KULIAH SMARTGRID S2 TSE
SEBELUM MID SEMESTER 2025

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Direktur TREC FTUI 2014-2022

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TROPICAL RENEWABLE ENERGY CENTER FTUI

UNIVERSITAS INDONESIA

Veritas, Probitas, Iustitia

EST. 1849

PROGRAM STUDI

MAGISTER TEKNIK SISTEM ENERGI

FAKULTAS

TEKNIK

SEJARAH, VISI dan TREN

SMARTGRID

Mengapa harus berubah ?

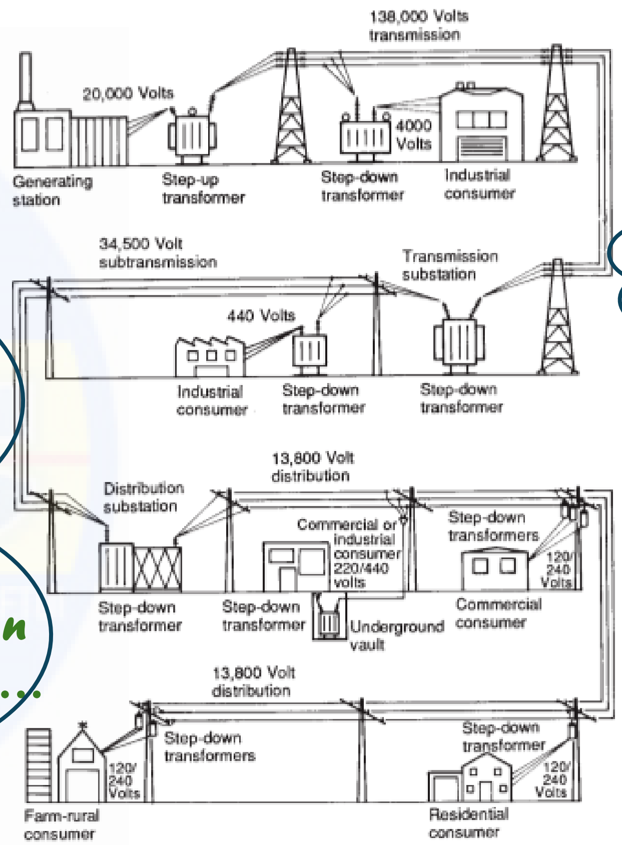


Figure 1-1. Typical electrical supply from generator to customer showing transformer applications and typical operating voltages.

Toh Harga minyak Lagi turun …

Energi terbarukan Intermitten lho …

Sudah stabil kok, Ngapain di utak utik..

Modal lagi …

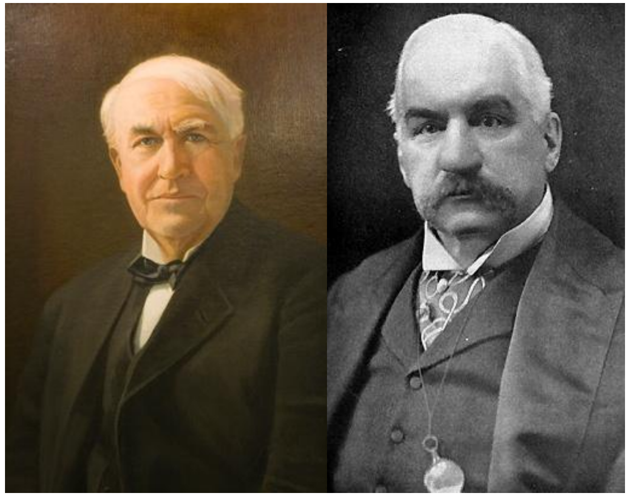
bla..bla..bla…

on September 4th,1882 at 3 p.m., in the Pearl Street Station NY, the 1st complete electricity grids DC system were operated by Edison. A 100-volt generator that burned coal to supply 400 lamps ,85 customers.

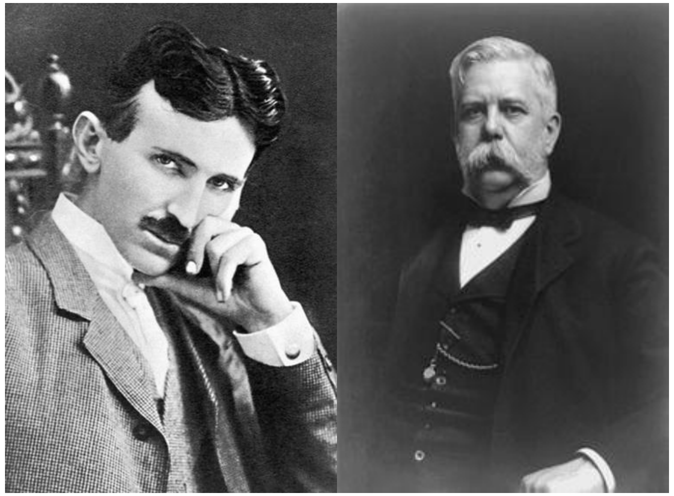
01

In 1884 that power station could energized 10,164 lamps 508 customers. Edison knew that…

02



Thomas A Edison and JP Morgan



Nicola Tesla & Westinghouse

03

1886 - Great Barrington, Massachusetts - the 1st full AC power system in the world was demonstrated using step up and step down transformers. The system was built by William Stanley and funded by Westinghouse.

04

1895 George Westinghouse opened the 1st major power plant in Niagara Falls using AC until 200 miles.

TREC
TROPICAL RENEWABLE ENERGY CENTER FTUI

Ilustrasi penulis

H I S T O R Y KETENAGALISTRIKAN

https://www3.uwsp.edu/cnr-ap/KEEP/Documents/AdHoc/TheWaroftheCurrents.pdf
https://www.priorylsst.co.uk/_site/data/files/lsst/2019-20%20jo%20oldham/FFED905AE2319AE9134BDE43A22BC100.pf

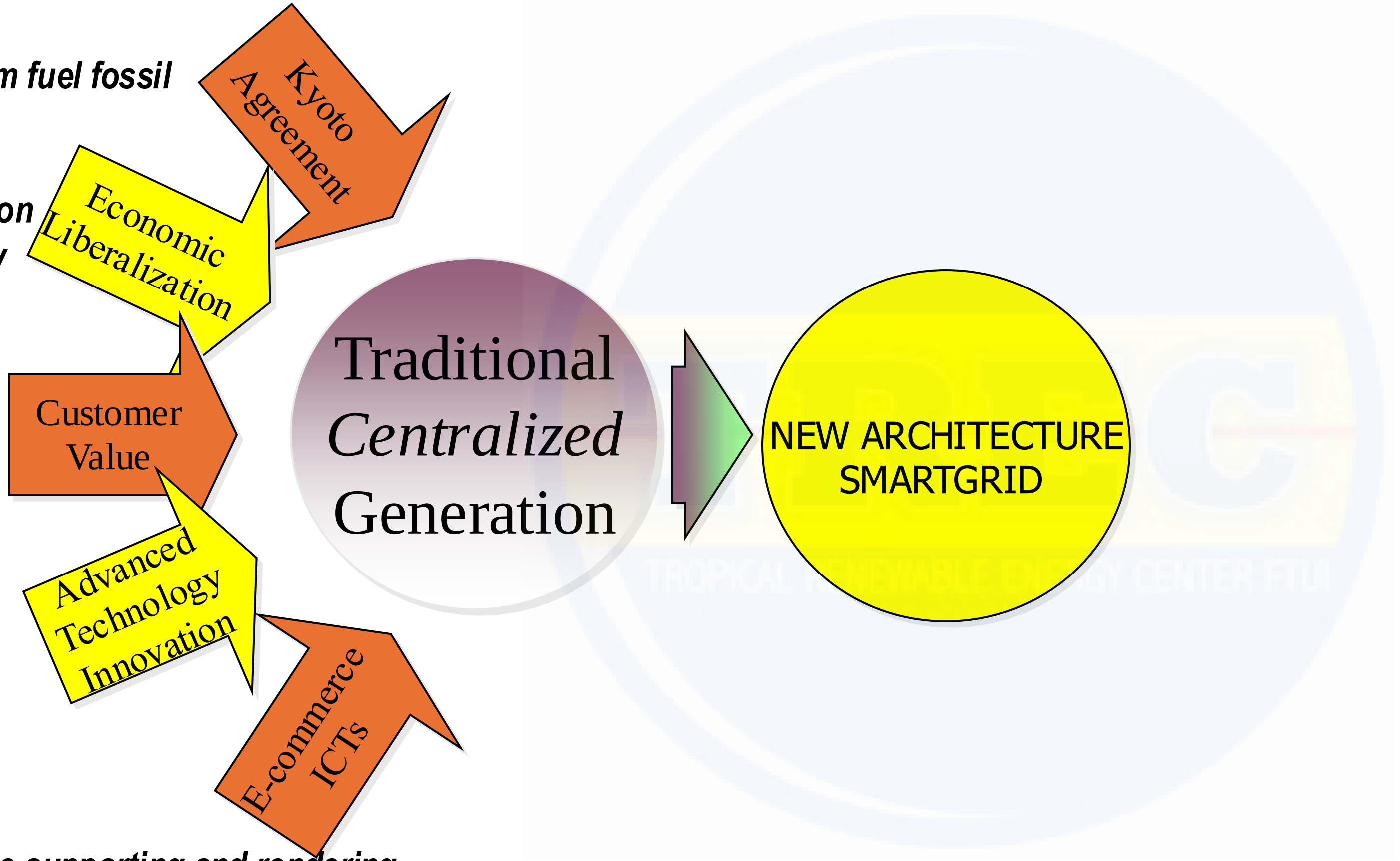
Background : Current situation „Electrical Power System“ in Europe (2006)

Reduce emission from fuel fossil

It had stimulated *competition and choice in electricity*

Highly Reliable,Power Quality
Black out in Europe, USA Terrorism
Security Issue

- Small generators ,Modular system, -Energy storage



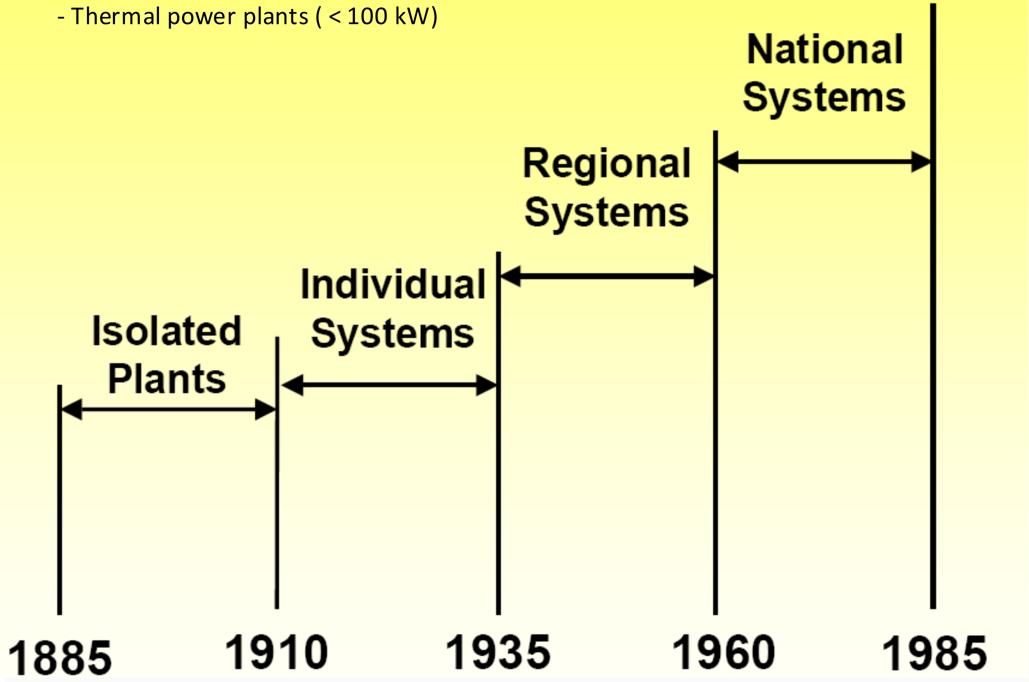
It will be supporting and rendering sophisticated operation of distribution networks

FIVE MASSIVE FORCES for Renew Europe's electricity networks → SMARTGRID

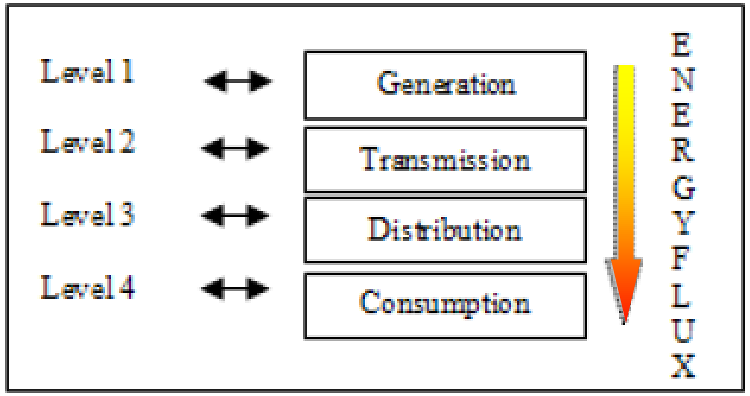
Sejarah pengembangan jaringan listrik/power grid

The development of the electric power grid

The first electric power systems (1870 -1885) were distributed !
- Small hydropower plants (< 100 kW)
- Thermal power plants (< 100 kW)



