9% more expensive than fixed tilted system under the same conditions. This amount has been created by using up to date cost related studies [137]. Consequently, for tracking options annual O&M is multiplied with 1.10 (=1.20/1.09). So annual O&M for PV PP's with single-axis tracking is 1.65% (=1.5×1.10) of the total cost. This calculation is made in order to avoid from duplication.

Compiling all the information explained the variable cost (C_V) equation is derived as shown in Eq. 92. If PP has battery the variable cost transforms in the form of Eq. 93. Furthermore, if the system has tracking feature the equation for variable cost is shown as in Eq. 94.

$$C_V = \sum_{n=1}^{N} \frac{0.015 \times C_I}{(1+r)^n} + \frac{C_i}{(1+r)^{10}} + \sum_{n=1}^{N} \frac{0.0025 \times C_I}{(1+r)^n} \tag{92}$$

$$C_{Vwb} = \sum_{n=1}^{N} \frac{0.015 \times C_I}{(1+r)^n} + \frac{C_i}{(1+r)^{10}} + \sum_{n=1}^{N} \frac{0.0025 \times C_I}{(1+r)^n} + \frac{C_b}{(1+r)^{10}} \tag{93}$$

$$C_{Vwtr} = \sum_{n=1}^{N} \frac{0.0165 \times C_I \times r_{f-tr}}{(1+r)^n} + \frac{C_i}{(1+r)^{10}} + \sum_{n=1}^{N} \frac{0.0025 \times C_I \times r_{f-tr}}{(1+r)^n} \tag{94}$$

where C_{Vwb} is a variable cost of PV PP with battery and C_{Vwtr} is a variable cost of PV PP with tracking system without battery.

3.1.2.4 Total Cost

Concisely, the cost analysis of the PV system simulated includes all the expenditures starting from the permission process until dismantling.

The expenditures included in the cost calculation are permission process expenditures, documentation and permission cost (C_p), module cost (C_M), balance of system (BoS) components such as mounting equipment (C_{me}), inverter (C_i), cable (C_w), earthing equipment (C_e), miscellaneous components (remote monitoring system (C_{rms}), land preparation and construction (C_{lp}), connection to grid (C_{nc}) (be netted off by the distribution company), labor (C_l), transformer (C_t), smart meter (C_{sm}), carbon market (C_{CM}), hedge/fence (C_h), security cameras (C_{sc}) and variable costs such as insurance (C_{ins}), system usage cost (C_{su}), O&M ($C_{O\&M}$) and replacement of inverters ($C_{i,r}$)). The resulting expression reads:

$$C_T = C_I + \sum_{n=1}^{N} \frac{C_V}{(1+r)^n} \quad . \tag{95}$$

C_T is the total cost from permission process till dismantling.

The last but not the least, the equation for the total cost of PV PP with single axis tracking ($C_{T,tr}$) is determined as:

$$C_{T,tr} = r_{f-tr} \times C_T + \sum_{n=1}^{N} \frac{C_{VwTr}}{\left(1+r\right)^n} \quad . \tag{96}$$

3.1.2.5 Capital, Finance Sources and Loans

Abovementioned equations are valid for the investments whose capitals are provided by the investor without any loan. However, the capital can also be provided as loan from the available mechanisms like Turseff, a specific funding mechanism by European Bank on Reconstruction and Development (EBRD). Turseff is able to provide credits for 100% of the eligible investments. Consequently, the initial cost can be taken under variable costs and there will not be initial cost in this case. On the other hand, this mechanism or investor may demand self-contribution for some percent of the investment [138]. Consequently, the cost with the loan is calculated with below mentioned Eq. 97.

$$C_T = pC_I + \sum_{n=1}^{N} \frac{C_V}{(1+r)^n} + \sum_{n=1}^{t} \frac{(1-p)(1+e)C_I}{t(1+r)^n} \tag{97}$$

where p is the share of self-contribution, e is the annual interest rate for loan and t is the period of payment of installments.

The loan opportunities in Turkish Market are elaborated in Appendix F and the list of loan sources are given in Table F.1 in Appendix F.

3.1.2.6 Discount Rate

Taking into account the time value of money as well as the risk of the investment, discount rate is one of the most important assumptions on the input parameters to the LCOE.

Therefore, in order to calculate NPV of the related parameters of the calculations the discount rate of the country in question has to be determined. These type of data specific to Turkey can generally be provided from the Central Bank of Turkey, similar studies and/or financing mechanisms providing loan/grants for solar investments.

Consequently, while Central Bank has 8.75% ratio [139], [140], some studies made calculations with 5% discount rate [38], [141], [142]. On the other hand Turkey Sustainable Energy Financing Facility (Turseff) Program under European Bank on Reconstruction and Development (EBRD) that is the funding program of which Turkey is the biggest customer [143] uses discount rate as 7% [138].

Because the algorithm is able to make calculation with any discount assumed this study suggests taking into account all the possibilities for the discount rate as mentioned above and make calculation with respect to each of them separately.

3.1.3 Economies of Scale

Scaling up the system size reduces the cost of the system in some ways: per-watt BOS costs because of bulk purchasing, labor costs that benefit from learning-related improvements for larger systems, and EPC overhead and developer costs that are spread over more installed capacity [137].

According to study done by NREL on the benchmark definition for the US solar market, unit cost for 100 kW system is 2.03 $/Wdc, while it is 1.85 $/Wdc for 200 kW, 1.77 $/Wdc for 500 kW, 1.74$/Wdc for 1 MW, 1.38 $/Wdc for 5 MW, 1.26 $/Wdc for 10 MW, 1.12 $/Wdc for 50 MW, 1.03 $/Wdc for 100 MW [137].

However, the reasons of discount in price with the increase in size of the system are being bulk purchasing and price change in labor and EPC costs and they are totally country or project specific. Thus, while it is not easy to use strict price ratio changing depending on the size of the PV PP, the study of NREL having updated results as mentioned above can shed light into the ratio for Turkey. In a nutshell, the algorithm is taking the cost for 1 MW as reference and if the price is between 5 MW the cost is calculated as if there was 5 times 1 MW and multiply it with 0.79 (=1.38/1.74). On the contrary, when the size of the PP decreases the cost increases. Consequently the algorithm takes for instance 500 kW system into account as half one MW and multiply it with 1.017(=1.77/1.74). The constants for the other sizes are given in Table 1.

Table 1 Intervals and variables for economies of scale

Interval Size (P) (kW)	Variable (v)	Equation
$0 \leq P \leq 100$	1.167 (=2.03/1.74)	(98)
$100 < P \leq 200$	1.167 (=2.03/1.74) – 1.063	(99)
$200 < P \leq 500$	1.063 (=1.85/1.74) – 1.017	(100)
$500 < P \leq 1000$	1.017 (=1.77/1.74) – 1	(101)
$1000 < P \leq 5000$	1 – 0.793 (=1.38/1.74)	(102)
$5001 < P \leq 10000$	0.793 – 0.724 (=1.26/1.74)	(103)
$10000 < P \leq 50000$	0.724 – 0.644 (=1.12/1.74)	(104)
$50000 < P \leq 100000$	0.644 – 0.592 (=1.03/1.74)	(105)

For each size between size interval ratio and proportion is applied. For instance, the size for the planned PV PP is 2000 MWs, it is located in interval size 5. So, the price for 1 MW is taken into account it is multiplied with 2 and 0.948 (1-(1-0.793)x(2000-1001)/(5000-1001)). Consequently, equation for the economies of scale is as follows:

$$EoS = 1.167 \quad if \; 0 \leq P \leq 100 \tag{98}$$

$$EoS = 1.167 - (0.104 \times (200 - P)/100) \quad if \; 100 < P \leq 200 \tag{99}$$

$$EoS = 1.063 - (0.046 \times (500 - P)/300) \quad if \; 200 < P \leq 500 \tag{100}$$

$$EoS = 1.017 - (0.017 \times (1000 - P)/500) \quad if \; 500 < P \leq 1000 \tag{101}$$

$$EoS = 0.793 + (0.207 \times (5000 - P)/4000) \quad if \; 1000 < P \leq 5000 \tag{102}$$

$$EoS = 0.724 + (0.069 \times (10000 - P)/5000) \quad if \; 5000 < P \leq 10000 \tag{103}$$

$$EoS = 0.644 + (0.080 \times (50000 - P)/40000) \quad if \; 10000 < P \leq 50000 \tag{104}$$

$$EoS = 0.592 + (0.052 \times (100000 - P)/50000) \quad if \ 50000 < P \leq 100000 \quad . \tag{105}$$

In order to apply EoS into total cost (C_T) following Eq. (106) is formed:

$$C_{T,EoS} = C_T \times EoS \quad . \tag{106}$$

3.2 The scenarios and Revenue, Profit, Payback Analysis

After determining cost of the PV PP, it is now necessity to make a study that reckons revenues, profits and payback times of solar electricity investments to examine economic feasibility of the options. In order to make this designation, when the cost is worked out and how much investments reap a profit are matched. While making these matches, previously calculated data for costs and electricity production in this study are utilized.

3.2.1 The Scenarios

While the cost is essentially using current prices, revenue on the contrary must be determined using future prices. Consequently there is a need to make projections and estimations about future prices with the aid of projections about interest rate, subsidies etc. By taking into account future possibilities that are likely to be observed in Turkey, this study considers alternative scenarios and estimates revenues under these scenarios. These scenarios can be adapted for use in any other economy.

In order to be able to calculate revenue, profit and payback time, the first thing to do is to identify scenarios how the system earns money from where under what conditions. In other words, the ways/options of selling electricity produced by the system has to be identified.

According to Turkish legislation on incentives [144], the permitted PV systems are awarded with 13.3 ¢ kWh^{-1} purchasing unit price during the first 10 years. Although this feed-in-tariff scheme has duration of 10 years, the Council of Ministers has the authority to extend it. Moreover, if the components of PV PP includes domestic contribution / local content in manufacturing, the amount increases to 19,5 ¢ kWh^{-1} (0.8 ¢ kWh^{-1} for integration and structural mechanics, 1.3 ¢ kWh^{-1} for PV modules, 3.5 ¢ kWh^{-1} for PV cells and 0.6 ¢ kWh^{-1} for invertor) for the first 5 years of the operation of the PP. After the end of the period with incentives, the options for the solar electricity producer are either to sell their products in DAM or to continue with self-consumption if it would be possible.

In the highlight of above information, we consider five main scenarios, some of which also contain sub-scenarios based on different assumptions. They are explained in details in the following texts that are entitled in italic with descriptive statements. The prices are given for unit electricity (kWh).

- *Scenario 1. Full feed-in-tariff with fixed price (13.3¢ for 30 years)*

In this scenario the main assumption is that at the end of the first 10 years, the Council of Ministers decides to maintain the feed-in-tariff at the same level. Consequently, during the lifetime of the system, the electricity is sold to the government at 13.3 ¢ kWh^{-1}.

The NPV of the revenue for this scenario option is computed as follows:

$$R_1 = \sum_{n=1}^{N} \frac{(0.133 \times E_n)}{(1+r)^n} \tag{107}$$

where *n* stands to indicate year and E_n represents the electricity production on *n*th year.

- *Scenario 2. Full feed-in-tariff with decreasing price*

Different than the previous one, in this scenario the Council of Ministers decides to sustain the feed-in-tariff but at a declining rate. In order to make reasonable assumptions regarding the amount of decreased feed-in-tariff, global examples are investigated [145]–[149] and conjuncture [150], [151] and future estimations of the electricity market and its general economic trends are reviewed. As a result, we adopt four sub-scenarios where the feed-in-tariff drops down from 13.3 to 10.5, 7.3,5 and 2.5 ¢ kWh^{-1} respectively after 10 years.

  - *Sub-scenario 2.1. 13.3 ¢ for 10 years + 10.5 ¢ for remaining 20 years*

The feed-in-tariff for unit electricity given for geothermal is 10.5 ¢ kWh^{-1}. For sub-scenario 2.1, this price is used as the decreased feed-in-tariff assumption. Thus, the unit electricity (in kWh) produced by the solar power plant is sold at 13.3 ¢ kWh^{-1} for the first 10 years; then it is sold at 10.5 ¢ kWh^{-1} for the rest of the lifetime.

The present value equation for this option is:

$$R_{2.1} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(0.105 \times E_n)}{(1+r)^n} \tag{108}$$

- *Sub-scenario 2.2. 13.3 ¢ for 10 years + 7.3 ¢ for remaining 20 years*

In sub-scenario 2.2, the feed-in-tariff for hydro and wind, 7.3 ¢ kWh^{-1} is used for the unit electricity price as the decreased feed-in-tariff of this sub-scenario. Hence, the electricity is sold at 13.3 ¢ kWh^{-1} for the first 10 years. Then, it is sold at 7.3 ¢ kWh^{-1} for the rest.

The revenue present value computation becomes:

$$R_{2.2} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(0.073 \times E_n)}{(1+r)^n} \, . \tag{109}$$

- *Sub-scenario 2.3. 13.3 ¢ for 10 years + 5 ¢ for remaining 20 years*

In sub-scenario 2.3, after 10 years, 5 ¢ kWh^{-1} is defined as the decreased feed-in-tariff. Hence, the unit electricity produced is sold at 13.3 ¢ kWh^{-1} for the first 10 years. Then, it is sold at 5 ¢ kWh^{-1} for the rest.

The present value of the future revenue stream for this option is as follows:

$$R_{2.3} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(0.05 \times E_n)}{(1+r)^n} \tag{110}$$

- *Sub-scenario 2.4. 13.3 ¢ for 10 years + 2.5 ¢ for remaining 20 years*

In sub-scenario 2.4, the decreased unit electricity price is taken as 2.5 ¢ kWh^{-1} that can be considered as either feed-in-tariff price or day-ahead market. Hence, the unit electricity produced by the PV system is sold at 13.3 ¢ kWh^{-1} for the first 10 years. Then, it is sold at 2.5 ¢ kWh^{-1}.

The equation for this option is:

$$R_{2.4} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(0.025 \times E_n)}{(1+r)^n} \, . \tag{111}$$

- *Scenario 3. Full feed-in-tariff with domestic contribution*

The national content requirements in power plant investments have a significant impact on the revenue streams since incentives increase by the amount of national content. Hence, we consider two alternative schemes, one (sub-scenario 3.1) with 100 percent local content and the other (sub-scenario 3.2) with only frames supplied from domestic sources.

- *Sub-scenario 3.1. Full feed-in-tariff with full domestic contribution (19.5¢ for 5 years + 13.3¢ for remaining 25 years)*

In sub-scenario 3.1, with the main assumption of 100% national content, the electricity will be sold at 19.5 ¢ kWh^{-1} for the first 5-year period and then the price is assumed to decrease to 13.3 ¢ kWh^{-1} for the remaining years.

The present value equation for this option is:

$$R_{3.1} = \sum_{n=1}^{5} \frac{(0.195 \times E_n)}{(1+r)^n} + \sum_{n=6}^{N} \frac{(0.133 \times E_n)}{(1+r)^n} \ . \tag{112}$$

- *Sub-scenario 3.2. Full feed-in-tariff with local content/domestic contribution of frames*

(14.1¢ for 5 years + 13.3¢ for remaining 25 years)

In this sub-scenario 3.2, first, the system is assumed to have domestic module frames produced by a domestic company with a related domestic production license. Second assumption is the extension of feed-in-tariff through the lifetime of the system by the decision of the Council of Ministers. Third assumption is that the government does not decrease the feed-in-tariff.

For this sub-scenario, as comprehended from the assumptions, the PV PP will be selling its production at a price of 14.1 ¢ kWh^{-1} for the first 5 years, and then the selling price will decrease to 13.3 ¢ kWh^{-1} and will be fixed throughout the lifetime of the system.

The present value computation under this scenario is given in Eq. 113 below:

$$R_{3.2} = \sum_{n=1}^{5} \frac{(0.141 \times E_n)}{(1+r)^n} + \sum_{n=6}^{N} \frac{(0.133 \times E_n)}{(1+r)^n} \ . \tag{113}$$

- *Scenario 4. Feed-in-tariff for a determined time and DAM for the remaining lifetime*
  - *Sub-scenario 4.1. Feed-in-tariff for a determined time and DAM with no-change in the price of electricity*

    (13.3 ¢ for 10 years + 5 ¢ for 20 years)

In this sub-scenario, the first assumption is that Council of Ministers withdraws feed-in-tariff scheme at the end of the first 10 years. This assumption is made due to the pressure felt in DAM prices. One of the reason why there is a pressure on the DAM prices is the increasing interest in the Renewable Energy Resources Support Mechanism (YEKDEM) due to $ getting stronger against Turkish lira (TL). The renewable power plants that applied to use YEKDEM was around 5500 MW in the beginning of 2015 (with almost no solar); however, it reached up to around 24,250 MWs as of today according to the Energy Market Regulatory Authority of Turkey (around 4744 MW solar by the end of June 2018). This is the main reason why this assumption is taken into consideration.

Therefore, solar electricity is sold in the DAM after 10 years. This scenario takes the DAM price for the 11th year of the investment and assumes this price in $s will remain constant over lifetime of the plant. Otherwise, DAM is a mechanism which is active for 24-hours a day. However, PV PP without a battery back-up is only able to provide electricity during day time. Consequently, the day-time periods when the solar electricity can be produced are taken into account in order to define monthly mean daily DAM for a specific month.

Hourly DAM prices per unit of electricity are gathered for the 2015-2017 period and they are analyzed to make hourly, then monthly mean daily DAM price estimations. We should again note that the solar electricity can be produced and sold during daytime hours and so the hourly averages are taken from sunrise to sunset. These daytime hours differ of course from month to month. The average daily values for each month are taken to compute the electricity production of that month. Then the algorithm runs with the assumption that the average DAM dollar prices do not change. Estimated monthly mean hourly and daily retail prices of electricity during daytime in DAM can be determined using Table D.1 and Table D.3 in Appendix D.

The equation for this sub-scenario is:

$$R_{4.1} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(U_{DAM} \times E_n)}{(1+r)^n} \tag{114}$$

where U_{DAM} is the unit price of electricity in DAM.

As mentioned in Appendix D by analyzing Table D.2, the unusual increase in the ratio between $ and TL, while the mean electricity price in TL has increased for the last three years, the value of this price in $ has decreased. Consequently, there should be some assumptions for the future situation such as continuation of current unusual situation between $ and TL that means decrease in electricity price in $ unit or as the other option the unusual movement is ceased and the exchange rate does not change considerably.

- *Sub-scenario 4.2. Feed-in-tariff for a determined time and DAM with increasing electricity price with 1% inflation in dollars (13.3¢ for 10 years+ 5.5¢ +1% inflation for remaining years)*

The only difference of this sub scenario with the previous one is the consideration of the inflation rate. The electricity price is estimated to increase with 1% inflation in US dollars. Because DAM comes into play on the 11th year, the above-mentioned 5 ¢ becomes 5.5 ¢ kWh^{-1} with 1% annual inflation.

Here after, the monthly average hourly prices of DAM used in the previous sub-scenario are adjusted with 1% annual inflation rate.