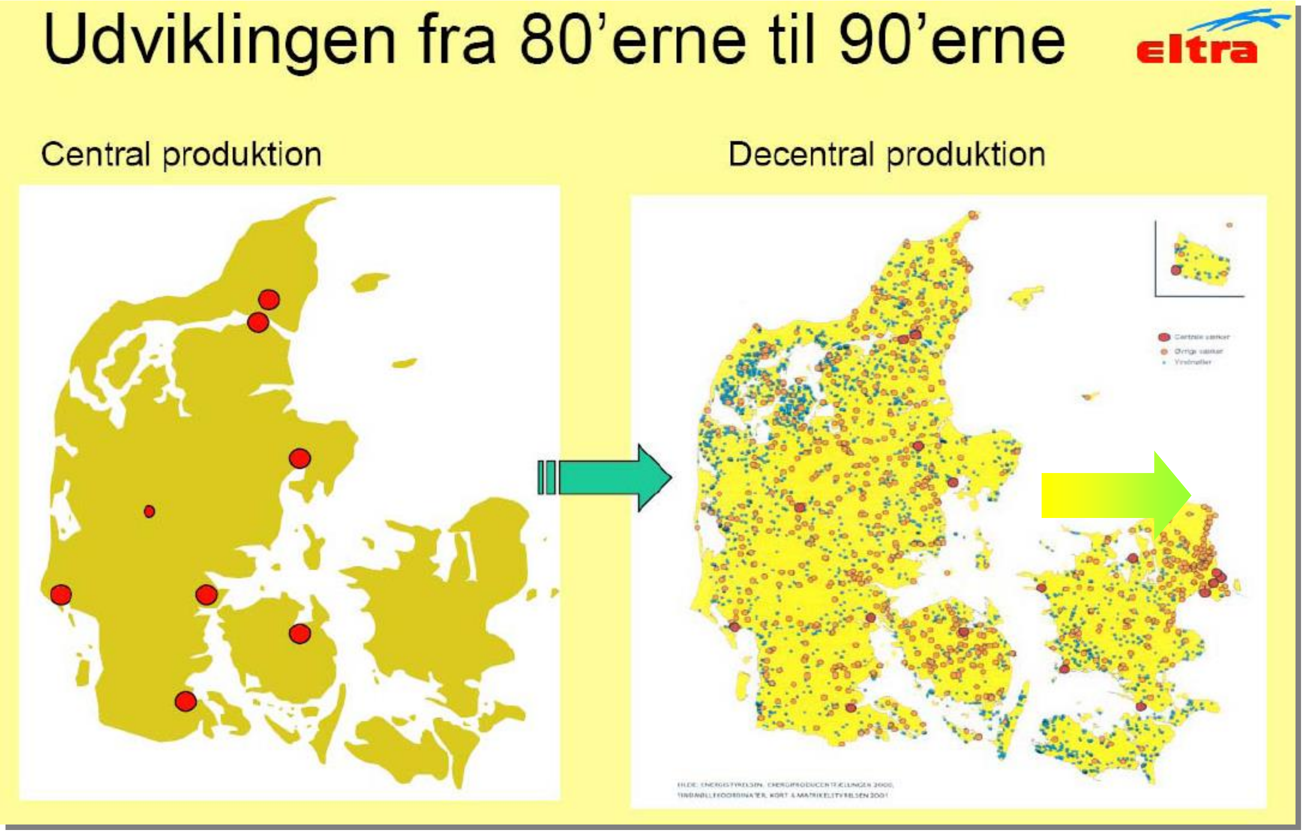
Taken from : Presentation Professor Göran Andersson ETH Zürich



M.Vignolo and R.Zeballos, "Transmission networks or distributed Generation ?"

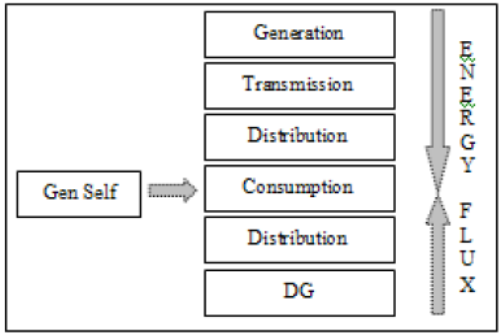
The traditional tasks of the power grid:
- Transmission of large power/energy quantities
- Optimisation of the operation
- Increase the reliability
- Make a power market possible

STRUKTUR ALURAN ENERGY CENTRALIZED



Kondisi KELISTRIKAN di Skandinavia era tahun 80-90-an

STRUKTUR ALURAN ENERGY SEJAK ADA DG



The <u>new tasks</u> of the power grid:
+ Optimisation of the operation
+ Increase the reliability
+ Make a power market possible
-Transmission of large power/energy quantities

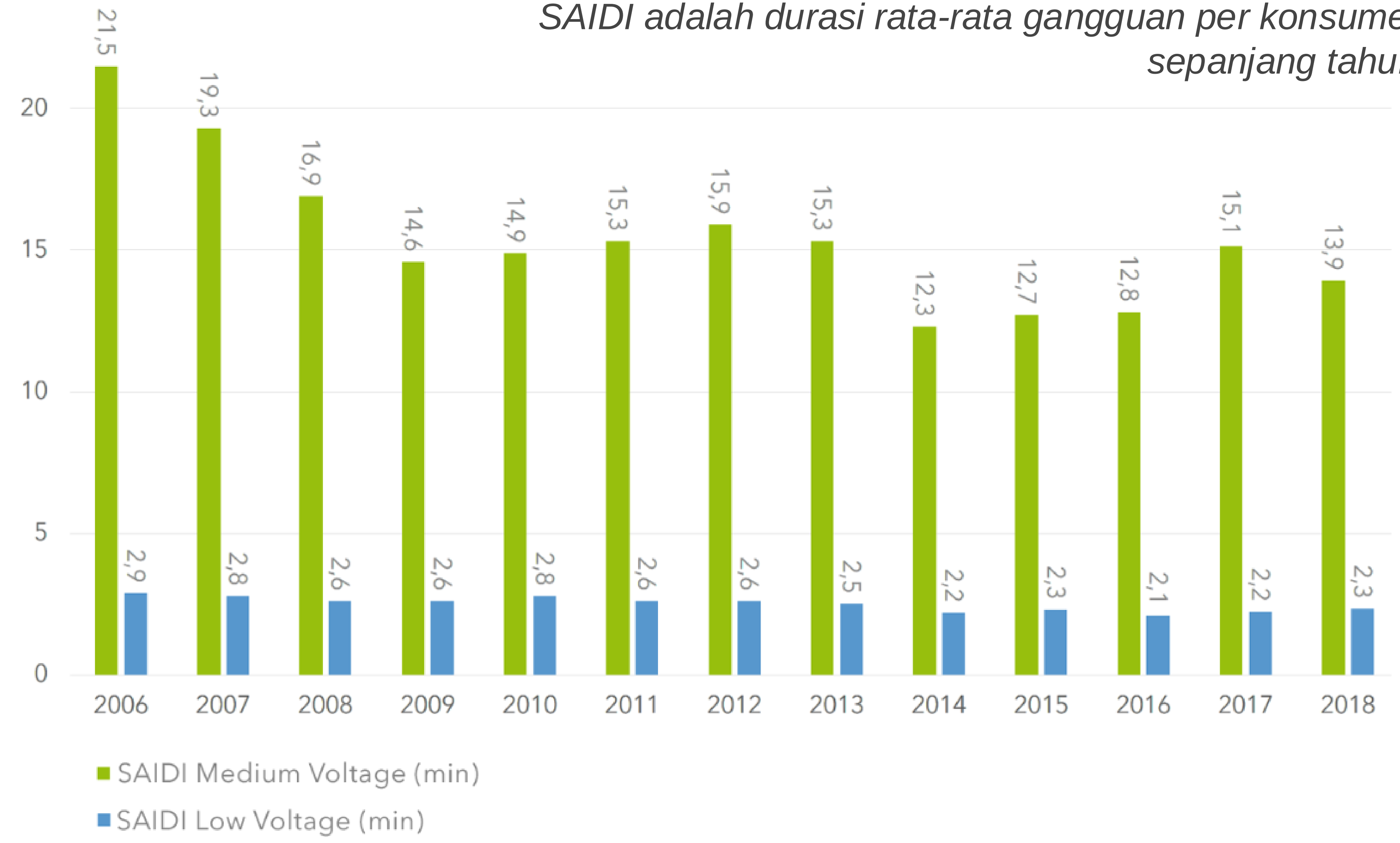
Paper berjudul : M.Vignolo and R.Zeballos, "Transmission networks or distributed Generation ?"

FENOMENA MENARIK

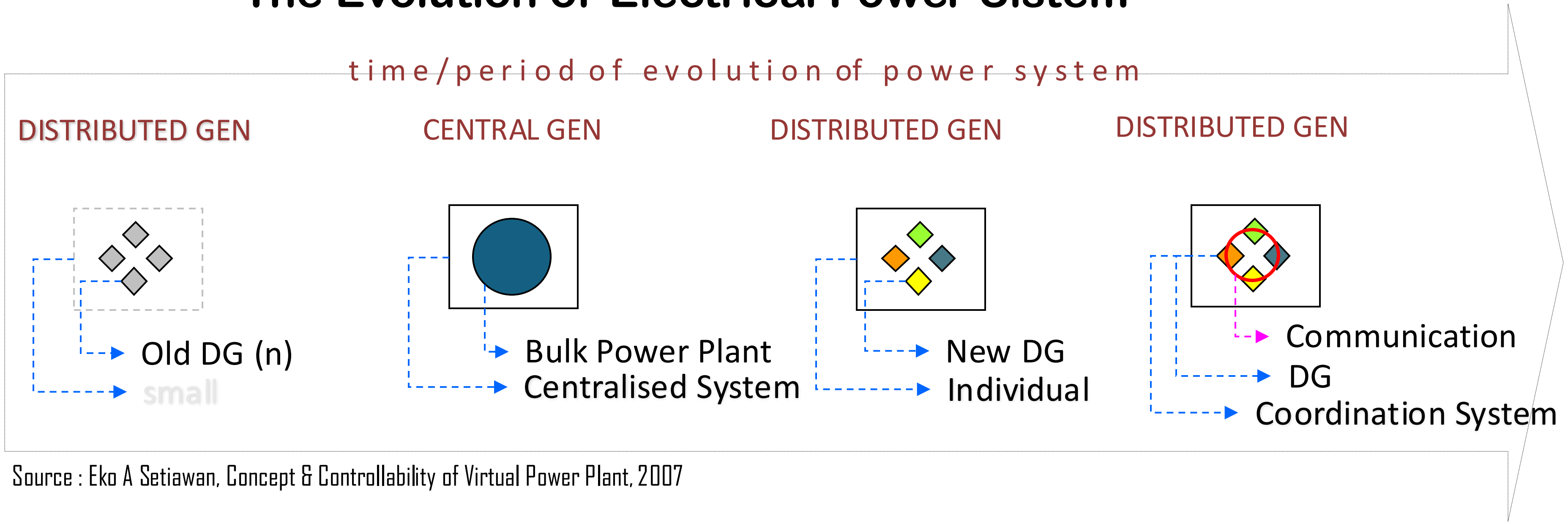
TREND INDEX SAIDI DI Jerman (System Average Interruption Duration Index), renewable energy dari angin dan solar PV justru indexnya relative menurun (artinya system makin stabil, durasi lama gangguan makin kecil)

SAIDI Germany 2006 - 2018

SAIDI adalah durasi rata-rata gangguan per konsumen sepanjang tahun.



The Evolution of Electrical Power Sistem



Source : Eko A Setiawan, Concept & Controllability of Virtual Power Plant, 2007

1881

-Small hydropower plants (< 100 kW)
-Thermal power plants (< 100 kW)
-A brush dynamo generator (DC)

≈1885 began the development of large scale power grids
-Introduction of three phase AC
-Large hydro power very competitive
-1891 ,1st Transmission 3P AC 25 kV; 1914, 70-150 kV

1941 Wind Turbine (1.25 MW)

1946 Solar cell (1849)

1954, 1st Nuclear Power Plant **1960,-1980** **2000 Microturbine, Bio diesel etc**

Karakteristik DG

1.Usually range of capacity
5 kW - 10 MW

2.Using renewable energy resources

3.Using fuel fossil
Resources (low emission)

4.Modular Electric Generation,
Near the consumers/load

5.Could interconnected with
Power Grid / Stand Alone Application

Fuel cell 5 kW Rumah Dual Power -UI,depok

https://www.youtube.com/watch?v=04gIKTBw7Ug&t=38s

table 2. distributed generation capabilities and system interfaces.

Technology	Typical Capability Ranges	Utility Interface
Solar, photovoltaic	A few W to several hundred kW	dc to ac converter
Wind	A few hundred W to a few MW	asynchronous generator
Geothermal	A few hundred kW to a few MW	synchronous generator
Ocean	A few hundred kW to a few MW	four-quadr. synchronous machine
ICE	A few hundred kW to tens of MW	synchr. generator or ac to ac converter
Combined cycle	A few tens of MW to several hundred MW	synchronous generator
Combustion turbine	A few MW to hundreds of MW	synchronous generator
Microturbines	A few tens of kW to a few MW	ac to ac converter
Fuel cells	A few tens of kW to a few tens of MW	dc to ac converter

30 kW microturbine.

https://www.researchgate.net/publication/3438152_Distributed_Generation_Semantic_Hype_or_the_Dawn_of_a_New_Era

European Technology Platform sebagai dasar peletakan VISI SMARTGRID di EROPA

NEW ARCHITECTURE SMARTGRID

- Untuk memenuhi permintaan listrik yang terus meningkat
- Memungkinkan tercipatanya pasar listrik Trans-Eropa dan membuat model bisnis baru kelistrikan
- Mengintegrasikan sumber daya yang berkelanjutan (termasuk sumber terbarukan)

The European Technology Platform (ETP) SmartGrids was set up in 2005 to create a joint vision for the European networks of 2020 and beyond. **The platform includes representatives from industry, transmission and distribution system operators, research bodies and regulators**. It has identified <u>clear objectives and proposes an ambitious strategy</u> to make a reality of this vision for the benefits of Europe and its electricity customers

Sumber : https://op.europa.eu/en/publication-detail/-/publication/a2ea8d86-7216-444d-8ef5-2d789fa890fc/language-en

Terkait VISI...

Europe's electricity markets and networks lie at the heart of our energy system and must evolve to meet the new challenges. The future trans-European grids must provide all consumers with a highly reliable, cost-effective power supply, fully exploiting the use of both large centralised generators and smaller distributed power sources throughout Europe.

- Visi jaringan listrik masa depan yang digulirkan oleh Advisory Council EU adalah sebuah platform teknologi → "SmartGrids“

- **Mengarah pada produk baru, proses dan layanan, dengan meningkatkan efisiensi industri dan penggunaan sumber daya energi bersih dengan memberikan keunggulan kompetitif bagi Eropa di pasar global.**

- Platform ini akan menjamin keamanan infrastruktur, membantu meningkatkan kehidupan masyarakat. Sehingga smart-grid menjadi elemen penting untuk mencapai ekonomi berbasis pengetahuan terbesar di dunia.