The equation for this option is:

$$R_{4.2} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \frac{U_{DAM} \times E_n}{(1+r)^{11}} + \sum_{n=12}^{N} \frac{U_{DAM} \times 1.01^n \times E_n}{(1+r)^n} \quad . \tag{115}$$

- *Sub-scenario 4.3. Feed-in-tariff for a determined time and DAM with decreasing electricity price with 1% inflation in dollars (13.3¢ for 10 years+ 4.6 ¢ -1% deflation for remaining years)*

In this sub-scenario, we introduce a decline in the annual inflation rate. The main assumptions for this sub scenario are the $ getting stronger against TL, increasing share of renewables and the nuclear power plant under construction that has a purchasing guarantee from the Turkish Government. Subsequently, this time, the electricity price in terms of $s is estimated to decrease by 1%. Because DAM comes into play on the 11th year, the above-mentioned 5 ¢ kWh^{-1} becomes 4.6 ¢ kWh^{-1}.

The monthly average hourly prices of DAM defined in the previous sub-scenario is used here after they are subjected to annual 1% deflation.

The equation for this sun-scenario is:

$$R_{4.3} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \frac{U_{DAM} \times E_n}{(1+r)^{11}} + \sum_{n=12}^{N} \frac{U_{DAM} \times 0.99^n \times E_n}{(1+r)^n} \quad . \tag{116}$$

- *Scenario 5. Self-Consumption throughout the life time*

In this scenario, we consider the PV system owner as the prosumer of energy. That is, the owner produces electricity for own consumption. However, the owner may have two different roles as a consumer: household or manufacturers. The sub-scenarios below consider each role separately.

- *Sub-scenario 5.1. Self-consumption by household consumer*

In this sub-scenario, the electricity produced is consumed by the same agent. In other words, the investor compensates his/her electricity consumption with solar electricity production. For this sub-scenario, the electricity price reflected to the consumer is taken into account in determining the net benefits. There must be assumptions on the change of end-user price over years. To make the most accurate calculations, electricity price is allowed to differ. Then the price projections are made separately for households and industry because electricity price differs depending on the status of end-user.

To be able to make reasonable predictions, we worked on electricity price trends for recent years (2012-2017) in Turkey and make interpolation/projection stemming from past values.

The future electricity price in Turkey, which is reflected to the end user, has been estimated as given in Appendix D.

The electricity price estimations for this study begin at 11.9 ¢ kWh^{-1} and change annually as shown in Table D.4 in Appendix D.

The equation for this option is:

$$R_{5.1} = \sum_{n=1}^{N} \frac{(U_{E,household} \times E_n)}{(1+r)^n} \quad . \tag{117}$$

- *Sub-scenario 5.2. Self-consumption for industrial purposes*

Because of end-user electricity price differs depending on the purpose of consumption such as industrial purpose or household consumption, this sub-scenario deals with industrial electricity use side. The end-user price for industrial use begins at 7.2 ¢ kWh^{-1} and changes yearly as derived from the Table D.4 in Appendix D.

$$R_{5.2} = \sum_{n=1}^{N} \frac{(U_{E,industry} \times E_n)}{(1+r)^n} \quad . \tag{118}$$

3.2.2 Revenue, Profit ve Payback Analysis Methodology

Revenue, profit and payback analysis are made with respect to NPV in this study. The calculations for these parameters are made for all above-mentioned scenarios and their sub-scenarios. Initially revenue is calculated, then profit and then payback time.

It is very important for the investors to know the payback time of their investments according to the net present value. Payback time reveals an exact time when the investment defrays all the costs with its revenue and return to profitability.

Pursuant to the scenarios mentioned, payback time differs since revenue differs. The payback time is identified using NPV values of the revenues with subtracted running costs, calculated for each year. That is, payback time in this study is identified as the exact time when total revenue exceeds the total cost.

Moreover, depending on the concept developed for payback time calculation within this study the change in discount rate also has high effect on payback time.

3.3 Levelized Cost of Electricity and New Economic Feasibility Concept

For the comparison of PV systems with its alternatives, the widespread method is LCOE in which per unit cost of electricity produced is calculated with respect to NPV [38], [132], [152]. In this way, LCOE is able to compute location specific costs under country specific conditions. However, the cost by itself may not mean much if revenue is not known. For solar electricity systems both cost and revenue of the same system vary from country to country, region to region, state to state even province to province because of the variable and policy, location depended parameters. There is also need to know the unit revenue of electricity produced with respect to NPV as developed in this study. Accordingly, for the exact value of the system there seems to be need to develop new concept that includes cost, revenue, profit and net feasibility. In that vein, this study developed new Economic Feasibility Concept whose components are LCOE, LROE, LPOE and NFM. Within this concept, the parameter to take revenue into account is LROE. Moreover, with the logic that if LCOE is subtracted from LROE, LPOE of the system is found as defined in this study. The higher LPOE, the more feasible system is. If LPOE is smaller than or equal to zero, this system is not feasible. In addition to these newly developed parameters, this concept also has one more parameter that is NFM. NFM corresponds to ratio of unit revenue per unit cost in basis of NPV. The higher NFM, the more feasible investment. If NFM is lower than one, the investment is not feasible.

The pillars of EFC are given in Figure 7.

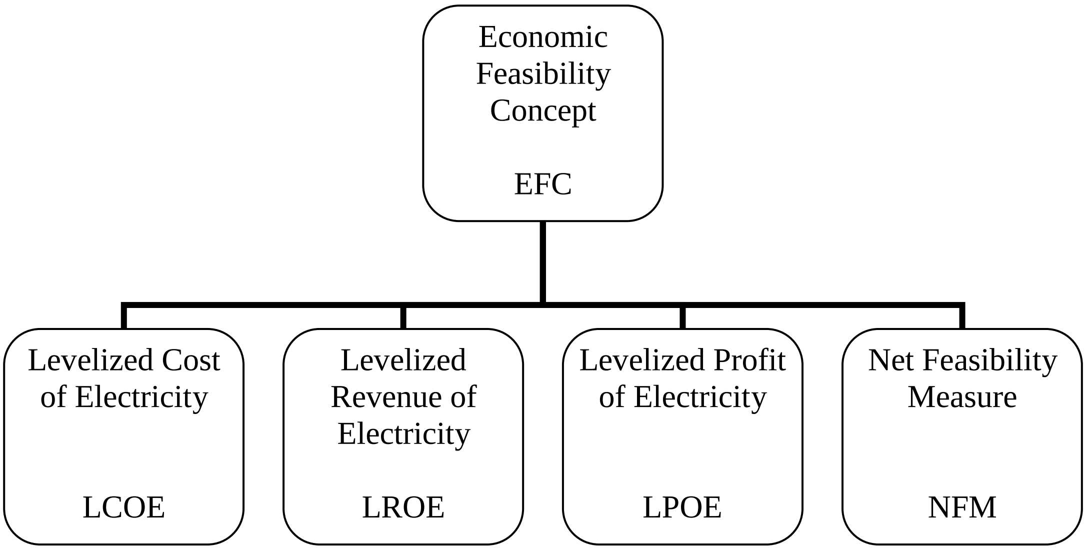

Figure 7 The pillars of Economic Feasibility Concept

3.3.1 Levelized Cost of Electricity

3.3.1.1 The Basic Definition of Levelized Cost of Electricity

The economic feasibility of an electricity generation project can be evaluated by various methods, but LCOE is the most frequently used one when comparing electricity generation technologies or considering grid parities for emerging technologies [38], [132], [152]. LCOE gives us the location specific unit cost of unit electricity production with NPV under technical and legal jurisdictions of the country in concern.

LCOE is basically the constant unit cost (per kWh or MWh) of a payment stream that has the same present value as the total cost of building and operating a generating plant over its life [38], [132].

3.3.1.2 Levelized Cost of Electricity Equation For PV

The basic LCOE equation reckoning the energy cost of a system is the following [44], [38], [129]:

$$LCOE = {C_I + \sum_{n=1}^{N} \frac{C_V}{(1+r)^n}} \Big/ {\sum_{n=1}^{N} \frac{E_n}{(1+r)^n}} \qquad (119)$$

where C_I is the initial cost of the system; C_V are variable costs that corresponds to operation and maintenance cost, insurance cost and battery and inverter replacement; r is discount rate; n is determined year; N is lifetime of the system.

3.3.2 New Economic Feasibility Concept

The method to define economic feasibility of any energy source/technology and comparison with alternatives are generally applied via LCOE as done for PV, *inter alia* [38], [129], [153]–[158]. LCOE can reveal country/region/state specific cost of the system however without knowing country/region/state specific revenue and profit of the system the results acquired may not mean anything. Similarly, U.S Energy Information Administration (EIA) supports the idea that LCOE may not be enough by itself to reach reasonable results [159], [160].

Consequently, similar to LCOE calculation we can also calculate the levelized version of revenue per unit electricity produced with respect to net present values. In the developed model for LROE we take present values of all the revenue streams under all scenarios separately and the total amount is divided by the present value of the total electricity produced by the system.

$$LROE = \left. \sum_{n=1}^{N} \frac{R_n}{(1+r)^n} \middle/ \sum_{n=1}^{N} \frac{E_n}{(1+r)^n} \right. \tag{120}$$

where R_n is the revenue of *n*th year.

The difference between LROE and LCOE gives LPOE of the investment as shown Eq. 121.

$$LPOE = LROE - LCOE \tag{121}$$

The higher the LPOE amount the higher the profitability of the investment. If LPOE is below zero so it is not feasible.

Additively, we also developed a new parameter, which can be used to show the feasibility of the investment, abbreviated as NFM that is net feasibility measure.

NFM gives the ratio of revenue and cost in net present values in other words ratio of LROE and LCOE. The higher the NFM, the higher the profitability is. NFM should be larger than one for an investment to be feasible.

$$NFM = \left. \sum_{n=1}^{N} \frac{R_n}{(1+r)^n} \middle/ \sum_{n=1}^{N} \frac{C_n}{(1+r)^n} \right. . \tag{122}$$

3.4 Extra Economical Parameters

There are some other parameters in addition to what was mentioned up to this point. These parameters are IRR, annual electricity production per 1 $ investment, electricity key performance indicator (KPI). On the other hand, this part also deals with contribution fee and decline in electricity selling amount in order to gain the tender for licensing options. In that way, the investor has chance to see how much makes how much effect on payback time.

3.4.1 Internal Rate of Return

Some banks demand IRR analysis when the loan application is made. In brief, IRR is the amount of interest rate that makes the NPV zero [161]. Consequently, this analysis is made by abiding by following equation:

$$NPV = C_I - \sum_{n=1}^{N} \frac{P_n}{(1+r)^n} \tag{123}$$

where IRR is r that equates NPV to zero and P_n is the profit of *n*th year. Hence, IRR is found from:

$$C_I = \sum_{i=1}^{N} \frac{P_n}{(1+r)^n} . \tag{124}$$

3.4.2 Contribution Fee analysis

When the Government initially determined the licensing market, it announced 600 MW of installed capacity for tendering process. For that 600 MW tender, in order to get license to install PV PP whose capacity is to be bigger than one MW, the contest between the applicants was realized. At this contest, who accepted to pay the highest fee gained the right to have license. Therefore, the investor should better to know how much contribution fee affects payback time how long. Consequently, for the estimation of the highest contribution fee an investor can handle/accept we define C_{CF} in addition to the total cost of the system. The C_{CF} that makes payback time 15 years is the last amount that can be acceptable. Beyond is not feasible. 15 years is a criterion of EBRD like loan channels. Condition is $C_T + C_{CF} = R_{NPV,15}$ where $R_{NPV,15}$ is cumulative revenue with respect to NPV at 15th year.

Then, the equation to calculate C_{CF} is formed as follows:

$$C_{CF} = R_{NPV,15} - C_T \; . \tag{125}$$

3.4.3 Willingness to Reduce Electricity Selling Price

This option is created just because there is a possibility of governments changing tender methods by modelling YEKA (RE-ZONE) tenders. If this change is applied, the one who is convinced to sell solar electricity at the lowest price will gain the tender. In that vein, at this part of the study, various amounts of electricity selling prices are checked with respect to pay back time.

Like in the previous title, the unit electricity price paying back the investment until 15th year of investments seems feasible.

The lowest electricity price fulfills the condition of $C_T = R_{NPV,15}$.

Then, equation the lowest acceptable electricity price U_{CF} is derived as given in Eq. 125.

$$U_{CF} = \frac{C_T}{E_{15}} \tag{126}$$

where E_{15} is the NPV of cumulative electricity production of the first 15 years.

3.4.4 Electric Key Performance Indicator

This parameter stands to indicate an amount of annual electricity production corresponding to 1 $/TL/€ investment. This parameter is demanded when the loan application is made to sources of funding like EBRD one of the popular loan sources. So, the calculation is made by utilizing following equation (Eq. 127):

$$KPI_E = E_1 / C_T \tag{127}$$

where E_1 is the electricity production of the first year and C_T is net present value of total cost of the system.

The algorithm derived throughout this study is given in Appendix G.

CHAPTER 4

CASE STUDY

In order to reveal the output of the algorithm, check whether the algorithm works and validate its results a case study including one MW PV PP simulated as installed on the roof of a dormitory located within METU Campus in Ankara capital of Turkey. The following subsections is simulating the PV PP and revealing calculated results of the algorithm.

- *Features of the location of the project:*

By using the algorithm, a 1 MW PV PP is simulated in the allocated territory within METU Ankara Campus on the roof of a Dormitory, as shown in Figure 2 and 3 (latitude: 39°53'12.61"N – 39.89°, longitude: 32°46'36.63"E – 32.78°).

Figure 8 Location of 1 MW PV PP – The roofs of dormitory in METU.

Figure 9 Location of 1 MW PV PP in Ankara, Turkey

The roofs of two dormitory buildings have enough space to install 1 MW PV PP. In this way, we get rid of bearing land cost.

Because of its capacity is 1 MW, it can be installed unlicensed and benefit from the opportunities provided according to related Turkish Law [12]. Consequently, a permission period for license exemption is followed.

- *Solar irradiation exposure, input:*

The total and monthly mean daily solar irradiation exposure of the location selected, $\bar{H}_0, \bar{H}, \bar{H}_B, \bar{H}_D$ and $\bar{H}_T$ values are given in Table 2.

Table 2 $\bar{H}_0, \bar{H}, \bar{H}_B, \bar{H}_D$ and $\bar{H}_T$ values

Month	$\bar{H}_0$	$\bar{H}$	$\bar{H}_B$	$\bar{H}_D$	$\bar{H}_T$
	MJ m^{-2}d^{-1}				
1	15.29	5.74	1.81	3.93	7.62
2	20.57	9.86	4.16	5.70	12.56
3	27.50	13.99	5.84	8.15	15.65
4	34.65	18.69	9.16	9.53	18.92
5	39.71	22.10	10.89	11.21	20.27
6	41.76	25.62	16.87	8.76	21.90
7	40.68	27.03	17.71	9.32	23.77
8	36.58	24.44	16.30	8.14	24.00
9	30.03	19.65	12.50	7.16	22.38
10	22.59	12.79	7.08	5.72	16.68
11	16.52	8.67	3.72	4.95	12.24
12	13.86	5.74	1.73	4.01	7.80
Total (MJ m^{-2}d^{-1})	10347.37	5921.56	3285.45	2616.11	6204.26
Total (kWh m^{-2}d^{-1})	2874.27	1644.88	912.62	732.25	1723.41

- *Design of the PV PP:*

Main components of this PV PP are PV modules, mounting structures' AC and DC cables, inverter, soiling/earthing equipment, remote monitoring system, transformer, hedges.

Since the PP simulated has 1 MW power, it requires 4000 modules whose power is assumed to be 250 Wp that is the module peak power that widely used in Turkey.

This design has been done with respect to central inverter: however, it can also be designed for micro inverters or string inverters. Consequently, there is 1 central inverter whose capacity is 1 MW.

The PV modules are located with principle of 5 in row and 2 in column in each array. There is 4 lines of strings and 1000 modules in each string. Consequently, there is 100 arrays in each string. Depending on this kind of design, the distance between lines should be 3.23 m.

The total area required for the PP is then calculated as 15,230 m^2.

- *Electricity Production of the system, output:*

The modules are selected as typical 250 Wp modules whose required information are given in Table 3 as taken from the official brochure [162].

Table 3 Module features

Parameter	Unit	Amount	Parameter	Unit	Amount
$\eta_{mp,ref}$	%	15.3	$\mu_{V_{oc}}$	%/°C	0.33
$V_{mp,ref}$	V	30.4	$T_{c,ref}$	°C	25
A_c	m^2	1.6335	$T_{c,NOCT}$	°C	46

$\eta_{mp,ref}$ is reference efficiency of the module, A_c is the module area, $V_{mp,ref}$ is the reference maximum power voltage, $\mu_{V_{oc}}$ is the temperature coefficient of open circuit voltage, $T_{c,ref}$ is the reference cell temperature and $T_{c,NOCT}$ is nominal operating cell temperature.

Its monthly mean daily and first year gross and net electricity production is given in Table 4. Gross electricity refers the total electricity produced by the PV modules and net electricity stands to indicate the final electricity given to the grid/provided to the consumers after the losses from inverters, cables etc., as mentioned in Chapter 2.

Table 4 First Year Gross and Net Electricity Production

Month	Electricity Prod.	Month	Electricity Prod.
1	77988	7	1180650
2	111442	8	181495
3	147401	9	149303
4	166385	10	147001
5	176637	11	113080
6	169284	12	79510
Total Gross	1700177 kWh	Total Gross	1.70 GWh
Total Net	1568189 kWh	Total Net	1.57 GWh

Because PV modules are degraded with time, we apply 0.5% annual degradation rate as determined by [112], [113], [163], [164] for that location. With the assumption of 30 years lifetime, the lifetime net cumulative electricity production of the PV PP 43788796 kWh or 43.79 GWh.

- *GHG Emission Reduction:*

The GHG emission reduction potential of the PV PP is calculated as 25,275 tones.

- *Cost, Revenue, Profit, Payback:*

The cumulative cost of the system in NPV is calculated as $1.20 million with 5% discount rate, $1.16 million with 7% discount rate and $1.13 million with 8.75 % discount rate.

On the other hand, above-mentioned calculations are made with the assumption that the investor has his/her own capital. If the investor needs to get loan with the assumption of annual 5% interest and 10-year payment term NPV of the cost becomes $1.36 million with 5% discount rate. This amount decreases to $1.21 million with 7% discount rate and $1.11 million with 8.75% discount rate.

The revenue, profit and payback time of the system depending on the scenarios written within this study are compiled in Table 5. These parameters are also calculated with respect to NPV form. Option r_1 corresponds to the calculations made with 5% discount rate. Options r_2 and r_3 stand to indicate 7% and 8.75% discount rates respectively.