Karakteristik

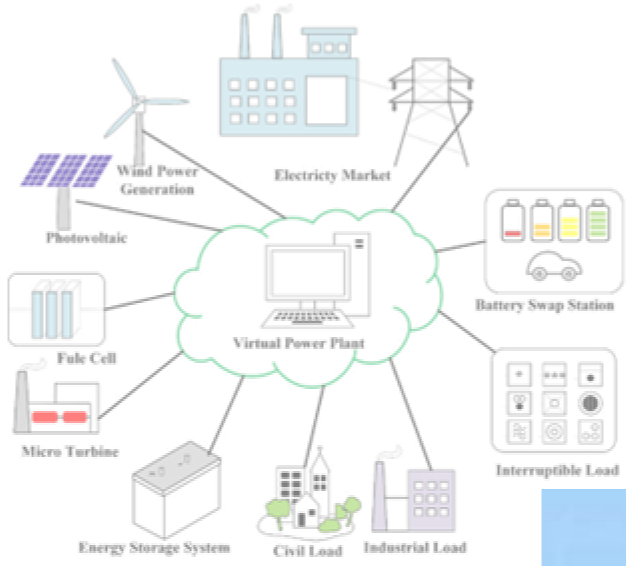
Visi SmartGrids bertumpu pada program penelitian, pengembangan, dan demonstrasi sehingga kedepannya jaringan listrik Eropa mempunyai karakteristik sbb:

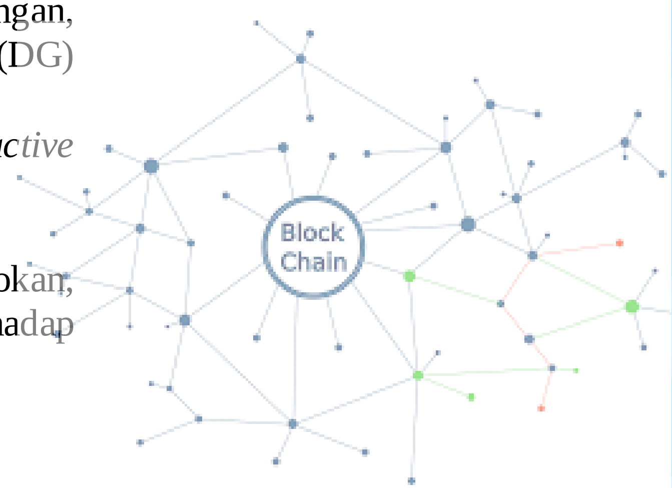
• **Fleksibel:** mampu memenuhi kebutuhan pelanggan sambil merespons perubahan dan tantangan ke depan;
(contoh pengmbangan microgrids, di TREC dikembangan nanogrids DC, P2P – peer to peer energy trading, dynamic response, dynamic price)

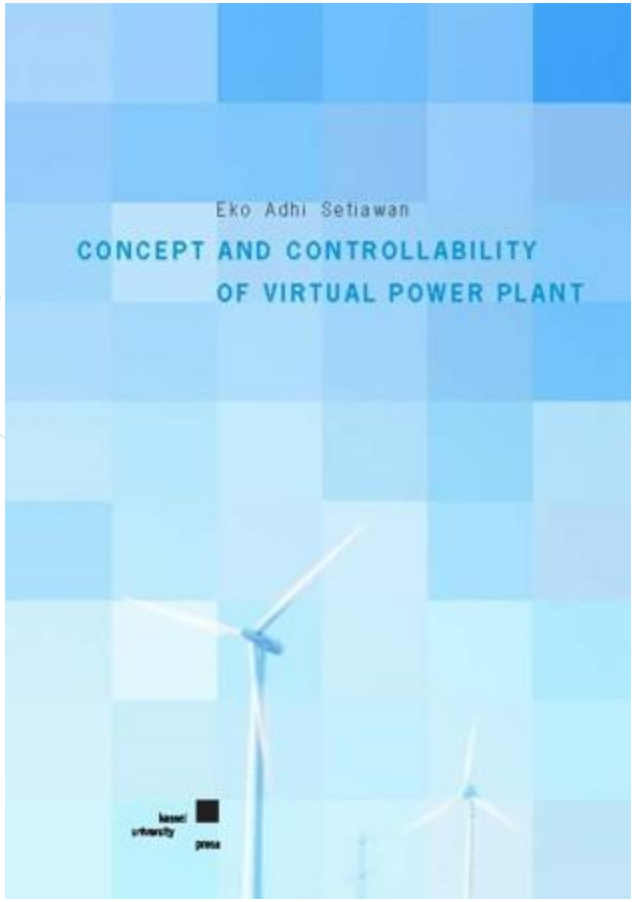
• **Dapat diakses:** memberikan akses koneksi ke semua pengguna jaringan, khususnya untuk sumber energi terbarukan dan pembangkit terdistribusi (DG) dengan efisiensi tinggi,emisi karbon rendah;
(contoh akan terjadi perubahan dari passive networks menjadi active networks)

• **Andal:** memastikan dan meningkatkan keamanan dan kualitas pasokan, konsisten dengan tuntutan era digital dengan ketahanan terhadap bahaya/ancaman dan ketidakpastian;
contoh teknologi ICT, block-chain, digital twin

• **Ekonomis:** memberikan nilai terbaik melalui inovasi, manajemen energi yang efisien dan kompetisi dan regulasi yang jelas
Contoh Pengembangan virtual power plant (VPP)







Making it happen

Enabling Europe's electricity grids to meet the challenges and opportunities of the 21st century and fulfil the expectations of society requires intensified and sustained research efforts. It is essential that this takes place in a coherent way addressing technical, commercial and regulatory factors, to minimise risk and allow business decisions to be made by companies in an environment of stability.

Key elements of the vision include:

- Creating a **toolbox of proven technical solutions** that can be deployed rapidly and cost-effectively, enabling existing grids to accept power injections from all energy resources;
- **Harmonising regulatory and commercial frameworks** in Europe to facilitate cross-border trading of both power and grid services, ensuring that they will accommodate a wide range of operating situations;
- Establishing **shared technical standards and protocols** that will ensure open access, enabling the deployment of equipment from any chosen manufacturer;
- Developing **information, computing and telecommunication systems** that enable businesses to utilise innovative service arrangements to improve their efficiency and enhance their services to customers;
- Ensuring the successful **interfacing of new and old designs** of grid equipment to ensure inter-operability of automation and control arrangements.

DO IT

Harapan...

Proyek-proyek yang dihasilkan dari visi SmartGrids akan merangsang inovasi dalam sistem jaringan dan teknologi informasi. Memberikan peluang kerja yang luas karena jaringan membutuhkan pekerja dengan keterampilan baru. SmartGrids akan membantu tercapainya pembangunan berkelanjutan dan di seluruh Eropa dengan sumber energi terbarukan yang berbeda2 namun saling melengkapi.

Pasar yang semakin liberal akan mendorong peluang perdagangan. Sistem smartgrid juga akan membentuk aliran informasi dua arah antara pemasok dan pengguna → listrik dan gas

[A Smart-Grid] → innovative products and services together with intelligent monitoring, control, communication to:

- Better facilitate the connection and operation of generators of all sizes and technologies;
- Allow consumers to play a part in optimizing the operation of the system;
- Provide consumers with greater information and choice of supply;
- Significantly reduce the environmental impact of the whole electricity supply system;
- Deliver enhanced levels of reliability and security of supply

SmartGrids is a new concept for electricity networks across Europe. The initiative responds to the rising challenges and opportunities, bringing benefits to all users, stakeholders and companies that perform efficiently and effectively.

Responding to needs

The electricity sector faces new challenges and opportunities which must be responded to in a vision of the future:

- **User-centric approach**: increased interest in electricity market opportunities, value added services, flexible demand for energy, lower prices, microgeneration opportunities;

- **Electricity networks renewal and innovation**: pursuing efficient asset management, increasing the degree of automation for better quality of service; using system wide remote control; applying efficient investments to solve infrastructure ageing;

SmartGrids' mission is to create a shared vision which:

- *enables Europe's electricity grids to meet the challenges and opportunities of the 21st century;*
- *fulfils the expectations of society;*
- *strengthens the European business context for the electricity sector and its international opportunities.*

- **Security of supply**: limited primary resources of traditional energy sources, flexible storage; need for higher reliability and quality; increase network and generation capacity;

- **Liberalised markets**: responding to the requirements and opportunities of liberalisation by developing and enabling both new products and new services; high demand flexibility and controlled price volatility, flexible and predictable tariffs; liquid markets for trading of energy and grid services;

- **Interoperability of European electricity networks**: supporting the implementation of the internal market; efficient management of cross border and transit network congestion; improving the long-distance transport and integration of renewable energy sources; strengthening European security of supply through enhanced transfer capabilities;

- **Distributed generation (DG) and renewable energy sources (RES)**: local energy management, losses and emissions reduction, integration within power networks;

- **Central generation**: renewal of the existing power-plants, development of efficiency improvements, increased flexibility towards the system services, integration with RES and DG;

- **Environmental issues**: reaching Kyoto Protocol targets; evaluate their impact on the electricity transits in Europe; reduce losses; increasing social responsibility and sustainability; optimising visual impact and land-use; reduce permission times for new infrastructure;

- **Demand response and demand side management (DSM)**: developing strategies for local demand modulation and load control by electronic metering and automatic meter management systems;

- **Politics and regulatory aspects**: continuing development and harmonisation of policies and regulatory frameworks in the European Union (EU) context;

- **Social and demographic aspects**: considering changed demand of an ageing society with increased comfort and quality of life.

SmartGrids is a necessary response to the environmental, social and political demands placed on energy supply.

SmartGrids will use revolutionary new technologies, products and services to create a strongly user-centric approach for all customers.

- The resulting six SmartGrids deployment priorities were then defined:

SmartGrids Deployment Priorities

- Deployment Priority #1: **Optimizing Grid Operation and Use**
- Deployment Priority #2: **Optimizing Grid Infrastructure**
- Deployment Priority #3: **Integrating Large Scale Intermittent Generation**
- Deployment Priority #4: **Information & Communication Technology**
- Deployment Priority #5: **Active Distribution Networks**
- Deployment Priority #6: **New Market Places, Users & Energy Efficiency**

In short, the approach adopted for the development of the generic deployment priorities takes full account of the complexity of SmartGrids, creates a robust strategic deployment framework, providing at the same time a precise scope, sharp focus and effective progress monitoring for the subsequent practical deployment.

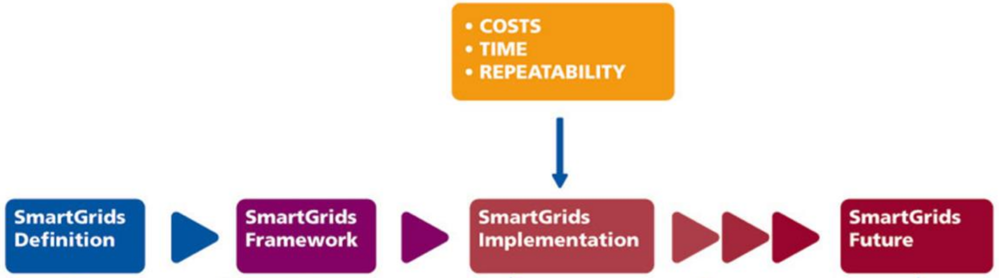
To reflect the real world needs, a time-line is used to indicate when each particular deployment step needs to be completed or commenced, if the required outcomes are to be realized. The milestones of the time-line, building upon the defined EU targets are shown in Figure 1 below.

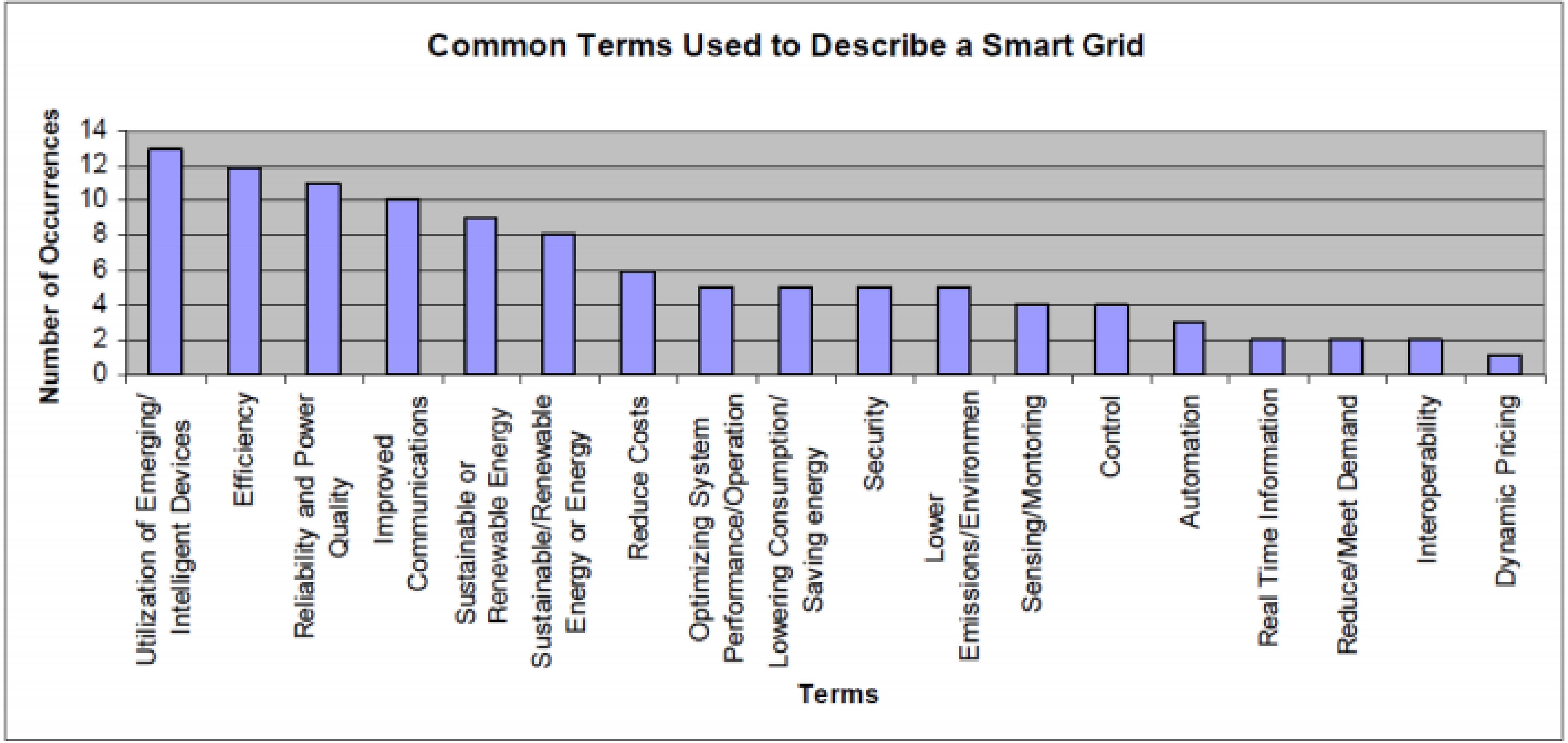
Figure 1: Timeline for SmartGrids deployment

reference

EUROPEAN COMMISSION

Directorate-General for Research
Directorate J – Energy
Unit 2 – Energy Production and Distribution Systems
Contact: Manuel Sánchez-Jiménez
E-mail: rtd-energy@cec.eu.int
Internet: http://europa.eu.int/comm/research/energy