Table 5 Revenue, profit and payback time of the PV PP

Scenarios	Sub scenarios	Revenue (M $)			Profit (M $)			Payback time (years)		
		r_1	r_2	r_3	r_1	r_2	r_3	r_1	r_2	r_3
1		3.03	2.47	2.10	1.83	1.31	0.96	5.98	6.49	7.02
2	1	2.73	2.25	1.94	1.53	1.09	0.80			
	2	2.38	2.00	1.75	1.18	0.84	0.62			
	3	2.13	1.82	1.62	0.92	0.66	0.48			
	4	1.85	1.63	1.47	0.65	0.47	0.34			
3	1	3.45	2.86	2.48	2.25	1.70	1.34	3.76	3.95	4.15
	2	3.09	2.52	2.15	1.89	1.36	1.01	5.60	6.06	6.55
4	1	2.13	1.82	1.62	0.92	0.66	0.48	5.98	6.49	7.02
	2	2.23	1.89	1.67	1.03	0.73	0.54			
	3	2.05	1.77	1.58	0.84	0.61	0.44			
5	1	3.03	2.43	2.05	1.83	1.27	0.92	6.68	7.30	7.96
	2	1.83	1.47	1.24	0.63	0.31	0.11	13.40	16.43	21.55

For the LCOE, LROE calculations electricity production amount is also required to be converted into NPV form. Consequently, the todays value of the electricity production is calculated as 22,836,439 kWh or 22.84 GWh for 5% discount rate. However, it becomes 18.55 GWh with 7% discount rate and 15.78 GWh with 8.75% discount rate.

- *LCOE, LROE, LPOE, NFM Calculations:*

  The calculated LCOE, LROE, LPOE and NFM values are given in Table 6.

Table 6 LCOE, LROE, LPOE and NFM for different scenarios

Scenarios	LCOE($/MWh)			LROE ($/MWh)			LPOE ($/MWh)			NFM		
	r_1	r_2	r_3	r_1	r_2	r_3	r_1	r_2	r_3	r_1	r_2	r_3
1	52.7	62.6	71.8	133.0	133.0	133.0	80.3	70.4	61.2	2.5	2.1	1.9
2.1				119.6	121.3	122.7	66.9	58.7	50.9	2.3	1.9	1.7
2.2				104.2	107.9	111	51.5	45.4	39.1	2.0	1.7	1.5
2.3				93.1	98.3	102.5	40.5	35.8	30.7	1.8	1.6	1.4
2.4				81.1	87.9	93.4	28.5	25.3	21.5	1.5	1.4	1.3
3.1				151.3	154.3	156.9	98.6	91.7	85.1	2.9	2.5	2.2
3.2				135.4	135.8	136.1	82.7	73.2	64.3	2.6	2.2	1.9
4.1				93.1	98.3	102.5	40.5	35.8.	30.7	1.8	1.6	1.4
4.2				97.7	102.2	105.8	45.0	39.6	34.0	1.9	1.6	1.5
4.3				84.6	95.4	100.0	36.9	32.8	28.2	1.7	1.5	1.4
5.1				132.7	131.1	129.9	80.0	68.6	58.1	2.5	2.1	1.8
5.2				80.3	79.3	78.6	27.6	16.8	6.8	1.5	1.3	1.1

For all the options, LPOE is quite bigger than zero and NFM is bigger than one. Consequently, this investment independent from the scenario is feasible. However, the most feasible results seems to be in the lifelong feed-in-tariff with domestic contribution scenario in 5% discount rate.

CHAPTER 5

RESULTS, CONCLUSION AND DISCUSSIONS

The most important steps for investments are to conduct techno-economic feasibility analysis, which is the appropriate way for the investor to make decision, and to create dynamic application projects, which define the most appropriate design to make investment, in order to see how the investment needs to be formed and to find out the economic future of the project. As well as being important, feasibility analysis are not easy to apply.

While requiring intense labor, time wasting and resource use, feasibility analysis has high inconvenience on economy and environment. The algorithm created by this study enables the creation of a software to have a feasibility analysis one click ahead, while it takes time with the hard work of many experts. Moreover, while identification of input data to software is hard work, this algorithm requires much less input data.

Just entering latitude and size of the project as input to the software, rest can be computed via the algorithm developed within this thesis.

This algorithm, which conceives many information with the least possible inputs, innovates the methods and technologies of solar electricity software programs. In addition, it will create a capacity and knowledge on the area that is not much worked in Turkey. The study will provide a sample methodology for forming of algorithm and software for other energy resources.

It will provide original sample, which is one of a kind in national and global scale. On the other hand, investors will be able to make their investment in a shorter time and more efficient way. In that way, resource consumption will be minimized. Therefore, this study will serve for all the pillars of sustainable development, namely economic, environmental and social and the process to tackle with climate change.

Furthermore, this algorithm, by giving certain and accurate projections, will contribute to science by serving for academic studies and to countries giving correct decision by serving for policy decision makers. The industry can easily decide which tool/technology to produce where. In addition to its being good example to R&D, with the updated versions and its ability to be applied to other energy technologies like wind, this study creates a sustainable R&D culture.

There are two main aspects that have utmost importance for solar energy technologies: productivity potential of the location of interest and economy. By estimating the solar irradiation exposure as input and electricity production as output the algorithm defines the potential of any PV PP to be installed anywhere within Turkey prior to investment.

Moreover, declining hardware costs of the PV PP especially module prices has increased the importance of soft costs [137]. Together with labor, installation etc, soft costs also include the design of the PP. Therefore, with better design and technology selection the soft costs can be minimized as much as possible owing to the algorithm.

The world is in the threshold of anthropogenic climate change threat [123]. The platform to tackle climate change threat and its mitigation and adaptation is a system established under UNFCCC. Within this platform countries have been trying to reduce their GHG emissions as much as possible by taking into account common but differentiated responsibilities and respective capabilities. Turkey is one of the Party to the Convention and has burden to contribute to global effort. This study also contributes to this process by calculating the emission reduction potential of any solar electricity investment.

Furthermore, photovoltaics is claimed to have high technical and economic feasibility owing to sharply decreasing cost, increasing interest and advancing technology. However, these claims can be best supported by the most accurate calculations in order to know real situation better. The performance and economic revenue of the system is generally calculated by general global accepted assumption that are not region/location specific/ local. On the contrary, it is obvious that making local calculations gives the most accurate results that are closest to the reality.

This study has some major contributions to the literature that were not yet been addressed previously. This algorithm consists of newly developed methodology for solar irradiation calculation, modified electricity production methodology, sui-generis original scenarios for revenue analysis, newly defined EFC, updated payback time analysis and developed new economic parameters.

The validation of the algorithm has also been made and the comparisons for validation reveals that the results of the calculations made through the algorithm reflects the truth and gives highly accurate results.

By following technological and scientific developments and studying on innovative contributions, strengthening the algorithm will be the further study for the author. Consequently, aerial neural networks (ANN), satellite measurement may be embedded into algorithm as updated version. On the other hand, the next step is to create software namely SOlAR TURnKEY and bring it into service.

REFERENCES

[1] IEA, *World Energy Outlook 2017*. 2017.

[2] Mayer JN, Philipps S, Hussein NS, Schlegl T, and Senkpiel C. "Current and Future Cost of Photovoltaics," *Agora Energiewende.* 2015.

[3] IRENA, "Renewable Power Generation Costs in 2017." [Online]. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf2018 [Accessed: 10-May-2018].

[4] SolarPower Europe, "Global Market Outlook for Solar Power 2017-2021," *SolarPower Europe*, 2017.

[5] SolarPowerEurope, "Digitalisation & Solar Task Force Report," 2017.

[6] NREL, "Best Research-Cell Efficiencies." [Online]. Available: https://www.nrel.gov/pv/assets/images/efficiency-chart.png. [Accessed: 10-May-2018].

[7] Lazard, "Levelised Cost of Energy Analysis," [Online]. Available: https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf. [Accessed: 15-Apr-2018].

[8] IRENA, "Solar data." [Online]. Available: http://www.irena.org/solar. [Accessed: 10-May-2018].

[9] Fraunhofer Institute, "Photovoltaics Report," [Online]. Available: https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/Photovoltaics-Report.pdf [Accessed: 10-May-2018].

[10] Frankfurt School/ FS-UNEP Collaborating Center for Climate & Sustainable Energy Finance, UN Environment's Economy Division, "Global trends in renewable energy investment," [Online]. Available: http://fs-unep-centre.org/sites/default/files/publications/gtr2018v2.pdf [Accessed: 10-May-2018].

[11] Karaveli AB, Soytas U and Akinoglu BG. "Comparison of large scale solar PV (photovoltaic) and nuclear power plant investments in an emerging market," *Energy*, vol. 84, pp. 656–665, 2015. https://doi.org/10.1016/j.energy.2015.03.025

[12] Karaveli AB, Soytas U, and Akinoglu BG. The Role of Legislations and Incentives in the Growth of a PV Market in a Developing Country, Proc. of the International Renewable and Sustainable Energy Conference (IRSEC'17), 2017.

[13] A. B. Karaveli, B. G. Akinoglu, and U. Soytas, "Development of new metrics for economic analysis of photovoltaic power plants and their application," *Submitt. to Energy Economics*, 2018.

[14] Labouret A and Villoz M. *Solar photovoltaic energy*, The Institution of Engineering and Technology. 2010.

[15] United Nations, "Sustainable Development Goals." [Online]. Available: https://www.un.org/sustainabledevelopment/energy/). [Accessed: 23-Apr-2018].

[16] World Bank, "Open Data." [Online]. Available: https://data.worldbank.org/. [Accessed: 11-May-2018].

[17] "Turkish Ministry of Foreign Affairs." [Online]. Available:

http://www.mfa.gov.tr/turkiye_nin-enerji-stratejisi.tr.mfa. [Accessed: 07-June-2018].

[18] European Photovoltaic Industry Association, “Unlocking the sunbelt - potential of photovoltaics.” [Online]. Available: https://www.mesia.com/wp-content/uploads/2017/09/EPIA-Unlocking_the_Sunbelt_Potential-of-PV.pdf). [Accessed: 23-Apr-2018].

[19] TEIAS, “Sectoral reports - Installed Power.” [Online]. Available: https://www.teias.gov.tr/sites/default/files/2018-05/kurulu_guc_nisan_2018.pdf. [Accessed: 10-May-2018].

[20] Turkstat, “Foreign Trade Statistics.” [Online]. Available: http://www.tuik.gov.tr/PreHaberBultenleri.do?id=27787. [Accessed: 07-June-2018].

[21] Valentin Software, “PVSol.” [Online]. Available: https://www.valentin-software.com/en/products/photovoltaics/57/pvsol-premium. [Accessed: 07-June-2018].

[22] PV Syst Photovoltaic Software, “PV Syst.” [Online]. Available: http://www.pvsyst.com/en/. [Accessed: 07-June-2018].

[23] NREL, “System Advisory Model.” [Online]. Available: https://www.nrel.gov/pv/assets/images/efficiency-chart.png. [Accessed: 11-May-2018].

[24] JRC - European Union, “EU PVGIS.” . [Online]. Available: http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php. [Accessed: 07-June-2018].

[25] TraceSoftware, “Archelios.” [Online]. Available: http://www.trace-software.com/archelios/photovoltaic-pv-software/. [Accessed: 07-June-2018].

[26] BlueSol, “BlueSol.” [Online]. Available: http://www.bluesolpv.com/dnnsite/default.aspx. [Accessed: 07-June-2018].

[27] Folsom Labs, “HelioScope.” [Online]. Available: https://www.helioscope.com/. [Accessed: 07-June-2018].

[28] Vela Solaris, “Polysun.” [Online]. Available: http://www.velasolaris.com/english/home.html. [Accessed: 07-June-2018].

[29] METU GÜNAM, “Solar Technologies.” [Online]. Available: http://gunam.metu.edu.tr/solar-tech/. [Accessed: 07-June-2018].

[30] International Energy Agency, “Renewables 2017: Analysis and Forecasts to 2022 - Executive Summary,” *J. Qual. Particip.*, 2017.

[31] International Renewable Energy Agency, *Renewable capacity statistics 2018*. 2018.

[32] Jamil B and Akhtar N. “Comparison of empirical models to estimate monthly mean diffuse solar radiation from measured data: Case study for humid-subtropical climatic region of India,” Renewable and Sustainable Energy Reviews, vol. 77. pp. 1326–1342, 2017. https://doi.org/10.1016/j.rser.2017.02.057

[33] Karaveli AB and Akinoglu BG. “Development of new monthly global and diffuse solar irradiation estimation methodologies and comparisons,” *Int. J. Green Energy*, 2018. https://doi.org/10.1080/15435075.2018.1452744.

[34] Duffie J and Beckman W. “Solar engineering of thermal processes," 3rd edition, *Wiley*. 2006.

[35] Akinoglu BG and Ecevit A. “Construction of a quadratic model using modified Ångstrom coefficients to estimate global solar radiation,” Sol. Energy, vol. 45, no. 2, pp. 85–92, 1990. https://doi.org/10.1016/0038-092X(90)90032-8.

[36] Klein SA. "Calculation of monthly average insolation on tilted surfaces," *Solar Energy*, vol. 19, no. 4. pp. 325–329, 1977. https://doi.org/10.1016/0038-092X(77)90001-9.
[37] Karaveli AB. "Nuclear Energy Versus Solar Energy (NUKE vs. PV): The Comparison of Their Economic Feasibilities and Environmental Aspects for Turkey," Middle East Technical University. January, 2014. [Online]. Available: http://etd.lib.metu.edu.tr/upload/12616740/index.pdf. [Accessed: 07-June-2018].
[38] Karaveli AB, Soytas U and Akinoglu BG. "Comparison of large scale solar PV (photovoltaic) and nuclear power plant investments in an emerging market," *Energy*, vol. 84, pp. 656–665, 2015. https://doi.org/10.1016/j.energy.2015.03.025.
[39] Bortolini M, Gamberi M, Graziani A, Manzini R and Mora C. "Multi-location model for the estimation of the horizontal daily diffuse fraction of solar radiation in Europe," *Energy Convers. Manag.*, vol. 67, pp. 208–216, 2013. https://doi.org/10.1016/j.enconman.2012.11.008.
[40] El Mghouchi Y, El Bouardi A, Choulli Z and Ajzoul T. "Models for obtaining the daily direct, diffuse and global solar radiations," *Renew. Sustain. Energy Rev.*, vol. 56, pp. 87–99, 2016. https://doi.org/10.1016/j.rser.2015.11.044.
[41] Muneer T, Younes S and Munawwar S. "Discourses on solar radiation modeling," *Renew. Sustain. Energy Rev.*, vol. 11, no. 4. pp. 551–602, 2007. https://doi.org/10.1016/j.rser.2005.05.006.
[42] Ozden T, Akinoglu BG and Turan R. "Long term outdoor performances of three different on-grid PV arrays in central Anatolia – An extended analysis," Renew. Energy, vol. 101, pp. 182–195, 2017. https://doi.org/10.1016/j.renene.2016.08.045.
[43] Akinoglu BG, "A review of sunshine-based models used to estimate monthly average global solar radiation," Renew. Energy, vol. 1, no. 3–4, pp. 479–497, 1991. https://doi.org/10.1016/0960-1481(91)90061-S.
[44] Akinoglu BG, "Recent advances in the relations between bright sunshine hours and solar irradiation," in Modeling Solar Radiation at the Earth's Surface: Recent Advances, *Springer*, Berlin, 2008, pp. 115–143. https://doi.org/10.1007/978-3-540-77455-6.
[45] Karaveli AB and Akinoglu BG. "Comparison of quadratic and linear models on the estimation of diffuse solar radiation for loction in Turkey," *Proc of. 9th International Conference on Sustainable Energy and Environmental Protection - SEEP2016*, 2016, pp. 103–107.
[46] Karaveli AB and Akinoglu BG. "Estimation of diffuse component for two locations in Turkey," *Proc. of International Conferance on Solar Energy for Buildings and Industry - Eurosun2016*, 2016, vol. 1990, pp. 1467–1474.
[47] Karaveli AB and Akinoglu BG. "Comparisons and critical assessment of global and diffuse solar irradiation estimation methodologies," *Int. J. Green Energy*, vol. 15, no. 5, pp. 325–332, 2018. https://doi.org/10.1080/15435075.2018.1452743.
[48] Das A, Park J, and Park J. "Estimation of available global solar radiation using sunshine duration over South Korea," *J. Atmos. Solar-Terrestrial Phys.*, vol. 134, pp. 22–29, 2015. https://doi.org/10.1016/j.jastp.2015.09.001.
[49] Akinoglu BG. "Quadratic variation of global solar radiation with bright sunshine hours," *Renew. Energy, Technol. Environ.*, pp. 2774–2778, 1992. https://doi.org/10.1016/B978-0-08-041268-9.50069-9.

[50] Akinoglu BG and Ener Rusen S. "Combining the satellite imagery with bright sunshine hours: A review," *J. Renew. Sustain. Energy*, vol. 5, no. 4, 2013. https://doi.org/10.1063/1.4812656.

[51] Karaveli AB, Soytas U, and Akinoglu BG. "Economic analysis of photovoltaic power plant in Turkey," *Proc. of 33rd European Photovoltaic Solar Energy Conference and Exhibition*, 2017, pp. 2235–2239.

[52] Ozden T, Karaveli AB and Akinoglu BG. "Evaluation and Comparisons of the Models to Calculate Solar Irradiation on Inclined Solar Panels for Ankara," in *33rd European PV Solar Energy Conference and Exhibition - EU PVSEC 2017*, 2017.

[53] Chang TP. "The Sun's apparent position and the optimal tilt angle of a solar collector in the northern hemisphere," *Sol. Energy*, vol. 83, no. 8, pp. 1274–1284, 2009. https://doi.org/10.1016/j.solener.2009.02.009.

[54] Kalogirou SA. *Solar Energy Engineering: Processes and Systems*. Academic Press, Amsterdam, 2014.

[55] Ahrens CD. "Meteorology today: an introduction to weather, climate, and the environment," 9th edition, *Brooks/Cole*. 2007.

[56] Liu BYH and Jordan RC. "The interrelationship and characteristic distribution of direct, diffuse and total solar radiation," Sol. Energy, vol. 4, no. 3, pp. 1–19, 1960. https://doi.org/10.1016/0038-092X(60)90062-1.

[57] Ineichen P, Guisan O, and Perez R. "Ground-reflected radiation and albedo," *Sol. Energy*, vol. 44, no. 4, pp. 207–214, 1990. https://doi.org/10.1016/0038-092X(90)90149-7.

[58] Muneer T. "Solar Radiation and Daylight Models," 2nd edition, *Elsevier Butterworth-Heinemann*. 2004.

[59] Ulgen K and Hepbasli A. "Diffuse solar radiation estimation models for Turkey's big cities," *Energy Convers. Manag.*, vol. 50, no. 1, pp. 149–156, 2009. https://doi.org/10.1016/j.enconman.2008.08.013.

[60] Tasdemiroglu E and Sever R. "Estimation of monthly average, daily, horizontal diffuse radiation in Turkey," *Energy*, vol. 16, no. 4, pp. 787–790, 1991. https://doi.org/10.1016/0360-5442(91)90030-P.

[61] Tasdemiroglu E and Sever R. "Estimation of total solar radiation from bright sunshine hours in Turkey," *Energy*, vol. 14, no. 12, pp. 827–830, 1989. https://doi.org/10.1016/0360-5442(89)90036-4.

[62] Ogelman H, Ecevit A and Tasdemiroglu E. "A new method for estimating solar radiation from bright sunshine data," *Sol. Energy*, vol. 33, no. 6, pp. 619–625, 1984. https://doi.org/10.1016/0038-092X(84)90018-5.

[63] Kumar R, Aggarwal RK and Sharma JD. "Comparison of regression and artificial neural network models for estimation of global solar radiations," *Renew. Sustain. Energy Rev.*, vol. 52, pp. 1294–1299, 2015. https://doi.org/10.1016/j.rser.2015.08.021.

[64] Khorasanizadeh H. and Mohammadi K. "Diffuse solar radiation on a horizontal surface: Reviewing and categorizing the empirical models," *Renew. Sustain. Energy Rev.*, vol. 53. pp. 338–362, 2016. https://doi.org/10.1016/j.rser.2015.08.037.

[65] Khogali A, Ramadan MRI, Ali ZEH, and Fattah YA. "Global and diffuse solar irradiance in Yemen (Y.A.R.)," *Sol. Energy*, vol. 31, no. 1, pp. 55–62, 1983. https://doi.org/10.1016/0038-092X(83)90033-6.

[66] Erbs DG, Klein SA and Duffie JA. "Estimation of the diffuse radiation fraction for hourly, daily and monthly-average global radiation," *Sol. Energy*,

vol. 28, no. 4, pp. 293–302, 1982. https://doi.org/10.1016/0038-092X(82)90302-4.

[67] Boukelia TE, Mecibah MS and Meriche IE. “General models for estimation of the monthly mean daily diffuse solar radiation (Case study: Algeria),” *Energy Convers. Manag.*, vol. 81, pp. 211–219, 2014. https://doi.org/10.1016/j.enconman.2014.02.035.

[68] Badescu V. “Correlations to estimate monthly mean daily solar global irradiation: Application to Romania,” *Energy*, vol. 24, no. 10, pp. 883–893, 1999. https://doi.org/10.1016/S0360-5442(99)00027-4.

[69] Despotovic M, Nedic V, Despotovic D and Cvetanovic S. “Review and statistical analysis of different global solar radiation sunshine models,” *Renew. Sustain. Energy Rev.*, vol. 52, pp. 1869–1880, 2015. https://doi.org/10.1016/j.rser.2015.08.035.

[70] Despotovic M, Nedic V, Despotovic D and Cvetanovic S. “Evaluation of empirical models for predicting monthly mean horizontal diffuse solar radiation,” *Renew. Sustain. Energy Rev.*, vol. 56, pp. 246–260, 2016. https://doi.org/10.1016/j.rser.2015.11.058.

[71] Meteonorm, “Meteonorm.” [Online]. Available: www.meteonorm.com/en/features. [Accessed: 27-Apr-2018].

[72] Aksoy B. “Estimated monthly average global radiation for Turkey and its comparison with observations,” *Renew. Energy*, vol. 10, no. 4, pp. 625–633, 1997. https://doi.org/10.1016/S0960-1481(96)00035-3.

[73] Aras H, Balli O and Hepbasli A. “Estimating the horizontal diffuse solar radiation over the Central Anatolia Region of Turkey,” *Energy Convers. Manag.*, vol. 47, no. 15–16, pp. 2240–2249, 2006. https://doi.org/10.1016/j.enconman.2005.11.024.

[74] Elminir HK, Azzam YA and Younes FI. “Prediction of hourly and daily diffuse fraction using neural network, as compared to linear regression models,” *Energy*, vol. 32, no. 8, pp. 1513–1523, 2007. https://doi.org/10.1016/j.energy.2006.10.010.

[75] Gevorkian P. *Large-Scale Solar Power System Design*. New York: Mc. Graw-Hill, 2011.

[76] Roger M and Jerry V. *Photovoltaic Systems Engineering*. 2nd Edition, CRC Press, Florida. 2005.

[77] "In Balance Energy Ltd." [Online]. Available: http://www.inbalance-energy.co.uk/articles/solar_panels_pv_calculator.html. [Accessed: 19-Apr-2018].

[78] Blazev SA. *Photovoltaics For Commercial and Utilities Power Generation*. CRC Press, 2011.

[79] Jungbluth N, Stucki M, Flury K, Frischknecht R and Büsser S. “Life Cycle Inventories of Photovoltaics,” *ESU-services Ltd.* 2012.

[80] de Wild-Scholten MJ, Alsema EA, Horst EW, Baechler M and Fthenakis VM. “A cost and environmental impact comparison of grid-connected rooftop and ground-based PV systems,” *21th Eur. Photovolt. Sol. Energy Conf. Dresden, Ger. 4-8 Sept. 2006*, no. September, pp. 4–8, 2006.

[81] Roberts S. *Solar Electricity: A Practical Guide to Designing and Installing Small Photovoltaic Systems*. Prentice Hall, 1992.

[82] TEDAS, “Specifications.” [Online]. Available: http://www.tedas.gov.tr/sx.web.docs/tedas/tedas_arge/docs/sartnameler/tedas_arge/TEDAŞ-MLZ-2015-061.pdf. [Accessed: 10-May-2018].

[83] Franquelo LG, Leon JI and Vazquez S. *Power Electronics for Renewable Energy Systems, Transportation and Industrial Applications*. Wiley. 2014.
[84] Ghafoor A and Munir A. "Design and economics analysis of an off-grid PV system for household electrification," *Renew. Sustain. Energy Rev.*, vol. 42, pp. 496–502, 2015. https://doi.org/10.1016/j.rser.2014.10.012.
[85] Lokeshreddy M, Kumar PJRP, Chandra SAM, Babu TS, and Rajasekar N. "Comparative study on charge controller techniques for solar PV system," *Energy Procedia*, 2017, vol. 117, pp. 1070–1077. https://doi.org/10.1016/j.egypro.2017.05.230.
[86] Abu Eldahab YE, Saad NH and Zekry A. "Enhancing the design of battery charging controllers for photovoltaic systems," *Renewable and Sustainable Energy Reviews*, vol. 58. pp. 646–655, 2016. https://doi.org/10.1016/j.rser.2015.12.061.
[87] Mirzaei A, Forooghi M, Ghadimi AA, Abolmasoumi AH and Riahi MR. "Design and construction of a charge controller for stand-alone PV/battery hybrid system by using a new control strategy and power management," *Sol. Energy*, vol. 149, pp. 132–144, 2017. https://doi.org/10.1016/j.solener.2017.03.046.
[88] Keane J. *Pico-solar electric systems: The earthscan expert guide to the technology and emerging market*. Routledge. 2014.
[89] Siemens AG, "Transformers for Solar Power Solutions," 2011. [Online] Avaliable:https://www.siemens.com/content/dam/internet/siemens-com/global/products-services/energy/high-voltage/transformers/brochures-transformers-en/siemens-transformers-for-solar-power-solutions.pdf [Accessed: 07-June-2018].
[90] van der Zwaan B and Rabl A. "The learning potential of photovoltaics: Implications for energy policy," *Energy Policy*, vol. 32, no. 13, pp. 1545–1554, 2004. https://doi.org/10.1016/S0301-4215(03)00126-5.
[91] Dunlop ED and Halton D. "The performance of crystalline silicon photovoltaic solar modules after 22 years of continuous outdoor exposure," *Progress in Photovoltaics: Research and Applications*, vol. 14, no. 1. pp. 53–64, 2006. https://doi.org/10.1002/pip.627.
[92] Sherwani AF, Usmani JA and Varun. "Life cycle assessment of solar PV based electricity generation systems: A review," *Renewable and Sustainable Energy Reviews*, vol. 14, no. 1. pp. 540–544, 2010. https://doi.org/10.1016/j.rser.2009.08.003.
[93] Pacca S, Sivaraman D and Keoleian GA. "Parameters affecting the life cycle performance of PV technologies and systems," *Energy Policy*, vol. 35, no. 6, pp. 3316–3326, 2007. https://doi.org/10.1016/j.enpol.2006.10.003.
[94] Pavlovic TM, Milosavljevic DD, Radivojevic AR, and Pavlovic MA. "Comparison and assessment of electricity generation capacity for different types of photovoltaic solar plants of 1 MW in Sokobanja, Serbia," *Therm. Sci.*, vol. 15, pp. 605–618, 2011. DOI: 10.2298/TSCI1103605P.
[95] Djurdjevic DZ. "Perspectives and assessments of solar PV power engineering in the Republic of Serbia," *Renewable and Sustainable Energy Reviews*, vol. 15, no. 5. pp. 2431–2446, 2011. https://doi.org/10.1016/j.rser.2011.02.025.
[96] Homer Energy, "Homer Pro 3.11." [Online]. Available: https://www.homerenergy.com/products/pro/docs/3.11/how_homer_calculates_the_pv_cell_temperature.html. [Accessed: 23-Apr-2018].
[97] Arkin AR. "Modeling of PV, electrolyzer and ga storage in a stand-alone

solar-fuel cell system," 1999.
[98] Goswami Y. *Advances in Solar Energy: Volume 16: An Annual Review of Research and Development in Renewable Energy Technologies*. Routledge, 2017.
[99] Babatunde AA, Abbasoglu S and Senol M. "Analysis of the impact of dust , tilt angle and orientation on performance of PV Plants," *Renew. Sustain. Energy Rev.*, vol. 90, no. March, pp. 1017–1026, 2018. https://doi.org/10.1016/j.rser.2018.03.102.
[100] Ahmed OK and Mohammed ZA. "Dust effect on the performance of the hybrid PV/Thermal collector," *Therm. Sci. Eng. Prog.*, vol. 3, pp. 114–122, 2017. https://doi.org/10.1016/j.tsep.2017.07.003.
[101] Tanesab J, Parlevliet D, Whale J and Urmee T. "Seasonal effect of dust on the degradation of PV modules performance deployed in different climate areas," *Renew. Energy*, vol. 111, pp. 105–115, 2017. https://doi.org/10.1016/j.renene.2017.03.091.
[102] Tanesab J, Parlevliet D, Whale J, Urmee T and Pryor T. "The contribution of dust to performance degradation of PV modules in a temperate climate zone," *Sol. Energy*, vol. 120, pp. 147–157, 2015. https://doi.org/10.1016/j.solener.2015.06.052.
[103] Andrews RW, Pollard A and Pearce JM. "The effects of snowfall on solar photovoltaic performance," *Sol. Energy*, vol. 92, pp. 84–97, 2013. https://doi.org/10.1016/j.solener.2013.02.014.
[104] Marion B, Schaefer R, Caine H and Sanchez G. "Measured and modeled photovoltaic system energy losses from snow for Colorado and Wisconsin locations," *Sol. Energy*, vol. 97, pp. 112–121, 2013. https://doi.org/10.1016/j.solener.2013.07.029.
[105] Andenæs E, Jelle BP, Ramlo K, Kolås T, Selj J and Foss SE. "The influence of snow and ice coverage on the energy generation from photovoltaic solar cells," *Solar Energy*, vol. 159. pp. 318–328, 2018. https://doi.org/10.1016/j.solener.2017.10.078.
[106] Baumgartner F. 5 – Photovoltaic (PV) balance of system components: Basics, performance. *The Perf. of PV Systems.* 2017. https://doi.org/10.1016/B978-1-78242-336-2.00005-7.
[107] Davies JA and McKay DC. "Estimating solar irradiance and components," *Sol. Energy*, vol. 29, no. 1, pp. 55–64, 1982. https://doi.org/10.1016/0038-092X(82)90280-8.
[108] "Photovoltaic Software." [Online]. Available: photovoltaic-software.com/DC_AC_drop_voltage_energy_losses_calculator.php. [Accessed: 24-Apr-2018].
[109] Starke M, Tolbert LM and Ozpineci B. "AC vs. DC distribution: A loss comparison," in *Transmission and Distribution Exposition Conference: 2008 IEEE PES Powering Toward the Future, PIMS 2008*, 2008.
[110] Rydh CJ and Sandén BA. "Energy analysis of batteries in photovoltaic systems. Part I: Performance and energy requirements," *Energy Convers. Manag.*, vol. 46, no. 11–12, pp. 1957–1979, 2005.
[111] Ahmad S, Shafie S and Ab Kadir MZA. "Power Feasibility of a Low Power Consumption Solar Tracker," *Procedia Environ. Sci.*, vol. 17, pp. 494–502, 2013. DOI: 10.1016/j.proenv.2013.02.064.
[112] Jordan DC and Kurtz SR. "Photovoltaic degradation rates - An Analytical Review," *Progress in Photovoltaics: Research and Applications*, vol. 21, no.

1. pp. 12–29, 2013.
[113] Klise GT, Lavrova O and Freeman JM. "Validation of PV-RPM Code in the System Advisor Model," 2017.
[114] Willmott CJ and Matsuura K. "Advantages of the mean absolute error (MAE) over the root mean square error (RMSE) in assessing average model performance," *Clim. Res.*, vol. 30, no. 1, pp. 79–82, 2005. doi: 10.3354/cr030079.
[115] McKeen S et al. "Assessment of an ensemble of seven real-time ozone forecasts over eastern North America during the summer of 2004," J. Geophys. Res. Atmos., vol. 110, no. 21, pp. 1–16, 2005. https://doi.org/10.1029/2005JD005858.
[116] Savage NH et al. "Air quality modelling using the Met Office Unified Model (AQUM OS24-26): model description and initial evaluation," Geosci. Model Dev., vol. 6, no. 2, pp. 353–372, 2013. doi: 10.5194/gmd-6-353-2013.
[117] T. Chai et al. "Evaluation of the United States National Air Quality Forecast Capability experimental real-time predictions in 2010 using Air Quality System ozone and NO2 measurements," Geosci. Model Dev., vol. 6, no. 5, pp. 1831–1850, 2013. https://doi.org/10.5194/gmd-6-1831-2013.
[118] Willmott CJ., Matsuura K. and Robeson SM. "Ambiguities inherent in sums-of-squares-based error statistics," Atmos. Environ., vol. 43, no. 3, pp. 749–752, 2009. https://doi.org/10.1016/j.atmosenv.2008.10.005.
[119] Taylor MH, Losch M, Wenzel M, and Schröter J. "On the sensitivity of field reconstruction and prediction using empirical orthogonal functions derived from Gappy data," J. Clim., vol. 26, no. 22, pp. 9194–9205, 2013. https://doi.org/10.1175/JCLI-D-13-00089.1.
[120] Chatterjee A, Engelen RJ, Kawa SR, Sweeney C, and Michalak AM. "Background error covariance estimation for atmospheric CO2 data assimilation," J. Geophys. Res. Atmos., vol. 118, no. 17, pp. 10140–10154, 2013. https://doi.org/10.1002/jgrd.50654.
[121] Jerez S, Montavez JP, Jimenez-Guerrero P, Gomez-Navarro JJ, Lorente-Plazas R and Zorita E. "A multi-physics ensemble of present-day climate regional simulations over the Iberian Peninsula," Clim. Dyn., vol. 40, no. 11–12, pp. 3023–3046, 2013. https://doi.org/10.1007/s00382-012-1539-1.
[122] Karaveli AB, Ozden T and Akinoglu BG. "Determining PV Module Performance and Comparisons," in *International Conference on Photovoltaic Science and Technologies - PVCON 2018,* 2018.
[123] IPCC Working Group 1, *IPCC Fifth Assessment Report (AR5) - The physical science basis*. 2014.
[124] Lindzen RS. "Can increasing carbon dioxide cause climate change?," *Proc. Natl. Acad. Sci.*, vol. 94, no. 16, pp. 8335–8342, 1997. https://doi.org/10.1073/pnas.94.16.8335.
[125] Plass GN. "The Carbon Dioxide Theory of Climatic Change," *Tellus*, vol. 8, no. 2, pp. 140–154, 1956. https://doi.org/10.1111/j.2153-3490.1956.tb01206.x.
[126] UNFCCC, "Tool to calculate the emission factor for an electricity system Version 06.0," 2017.
[127] UNFCCC, "Turkish Green House Gas Inventory Report", April. 2018.
[128] Ulgen S, Or I, Saygın H, Kumbaroğlu G and Atiyas I. *The Turkish Model for Transition to Nuclear Energy*. EDAM (Center for Ekonomics and Foreign Policy Studies), 2011.

[129] Hernández-Moro J and Martínez-Duart JM. "Analytical model for solar PV and CSP electricity costs: Present LCOE values and their future evolution," *Renewable and Sustainable Energy Reviews*, vol. 20. pp. 119–132, 2013. https://doi.org/10.1016/j.rser.2012.11.082.
[130] Zweibel K. "Should solar photovoltaics be deployed sooner because of long operating life at low, predictable cost?," *Energy Policy*, vol. 38, no. 11, pp. 7519–7530, 2010. https://doi.org/10.1016/j.enpol.2010.07.040.
[131] Ayompe LM, Duffy A, McCormack SJ and Conlon M. "Projected costs of a grid-connected domestic PV system under different scenarios in Ireland, using measured data from a trial installation," *Energy Policy*, vol. 38, no. 7, pp. 3731–3743, 2010. https://doi.org/10.1016/j.enpol.2010.02.051.
[132] Branker K, Pathak MJM, and Pearce JM. "A review of solar photovoltaic levelized cost of electricity," *Renew. Sustain. Energy Rev.*, vol. 15, no. 9, pp. 4470–4482, 2011. https://doi.org/10.1016/j.rser.2011.07.104.
[133] IEA, "Technology Roadmap: Solar Photovoltaic Energy," *Technol. Roadmap*, p. 60, 2014.
[134] Breyer C and Gerlach A. "Global Overview on Grid-Parity Event Dynamics," *Prog. Photovoltaics Res. Appl.*, vol. 21, no. 1, pp. 121–136, 2013. doi: 10.4229/25thEUPVSEC2010-6CV.4.11.
[135] Yang CJ. "Reconsidering solar grid parity," *Energy Policy*, vol. 38, no. 7, pp. 3270–3273, 2010. https://doi.org/10.1016/j.enpol.2010.03.013.
[136] Cellura M, Di Gangi A, Longo S and Orioli A. "Photovoltaic electricity scenario analysis in urban contests: An Italian case study," *Renewable and Sustainable Energy Reviews*, vol. 16, no. 4. pp. 2041–2052, 2012. https://doi.org/10.1016/j.rser.2012.01.032.
[137] NREL, "U. S. Solar Photovoltaic System Cost Benchmark : Q1 2017," *NREL*, 2017.
[138] European Bank on Reconstruction and Development, "Turkey Sustainable Energy Financing Facility." [Online]. Available: http://www.turseff.org/page/eligibility-criteria. [Accessed: 15-Apr-2018].
[139] "Federal Reserve Bank of St. Louis." [Online]. Available: https://fred.stlouisfed.org/series/INTDSRTRM193N. [Accessed: 15-Apr-2018].
[140] "Central Bank of Turkey." [Online]. Available: http://www.tcmb.gov.tr/wps/wcm/connect/TR/TCMB+TR/Main+Menu/Temel+Faaliyetler/Para+Politikasi/Reeskont+ve+Avans+Faiz+Oranlari. [Accessed: 15-Apr-2018].
[141] Celik AN, Muneer T and Clarke P. "Optimal sizing and life cycle assessment of residential photovoltaic energy systems with battery storage," *Prog. Photovoltaics Res. Appl.*, vol. 16, no. 1, pp. 69–85, 2008. https://doi.org/10.1002/pip.774.
[142] International Energy Agency, "Projected Cost of Generating Electricity 2015 Edition," 2015.
[143] European Bank on Reconstruction and Development, "News." [Online]. Available: http://www.ebrd.com/news/2018/ebrd-invests-in-a-record-51-projects-in-turkey-in-2017.html. [Accessed: 18-Apr-2018].
[144] EMRA, "Turkish Energy Market Regulatory Authority." [Online]. Available: http://www.epdk.org.tr/. [Accessed: 07-June-2018].
[145] Kumar Sahu B, "A study on global solar PV energy developments and policies with special focus on the top ten solar PV power producing countries,"