Common Terms Used to Describe a Smart Grid
Number of Occurrences
14
12
10
8
6
4
2
0
Utilization of Emerging/ Intelligent Devices
Efficiency
Reliability and Power Quality
Improved Communications
Sustainable or Renewable Energy
Sustainable/Renewable Energy or Energy
Reduce Costs
Optimizing System Performance/Operation
Lowering Consumption/ Saving energy
Security
Lower Emissions/Environmen
Sensing/Montoring
Control
Automation
Real Time Information
Reduce/Meet Demand
Interoperability
Dynamic Pricing
Terms

European Union Technology Platform (ETP) mendefinisikan *smart grid* sebagai sebuah jaringan listrik yang secara cerdas mengintegrasikan semua aksi pengguna yang terhubung dengan jaringan tersebut -yakni produsen, konsumen, ataupun yang bertindak sebagai produsen sekaligus konsumen- sehingga diperoleh suplai listrik yang efisien, berkesinambungan, aman dan ekonomis.[2]

U.S. Departement of Energy (DoE) mendefinisikan *smart grid* sebagai jaringan yang menggunakan teknologi digital untuk meningkatkan kehandalan, keamanan, dan efisiensi (ekonomi dan energi) sistem listrik dari mulai pembangkit besar sampai konsumen termasuk sistem pembangkitan terdistribusi dan penyimpanan energi.[3]

International Energy Agency (IEA) mendefinisikan *smart grid* sebagai jaringan listrik yang menggunakan teknologi canggih dan digital untuk memantau dan mengelola transportasi listrik dari semua sumber pembangkit sehingga dapat memenuhi berbagai variasi kebutuhan listrik pengguna akhir.[4]

DISTRIBUTED GENERATION

SMARTGRID

ELSEVIER

Electric Power Systems Research 57 (2001) 195–204

ELECTRIC POWER SYSTEMS RESEARCH

www.elsevier.com/locate/epsr

reference

Distributed generation: a definition

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Abstract

Distributed generation (DG) is expected to become more important in the future generation system. The current literature, however, does not use a consistent definition of DG. This paper discusses the relevant issues and aims at providing a general definition for distributed power generation in competitive electricity markets. In general, DG can be defined as electric power generation within distribution networks or on the customer side of the network. In addition, the terms distributed resources, distributed capacity and distributed utility are discussed. Network and connection issues of distributed generation are presented, too.

Due to the large variations in the definitions used in the literature, the following different issues have to be discussed to define distributed generation more precisely:

A. the purpose;
B. the location;
C. the rating of distributed generation;
D. the power delivery area;
E. the technology;
F. the environmental impact;
G. the mode of operation;
H. the ownership, and
I. the penetration of distributed generation.

In the literature, a large number of terms and definitions is used in relation to distributed generation.

For example, Anglo-American countries often use the term 'embedded generation', North American countries the term 'dispersed generation', and in Europe and parts of Asia, the term 'decentralised generation' is applied for the same type of generation.

In addition, in regards to the rating of distributed generation power units, the following different definitions are currently used:

1. The *Electric Power Research Institute* defines distributed generation as generation from 'a few kilowatts up to 50 MW' [4];
2. According to the *Gas Research Institute*, distributed generation is 'typically [between] 25 and 25 MW' [5];
3. Preston and Rastler define the size as 'ranging from a few kilowatts to over 100 MW' [3];
4. Cardell defines distributed generation as generation 'between 500 kW and 1 MW' [6];

2.2. Location

The definition of the location of the distributed generation plants varies among different authors. Most authors define the location of DG at the distribution side of the network, some authors also include the customers side, and some even include the transmission side of the network [3]. We think that the following definition is appropriate:

Definition B1. *The location of distributed generation is defined as the installation and operation of electric power generation units connected directly to the distribution network or connected to the network on the customer site of the meter.*

2.3. Rating of distributed generation

The maximum possible rating of the distributed generation source is often used within the definition of distributed generation in the literature (see beginning of Section 2). Our definition, however, does not include any information regarding the rating of the distributed generation source.

Definition C1. *The rating of the DG power source is not relevant for our proposed definition.*

The motivation for this approach is that:

1. the rating is 'not critical to the definition of what constitutes distributed generation' [3];
2. the maximum rating that can be connected to a distribution system depends on the capacity of the distribution system, which is correlated to the voltage level within the distribution system. The technical design of each distribution system is unique, therefore, no general definition of the maximum generation capacity that can be connected to a distribution system can be given.

The technical issues related to distributed generation, however, can vary significantly with the rating. Therefore, it is appropriate to introduce categories of distributed generation. We suggest the following distinction for these categories:

Micro	distributed generation: ~ 1 Watt < 5 kW;
Small	distributed generation: 5 kW $<$ 5 MW;
Medium	distributed generation: 5 MW $<$ 50 MW;
Large	distributed generation: 50 MW $< \sim 300$ MW.

Some authors define generation between 1 kW and 1 MW as dispersed generation. However, this definition is not used consistently in the literature and should therefore not be applied in this way.

2.4. Power delivery area

Some authors also define the power delivery area, e.g. all power generated by DG is used within the distribution network. In certain circumstances, defining the power delivery area is not very helpful, as the following example illustrates:

The New Zealand utility *Wairarapa Electricity* operated a 3.5 MW wind farm within its 11/33 kV southern distribution network (the wind farm is now owned by the *Electricity Cooperation of New Zealand*). The produced energy is almost totally used within its own network, however, during nights with very low demand and high wind speeds the wind farm actually exports energy back into the transmission system [12].

A definition of the area of power delivery restricted to the distribution network would disqualify this project as distributed generation, despite the fact that it is a very typical DG project. Furthermore, any restriction of the power delivery areas in the definition of DG would result in complex analyses of the power flow in the distribution network. Therefore:

Definition D1. *The area of the power delivery is not relevant for our proposed definition of DG.*

2.5. Technology

Often the term distributed generation is used in combination with a certain generation technology category, e.g. renewable energy technology. According to our definition, however, the technology that can be used is not limited.

Definition E1. *The technology used for DG is not relevant for the here proposed definition.*

Table 1
Technologies for distributed generation[a]

Technology	Typical available size per modul
Combined cycle gas T.	35–400 MW
Internal combustion engines	5 kW–10 MW
Combustion turbine	1–250 MW
Micro-Turbines	35 kW–1 MW
Renewable	
Small hydro	1–100 MW
Micro hydro	25 kW–1 MW
Wind turbine	200 Watt–3 MW
Photovoltaic arrays	20 Watt–100 kW
Solar thermal, central receiver	1–10 MW
Solar thermal, Lutz system	10–80 MW
Biomass, e.g. based on gasification	100 kW–20 MW
Fuel cells, phosacid	200 kW–2 MW
Fuel cells, molten carbonate	250 kW–2 MW
Fuel cells, proton exchange	1 kW–250 kW
Fuel cells, solid oxide	250 kW–5 MW
Geothermal	5–100 MW
Ocean energy	100 kW–1 MW
Stirling engine	2–10 kW
Battery storage	500 kW–5 MW

[a] Source: Linden et al. [19], IEA [20], p. 64, Duffie et al. [21], pp. 638 and author.

2.6. Environmental impact

Often DG technologies are described as more environmentally friendly than centralised generation. According to our definition, however, the environmental impact of the DG technology is not relevant.

Definition F1. *The environmental impact of DG is not relevant for the here proposed definition.*

The motivation for this approach is that the analysis of the environment impact is too complex, to be included in the here proposed definition.

Table 2
Comparison of energy amortisation time and emissions of various energy technologies

Technology	Energy pay back time in months[a]	SO_2 in kg/GWh[a]	NO_x in kg/GWh[a]	CO_2 in t/GWh[a]	CO_2 and CO_2 equivalent for methane in t/GWh[b]
Coal fired (pit)	1.0–1.1	630–1370	630–1560	830–920	1240
Nuclear	N.A	N.A.	N.A.	N.A	28–54
Gas (CCGT)	0.4	45–140	650–810	370–420	450
Large hydro	5–6	18–21	34–40	7–8	5
Renewable distributed generation technologies					
Micohydro	9–11	38–46	71–86	16–20	N.A.
Smallhydro	8–9	24–29	46–56	10–12	2
Windturbine					
4.5 m/s	6–20	18–32	26–43	19–34	N.A.
5.5 m/s	4–13	13–20	18–27	13–22	N.A.
6.5 m/s	2–8	10–16	14–22	10–17	11
Photovoltaic					
Mono-cystalline	72–93	230–295	270–340	200–260	N.A.
Multi–cystalline	58–74	260–330	250–310	190–250	228
Amorphous	51–66	135–175	160–200	170–220	N.A.
Geothermal	N.A.	N.A.	N.A.	N.A	50–70
Tidal	N.A.	N.A.	N.A.	N.A	2

[a] *Source:* Kaltschmitt et al. [22].
[b] *Source:* Lewin [23], Fritsch et al. [24], also Ackermann [25]; All figures include direct and indirect emissions based on average German energy mix, technology efficiency, solar radiation and typical lifetime.

2.8. Ownership

It is frequently argued that DG has to be owned by independent power producers or by the customers themselves, to qualify as DG. According to our definition, however, the ownership is not relevant.

Definition H1. *The ownership of DG is not relevant for the here proposed definition.*

The motivation for this approach is based on different international experiences regarding the ownership of distributed generation. In Sweden, for example independent generators as well as traditional generators are involved in DG.

2.7. Mode of operation

The issue of the mode of operation is based on the wide-spread view that DG is 'relatively unencumbered by the rules of operation of central systems (scheduling, pool pricing, dispatch, etc.)' [3].

According to our definition, however, the mode of operation is not relevant.

Definition G1. *The mode of operation of distributed power generation is not relevant for the here proposed definition.*

The motivation for this approach is based on large variations in the international regulations regarding the operation of electricity network.

Taking the English and Welsh regulations as an example, a power unit connected to the distribution system with a capacity of more than 100 MW would be treated by the market regulations as a centralised power unit, but a unit with less than 100 MW would be less encumbered in the rules of operation [7].

Therefore, it cannot be assumed in general that distributed generation is relatively unencumbered by the rules of operation.

In situations, however, where distributed generation receives a special treatment by the regulations, this can be specially mentioned, for example: *not centrally dispatched distributed generation.*

2.9. Penetration of distributed generation

Regarding the total amount of DG within a distribution network, some authors assume that DG stands for completely decentralised power generation, that does not require any transmission lines or large centralised power plants [17]. Other authors assume that distributed generation will be able to provide only a fraction of the local energy demand.

According to our definition, however, the penetration level of DG is not relevant.

Definition I1. *The penetration level of DG is not relevant for the here proposed definition.*

Table 1

Nation	Distribution in use	Voltage (V)	Frequency (Hz)
Afghanistan, Albania, Andorra, Angola, Argentina, Armenia, Azerbaijan, Azores, Benin, Belarus, Bosnia Herzegovina, Burkina Faso, Burundi, Cape Verde, Chad, Chile, China, Comoros, Congo-Kinshasa, Egypt, Ethiopia, Gabon, Djibouti , Greenland, Guinea, Guinea Bissau, French Guiana, Hong Kong, Faroe Islands, Kazakhstan, Kyrgyzstan, Lesotho, Macao, Macedonia, Mali, Martinique, Moldova, Mozambique, Niger, New Caledonia, Central African Republic, Reunion, Russia, Serbia and Montenegro , Syria, Tajikistan, Thailand, Turkmenistan, Ukraine, Uzbekistan, Zimbabwe	S	220	50
Algeria, Austria, Bahrain, Belgium, Bhutan, Botswana, Bulgaria, Cameroon, Vatican City, Congo-Brazzaville, Ivory Coast, Croatia, Denmark, Dominica, United Arab Emirates, Eritrea, Estonia, Finland, France, Gambia, Gaza (Gaza Strip), Germany, Ghana, Greece, Grenada, India, Indonesia, Iran, Iraq, Ireland, Northern Ireland (United Kingdom), Iceland, Channel Islands, Israel, Italy, Laos, Libya, Liechtenstein, Lithuania, Luxembourg, Malawi, Maldives, Malaysia, Mauritius, Monaco, Mongolia, Namibia, Norway, New Zealand, Holland, Pakistan, Poland, Portugal, Czech Republic, Romania, Rwanda, Saint Vincent and the Grenadines (Winward Is.), Samoa, Sierra Leone , Singapore, Slovakia, Slovenia, Spain, Sri Lanka, Sudan, South Africa, Sweden, Switzerland, Swaziland, Tanzania, Tunisia, Turkey, Hungary, Yemen, Zambia	S	230/400	50
Netherlands Antilles, Cameroon, France, Indonesia, Canary Islands (Spain), Balearic Islands, Italy, Libia, Madagascar, Morocco, Principality of Monaco, Senegal, Spain, Tunisia, Vietnam.	S	127/220	50
Australia, Brunei, Cyprus, Fiji, Gibraltar, Isle of Man, Cook Islands, Channel Islands, Falkland Islands, Kenya, Kuwait, Malaysia, Malta, Nauru, Nigeria, Oman, Papua New Guinea, Qatar, United Kingdom, Saint Lucia, Tonga, Uganda	S	240/415	50
Bangladesh	S	220/400	50
Barbados	S	115/200	50
Netherlands Antilles, Bolivia, Cambodia, Cameroon, United Arab Emirates, Balearic Islands, France, Jordan, Guadalupe, India, Canary Islands, Lebanon, Madagascar, Madeira (Portugal), Morocco, Namibia, Paraguay, Somalia, South Africa, Togo, Vietnam	S	220/380	50
North Korea, Jamaica, Togo	D	110/220	50
Cambodia	S	120/208	50
Barbados	D	115/230	50
Equatorial Guinea, Latvia, Mauritania, Myammar Burma, Timor-est, Uruguay	M	220	50
Kiribati	-	240	50
Lebanon	S	110/190	50
United Kingdom	D	240/480	50
Nepal	S	230/460	50
Madeira (Portugal), Somalia	D	220/440	50
Somalia, Panama, Perù	D	110/220	50
India	D	250/500	50
Seychelles	T	240	50
Japan	D	100/200	50/60

Definition 1. *Distributed generation is an electric power source connected directly to the distribution network or on the customer site of the meter.*

The distinction between distribution and transmission networks is based on the legal definition. In most competitive markets, the legal definition for transmission networks is usually part of the electricity market regulation. Anything that is not defined as transmission network in the legislation, can be regarded as distribution network.