Renewable and Sustainable Energy Reviews, vol. 43. pp. 621–634, 2015. https://doi.org/10.1016/j.rser.2014.11.058.
[146] Wang H, Zheng S, Zhang Y, and Zhang K, "Analysis of the policy effects of downstream Feed-In Tariff on China's solar photovoltaic industry," *Energy Policy*, vol. 95, pp. 479–488, 2016. https://doi.org/10.1016/j.enpol.2016.03.026.
[147] Muhammad-Sukki F *et al.*, "Feed-in tariff for solar photovoltaic: The rise of japan," *Renew. Energy*, vol. 68, pp. 636–643, 2014. https://doi.org/10.1016/j.renene.2014.03.012.
[148] Lee M, Hong T and Koo C. "An economic impact analysis of state solar incentives for improving financial performance of residential solar photovoltaic systems in the United States," *Renewable and Sustainable Energy Reviews*, vol. 58. pp. 590–607, 2016. https://doi.org/10.1016/j.rser.2015.12.297.
[149] Campoccia A, Dusonchet L, Telaretti E and Zizzo G. "An analysis of feed'in tariffs for solar PV in six representative countries of the European Union," *Sol. Energy*, vol. 107, pp. 530–542, 2014. https://doi.org/10.1016/j.solener.2014.05.047.
[150] EXIST, "2016 Electricity market report," 2016. [Online]. Available: https://www.epias.com.tr/wp-content/uploads/2017/05/EPİAS_2016_Electricity_Market_Report.pdf. [Accessed: 07-June-2018].
[151] EMRA, "Monthly Electricity Reports." [Online]. Available: http://www.epdk.org.tr/Detay/Icerik/3-0-23/elektrikaylik-sektor-raporlar. [Accessed: 07-June-2018].
[152] International Renewable Energy Agency, "IRENA Cost and Competitiveness Indicators: Rooftop Solar PV," *Int. Renew. Energy Agency, Abu Dhabi*, 2017.
[153] Parrado C, Girard A, Simon F and Fuentealba E. "2050 LCOE (Levelized Cost of Energy) projection for a hybrid PV (photovoltaic)-CSP (concentrated solar power) plant in the Atacama Desert, Chile," *Energy*, vol. 94, pp. 422–430, 2016. https://doi.org/10.1016/j.energy.2015.11.015.
[154] Ueckerdt F, Hirth L, Luderer G and Edenhofer O. "System LCOE: What are the costs of variable renewables?," *Energy*, vol. 63, pp. 61–75, 2013. https://doi.org/10.1016/j.energy.2013.10.072.
[155] Tran TTD and Smith AD. "Incorporating performance-based global sensitivity and uncertainty analysis into LCOE calculations for emerging renewable energy technologies," *Appl. Energy*, vol. 216, pp. 157–171, 2018. https://doi.org/10.1016/j.apenergy.2018.02.024.
[156] Lai CS and McCulloch MD. "Levelized cost of electricity for solar photovoltaic and electrical energy storage," *Appl. Energy*, vol. 190, pp. 191–203, 2017. https://doi.org/10.1016/j.apenergy.2016.12.153.
[157] Lazard, "Levelised Cost of Energy Analysis," 2017. [Online]. Available: https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf [Accessed: 07-June-2018].
[158] Zou H, Du H, Brown MA and Mao G. "Large-scale PV power generation in China: A grid parity and techno-economic analysis," *Energy*, vol. 134, pp. 256–268, 2017. https://doi.org/10.1016/j.energy.2017.05.192.
[159] US EIA, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2018," 2018.
[160] US EIA, "Annual Energy Outlook 2018 with projections to 2050," *J. Phys. A*

Math. Theor., vol. 44, no. 8, pp. 1–64, 2018.
[161] Investopedia, “Internal Rate of Return.” [Online]. Available: https://www.investopedia.com/terms/i/irr.asp. [Accessed: 24-Apr-2018].
[162] Yingli Solar, “250 Wp Module Brochure.” [Online]. Available: http://www.yinglisolar.com/assets/uploads/products/downloads/YGE_60_Cell_Series_EN.pdf. [Accessed: 18-Apr-2018].
[163] Jordan DC, Kurtz SR, VanSant K, and Newmiller J. “Compendium of photovoltaic degradation rates,” *Prog. Photovoltaics Res. Appl.*, vol. 24, no. 7, pp. 978–989, 2016. https://doi.org/10.1002/pip.2744.
[164] Stein JS and Farnung B. “PV Performance Modeling Methods and Practices,” IEA. 2017.
[165] EXIST, “Transparency Platform.” [Online]. Available: https://seffaflik.epias.com.tr/transparency/piyasalar/gop/ptf.xhtml. [Accessed: 13-Jun-2018].
[166] Central Bank of Turkey, “Currency rates.” [Online]. Available: http://www.tcmb.gov.tr/kurlar/kurlar_tr.html. [Accessed: 15-Apr-2018].
[167] Turkish Statistical Institute, “Electricity Prices.” [Online]. Available: www.tuik.gov.tr/PdfGetir.do?id=24637. [Accessed: 15-Apr-2018].

APPENDICES

A. Mean days of the month and declination

Table A. 1. Mean days of each month and declination of these mean days

Month	Mean day (n_d)	Declination (δ)
January	17	-20.9
February	47	-13.0
March	75	-2.4
April	105	9.4
May	135	18.8
June	162	23.1
July	198	21.2
August	228	13.5
September	258	2.2
October	288	-9.6
November	318	-18.9
December	344	-23.0

B. Derivation of Solar Irradiation Calculation Methodology

The derivations of equations developed in this thesis are given in a step by step approach as followings.

Derivation of the equation of monthly coefficients global linear (MCGL)

The beam component within the time interval n_i,

$$I_B = I_0 \tau n_i \tag{B. 1}$$

$$I_{D1} = I_0 (1-\tau)\beta' n_i \tag{B. 2}$$

$$I_{D2} = I_0 \tau\tau'(1-n_i) \tag{B. 3}$$

$$I_D = I_0(1-\tau)\beta' n_i + I_0\tau\tau'(1-n_i) \tag{B. 4}$$

$$I = I_B + I_D = I_0\left[\tau n_i + n_i(1-\tau)\beta' + \tau\tau'(1-n_i)\right] \tag{B. 5}$$

Now replacing n_i with $\bar{n}/\bar{N}$ and parameters with their monthly mean versions,

$$\bar{H} = \bar{H}_0\left[\tau_e \bar{n}/\bar{N} + \bar{n}/\bar{N}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\bar{n}/\bar{N})\right] \tag{B. 6 }$$

$$\frac{\bar{H}}{\bar{H}_0} = \frac{\bar{n}}{\bar{N}}(\tau_e + (1-\tau_e)\beta'_e - \tau_e\tau'_e) + \tau_e\tau'_e \tag{B. 7 }$$

$$\frac{\bar{H}}{\bar{H}_0} = \frac{\bar{n}}{\bar{N}}(\tau_e + \beta'_e - \tau_e\beta'_e - \tau_e\tau'_e) + \tau_e\tau'_e \tag{B. 8 }$$

Then this equation can be written as:

$$\frac{\bar{H}}{\bar{H}_0} = a + b\frac{\bar{n}}{\bar{N}}$$

where

$a = \tau_e\tau'_e$ and $b = \tau_e + \beta'_e - \tau_e\beta'_e - \tau_e\tau'_e$.

Derivation of the equation of monthly coefficients diffuse linear (MCDL)

Starting from the diffuse part within n_i:

$$I_D = I_0(1-\tau)\beta' n_i + I_0\tau\tau'(1-n_i) \tag{B. 4}$$

Then shifting to monthly mean parameters,

$$\overline{H}_D = \overline{H}_0\left[\overline{n}/\overline{N}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\overline{n}/\overline{N})\right] \quad \text{(B. 9)}$$

$$\overline{H}_D = \overline{H}_0\left[\overline{n}/\overline{N}(\beta'_e - \tau_e\beta'_e) + \tau_e\tau'_e - \overline{n}/\overline{N}\tau_e\tau'_e)\right] \quad \text{(B. 10)}$$

$$\overline{H}_D = \overline{H}_0\left[\overline{n}/\overline{N}(\beta'_e - \tau_e\beta'_e - \tau_e\tau'_e) + \tau_e\tau'_e\right] \quad \text{(B. 11)}$$

The equation can be written as:

$$\overline{H}_D / \overline{H}_0 = a' + b'(\overline{n}/\overline{N})$$

where

$a' = \tau_e\tau'_e$ and $b' = \beta'_e - \tau_e\beta'_e - \tau_e\tau'_e$.

Derivation of the equation of monthly coefficients global quadratic (MCGQ)

Launching with the diffuse part including its components during a bright sunshine period and cloudy sky period and after ground reflection and atmosphere back-scattering within n_i,

$$I_B = I_0\tau n_i \quad \text{(B. 1)}$$

$$I_{D1} = I_0(1-\tau)\beta' n_i \quad \text{(B. 2)}$$

$$I_{D2} = I_0\tau\tau'(1-n_i) \quad \text{(B. 3)}$$

$$I_{D3} = I_0\left[\tau n_i + n_i(1-\tau)\beta' + \tau\tau'(1-n_i)\right]\alpha\beta \quad \text{(B. 12)}$$

$$\begin{aligned} I_D &= I_{D1} + I_{D2} + I_{D3} \\ &= I_0(1-\tau)\beta' n_i + I_0\tau\tau'(1-n_i) + \left[\tau n_i + n_i(1-\tau)\beta' + \tau\tau'(1-n_i)\right]\alpha\beta \end{aligned} \quad \text{(B. 13)}$$

$$I = I_B + I_D = I_0\left[\tau n_i + n_i(1-\tau)\beta' + \tau\tau'(1-n_i)\right](1+\alpha\beta) \quad \text{(B. 14)}$$

Now replacing n_i with $\overline{n}/\overline{N}$ and parameters with their monthly mean versions,

$$\overline{H} = \overline{H}_0\left[\tau_e \overline{n}/\overline{N} + \overline{n}/\overline{N}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\overline{n}/\overline{N})\right](1+\alpha_e\beta_e) \quad \text{(B. 15)}$$

where $\beta_e = 0.0685 \; n/N + \alpha'_e(1-n/N)$.

$$\frac{\overline{H}}{\overline{H}_0} = \left[\tau_e\frac{\overline{n}}{\overline{N}} + \frac{\overline{n}}{\overline{N}}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\frac{\overline{n}}{\overline{N}})\right]\left[1+\alpha_e(0.0685\;\frac{\overline{n}}{\overline{N}} + \alpha'_e(1-\frac{\overline{n}}{\overline{N}}))\right],$$

$$\frac{\overline{H}}{\overline{H}_0} = \left[\tau_e\frac{\overline{n}}{\overline{N}} + \frac{\overline{n}}{\overline{N}}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\frac{\overline{n}}{\overline{N}})\right]\left[1+\alpha_e(0.0685\;\frac{\overline{n}}{\overline{N}} + \alpha'_e(1-\frac{\overline{n}}{\overline{N}}))\right],$$

$$\frac{\overline{H}}{\overline{H}_0} = \left[\tau_e\frac{\overline{n}}{\overline{N}} + \frac{\overline{n}}{\overline{N}}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\frac{\overline{n}}{\overline{N}})\right] + \left[\tau_e\frac{\overline{n}}{\overline{N}} + \frac{\overline{n}}{\overline{N}}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\frac{\overline{n}}{\overline{N}})\right],$$

$$*\,\alpha_e(0.0685\;\frac{\overline{n}}{\overline{N}} + \alpha'_e(1-\frac{\overline{n}}{\overline{N}}))$$

$$\frac{\overline{H}}{\overline{H}_0} = \tau_e\tau'_e + \frac{\overline{n}}{\overline{N}}(\tau_e + (1-\tau_e)\beta'_e - \tau_e\tau'_e) + \left[\tau_e \frac{\overline{n}}{\overline{N}} + \frac{\overline{n}}{\overline{N}}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\frac{\overline{n}}{\overline{N}})\right],$$
$$*(0.0685\ \alpha_e \frac{\overline{n}}{\overline{N}} + \alpha_e\alpha'_e - \alpha_e\alpha'_e\frac{\overline{n}}{\overline{N}}))$$

$$\frac{\overline{H}}{\overline{H}_0} = \tau_e\tau'_e + \frac{\overline{n}}{\overline{N}}(\tau_e + (1-\tau_e)\beta'_e - \tau_e\tau'_e) + (\frac{\overline{n}}{\overline{N}})^2(0.0685\ \alpha_e\tau_e - \tau_e\alpha_e\alpha'_e$$
$$+ (1-\tau_e)\beta'_e 0.0685\ \alpha_e - (1-\tau_e)\beta'_e\alpha_e\alpha'_e - \tau_e\tau'_e 0.0685\ \alpha_e + \tau_e\tau'_e\alpha_e\alpha'_e) \quad ,$$
$$+ \frac{\overline{n}}{\overline{N}}(\tau_e\alpha_e\alpha'_e + (1-\tau_e)\beta'_e\alpha_e\alpha'_e + \tau_e\tau'_e 0.0685\ \alpha_e - 2\tau_e\tau'_e\alpha_e\alpha'_e) + \tau_e\tau'_e\alpha_e\alpha'_e$$

$$\frac{\overline{H}}{\overline{H}_0} = (\tau_e\tau'_e + \tau_e\tau'_e\alpha_e\alpha'_e) + \frac{\overline{n}}{\overline{N}}(\tau_e + (1-\tau_e)\beta'_e - \tau_e\tau'_e + \tau_e\alpha_e\alpha'_e$$
$$+ (1-\tau_e)\beta'_e\alpha_e\alpha'_e + \tau_e\tau'_e 0.0685\ \alpha_e - 2\tau_e\tau'_e\alpha_e\alpha'_e) + (\frac{\overline{n}}{\overline{N}})^2(0.0685\ \alpha_e\tau_e \quad .$$
$$- \tau_e\alpha_e\alpha'_e + (1-\tau_e)\beta'_e 0.0685\ \alpha_e - (1-\tau_e)\beta'_e\alpha_e\alpha'_e - \tau_e\tau'_e 0.0685\ \alpha_e + \tau_e\tau'_e\alpha_e\alpha'_e)$$

Then this equation can be written as:

$$\overline{H}/\overline{H}_0 = a_0 + a_1(\overline{n}/\overline{N}) + a_2(\overline{n}/\overline{N})^2 \tag{B. 16}$$

where

$$a_0 = \tau_e\tau'_e(1+\alpha_e\alpha'_e),$$

$$a_1 = \tau_e + (1-\tau_e)\beta'_e - \tau_e\tau'_e + \tau_e\alpha_e\alpha'_e + (1-\tau_e)\beta'_e\alpha_e\alpha'_e + \tau_e\tau'_e 0.0685\ \alpha_e - 2\tau_e\tau'_e\alpha_e\alpha'_e$$

and

$$a_2 = 0.0685\ \tau_e\alpha_e - \tau_e\alpha_e\alpha'_e + 0.0685\ \beta'_e\alpha_e - \beta'_e\alpha_e\alpha'_e - 0.0685\ \alpha_e\tau_e\beta'_e + \tau_e\beta'_e\alpha_e\alpha'_e$$
$$- 0.0685\ \tau_e\tau'_e\alpha_e + \tau_e\tau'_e\alpha_e\alpha'_e \quad .$$

Derivation of the equation of monthly coefficients diffuse quadratic (MCDQ)

Launching with the diffuse part including its components during a bright sunshine period and cloudy sky period and after ground reflection and atmosphere back-scattering within n_i,

$$I_{D1} = I_0(1-\tau)\beta' n_i \tag{B. 2}$$

$$I_{D2} = I_0\tau\tau'(1-n_i) \tag{B. 3}$$

$$I_{D3} = I_0[\tau n_i + n_i(1-\tau)\beta' + \tau\tau'(1-n_i)]\alpha\beta \tag{B. 12}$$

$$\begin{aligned} I_D &= I_{D1} + I_{D2} + I_{D3} \\ &= I_0(1-\tau)\beta' n_i + I_0\tau\tau'(1-n_i) + [\tau n_i + n_i(1-\tau)\beta' + \tau\tau'(1-n_i)]\alpha\beta \end{aligned} \tag{B.13}$$

Now replacing n_i with $\overline{n}/\overline{N}$ and parameters with their monthly mean versions,

$$\frac{\overline{H}_D}{\overline{H}_0} = \frac{\overline{n}}{\overline{N}}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\frac{\overline{n}}{\overline{N}})$$

$$+\left[(\tau_e\frac{\overline{n}}{\overline{N}} + \frac{\overline{n}}{\overline{N}}(1-\tau_e)\beta'_e + \tau_e\tau'_e(1-\frac{\overline{n}}{\overline{N}}))\alpha_e(0.0685\frac{\overline{n}}{\overline{N}} + \alpha'_e(1-\frac{\overline{n}}{\overline{N}}))\right]$$

$$\frac{\overline{H}_D}{\overline{H}_0} = \tau_e\tau'_e + \tau_e\tau'_e\alpha_e\alpha'_e$$

$$+\frac{\overline{n}}{\overline{N}}(\beta'_e - \tau_e\beta'_e - \tau_e\tau'_e + \tau_e\alpha_e\alpha'_e + \beta'_e\alpha_e\alpha'_e - \tau_e\beta'_e\alpha_e\alpha'_e - 2\tau_e\tau'_e\alpha_e\alpha'_e + \tau_e\tau'_e 0.0685\ \alpha_e)$$

$$+(\frac{\overline{n}}{\overline{N}})^2(\tau_e 0.0685\ \alpha_e - \tau_e\alpha_e\alpha'_e + \beta'_e 0.0685\ \alpha_e - \beta'_e\alpha_e\alpha'_e - 0.0685\ \alpha_e\tau_e\beta'_e$$

$$+\tau_e\beta'_e\alpha_e\alpha'_e - \tau_e\tau'_e 0.0685\ \alpha_e + \tau_e\tau'_e\alpha_e\alpha'_e)$$

The equation is acquired as:

$$\overline{H}_D/\overline{H}_0 = a'_0 + a'_1(\overline{n}/\overline{N}) + a'_0(\overline{n}/\overline{N})^2 \qquad \text{(B. 17)}$$

where

$a'_0 = \tau_e\tau'_e(1+\alpha_e\alpha'_e)$,

$a'_1 = \beta'_e - \tau_e\beta'_e - \tau_e\tau'_e + \tau_e\alpha_e\alpha'_e + \beta'_e\alpha_e\alpha'_e - \tau_e\beta'_e\alpha_e\alpha'_e - 2\tau_e\tau'_e\alpha_e\alpha'_e + \tau_e\tau'_e 0.0685\ \alpha_e$

and

$a'_2 = 0.0685\ \tau_e\alpha_e - \tau_e\alpha_e\alpha'_e + 0.0685\ \beta'_e\alpha_e - \beta'_e\alpha_e\alpha'_e - 0.0685\ \alpha_e\tau_e\beta'_e + \tau_e\beta'_e\alpha_e\alpha'_e$
$- 0.0685\ \tau_e\tau'_e\alpha_e + \tau_e\tau'_e\alpha_e\alpha'_e$

Derivation of the equation of monthly coefficients global depended diffuse from linear equation (MCGD)

$\overline{H}/\overline{H}_0 = a + b(\overline{n}/\overline{N})$.