The definition of distributed generation does not define the rating of the generation source, as the maximum rating depends on the local distribution network conditions, e.g. voltage level. It is, however, useful to introduce categories of different ratings of distributed generation. The following categories are suggested:

Micro	distributed generation: ~ 1 Watt < 5 kW;
Small	distributed generation: 5 kW < 5 MW;
Medium	distributed generation: 5 MW < 50 MW;
Large	distributed generation: 50 MW < 300 MW

Table 1: Typical distribution network voltage levels used by some of the European countries

Countries	Typical voltage levels used
UK	132 / 33 / 11 / 0.4 (kV)
Germany	110 / 20 / 0.4 (kV)
France	225 / 20 / 0.4 (kV)
Finland	110 / 20 / 0.4 (kV)
Greece	150 / 20 / 0.4 (kV)

ETH zürich Research Collection

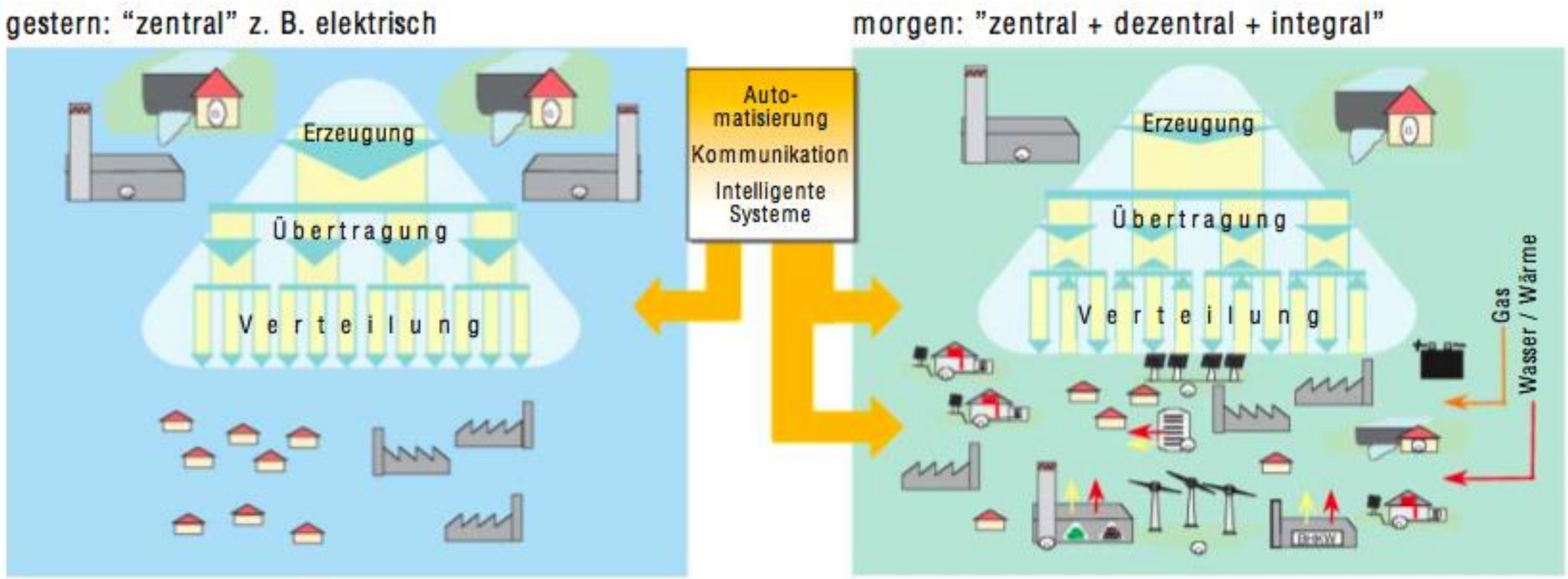
Report

Distributed generation
literature review and outline of the Swiss situation

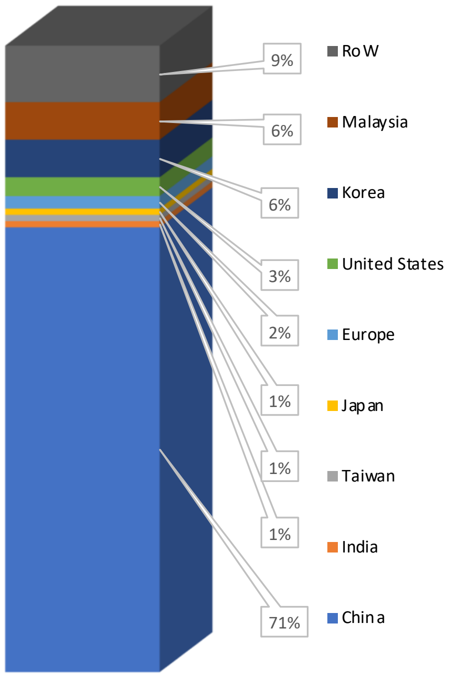
Author(s):
Koeppel, Gaudenz

Reference (SANGAT DIANJURKAN UNTUK DI DOWNLOAD)
https://www.research-collection.ethz.ch/bitstream/handle/20.500.11850/147712/eth-26771-01.pdf

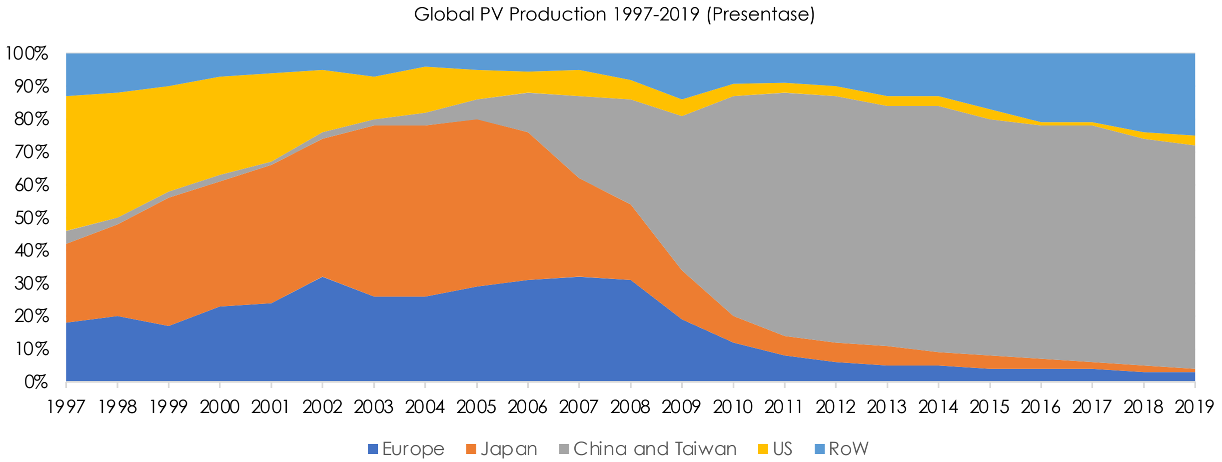
SISTEM KELISTRIKAN KEMARIN (gestern) dan BESOK (morgen)

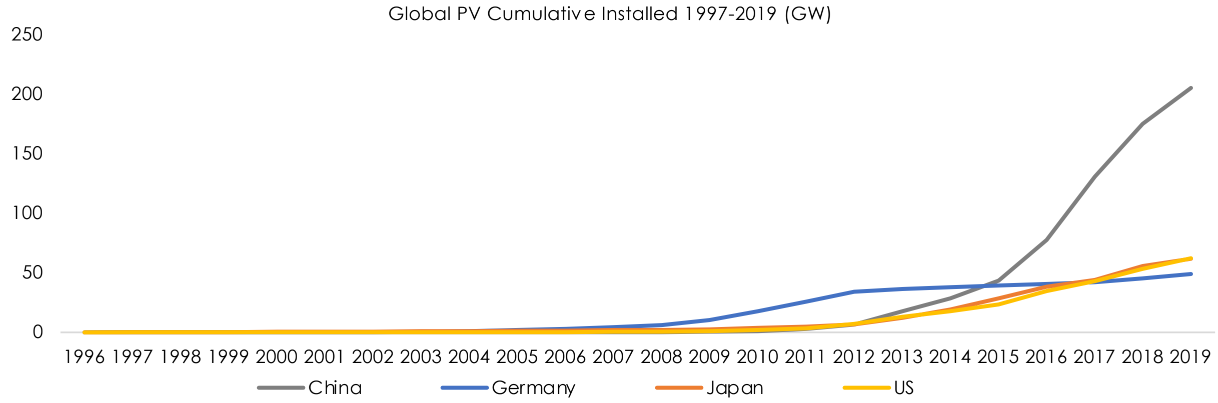


Dr. Rainer Bitsch •Technische Anforderungen an dezentrale Versorgungsstrukturen in Europa,2001



PV Global Market Distribution of Total 115 GW in 2019

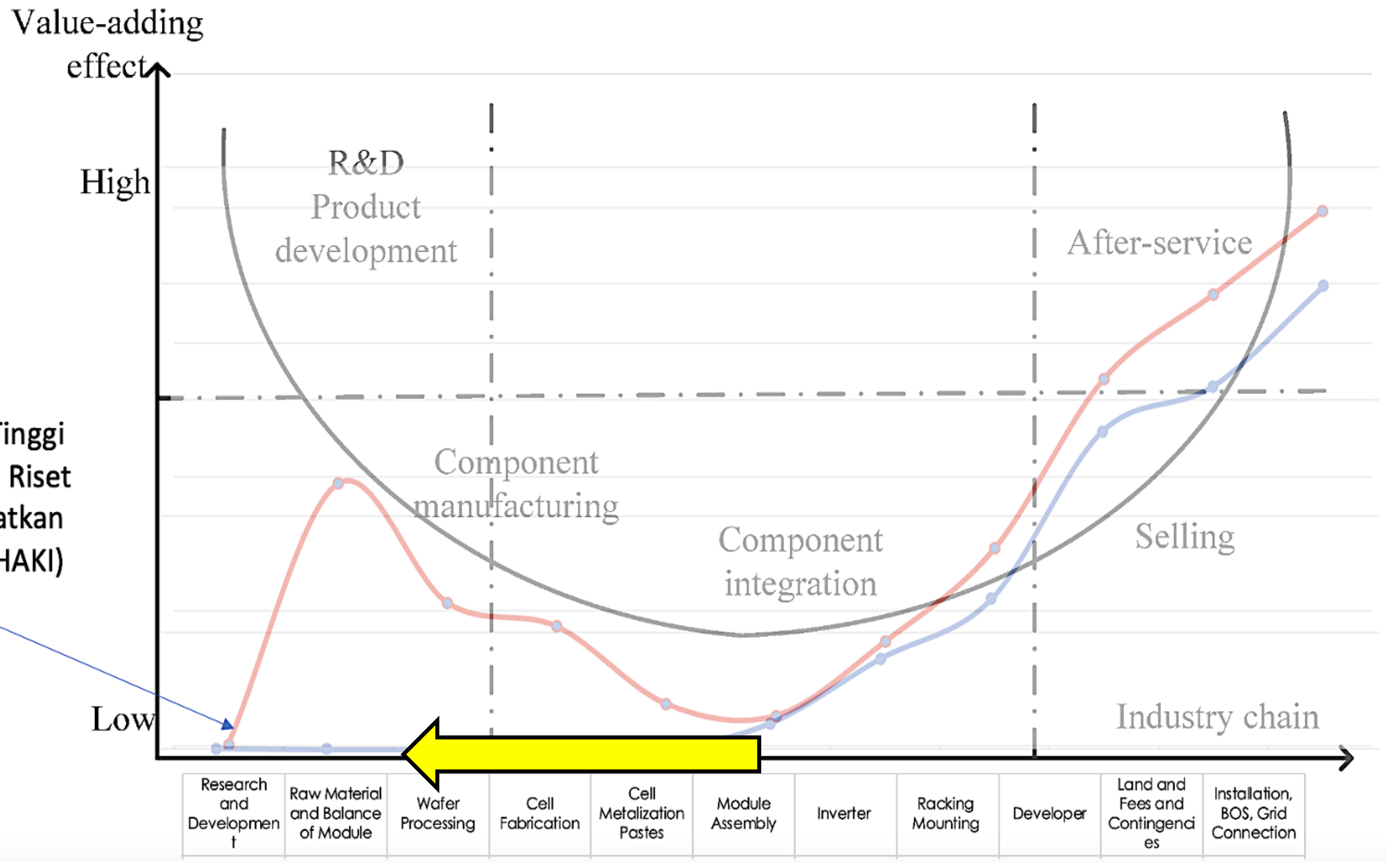




Source: BP Statistical , International Energy Agency Photovoltaics Power Systems Programme, HIS Markit, ISE Fraunhofer, and further processed.