$\overline{H}_D/\overline{H}_0 = a' + b'(n/N)$.

Using the first equation:

$a = \overline{H}/\overline{H}_0 - b(\overline{n}/\overline{N})$.

Since, $a = a'$, inserting a into the second equation:

$\overline{H}_D/\overline{H}_0 = \overline{H}/\overline{H}_0 - b(\overline{n}/\overline{N}) + b'(\overline{n}/\overline{N})$,

$\overline{H}_D/\overline{H}_0 = \overline{H}/\overline{H}_0 + (b' - b)(\overline{n}/\overline{N})$.

Moreover,

$b' = b - \tau_e$.

Consequently, we get:

$$\overline{H}_D/\overline{H}_0 = \overline{H}/\overline{H}_0 - \tau_e(\overline{n}/\overline{N}) \qquad \text{(B. 18)}$$

Derivation of the equation of monthly coefficients global depended diffuse (MCGD) from quadratic equation

A procedure similar to the one applied in the above-mentioned steps are applicable to quadratic equations too. Moreover, quadratic equations have two mutual parameters as shown below:

$$\overline{H}/\overline{H}_0 = a_0 + a_1(\overline{n}/\overline{N}) + a_2(\overline{n}/\overline{N})^2 \ ,$$

$$\overline{H}_D/\overline{H}_0 = a_0^{'} + a_1^{'}(\overline{n}/\overline{N}) + a_2^{'}(\overline{n}/\overline{N})^2 \, .$$

Since, $a_0 = a_0^{'}$ and $a_2 = a_2^{'}$,

$$a_0 + a_2(\overline{n}/\overline{N})^2 = \overline{H}/\overline{H}_0 - a_1(\overline{n}/\overline{N}) \, .$$

So;

$$\overline{H}_D/\overline{H}_0 = \overline{H}/\overline{H}_0 + (a_1^{'} - a_1)(\overline{n}/\overline{N}) \, .$$

where

$$a_1^{'} = \beta_e' - \tau_e\beta_e' - \tau_e\tau_e' + \tau_e\alpha_e\alpha_e' + \beta_e'\alpha_e\alpha_e' - \tau_e\beta_e'\alpha_e\alpha_e' - 2\tau_e\tau_e'\alpha_e\alpha_e' + \tau_e\tau_e' 0.0685 \ \alpha_e \ ,$$

$$a_1 = \tau_e + (1-\tau_e)\beta_e' - \tau_e\tau_e' + \tau_e\alpha_e\alpha_e' + (1-\tau_e)\beta_e'\alpha_e\alpha_e' + \tau_e\tau_e' 0.0685 \ \alpha_e - 2\tau_e\tau_e'\alpha_e\alpha_e' \, .$$

Then,

If $a_1^{'} - a_1 = c$, hence,

$$\overline{H}_D/\overline{H}_0 = \overline{H}/\overline{H}_0 + c(\overline{n}/\overline{N}) \qquad \text{(B. 19)}$$

where

$$\begin{aligned} c = {} & \beta_e' - \tau_e\beta_e' - \tau_e\tau_e' + \tau_e\alpha_e\alpha_e' + \beta_e'\alpha_e\alpha_e' - \tau_e\beta_e'\alpha_e\alpha_e' - 2\tau_e\tau_e'\alpha_e\alpha_e' + \tau_e\tau_e' 0.0685 \ \alpha \ - \\ & (\tau_e + (1-\tau_e)\beta_e' - \tau_e\tau_e' + \tau_e\alpha_e\alpha_e' + (1-\tau_e)\beta_e'\alpha_e\alpha_e' + \tau_e\tau_e' 0.0685 \ \alpha_e - 2\tau_e\tau_e'\alpha_e\alpha') \end{aligned} \, .$$

By abbreviating c, we get: $c = -\tau_e$.

C. Graphical Climatic Data Method Information of Locations

Table C. 1. Geographical, climatic, data, method information of locations

City	Lat.	Long.	Avaliable data	Ref. City	Equation Type
Adana	36.98	35.30	$\overline{H}$, $\overline{n}$	Aydin	MCGQ-MCGD
Adiyaman	37.76	38.28		Ankara	MCGQ-MCDQ
Afyon	38.74	30.56	$\overline{H}$, $\overline{n}$	Mugla	MCGQ-MCGD
Agri	39.73	43.05	$\overline{H}$, $\overline{n}$	Eskisehir	MCGQ-MCGD
Aksaray	38.37	34.00	$\overline{H}$, $\overline{n}$	Ankara	MCGQ-MCGD
Amasya	40.66	35.84		Ankara	MCGQ-MCDQ
Ankara	39.97	32.66	$\overline{H}$, $\overline{H}_D$, $\overline{n}$	Ankara	MCGQ-MCGD
Antalya	36.74	29.91	$\overline{H}$, $\overline{n}$	Aydin	MCGL- MCGD
Ardahan	41.11	42.70		Istanbul	MCGQ-MCDQ
Artvin	41.18	41.82	$\overline{H}$, $\overline{n}$	Istanbul	MCGQ-MCGD
Aydin	37.84	27.84	$\overline{H}$, $\overline{H}_D$, $\overline{n}$	Aydin	MCGQ-MCGD
Balikesir	39.50	26.98	$\overline{H}$, $\overline{n}$	Aydin	MCGL-MCGD
Bartin	41.75	32.38	$\overline{H}$, $\overline{H}_D$, $\overline{n}$	Amasra	MCGQ-MCGD
Batman	37.84	41.36		Aydin	MCGQ-MCDQ
Bayburt	40.26	40.23		Amasra	MCGQ-MCDQ
Bilecik	40.14	29.98		Ankara	MCGQ-MCDQ
Bingol	38.96	41.05	$\overline{H}$, $\overline{n}$	Ankara	MCGQ-MCGD
Bolu	40.73	31.60	$\overline{H}$, $\overline{n}$	Ankara	MCGQ-MCGD
Burdur	37.46	30.07		Aydin	MCGL- MCDQ
Canakkale	40.15	26.41		Aydin	MCGL- MCDQ
Cankiri	40.60	33.62		Ankara	MCGQ-MCDQ
Corum	40.50	34.60		Ankara	MCGQ-MCDQ
Denizli	37.61	29.23		Aydin	MCGL- MCDQ
Diyarbakir	38.27	39.77	$\overline{H}$, $\overline{n}$	Aydin	MCGQ-MCDQ
Duzce	40.84	31.16		Istanbul	MCGQ-MCDQ
Edirne	41.68	26.56		Tekirdag	MCGQ-MCDQ
Elazig	38.69	39.93	$\overline{H}$, $\overline{n}$	Aydin	MCGQ-MCGD

Erzincan	39.75	39.49	$\overline{H}$, $\overline{n}$	Eskisehir	MCGQ-MCGD
Erzurum	40.30	41.54	$\overline{H}$, $\overline{n}$	Eskisehir	MCGQ-MCGD
Eskisehir	39.77	30.55	$\overline{H}$, $\overline{H}_D$, $\overline{n}$	Eskisehir	MCGQ-MCGD
Gaziantep	37.07	37.38		Aydin	MCGQ-MCDQ
Giresun	40.92	38.39		Istanbul	MCGQ-MCDQ
Gumushane	40.46	39.47	$\overline{H}$, $\overline{n}$	Amasra	MCGQ-MCGD
Hakkari	37.58	43.74	$\overline{H}$, $\overline{n}$	Eskisehir	MCGQ-MCGD
Hatay	36.40	36.35		Aydin	MCGQ-MCDQ
Igdir	39.92	44.04		Eskisehir	MCGQ-MCDQ
Isparta	37.79	30.77	$\overline{H}$, $\overline{n}$	Aydin	MCGL- MCGD
Istanbul	40.99	29.21	$\overline{H}$, $\overline{H}_D$, $\overline{n}$	Istanbul	MCGQ-MCGD
Izmir	38.46	27.37	$\overline{H}$, $\overline{n}$	Aydın	MCGL- MCGD
Karabuk	41.19	32.74		Ankara	MCGQ-MCDQ
Karaman	37.19	33.22	$\overline{H}$, $\overline{n}$	Ankara	MCGQ-MCGD
Kastamonu	41.37	33.78	$\overline{H}$, $\overline{n}$	Ankara	MCGQ-MCGD
Kayseri	38.37	35.48	$\overline{H}$, $\overline{n}$	Ankara	MCGQ-MCGD
Kilis	36.71	37.11	$\overline{H}$, $\overline{n}$	Ankara	MCGQ-MCGD
Kirikkale	39.84	33.51		Ankara	MCGQ-MCDQ
Kirklareli	41.74	27.22	$\overline{H}$, $\overline{n}$	Tekirdag	MCGQ-MCGD
Kirsehir	39.23	33.98		Ankara	MCGQ-MCDQ
Kocaeli	40.85	29.88		Istanbul	MCGQ-MCDQ
Konya	37.68	31.75	$\overline{H}$, $\overline{n}$	Eskisehir	MCGQ-MCGD
Kutahya	39.42	29.99		Eskisehir	MCGQ-MCDQ
Malatya	38.35	38.25	$\overline{H}$, $\overline{n}$	Aydin	MCGL- MCGD
Manisa	38.84	28.11		Ankara	MCGL- MCDQ
Maras	38.02	36.48	$\overline{H}$, $\overline{n}$	Ankara	MCGQ-MCGD
Mardin	37.34	40.62		Aydin	MCGQ-MCDQ
Mugla	37.21	28.37	$\overline{H}$, $\overline{H}_D$, $\overline{n}$	Mugla	MCGQ-MCGD
Mus	38.73	41.49		Ankara	MCGQ-MCDQ
Nevsehir	38.69	34.69		Eskisehir	MCGQ-MCDQ
Nigde	37.55	34.49	$\overline{H}$, $\overline{n}$	Eskisehir	MCGQ-MCGD

Ordu	41.14	37.29	$\overline{H}$, $\overline{n}$	Istanbul	MCGQ-MCGD
Osmaniye	37.21	36.18		Aydin	MCGL-MCDQ
Rize	41.04	40.50	$\overline{H}$, $\overline{n}$	Istanbul	MCGQ-MCGD
Sakarya	40.69	30.44		Ankara	MCGQ-MCDQ
Samsun	41.28	36.34		Sinop	MCGQ-MCDQ
Siirt	37.87	42.15		Aydin	MCGQ-MCDQ
Sinop	42.03	35.16	$\overline{H}$, $\overline{H}_D$, $\overline{n}$	Sinop	MCGQ-MCGD
Sirnak	37.42	42.49		Eskisehir	MCGQ-MCDQ
Sivas	39.19	36.08	$\overline{H}$, $\overline{n}$	Eskisehir	MCGQ-MCGD
Tekirdag	40.96	27.50	$\overline{H}$, $\overline{H}_D$, $\overline{n}$	Tekirdag	MCGQ-MCGD
Tokat	40.39	36.63		Ankara	MCGQ-MCDQ
Trabzon	40.80	39.58		Istanbul	MCGQ-MCDQ
Tunceli	39.31	39.44		Eskisehir	MCGQ-MCDQ
Urfa	37.37	38.51	$\overline{H}$, $\overline{n}$	Aydin	MCGQ-MCGD
Usak	38.67	29.41		Mugla	MCGQ-MCDQ
Van	38.47	43.35	$\overline{H}$, $\overline{n}$	Eskisehir	MCGQ-MCGD
Yalova	40.65	29.28		Ankara	MCGQ-MCDQ
Yozgat	39.19	35.25	$\overline{H}$, $\overline{n}$	Ankara	MCGL- MCGD
Zonguldak	41.45	31.79		Amasra	MCGQ-MCGD

D. Price Estimation for Day Ahead Mechanism and End-user Prices

In Turkish market, if an electricity producing system does not benefit from YEKDEM mechanism, it is welcome by the Day Ahead Mechanism (DAM).

In order to be able to make appropriate and precise assumptions for the future prices of the DAM, this study has taken last three-year's hourly DAM prices as basis in order to see the trend and make projections based on this basis.

PV systems without battery is only able to produce electricity when sun shines however, the ones with battery is able to feed the grid whenever demanded. Consequently, last three years DAM prices are taken as total daily prices and daily prices when sun shines by compiling hourly prices released by the EPIAS Transparency Platform [165]. Monthly mean daily prices of DAM for the last three years are given in Table D.1.

Table D. 1 Monthly mean daily prices of DAM in TL and $

Months	2015		2016		2017	
	TL	$	TL	$	TL	$
January	172.9	75.68	149.6	49.18	181.3	48.12
February	140.1	57.02	103.7	35.16	172.6	47.24
March	124.4	47.38	108.8	37.64	145.3	38.89
April	101.7	37.66	118.5	41.43	145.1	39.37
May	108.5	41.86	117.5	39.48	152.4	42.77
June	124.7	45.54	141.7	48.33	148.5	42.33
July	132.8	50.26	135.1	46.76	175.1	49.07
August	154.7	54.52	161.5	54.62	173.3	49.05
September	160.7	52.70	139.8	47.00	178.5	51.92
October	137.6	47.64	140.5	45.44	164.1	45.01
November	133.7	46.38	148.1	45.18	174.7	44.89
December	163.6	54.99	203.9	57.88	203.9	52.73
Annual av.	138.0	50.97	139.0	45.67	167.9	45.95

The TL - $ conversion is made by taking into account the currency rate officially announced by Turkish Central Bank. The monthly mean daily $ - TL currencies are given in Table D.2 [166].

Table D. 2 $ - TL currency announced by Turkish Central Bank.

Months	2015	2016	2017
January	2.28	3.04	3.77
February	2.46	2.95	3.65
March	2.63	2.89	3.74
April	2.70	2.86	3.69
May	2.59	2.98	3.56
June	2.74	2.93	3.51
July	2.64	2.89	3.57
August	2.84	2.96	3.53
September	3.05	2.97	3.44
October	2.89	3.09	3.65
November	2.88	3.28	3.89
December	2.98	3.52	3.87

On the other hand, monthly mean daily prices of DAM for the sunny part of each day for the last three years are given in Table D.3.

Table D. 3 Prices of DAM for sunny part of monthly mean days in TL and $

Months	2015		2016		2017	
	TL	$	TL	$	TL	$
January	192.6	84.30	173.2	56.94	206.4	54.76
February	165.5	67.38	134.7	45.68	195.1	53.42
March	145.3	55.35	131.7	45.58	159.2	42.61
April	120,0	44.41	136.8	47.82	162.2	43.98
May	129.7	50.02	163.9	45.33	172.3	48.35
June	129.5	47.31	152.2	51.91	155.6	44.33
July	248.0	55.99	145.8	50.48	196.1	54.98
August	168.9	59.53	172.8	58.44	189.8	53.72
September	182.8	59.95	160.7	54.06	197.9	57.55
October	158.8	54.97	161.3	52.16	182.4	50.00
November	151.0	52.37	170.4	52.01	194.3	49.94
December	192.3	64.62	233.6	66.33	233.6	60.42
Annual av.	157.0	58.02	159.0	52.23	187.1	51.17

Checking these data, beginning with 5 ¢ per kWh is reasonable. On the other hand, for the self-consumption option we need to make estimations of end user electricity price for both households and industry in Turkey.

End user electricity prices for the last 5 years are checked by using statistics of TurkStat [167] and below mentioned Table D.4 is created.

Table D. 4 End-user Electricity Prices in Turkey

Year-term	Industry		Household		Year-term	Industry		Household	
Currency	TL	$	TL	$		TL	$	TL	$
2012-1	20.7	11	30.9	16.4	2015-2	24.4	9.1	38.9	14.5
2012-2	22.8	12.6	33.9	18.8	2016-1	28.2	9.6	41.3	14
2013-1	24.1	13.5	35.7	20.1	2016-2	25.2	8.7	41.3	14.3
2013-2	23.4	12.1	35.3	18.3	2017-1	25.4	7.2	41.3	11.7
2014-1	23.4	10.8	35.4	16.3	2017-2			41.3	11.7
2014-2	23.6	11.1	37.4	17.6	2018-1			44.8	11.9
2015-1	24.4	10.4	38.9	16.6					

E. Permission Process

For unlicensed process, five main steps to follow for permission are determined as follows:

- Conformity assessment for the land where PV PP is to be established,
- Document gathering and application for call letter
- Handling of call letter and making system connection agreement
- Installing the system (including construction, electrics and electromechanics works and recruitment of all the equipment)
- Temporary acceptation and commissioning

The steps, which requires expenditure for investor and their costs to the investor, are listed as below:

Table E. 1 Step by step permission process

Activity	Sub-activities
Conformity assessment of the land	Land classification information Availability of transformer capacity Distance to connection point criteria Technical availability like enough solar irradiation Infrastructure availability like having road
Document gathering and Application for the call letter	Application Form Certificate of authority Application Fee Single Line Diagram Application Diagram with coordinate Land class application letter or provincial directories
Handling call letter	
System connection agreement	Project approval fee Project Approval process Production Plant Project Signing of system connection agreement
System’s installing	Land permission System installation
Temporary Acceptation	
Commissioning	

On the other hand, the steps of licensing period from beginning to the end defined in aforementioned legal texts are listed as follows:

- EMRA related authority of the government announces the amount and places of licenses to be distributed
- The measurement obligation is provided by 6 months on-site measurement and 6 months interpolation by those who demand to get licence.
- Necessary documents are gathered and made them ready for application
- Application is made within the announced period.
- Contribution fee Contests are organized/realized.
- Pre-licenses are distributed to those who has accepted to pay the highest contribution fee.
- Licenses are gathered after they are announced in the Official Journal with signatures of Council of Ministers.
- System is installed.
- Commissioning is made.

F. Financial Opportunities for Solar Electricity Investments

On one hand, the investor can cover all expenses with his own capital if he/she can afford by having enough liquidity. On the other hand, he/she has an opportunity to get fiscal support as grant or loan. Turkish market has four main type of tools to provide liquidity for solar electricity projects that are grants, international loans via local banks, credits/loans from local banks and leasing.

There are two basic mechanisms that investors can benefit from grants. They are Clean Energy Fiscal Support Programs by National Development Agencies and calls including solar electricity investments by EU's Instrument for Pre-Accession Assistance Rural Development Program (IPARD) II. Term. What National Development Agencies provide is a grant-based support program available for intuitions consuming electricity and/or having agricultural activity in rural areas in parallel with the idea of meeting/compensating self-consumption through solar electricity. The share of the support is 50% for profit-making companies and 75% for nonprofit organizations.

The amount of IPARD II term support is up to 500,000 € with the maximum share of 65%.

As a second option, the liquidity can be provided from international mechanisms like EBRD, Asian Development Bank, World Bank, French Development Agency (AFD), kfW Development Bank, Japan Bank for International Cooperation (JBIC).

As the most familiar one, EBRD supports are mainly divided into 3 programs, which are TurSEFF, MidSEFF and TuREEFF. These programs provides loans with bankable amount of interests. The credits are distributed via local banks.