SMILING CURVE dari SOLAR PV di INDONESIA
Ilustrasi dari penulis

Peran Perguruan Tinggi dan Lembaga Riset Meningkatkan Paten (HAKI)



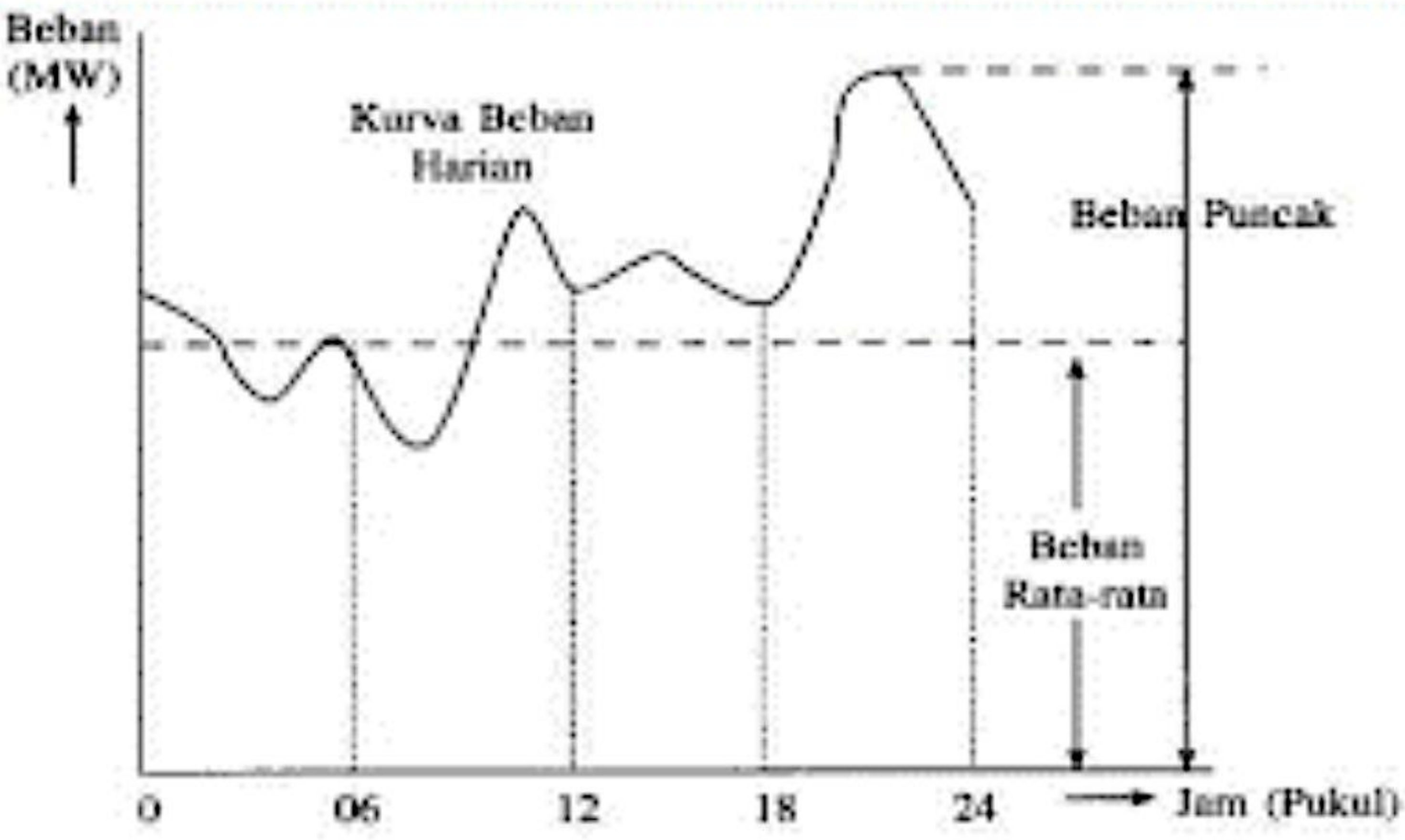
Dr.-Ing Eko Adhi Setiawan,IPU, Iqbal Ramli,MT

KULIAH Demand Response -2025

SMARTGRID

Dr.-Ing Eko A SETIAWAN.,IPU.,ASEAN Eng., APEC Eng

PROFIL BEBAN



Gambar 2.2. Beban Puncak dan Rata-Rata Sistem

Sumber :
Pengembangan Metode Skema Tarif Listrik Dinamis Kombinasi TOU dan CPP pada pelanggan rumah tangga di sistem Jawa Madura Bali
Tesis S2: Agus Setiawan, Eko A Setiawan, UI

Tabel 3.2. Rata-rata Daya Pembangkit Per 30 Menit

Jam	PLTG	PLTD	PLTA	PLTA-IPP	PLTGU	PLTGU-IPP	PLTP	PLTP-IPP	PLTU	PLTU-IPP
00:30	0	102,53	682,11	146,13	3368,17	284,90	305,23	748,75	9797,47	3747,05
01:00	0	102,73	652,75	146,25	3319,84	279,77	304,98	748,44	9738,98	3698,15
01:30	0	103,05	627,54	146,23	3283,35	277,10	304,89	749,03	9657,06	3657,29
02:00	0	102,72	602,18	146,24	3235,33	279,73	304,39	748,85	9556,27	3606,46
02:30	0	102,40	604,07	146,27	3211,70	285,76	304,57	748,90	9434,98	3546,06
03:00	0	102,03	570,30	145,66	3182,55	292,11	306,02	748,79	9373,60	3509,38
03:30	0	101,58	570,29	145,70	3171,03	294,25	304,70	748,86	9353,69	3499,15
04:00	0	101,45	582,00	144,66	3172,68	300,58	304,77	748,59	9403,45	3529,13
04:30	0	101,47	619,42	144,47	3196,13	309,51	304,77	747,99	9587,91	3655,39
05:00	0	102,13	671,06	143,87	3222,13	314,96	304,94	747,95	9764,04	3800,40
05:30	0	100,69	736,26	144,55	3281,05	302,64	305,10	747,68	9904,99	3914,73
06:00	0	100,46	657,59	144,63	3226,85	312,71	305,72	747,06	9838,07	3887,00
06:30	0	101,00	633,94	144,16	3211,23	331,32	308,79	746,82	9730,50	3838,03
07:00	0	103,55	599,98	144,74	3218,41	347,14	308,67	746,21	9751,54	3849,98
07:30	0	104,51	674,11	144,47	3429,45	341,27	308,34	746,03	10092,16	4072,27
08:00	0	105,72	705,61	145,41	3646,11	323,44	307,90	747,21	10362,13	4281,01
08:30	0	107,59	811,10	145,78	3889,03	312,21	309,49	746,71	10565,07	4512,73
09:00	0	109,75	857,41	146,19	4031,02	306,47	310,57	746,16	10666,44	4636,17
09:30	0	115,43	915,98	147,59	4198,97	309,84	310,06	746,49	10707,05	4687,34
10:00	0	117,37	989,67	146,53	4344,00	302,26	309,67	746,79	10747,54	4718,11
10:30	0	118,90	1069,74	146,84	4439,33	292,34	302,32	747,31	10785,81	4743,35
11:00	0	120,02	1034,16	146,86	4461,99	294,03	302,90	747,63	10790,91	4734,41
11:30	0	119,95	841,98	146,80	4290,34	340,13	303,21	746,98	10575,32	4506,25
12:00	0	120,02	756,61	147,11	4110,98	399,50	303,55	746,76	9975,51	4180,09
12:30	0	120,88	745,88	144,97	4113,47	402,86	303,43	747,57	9939,70	4155,78
13:00	0	122,14	958,21	145,46	4338,04	348,87	303,51	747,02	10428,60	4459,80
13:30	0	122,92	1112,51	146,41	4611,34	291,65	303,16	746,65	10814,22	4732,63
14:00	0	123,36	1086,84	146,63	4596,06	290,23	302,87	747,29	10825,40	4765,54
14:30	0	123,08	1052,13	147,29	4584,61	295,61	302,78	748,79	10793,27	4742,30
15:00	0	122,11	976,94	147,06	4524,69	303,52	302,66	748,67	10770,81	4708,77
15:30	0	121,43	1026,22	145,20	4513,42	309,12	302,05	748,75	10775,71	4707,38
16:00	0	119,66	932,24	145,16	4447,49	319,75	302,08	749,47	10762,78	4702,40
16:30	0,22	120,00	922,64	146,65	4424,15	316,46	300,95	749,66	10727,09	4673,33
17:00	3,72	123,16	870,48	147,49	4385,60	321,82	300,98	750,59	10734,07	4693,53
17:30	7,65	133,43	1028,62	147,04	4547,01	320,94	301,39	750,28	10850,26	4767,73
18:00	8,22	139,96	1124,00	147,67	4781,20	343,00	301,81	749,79	11001,52	4891,93
18:30	7,38	140,14	1145,57	147,62	4721,82	349,90	301,89	749,99	11029,71	4932,96
19:00	6,65	138,14	1105,98	147,22	4660,74	341,19	302,55	750,08	11025,55	4924,48
19:30	5,84	134,25	1116,83	147,57	4605,23	333,68	303,23	751,61	11005,94	4898,61
20:00	3,75	131,56	1080,23	147,63	4482,10	326,95	303,69	751,56	10989,82	4886,40
20:30	2,79	127,74	1070,96	146,66	4368,51	305,69	304,24	752,73	10950,09	4853,01
21:00	1,62	118,91	943,19	147,68	4194,87	297,35	304,29	752,28	10900,56	4795,12
21:30	0	111,14	872,13	147,67	4010,07	287,22	304,44	751,53	10773,16	4631,30
22:00	0	106,70	824,86	147,74	3833,63	279,50	304,46	752,61	10570,22	4453,75
22:30	0	104,73	805,89	148,33	3747,31	272,59	304,35	752,76	10439,65	4308,82
23:00	0	103,23	728,28	148,34	3586,67	279,73	304,50	752,74	10288,26	4147,40
23:30	0	101,71	744,82	148,40	3452,28	283,97	304,69	752,64	10152,60	3994,10
00:00	0	99,05	686,54	148,04	3318,63	285,74	303,40	751,64	10033,12	3873,36

BESARNYA BPP

Tabel 3.3. BPP rata-rata per pembangkit[7]

Pembangkit	BPP (Rp/KWh)
PLTG	10090,35
PLTD	1879,85
PLTA	897,1
PLTA-IPP	882,5
PLTGU	1094,81
PLTGU-IPP	1143,35
PLTP	1980,14
PLTP-IPP	1070,136364
PLTU	806,71
PLTU-IPP	1014,846154

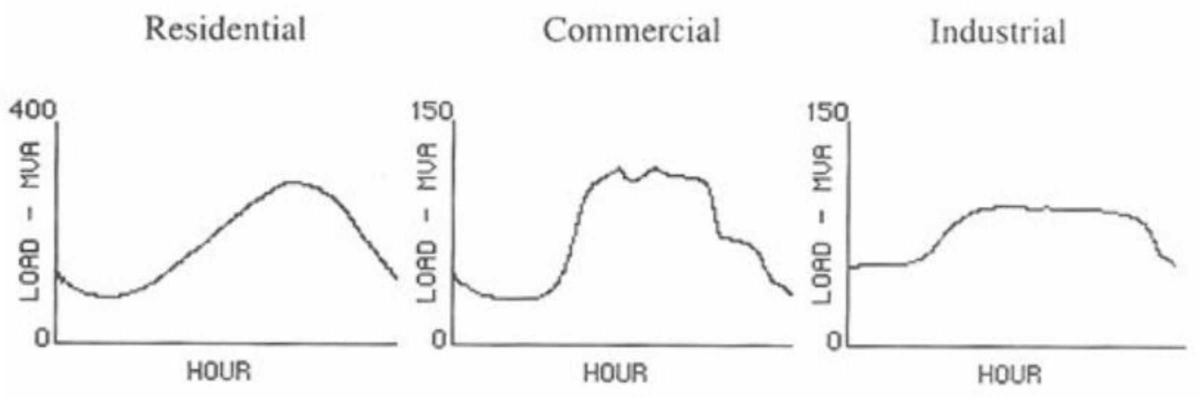
Sumber : Data Laporan Statistik PLN tahun 2017

Sumber : Pengembangan Metode Skema Tarif Listrik Dinamis Kombinasi TOU dan CPP pada pelanggan rumah tangga di sistem Jawa Madura Bali
Tesis S2: Agus Setiawan, Eko A Setiawan, UI

Three main strategies are presented as alternatives of how a customer can change his/her use of electricity [8]:

1. *Foregoing*: Reducing demand in peak-price periods, without making it up later.
2. *Shifting*: Rescheduling demand away from peak-price periods to low-price periods.
3. *Onsite generation*: Turning on an onsite or backup emergency generator to supply some or all of the electricity needs of the customer.

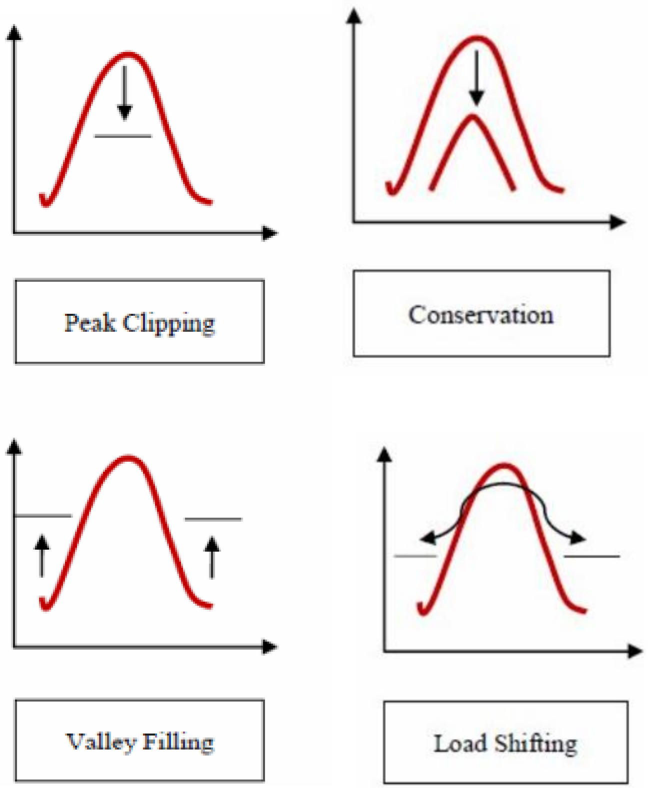
The different strategies may be implemented either as manual responses to the hourly energy price or automatic response based on the price or the time of day.



Optimal Scheme with Load Forecasting for Demand Side Management (DSM) in Residential Areas

January 2013 · Energy and Power Engineering 05(04):889-896
DOI: 10.4236/epe.2013.54B171

M. Abogaleela · Magdy El-Marsafawy · Mohamed El-Sobki



ELSEVIER
Utilities Policy
Volume 40, June 2016, Pages 15-25

Time-based pricing and electricity demand response: Existing barriers and next steps

Cherrelle Eid [a], Elta Koliou [a], Mercedes Valles [b], Javier Reneses [b], Rudi Hakvoort [a]

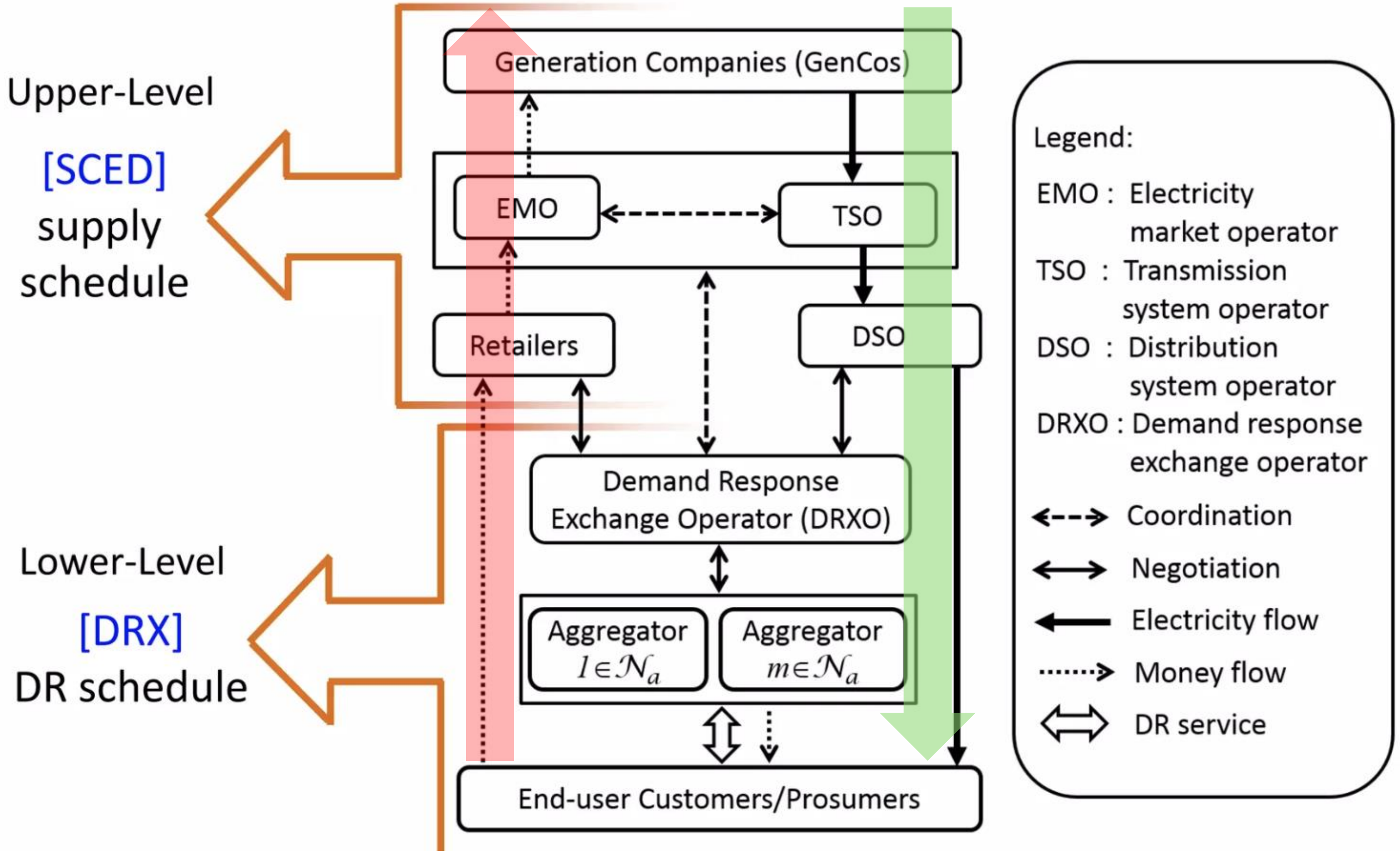
(tambahan bacaan)

Sumber:
https://www.sciencedirect.com/science/article/pii/S0957178716300947

A Framework of DRX Integrated MCM

SCED – Security Constraint Economic Dispatch

DRX – Demand Response Xchange



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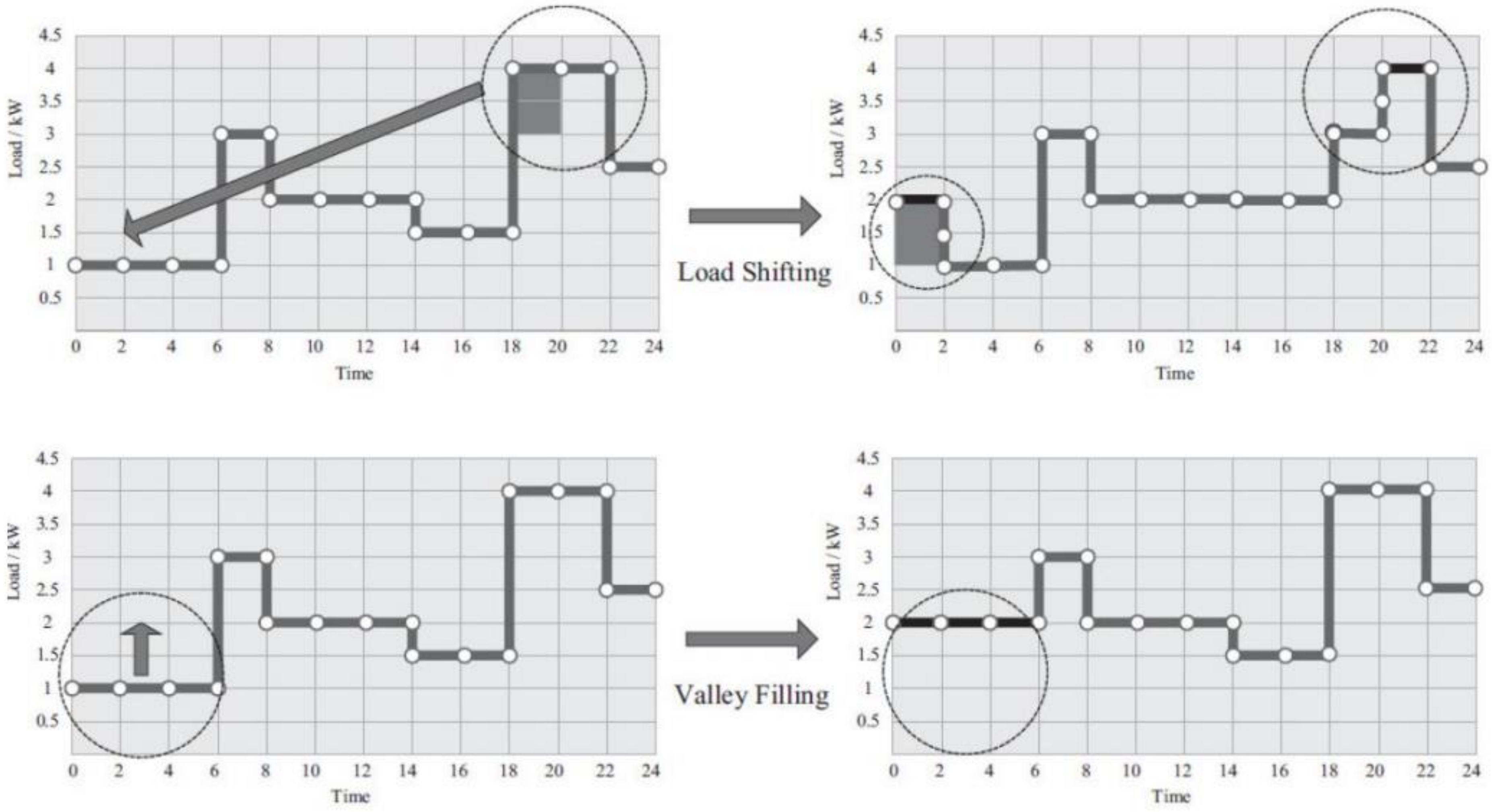
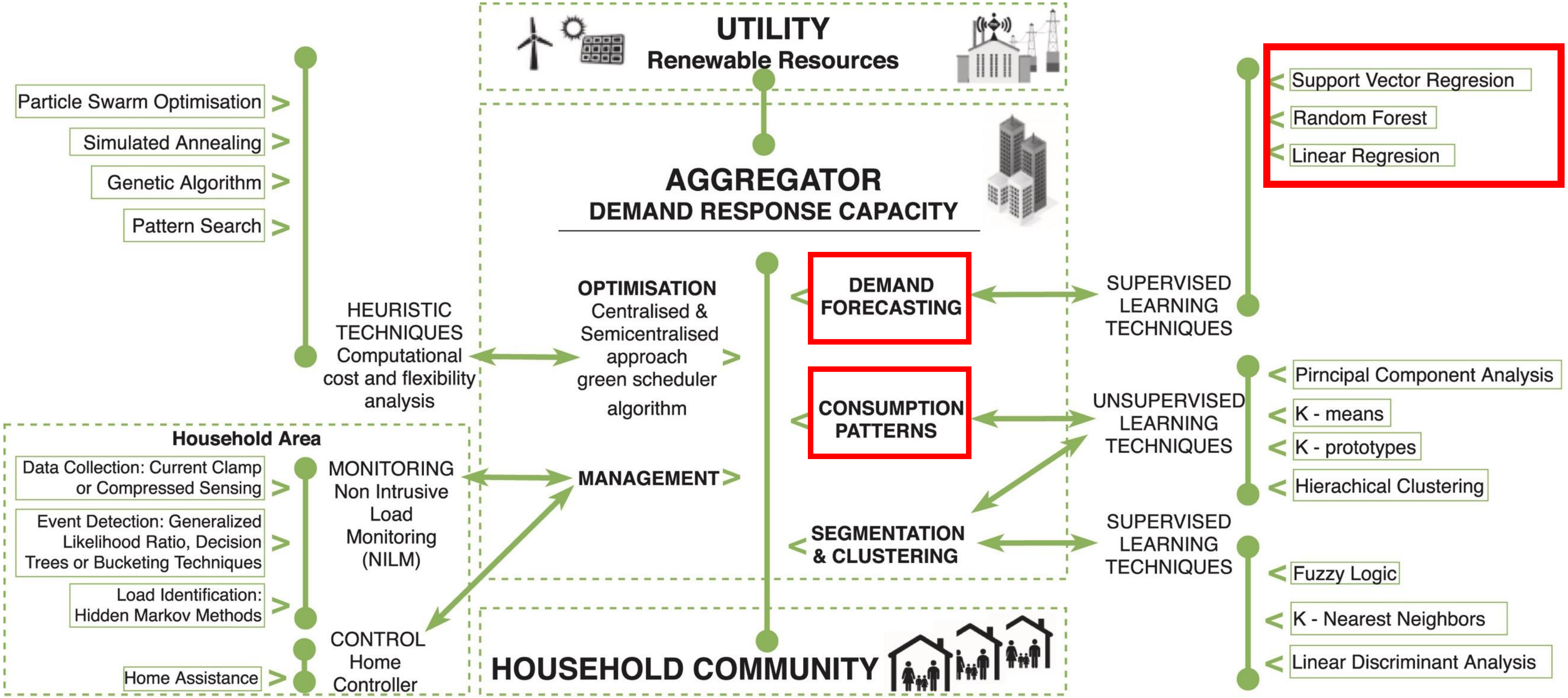
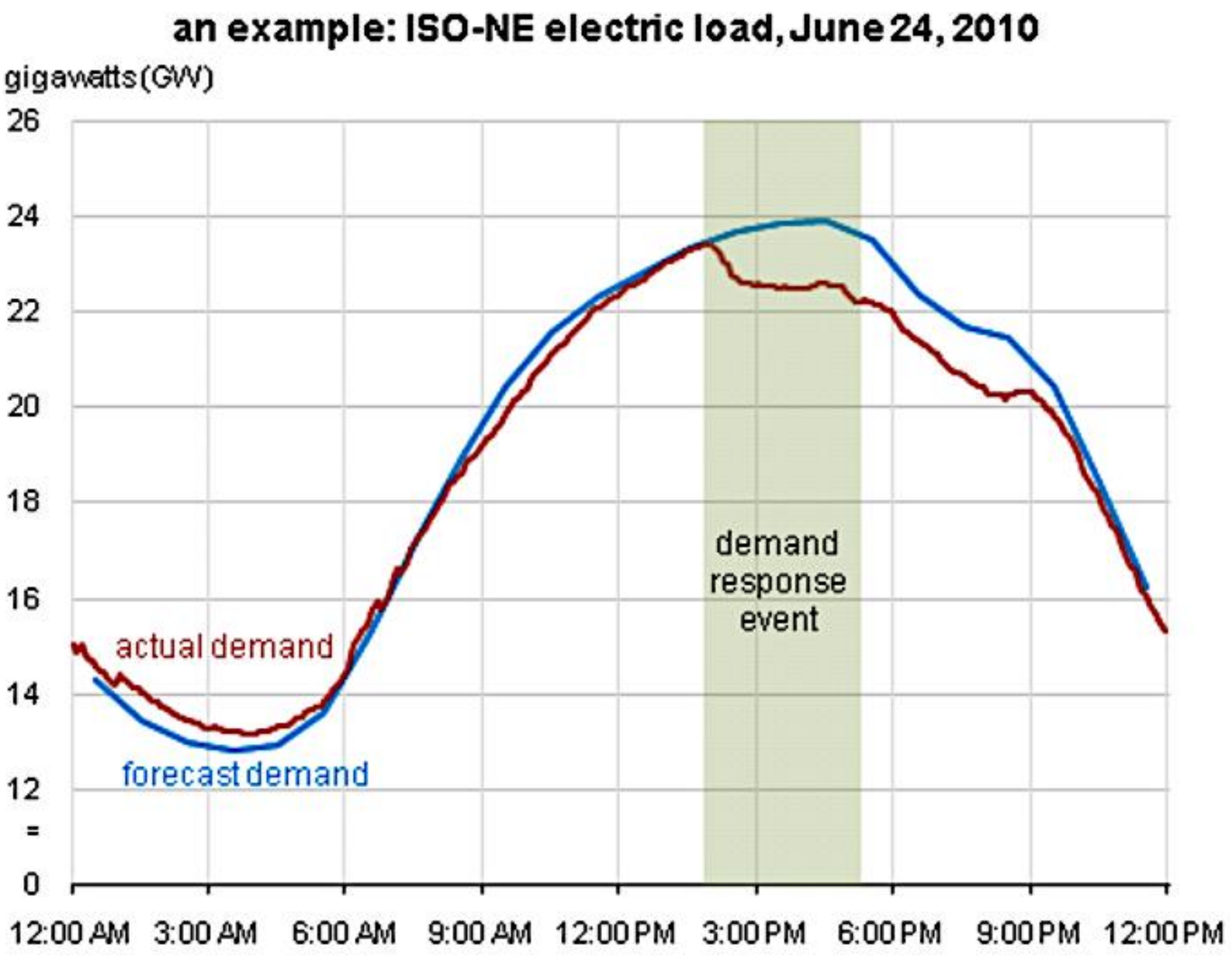


Load Shifting
Valley Filling
Load / kW
Time



SUDAH DIJELASKAN DI KULIAH

KASUS 1



Grafik beban listrik ISO-NE (ISO New England) pada tanggal 24 Juni 2010, yang menunjukkan pengaruh Demand Response (DR) terhadap beban listrik.