Moreover, World Bank, kfW and AFD have reasonable opportunities for investors.

Furthermore, local banks have their own loan mechanisms like Solar Energy Credit by Garanti Bank, Renewable Energy Credits with the cooperation of Halkbank and AFD, unlicensed electricity production support credit by Halkbank, Turkey Economy Bank's credit program with the collaboration of AFD and Turkey Finance Bank with produce your own electricity program.

Table F.1 reveals the credit opportunities to be benefit from/through local banks.

Table F. 1 Credit opportunities of local banks and their international partners

BANK NAME	**LOAN PROGRAMS**
Akbank	EBRD – MidSEFF
Denizbank	EBRD – MidSEFF and TurSEFF
Finansbank	EBRD – MidSEFF
Garanti	EBRD – MidSEFF Solar Energy Credits
Halkbank	Unlicenced Electricity production Support Loans AFD – Renewable Energy Credit
İş Bankası	EBRD – MidSEFF, TurSEFF and TurEEFF
Şekerbank	EBRD – TurEEFF
TEB	AFD – Energy Credit
Turkey Finance Bank	Produce your own Electricity Loans
Vakifbank	EBRD – MidSEFF and TurSEFF World Bank – SME Energy Eff. Project
Yapıkredi	EBRD – MidSEFF and TurSEFF
Ziraat Bankası	World Bank - SME Energy Eff. Project

These programs enables 0.5-2-year delay and up to 10-year payment term for repays. This software will be assuming some percent of loans like 4, 5, 6, 10% and determine the feasibility analysis. Moreover, by stabilizing payback time in a certain time, it will be defining the reasonable loan amounts.

As the last option, investor can apply to leasing method which is provided by Deniz leasing and Yapikredi Leasing in Turkey.

G. Algorithm of SOlAR TURnKEY

The algorithm needs latitude of the location and size of the planned power plant as input. Then $\overline{H}_0$, $\overline{H}$, $\overline{H}_D$, $\overline{H}_B$ and $\overline{H}_T$ are calculated respectively under the title of solar irradiation physics (Section 2.1) in order to determine the input of the PV system. Under the design title of the study (Section 2.2), the information on number of modules, type and number of inverters, distance between PV lines and total area needed for the PP are produced. For the electricity production part (Section 2.3) gross electricity produced by the system and net electricity given to the grid/consumer are calculated. In economics part (Chapter 3), the calculations for cost, revenue, profit, payback, LCOE, LROE, LPOE, NFM and other economic parameters are made. Then, the final report can be made available.

The equations of the algorithm are given as follows:

1. Input: Latitude (ϕ), **Size** (P_T)

2. Solar Irradiation Physics:

2.1. Extraterrestrial Solar Irradiation ($\overline{H}_0$):

$$\overline{H}_0 = \frac{11810800}{\pi}\left(1 + 0.033\cos(0.9863013698630137 \times n_d)\right)\cos\phi\cos\left(23.45\sin\left(\frac{284+n_d}{365}\right)\right)$$

$$\sin\left(\cos^{-1}\left(-\tan\phi\tan\left(23.45\sin\left(\frac{284+n_d}{365}\right)\right)\right)\right) + \frac{\pi\left(\cos^{-1}\left(-\tan\phi\tan\left(23.45\sin\left(\frac{284+n_d}{365}\right)\right)\right)\right)}{180}$$

$$\sin\phi\sin\left(23.45\sin\left(\frac{284+n_d}{365}\right)\right)$$

where n_d is

Month	Mean day	Month	Mean day	Month	Mean day
January	17	May	135	September	258
February	47	June	162	October	288
March	75	July	198	November	318
April	105	August	228	December	344

2.2. Total solar irradiation on horizontal surface ($\overline{H}$):

For the locations within Ankara, Adiyaman, Aksaray, Amasya, Bilecik, Bingol, Bolu, Cankiri, Corum, Karabuk, Karaman, Kastamonu, Kayseri, Kilis, Kirikkale, Kirsehir, Maras, Mus, Nevsehir, Sakarya, Tokat Yozgat, Yalova

$$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2$$

Month	a_0	a_1	a_2	Month	a_0	a_1	a_2
1	0.269	0.429	-0.035	7	0.411	0.378	-0.032
2	0.327	0.394	-0.033	8	0.409	0.372	-0.032
3	0.366	0.364	-0.031	9	0.431	0.322	-0.028
4	0.359	0.390	-0.033	10	0.347	0.405	-0.034
5	0.379	0.380	-0.032	11	0.386	0.291	-0.025
6	0.309	0.524	-0.043	12	0.312	0.336	-0.028

For Aydin, Adana, Batman, Burdur, Diyarbakir, Elazig, Gaziantep, Hatay, Mardin, Mersin, Urfa

$$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2$$

Month	a_0	a_1	a_2	Month	a_0	a_1	a_2
1	0.284	0.431	-0.036	7	0.519	0.221	-0.021
2	0.279	0.460	-0.038	8	0.401	0.334	-0.029
3	0.306	0.431	-0.036	9	0.396	0.342	-0.029
4	0.383	0.336	-0.029	10	0.362	0.376	-0.032
5	0.432	0.272	-0.024	11	0.350	0.348	-0.029
6	0.485	0.255	-0.023	12	0.266	0.455	-0.037

For Eskisehir, Agri, Bitlis Erzincan, Erzurum, Hakkari, Igdir, Konya, Kutahya, Nigde, Sivas, Sirnak, Tunceli, Van

$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2$

Month	a_0	a_1	a_2	Month	a_0	a_1	a_2
1	0.393	0.375	-0.032	7	0.245	0.570	-0.046
2	0.272	0.489	-0.040	8	0.257	0.529	-0.043
3	0.294	0.493	-0.040	9	0.330	0.445	-0.037
4	0.289	0.510	-0.042	10	0.368	0.353	-0.030
5	0.310	0.466	-0.038	11	0.338	0.408	-0.034
6	0.233	0.587	-0.047	12	0.258	0.453	-0.037

For Istanbul, Ardahan, Artvin, Duzce, Giresun, Kocaeli, Ordu, Rize, Trabzon

$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2$

Month	a_0	a_1	a_2	Month	a_0	a_1	a_2
1	0.279	0.363	-0.030	7	0.405	0.314	-0.027
2	0.231	0.437	-0.036	8	0.351	0.361	-0.031
3	0.241	0.471	-0.038	9	0.338	0.361	-0.030
4	0.345	0.351	-0.030	10	0.330	0.333	-0.028
5	0.342	0.375	-0.032	11	0.321	0.309	-0.026
6	0.307	0.448	-0.037	12	0.221	0.438	-0.036

For Tekirdag, Edirne, Kirklareli

$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2$

Month	a_0	a_1	a_2	Month	a_0	a_1	a_2
1	0.248	0.437	-0.036	7	0.432	0.347	-0.030
2	0.289	0.376	-0.031	8	0.434	0.263	-0.023
3	0.258	0.439	-0.036	9	0.385	0.292	-0.025
4	0.300	0.472	-0.039	10	0.290	0.416	-0.034
5	0.365	0.399	-0.034	11	0.336	0.324	-0.027
6	0.320	0.454	-0.038	12	0.272	0.415	-0.034

For Mugla, Afyon, Usak

$$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2$$

Month	a_0	a_1	a_2	Month	a_0	a_1	a_2
1	0.216	0.522	-0.042	7	0.406	0.364	-0.031
2	0.272	0.488	-0.040	8	0.487	0.234	-0.021
3	0.293	0.429	-0.035	9	0.421	0.316	-0.027
4	0.403	0.333	-0.029	10	0.367	0.414	-0.035
5	0.299	0.447	-0.037	11	0.274	0.570	-0.046
6	0.303	0.494	-0.041	12	0.207	0.569	-0.046

For Amasra/Bartin, Bayburt, Gumushane, Zonguldak

$$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2$$

Month	a_0	a_1	a_2	Month	a_0	a_1	a_2
1	0.230	0.501	-0.041	7	0.393	0.367	-0.031
2	0.239	0.482	-0.039	8	0.454	0.256	-0.023
3	0.272	0.451	-0.037	9	0.347	0.379	-0.032
4	0.230	0.573	-0.046	10	0.250	0.480	-0.039
5	0.277	0.475	-0.039	11	0.210	0.535	-0.043
6	0.323	0.426	-0.035	12	0.233	0.520	-0.042

For Sinop, Samsun

$$\overline{H} / \overline{H}_0 = a_0 + a_1(\overline{n} / \overline{N}) + a_2(\overline{n} / \overline{N})^2$$

Month	a_0	a_1	a_2	Month	a_0	a_1	a_2
1	0.464	0.231	-0.021	7	0.474	0.306	-0.027
2	0.384	0.332	-0.028	8	0.415	0.362	-0.031
3	0.378	0.360	-0.031	9	0.412	0.352	-0.030
4	0.422	0.336	-0.029	10	0.377	0.389	-0.033
5	0.419	0.336	-0.029	11	0.399	0.344	-0.029
6	0.447	0.354	-0.030	12	0.393	0.334	-0.029

For Denizli, Izmir, Manisa

$\overline{H} / \overline{H}_0 = a + b(\overline{n} / \overline{N})$

Month	a	b	Month	a	b
1	0.281	0.373	7	0.459	0.287
2	0.346	0.333	8	0.462	0.277
3	0.385	0.305	9	0.480	0.235
4	0.383	0.323	10	0.379	0.329
5	0.403	0.313	11	0.408	0.236
6	0.352	0.427	12	0.324	0.287

For Antalya, Balikesir, Canakkale, Isparta, Malatya, Osmaniye,

$\overline{H} / \overline{H}_0 = a + b(\overline{n} / \overline{N})$

Month	a	b	Month	a	b
1	0.308	0.362	7	0.588	0.122
2	0.307	0.385	8	0.498	0.198
3	0.338	0.353	9	0.475	0.224
4	0.416	0.265	10	0.412	0.285
5	0.460	0.210	11	0.388	0.273
6	0.526	0.181	12	0.297	0.377

2.3. Diffuse Solar irradiation on horizontal surface ($\overline{H}_D$):

For Ankara, Adiyaman, Aksaray, Bingol, Bolu, Karaman, Kastamonu, Kayseri, Kilis, Kirsehir, Manisa, Maras, Mus, Yozgat

$\overline{H}_D = \overline{H} - \overline{H}_0 \tau_e (\overline{n} / \overline{N})$

Month	τ_e	Month	τ_e	Month	τ_e
1	0.467	5	0.563	9	0.561
2	0.506	6	0.660	10	0.551
3	0.523	7	0.610	11	0.451
4	0.548	8	0.599	12	0.401

For Eskisehir, Agri, Erzincan, Erzurum, Hakkari, Igdir, Kars, Konya, Nigde, Sivas, Van

$\overline{H}_D = \overline{H} - \overline{H}_0 \tau_e (\overline{n} / \overline{N})$

Month	τ_e	Month	τ_e	Month	τ_e
1	0.579	5	0.581	9	0.581
2	0.555	6	0.634	10	0.510
3	0.594	7	0.628	11	0.541
4	0.611	8	0.589	12	0.483

For Aydin, Adana, Antalya, Balikesir, Burdur, Batman, Canakkale, Denizli, Diyarbakir, Elazig, Gaziantep, Hatay, Isparta, Izmir, Malatya, Mardin, Osmaniye, Urfa

$\overline{H}_D = \overline{H} - \overline{H}_0 \tau_e (\overline{n} / \overline{N})$

Month	τ_e	Month	τ_e	Month	τ_e
1	0.492	5	0.493	9	0.537
2	0.526	6	0.549	10	0.534
3	0.525	7	0.553	11	0.478
4	0.510	8	0.533	12	0.500

For Mugla, Afyon

$\overline{H}_D = \overline{H} - \overline{H}_0 \tau_e (\overline{n} / \overline{N})$

Month	τ_e	Month	τ_e	Month	τ_e
1	0.517	5	0.537	9	0.539
2	0.555	6	0.608	10	0.595
3	0.503	7	0.584	11	0.672
4	0.534	8	0.523	12	0.570

For Istanbul, Ardahan, Artvin, Duzce, Giresun, Kocaeli, Ordu, Rize, Trabzon

$\overline{H}_D = \overline{H} - \overline{H}_0 \tau_e (\overline{n} / \overline{N})$

Month	τ_e	Month	τ_e	Month	τ_e
1	0.390	5	0.501	9	0.476
2	0.420	6	0.551	10	0.425
3	0.483	7	0.511	11	0.379
4	0.473	8	0.496	12	0.407

For Tekirdag, Edirne, Kirklareli

$\overline{H}_D = \overline{H} - \overline{H}_0 \tau_e (\overline{n} / \overline{N})$

Month	τ_e	Month	τ_e	Month	τ_e
1	0.446	5	0.571	9	0.450
2	0.423	6	0.579	10	0.481
3	0.465	7	0.599	11	0.422
4	0.574	8	0.485	12	0.452

For Amasra, Bayburt, Gumushane, Zonguldak

$\overline{H}_D = \overline{H} - \overline{H}_0 \tau_e (\overline{n} / \overline{N})$

Month	τ_e	Month	τ_e	Month	τ_e
1	0.510	5	0.543	9	0.515
2	0.496	6	0.546	10	0.510
3	0.502	7	0.567	11	0.527
4	0.610	8	0.504	12	0.540

For Sinop, Samsun

$\overline{H}_D = \overline{H} - \overline{H}_0 \tau_e (\overline{n} / \overline{N})$

Month	τ_e	Month	τ_e	Month	τ_e
1	0.484	5	0.563	9	0.575
2	0.505	6	0.631	10	0.573
3	0.535	7	0.604	11	0.546
4	0.568	8	0.593	12	0.521

For Amasya, Bilecik, Cankiri, Corum, Karabuk, Nevsehir, Sakarya, Tokat, Yalova

$$\overline{H}_D / \overline{H}_0 = a_0' + a_1'(\overline{n}/\overline{N}) + a_2'(\overline{n}/\overline{N})^2$$

Month	a_0'	a_1'	a_2'	Month	a_0'	a_1'	a_2'
1	0.269	-0.038	-0.035	7	0.411	-0.232	-0.032
2	0.327	-0.112	-0.033	8	0.409	-0.227	-0.032
3	0.366	-0.159	-0.031	9	0.431	-0.240	-0.028
4	0.359	-0.158	-0.033	10	0.347	-0.146	-0.034
5	0.379	-0.184	-0.032	11	0.386	-0.160	-0.025
6	0.309	-0.136	-0.043	12	0.312	-0.065	-0.028

For Bitlis, Kutahya, Sirnak, Tunceli,

$$\overline{H}_D / \overline{H}_0 = a_0' + a_1'(\overline{n}/\overline{N}) + a_2'(\overline{n}/\overline{N})^2$$

Month	a_0'	a_1'	a_2'	Month	a_0'	a_1'	a_2'
1	0.393	-0.204	-0.032	7	0.245	-0.059	-0.046
2	0.272	-0.066	-0.040	8	0.257	-0.060	-0.043
3	0.294	-0.101	-0.040	9	0.330	-0.136	-0.037
4	0.289	-0.101	-0.042	10	0.368	-0.157	-0.030
5	0.310	-0.115	-0.038	11	0.338	-0.133	-0.034
6	0.233	-0.047	-0.047	12	0.258	-0.030	-0.037

For Aydin

$$\overline{H}_D / \overline{H}_0 = a_0' + a_1'(\overline{n}/\overline{N}) + a_2'(\overline{n}/\overline{N})^2$$

Month	a_0'	a_1'	a_2'	Month	a_0'	a_1'	a_2'
1	0.284	-0.061	-0.036	7	0.519	-0.332	-0.021
2	0.279	-0.066	-0.038	8	0.401	-0.199	-0.029
3	0.306	-0.095	-0.036	9	0.396	-0.195	-0.029
4	0.383	-0.174	-0.029	10	0.362	-0.158	-0.032
5	0.432	-0.221	-0.024	11	0.350	-0.129	-0.029
6	0.485	-0.294	-0.023	12	0.266	-0.044	-0.037

For Usak

$$\overline{H}_D / \overline{H}_0 = a_0^{'} + a_1^{'}(\overline{n} / \overline{N}) + a_2^{'}(\overline{n} / \overline{N})^2$$

Month	$a_0^{'}$	$a_1^{'}$	$a_2^{'}$	Month	$a_0^{'}$	$a_1^{'}$	$a_2^{'}$
1	0.216	0.005	-0.042	7	0.406	-0.220	-0.031
2	0.272	-0.067	-0.040	8	0.487	-0.289	-0.021
3	0.293	-0.074	-0.035	9	0.421	-0.223	-0.027
4	0.403	-0.201	-0.029	10	0.367	-0.181	-0.035
5	0.299	-0.090	-0.037	11	0.274	-0.102	-0.046
6	0.303	-0.115	-0.041	12	0.207	-0.001	-0.046

2.4. Beam solar irradiation on horizontal surface ($\overline{H}_B$):

$$\overline{H}_B = \overline{H} - \overline{H}_D$$

2.5. Solar irradiation on tilted surface with fixed tilt system ($\overline{H}_T$):

$$\overline{H}_T = \overline{H}_B \overline{R}_B + \overline{H} \rho_g \left(\frac{1 - \cos \beta}{2} \right) + \overline{H}_D \left(\frac{1 + \cos \beta}{2} \right)$$

where

$$\omega_s^{'} = \min \begin{Bmatrix} \cos^{-1}(-\tan \phi \tan \delta) \\ \cos^{-1}(-\tan(\phi - \beta) \tan \delta) \end{Bmatrix}$$

$$\overline{R}_B = \frac{\cos(\phi - \beta) \times \cos(\delta) \times \sin \omega_s^{'} + \frac{\pi}{180} \times \omega_s^{'} \times \sin(\phi - \beta) \times \sin \delta}{\cos \phi \times \cos \delta \times \sin \omega_s + \frac{\pi}{180} \times \omega_s \times \sin \phi \times \sin \delta}$$

$$\rho_g = 0.2$$

$$\delta = 23.45 \sin \left(\frac{284 + n_d}{365} \right)$$

$$\omega_s = \cos^{-1}(-\tan \phi \tan \delta)$$

$\beta_f = 0.764 \times \phi + 2.14$ (For fixed tilt system)

$\beta_t = \left| \phi - 23.45 \sin \left(\frac{284 + n_d}{365} \right) \right|$ (For one-axis monthly mean daily tracking system)

3. Solar Design:

3.1. Number of Modules (M_M):

$$M_M = P_T / P_M$$

3.2. Distance between PV lines (D_T):

$$D_1 = X \times \cos \beta$$

$$H = X \times \sin \beta$$

$$D_2 = H \times \tan(\delta_m + \phi)$$

$$D_T = D_1 + D_2$$

3.3. Length of a string:

3.3.1. Two vertical modules in column ($X_{2,v}$):

$$X_{2,v} = 2 \times w$$

3.3.2. Two vertical modules in column ($X_{3,v}$):

$$X_{3,v} = 3 \times w$$

3.3.3. Two horizontal modules in column ($X_{2,,h}$):

$$X_{2,h} = 2 \times h$$

3.3.4. Three horizontal modules in column ($X_{3,h}$):

$$X_{3,h} = 3 \times h$$

3.4. Amount of mounting materials:

3.4.1. Amount of aluminum used (M_{AL}):

$$M_{AL} = M_{AL,unit} \times A_M$$

3.4.2. Amount of steel used (M_{ST}):

$$M_{ST} = M_{ST,unit} \times A_M$$

3.4.3. Amount of concrete used (M_{CONC}):

$$M_{CONC} = M_{CONC,unit} \times A_M$$

3.5. AC/DC Cables

3.6. Cross sectional area of cable:

$$d = I_{mp} \times l \times 0.04 / V$$

3.6.1. Total cable length

$$D_{L,C} = P_T \times d_{L,C}$$

3.7. Type and Amount of inverters

3.7.1. Amount of micro inverters ($M_{i,m}$):

$$M_{i,m} = M_M$$

3.7.2. Amount of string inverters ($M_{i,s}$):

$$M_{i,s} = M_s$$

3.7.3. Total Power of string inverters ($P_{i,s}$):

$$P_{i,s} = P_s$$

3.7.4. Amount of central inverters ($M_{i,c}$):

$$M_{i,c} = 1$$

3.7.5. Total Power of central inverters ($P_{i,c}$):

$$P_{i,c} = P_T$$

3.8. Battery

3.8.1. Capacity of battery:

$$E_B = \left(n_{day} \times E_m\right) \times D_d$$

3.9. Total Area of PP

3.9.1. Area of modules (A_M):

$$A_m = (N_L \times D_1 + (N_L - 1) \times D_2) \times W_L$$

3.9.2. Area of Inverters (A_i):

3.9.2.1. Area required for central inverter ($A_{i,c}$):

$$A_{i,c} = W_{i,b} \times L_{i,b}$$

3.9.2.2. Total area required for string inverters ($A_{i,s}$):

$$A_{i,s} = (W_{i,b} \times L_{i,b}) \times N_i$$

3.9.3. Area required for transformer (A_t):

$$A_t = W_{t,b} \times L_{t,b}$$

3.9.4. Total area required for the system (A_T):

$$A_T = A_m + A_{fs} + A_b + A_i + A_t$$

4. Electricity Production (E):

4.1. Electricity Production of the system (E_T)

4.1.1. Cell Temperature ($\overline{T}_C$):

$$\overline{T}_c = \overline{H}_{t,i}\left(\frac{T_{c,NOCT}-20}{800}\right)+\overline{T}_a$$

4.1.2. Current at maximum power point ($\overline{I}_{mpp}$):

$$\overline{I}_{mpp} = \frac{\overline{H}_T}{\overline{H}_{T,ref}}\left(I_{mpp,ref}\times\mu_{I_{sc}}\left(\overline{T}_c - T_{c,ref}\right)\right)$$

4.1.3. Voltage at maximum power point ($\overline{V}_{mpp}$):

$$\overline{V}_{mpp} = V_{mpp,ref} + \mu_{V_{OC}}(\overline{T}_c - T_{c,ref})$$

4.1.4. Maximum power efficiency of the PV system (η_{mpp}):

$$\eta_{mpp} = \eta_{mpp,ref} + \mu_{\eta,mpp}(T_c - T_{c,ref}) \text{ and } \eta_{mpp} = \frac{I_{mpp}V_{mpp}}{A_c G_T}$$

4.1.5. Temperature coefficient of efficiency ($\mu_{\eta,mpp}$):

$$\mu_{\eta,mpp} = \eta_{mpp,ref}\frac{\mu_{Voc}}{V_{mpp}}$$

4.1.6. Monthly mean daily electricity production ($\overline{E}$):

$$\overline{E} = \eta_{mpp,ref}\left(1+\frac{\mu_{V_{oc}}(\overline{T}_c - T_{c,ref})}{V_{mpp,ref}+\mu_{V_{oc}}\left(\overline{T}_c - T_{c,ref}\right)}\right)\overline{H}_T A_C \ .$$

4.1.7. Annual Electricity production ($E_{T,a}$):

$$E_{T,a} = \sum_{i=1}^{12}\overline{E}_i \times n_i$$

4.2. Electricity Provided by the PV PP (net)

4.2.1. Inverter Loss

$$E_{out,i} = E_{in,i}\times\eta_i - E_{used,i}$$

$$L_i = \frac{E_{in,i}-E_{out,i}}{E_{in,i}}\times 100$$

4.2.2. Cabling Loss

$$E_{out,ACcable} = E_{in,ACcable}\times\eta_{AC,cable}$$

$$L_c = l_1 l_2 l_3 \rho I_{mpp}^2$$

4.2.3. Battery Loss

$$L_B = (1 - \eta_B)$$

4.2.4. Tracking system electricity consumption

$$L_{Tr} = EC_{Tr}$$

4.2.5. Total Loss

$$L_{total}\ (\%) = 100\left[1 - \prod_t 1 - \frac{L_t}{100}\right]$$

4.2.6. Annual Net Electricity Provided

$$E_{N,a} = E_{T,a} \times (1 - L_{total})$$

4.3. Lifetime electricity Production

$$E_T = E_{N,a} + \sum_{n=1}^{N} E_{N,a} \times (1 - d)^n$$

5. GHG Emission Reduction Potential:

5.1. Emission reduction potential of the system (ER_{CO_2}):

$$ER_{CO_2} = 0.6031\ tCO_2 / MWh \times E_T$$

5.2. Total revenue from emission reduction certificates (R_{CO_2}):

$$R_{CO_2} = ER_{CO_2} \times U_{CO_2} - C_{CO_2}$$

6. Solar Economics:

6.1. Costs

6.1.1. Rooftop system (up to 10 kW) permission cost ($C_{p,rooftop}$):

$$C_{p,rooftop} = U_1$$

6.1.2. Ground mounted system permission cost ($C_{p,ground}$):

$$C_{p,ground} = U_2$$

6.1.3. Cost of Modules (C_M):

$$C_M = U_M \times P_T$$

6.1.4. Cost of BoS Equipments (C_{BoS}):

$$C_{BoS} = C_w + C_i + C_e + C_r + C_t + C_h + C_l + C_c$$

6.1.5. Cost of BoS Equipments with Battery(C_{BoSwb}):

$$C_{BoSwB} = C_{BoS} + C_b + C_{cc} + C_{mppt}$$

6.1.6. Cost of Mounting Equipments (C_{ME}):

$C_{ME} = M_{ME} \times U_{ME}$

6.1.7. Cost of Inverters (C_i):

$C_{i,s} = M_{i,s} \times U_{i,s}$ (For string inverters)

$C_{i,m} = M_M \times U_{i,m}$ (For micro inverters)

$C_{i,c} = U_{i,c}$ (For central inverter)

6.1.8. Cost of Cables (C_w):

$C_w = U_w \times l_c$

6.1.9. Earthing Cost (C_e):

$C_e = U_e \times M_e$

6.1.10. Battery Cost (C_b):

$C_b = U_b \times M_b$

6.1.11. Cost of Charge Controller (C_{CC}):

$C_{cc} = U_{cc} \times M_{cc}$

6.1.12. Cost of MPPT (C_{mppt}):

$C_{mppt} = U_{mppt} \times M_{mppt}$

6.1.13. Cost of Remote Monitoring (C_{rm}):

$C_{rm} = U_{rm} \times M_{rm}$

6.1.14. Cost of Land Preperation (C_{lp}):

$C_{lp} = C_{tu} + C_{gr} + C_{rc}$

6.1.15. Cost of Grid Connection (C_{nc}):

$C_{nc} = C_{Cb} + C_t + C_{EP} + C_{Ex} + C_{Ser}$

6.1.16. Cost of Labor (C_{Lb}):

$C_{Lb} = (M_t \times U_{Lb}) \times M_{Lb}$

6.1.17. Smart Meter (C_{sm}):

$C_{sm} = A_{sm} \times U_{sm}$

6.1.18. Carbon Mechanism (C_{cm}):

$C_{CM} = C_{CO_2} - R_{CO_2}$

6.1.19. System Usage Cost (C_{su}):

$$C_{su} = \sum_{n=0}^{N} \frac{U_{su} \times E_n}{(1+r)^n}$$

6.1.20. Cost of Hedge (C_h):

$$C_h = L_h \times U_h$$

6.1.21. Security Cameras (C_{sc}):

$$C_{sc} = M_{sc} \times U_{sc}$$

6.1.22. Cost of Insurance (C_{Ins}):

$$C_{Ins} = \sum_{n=1}^{N} \frac{0.0025 \times C_I}{(1+d)^n}$$

6.1.23. Variable Cost (C_V):

$$C_V = \sum_{n=1}^{N} \frac{0.015 \times C_I}{(1+r)^n} + \frac{C_i}{(1+r)^{10}} + \sum_{n=1}^{N} \frac{0.0025 \times C_I}{(1+r)^n}$$

6.1.24. Variable cost with battery O&M (C_{Vwb}):

$$C_{Vwb} = \sum_{n=1}^{N} \frac{0.015 \times C_I}{(1+r)^n} + \frac{C_i}{(1+r)^{10}} + \sum_{n=1}^{N} \frac{0.0025 \times C_I}{(1+r)^n} + \frac{C_b}{(1+r)^{10}}$$

6.1.25. Variable cost with Transformer (C_{Vwtr}):

$$C_{Vwtr} = \sum_{n=1}^{N} \frac{0.0165 \times C_I \times r_{f-tr}}{(1+r)^n} + \frac{C_i}{(1+r)^{10}} + \sum_{n=1}^{N} \frac{0.0025 \times C_I \times r_{f-tr}}{(1+r)^n}$$

6.1.26. Total cost (C_T):

6.1.26.1. With own capital

$$C_T = C_I + \sum_{n=1}^{N} \frac{C_V}{(1+r)^n}$$

6.1.26.2. With tracking system

$$C_{T,tr} = r_{f-tr} \times C_T + \sum_{n=1}^{N} \frac{C_{VwTr}}{\left(1+r\right)^n}$$

6.1.26.3. With loan

$$C_T = pC_I + \sum_{n=1}^{N} \frac{C_V}{(1+r)^n} + \sum_{n=1}^{t} \frac{(1-p)(1+e)C_I}{t(1+r)^n}$$

6.1.26.4. Cost of PV PP with single-axis tracking

$$C_{T,tr} = r_{f-tr} \times C_T + \sum_{n=1}^{N} \frac{r_{f-tr} \times C_T \times 0.015}{(1+r)^n}$$

6.2. Economies of Scale

$$EoS = 1.167 \quad if \ 0 \le P \le 100$$

$$EoS = 1.167 - (0.104 \times (200 - P)/100) \quad if \ 100 < P \le 200$$

$$EoS = 1.063 - (0.046 \times (500 - P)/300) \quad if \ 200 < P \le 500$$

$$EoS = 1.017 - (0.017 \times (1000 - P)/500) \quad if \ 500 < P \le 1000$$

$$EoS = 0.793 + (0.207 \times (5000 - P)/4000) \quad if \ 1000 < P \le 5000$$

$$EoS = 0.724 + (0.069 \times (10000 - P)/5000) \quad if \ 5000 < P \le 10000$$

$$EoS = 0.644 + (0.080 \times (50000 - P)/40000) \quad if \ 10000 < P \le 50000$$

$$EoS = 0.592 + (0.052 \times (100000 - P)/50000) \quad if \ 50000 < P \le 100000$$

$$C_{T,EoS} = C_T \times EoS$$

6.3. Revenue:

6.3.1. Scenario 1

$$R_1 = \sum_{n=1}^{N} \frac{(0.133 \times E_n)}{(1+r)^n}$$

6.3.2. Scenario 2

6.3.2.1. Sub-scenario 2.1

$$R_{2.1} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(0.105 \times E_n)}{(1+r)^n}$$

6.3.2.2. Sub-scenario 2.2

$$R_{2.2} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(0.073 \times E_n)}{(1+r)^n}$$

6.3.2.3. Sub-scenario 2.3

$$R_{2.3} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(0.05 \times E_n)}{(1+r)^n}$$

6.3.2.4. Sub-scenario 2.4

$$R_{2.4} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(0.025 \times E_n)}{(1+r)^n}$$

6.3.3. Scenario 3

6.3.3.1. Sub-scenario 3.1

$$R_{3.1} = \sum_{n=1}^{5} \frac{(0.195 \times E_n)}{(1+r)^n} + \sum_{n=6}^{N} \frac{(0.133 \times E_n)}{(1+r)^n}$$

6.3.3.2. Sub-scenario 3.2

$$R_{3.2} = \sum_{n=1}^{5} \frac{(0.141 \times E_n)}{(1+r)^n} + \sum_{n=6}^{N} \frac{(0.133 \times E_n)}{(1+r)^n}$$

6.3.4. Scenario 4

6.3.4.1. Sub-scenario 4.1

$$R_{4.1} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \sum_{n=11}^{N} \frac{(U_{DAM} \times E_n)}{(1+r)^n}$$

6.3.4.2. Sub-scenario 4.2

$$R_{4.2} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \frac{U_{DAM} \times E_n}{(1+r)^{11}} + \sum_{n=12}^{N} \frac{U_{DAM} \times 1.01^n \times E_n}{(1+r)^n}$$

6.3.4.3. Sub-scenario 4.3

$$R_{4.3} = \sum_{n=1}^{10} \frac{(0.133 \times E_n)}{(1+r)^n} + \frac{U_{DAM} \times E_n}{(1+r)^{11}} + \sum_{n=12}^{N} \frac{U_{DAM} \times 0.99^n \times E_n}{(1+r)^n}$$

6.3.5. Scenario 5

6.3.5.1. Sub-scenario 5.1

$$R_{5.1} = \sum_{n=1}^{N} \frac{(U_{E,household} \times E_n)}{(1+r)^n}$$

6.3.5.2. Sub-scenario 5.2

$$R_{5.2} = \sum_{n=1}^{N} \frac{(U_{E,industry} \times E_n)}{(1+r)^n}$$

6.4. LCOE, LROE, NF, LPOE

6.4.1. LCOE:

$$LCOE = \left. C_I + \sum_{n=1}^{N} \frac{C_V}{\left(1+r\right)^n} \middle/ \sum_{n=1}^{N} \frac{E_n}{\left(1+r\right)^n} \right.$$

6.4.2. LROE:

$$LROE = {\sum_{n=1}^{N} \frac{R_n}{(1+r)^n}} \bigg/ {\sum_{n=1}^{N} \frac{E_n}{(1+r)^n}}$$

6.4.3. LPOE:

$$LPOE = LROE - LCOE$$

6.4.4. NFM:

$$NFM = {\sum_{n=1}^{N} \frac{R_n}{(1+r)^n}} \bigg/ {\sum_{n=1}^{N} \frac{C_n}{(1+r)^n}}$$

6.5. Extra Economical Parameters:

6.5.1. Internal Rate of Return (IRR):

$$C_I = \sum_{i=1}^{N} \frac{P_n}{(1+r)^n}$$

6.5.2. Maximum Contribution Fee:

$$C_{CF} = R_{NPV,15} - C_T$$

6.5.3. Willing to reduce electricity selling price:

$$U_{CF} = \frac{C_T}{E_{15}}$$

6.5.4. Electricity Key Performance Indicator (Annual electricity production per 1 $/TL/€ investment):

$$KPI_E = E_1 \big/ C_T$$

CURRICULUM VITAE

PERSONAL INFORMATION

Surname, Name: Karaveli, Abdullah Buğrahan
Nationality: Turkish (TC)
Date and Place of Birth: 27 April 1986, Ankara
Marital Status: Married
Phone: +90 532 510 73 54
Email: bugrahankaraveli@gmail.com, bugrahan.karaveli@metu.edu.tr

EDUCATION

Degree	**Institution**	**Year of Graduation**
MSc	METU Earth System Science	2014
BS	METU Environmental Engineering	2009
High School	Fethiye Kemal Mumcu Anadolu High School, Ankara	2004

WORK EXPERIENCE

Year	**Place**	**Enrollment**
2009-Present	Turkish Ministry of Science, Industry and Technology	European Union Expert
2016-2017	Turkish Ministry of Energy and Natural Resources (Temporary Duty)	European Union Expert

FOREIGN LANGUAGES

Advanced English, Intermediate Russian

PUBLICATIONS

1. Karaveli A.B., Akinoglu B.G. and Soytas U. “Development of new metrics for economic analysis of photovoltaic power plants and their application” Submitted to Energy Economics (2018)

2. Karaveli A.B., Soytas U. and Akinoglu B.G., “Measurement of economic feasibilities of PV power plants – Application to Turkey” Proc. of PVCon 2018: International Conference on Photovoltaic Science and Technologies

3. Karaveli A.B., Akinoglu B.G. and Ozden T., “Determining PV module performance and comparisons” International Conference on Photovoltaic Science and Technologies’ Proc. of PVCon 2018: International Conference on Photovoltaic Science and Technologies

4. Karaveli A.B., Akinoglu B.G. “Development of new monthly global and diffuse solar irradiation estimation methodologies and comparisons” International Journal of Green Energy. 15(5).333-346 (2018)

5. Karaveli A.B., Akinoglu B.G. “Comparisons and critical assessment of global and diffuse solar irradiation estimation methodologies” International Journal of Green Energy. 15(5).325-332 (2018)

6. Karaveli A.B., Soytas U. and Akinoglu B.G. “The Role of Legislations and Incentives in the Growth of a PV Market in a Developing Country”, Proc. of IRSEC 2017: International Renewable and Sustainable Energy Conference

7. Karaveli A.B., Akinoglu B.G. and Soytas U. “Economic Analysis of Photovoltaic Power Plants in Turkey”, Proc. of EU PVSEC 2017: European PV Solar Energy Conference and Exhibition

8. Ozden T., Karaveli A.B. and Akinoglu B.G., “Evaluation and comparisons of the models to calculate solar irradiation on an inclined solar panels for Ankara” Proc. of EU PVSEC 2017: European PV Solar Energy Conference and Exhibition

9. Karaveli A.B., Akinoglu B.G., “Comparison of quadratic and linear models on the estimation of diffuse solar radiation for a location in Turkey” Proc. of SEEP 2016: 9th Int. Conf. on Sustainable Energy and Environmental Protection

10. Karaveli A.B., Akinoglu B.G., “Estimation of diffuse component for two locations in Turkey” Proc of EuroSun 2016: Int. Conf. on Solar Energy for Buildings and Industry

11. Karaveli A.B., “Nuclear Energy and Turkey, specific to Mersin Akkuyu Nuclear Power Plant” (In Turkish), Journal of Energy and Diplomacy (2015)

12. Karaveli A.B., Soytas U. and Akinoglu B.G. “Comparison of large scale solar PV (photovoltaic) and nuclear power plant investments in an emerging market” Energy 84. 656-665 (2015)

13. Karaveli A. B., “Nuclear versus Solar Energy (NUKE vs. PV): The Comparison of their Economic Feasibilities and Environmental Aspects for Turkey” ODTÜ (METU) (2014)

14. Karaveli A.B., EU Sustainable Industry Policies and Turkey within the context of Sustainable Development (In Turkish), Ministry of Science, Industry and Technology (2012)

15. Karaveli A.B., “AB u Hava” (In Turkish) Divan (19) (2011)

AWARDS

METU Thesis of the Year Award – 2015