Analisis Gambar:
Sumbu Y (Vertikal) menunjukkan konsumsi listrik dalam gigawatt (GW).
Sumbu X (Horizontal) menunjukkan waktu dalam satuan jam sepanjang hari.

Garis Biru: Forecast demand (permintaan listrik yang diprediksi).
Garis Merah: Actual demand (permintaan listrik yang terjadi secara nyata).
Zona Hijau: Menunjukkan periode Demand Response Event, sekitar pukul 3:00 PM hingga 6:00 PM.

Sebagai contoh, pada sore hari tanggal 24 Juni 2010, cuaca di New England sangat panas dan lembab. Sekitar **1.800 megawatt (MW)** kapasitas pembangkit listrik mengalami gangguan tak terduga, sehingga operator sistem independen (**ISO-NE**) memiliki sedikit cadangan operasional (**pembangkit cadangan**).Untuk mengembalikan tingkat cadangan operasional yang memadai, **ISO-NE mengaktifkan program Demand Response mereka**. Pada sore itu, **ISO-NE meminta utilitas di seluruh New England untuk mengurangi beban sebesar 669 MW melalui Demand Response**. Program ini berhasil mengurangi permintaan listrik sebesar **653 MW**. Wilayah ini memiliki **Independent System Operator - New England (ISO-NE)** yang bertanggung jawab atas pengelolaan sistem tenaga listrik dan pasar listrik grosir di wilayah tersebut

Temuan Utama

Sebelum Demand Response (DR) Event

- **Forecast dan actual demand hampir sama** hingga mendekati pukul 3:00 PM.
- Beban listrik mencapai puncaknya mendekati **24 GW**.

Saat DR Event (3:00 PM - 6:00 PM)

- **Actual demand turun dibandingkan forecast demand**, yang berarti ada intervensi dari mekanisme DR.
- Ini menunjukkan bahwa pelanggan merespons insentif atau sinyal pasar untuk **mengurangi konsumsi listrik.**

Setelah DR Event (6:00 PM - 12:00 AM)

- Beban kembali mendekati nilai prediksi, tetapi tetap sedikit lebih rendah dari forecast.

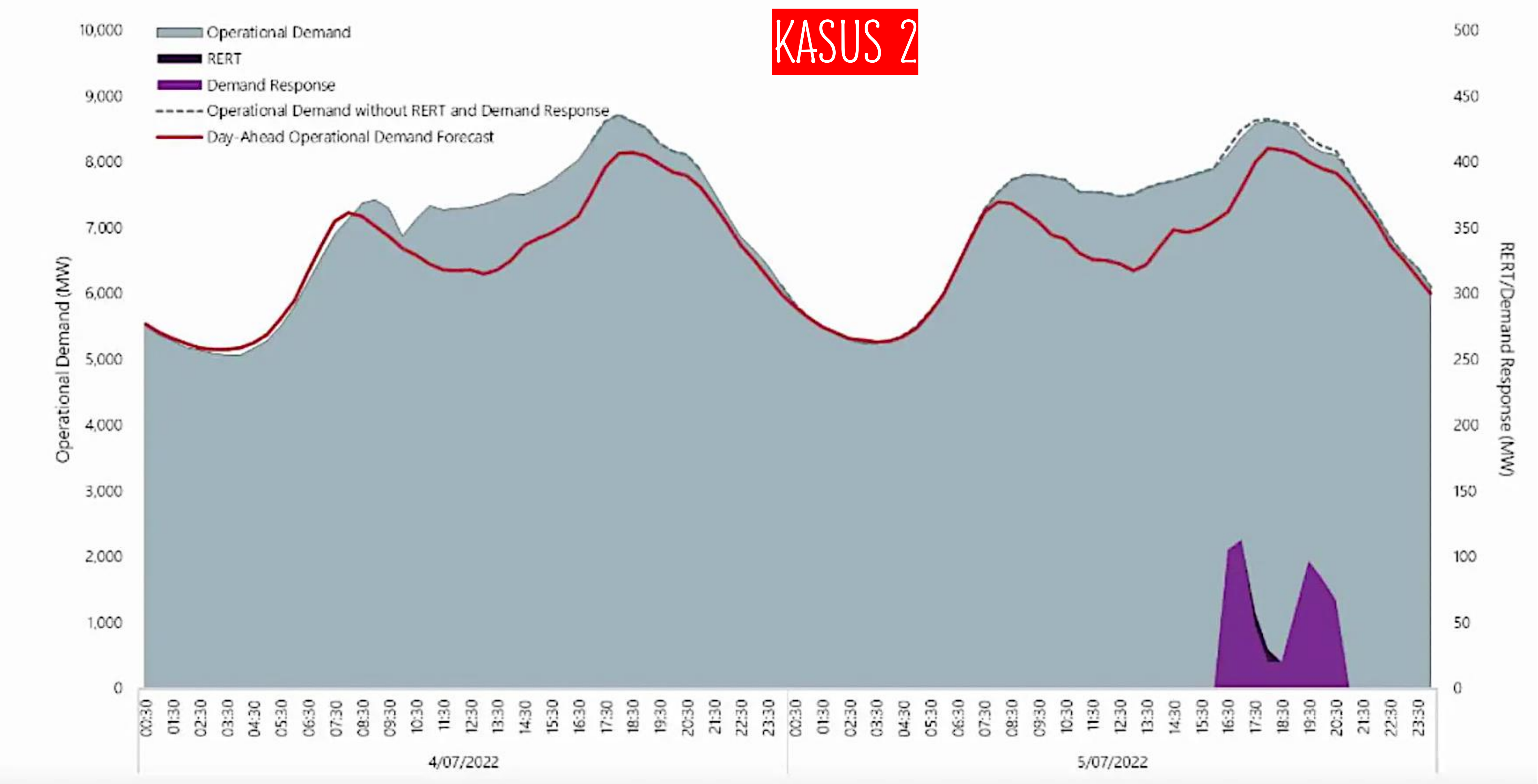
CATATAN

DR berhasil menurunkan puncak beban listrik, mengurangi kebutuhan akan pembangkit tambahan (misalnya, pembangkit cadangan berbasis gas atau diesel).**Manfaat DR dalam sistem ini:Mengurangi beban puncak**, sehingga menghindari biaya tinggi untuk pembangkitan listrik tambahan.

Meningkatkan stabilitas jaringan, karena beban listrik lebih terkendali.

Mengurangi emisi karbon, terutama jika pengurangan beban mengurangi pemakaian pembangkit berbahan bakar fosil.

KASUS 2


Operational Demand
RERT
Demand Response
Operational Demand without RERT and Demand Response
Day-Ahead Operational Demand Forecast
Operational Demand (MW)
RERT/Demand Response (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
500
450
400
350
300
250
200
150
100
50
0
00:30
01:30
02:30
03:30
04:30
05:30
06:30
07:30
08:30
09:30
10:30
11:30
12:30
13:30
14:30
15:30
16:30
17:30
18:30
19:30
20:30
21:30
22:30
23:30
4/07/2022
5/07/2022

KETERANGAN GAMBAR :

- **Sumbu Y (kiri, skala MW):** Menunjukkan **permintaan listrik operasional** dalam megawatt (MW).
- **Sumbu Y (kanan, skala MW):** Menunjukkan kapasitas **RERT dan Demand Response (DR)** yang diaktifkan.
- **Sumbu X:** Waktu dalam format 24 jam untuk dua hari, **4 Juli dan 5 Juli 2022**.
- **Area Abu-Abu: Operational Demand (Permintaan listrik yang terjadi).**
- **Garis Merah: Day-Ahead Operational Demand Forecast (Prakiraan permintaan listrik sehari sebelumnya).**
- **Garis Hitam Putus-Putus: Operational Demand without RERT and Demand Response (Permintaan listrik tanpa intervensi RERT dan DR).**
- **Area Ungu: RERT (Reliability and Emergency Reserve Trader) dan Demand Response (DR), menunjukkan pengurangan beban akibat intervensi ini.**

Temuan Utama

1.Ketidaksesuaian Antara Forecast dan Permintaan Aktual

1. Prakiraan permintaan listrik **(garis merah)** lebih rendah dibandingkan dengan permintaan aktual **(area abu-abu)**, terutama pada puncak beban.
2. Ini menunjukkan adanya kesalahan dalam **prakiraan permintaan listrik**, yang kemungkinan dipengaruhi oleh cuaca ekstrem atau faktor lain.

2.Aktivasi RERT dan Demand Response pada 5 Juli 2022

1. **Sore hingga malam hari pada 5 Juli**, terlihat adanya aktivasi **RERT dan DR (ditunjukkan oleh area ungu)**.
2. Hal ini mengindikasikan bahwa untuk menjaga stabilitas sistem, operator pasar listrik **meminta pelanggan tertentu untuk mengurangi konsumsi mereka**.
3. Kapasitas RERT/DR mencapai sekitar **150-200 MW**, yang cukup signifikan dalam membantu

POIN PENTING:

- Prakiraan cuaca yang tidak akurat menyebabkan tantangan bagi Australian Energy Market Operator (AEMO), terutama di pusat beban terbesar. Kesalahan dalam prakiraan suhu, terutama selama kondisi dingin ekstrem, menyebabkan perkiraan permintaan listrik yang meleset, sehingga AEMO harus berupaya keras memastikan kapasitas listrik yang cukup untuk memenuhi permintaan.
    - Sebagai contoh, pada awal Juli tahun sebelumnya di Queensland, kondisi dingin ekstrem tidak terduga menyebabkan permintaan listrik mencapai puncak musim dingin tertinggi sebesar 8.716 MW, yang memaksa AEMO mengeluarkan peringatan "lack of reserve" pada 4 dan 5 Juli.
- Selain itu, wilayah seperti Penrith di barat Sydney mengalami tingkat kesalahan prakiraan tertinggi, yang menjadi masalah bagi AEMO karena area tersebut memiliki beban residensial terbesar di jaringan utama negara.
- Dengan demikian, prakiraan cuaca yang tidak akurat, terutama selama kondisi dingin ekstrem, dapat menyebabkan perkiraan permintaan listrik yang meleset, memaksa AEMO untuk mengambil tindakan darurat guna memastikan pasokan listrik yang memadai.

Link kasus 2. https://reneweconomy.com.au/dud-weather-forecasts-prove-a-headache-for-aemo-particularly-in-biggest-load-centre/

Fitur	RERT (Supply-Side)	DR (Customer-Side)
✓ Sumber daya	Pembangkit cadangan, baterai besar, genset industri	Pelanggan besar (industri, komersial, rumah tangga)
✓ Tujuan	Menambah pasokan listrik darurat	Mengurangi permintaan listrik saat kondisi kritis
✓ Kapan diaktifkan?	Saat ada kekurangan pasokan listrik	Saat ada lonjakan permintaan listrik
✓ Siapa yang berpartisipasi?	Penyedia listrik di luar pasar utama	Pelanggan listrik (industri, komersial, rumah tangga)
✓ Manfaat utama	Menjaga keandalan sistem listrik dengan menambah daya	Mengurangi tekanan pada jaringan listrik tanpa perlu pembangkit tambahan

Perbandingan Strategi Demand Response dengan metode LMP: Mengurangi Konsumsi vs. Menggeser Beban

Untuk memahami bagaimana mekanisme **Locational Marginal Pricing (LMP)** bekerja dalam Demand Response (DR), kita akan menggunakan contoh **pabrik baja di Texas** yang beroperasi dalam pasar listrik **ERCOT**, dimana harga listrik bervariasi tergantung pada kondisi permintaan dan pasokan.

Situasi Awal: Harga Listrik di Waktu Puncak

- Pada **pukul 14:00 - 16:00 (jam puncak)**, harga listrik melonjak hingga **$0.75/kWh** karena permintaan tinggi akibat cuaca panas ekstrem.
- **Pabrik baja ini memiliki konsumsi listrik sebesar 2.5 MW** selama periode ini.
- Jika **tidak melakukan tindakan apapun**, biaya listriknya adalah:
- **Artinya, mereka harus membayar $3,750 untuk konsumsi listrik di jam puncak.**

Opsi 1: Mengurangi Konsumsi (Mendapatkan Kompensasi LMP)

Jika pabrik memilih untuk **mengurangi konsumsi listrik sebesar 2.5 MW** sesuai dengan skema **Demand Response berbasis LMP**, mereka akan dibayar oleh sistem pasar listrik dengan tarif yang sama **($0.75/kWh)** **sebagai insentif**.

$$2.5\ \mathrm{MW} \times 1000\ \mathrm{kW/MW} \times 2\ \mathrm{jam} \times 0.75\ \mathrm{USD/kWh} = 3,750\ \mathrm{USD}$$

Keuntungan:

- Pabrik tidak perlu membayar tagihan listrik saat harga mahal.
- Pabrik justru **mendapatkan $3,750 dari sistem LMP**.

Kekurangan:

- Pabrik harus **menghentikan operasinya selama 2 jam**, yang mungkin berdampak pada produksi

Skenario DLC

Perbandingan Strategi Direct Load Control (DLC): Menggunakan AC/Air Conditioners Tanpa Batas vs. Mengikuti Program DLC

- Untuk memahami bagaimana mekanisme **Direct Load Control (DLC)** bekerja dalam Demand Response (DR), kita akan menggunakan contoh **sebuah rumah tangga di Los Angeles, California**, yang merupakan pelanggan **PG&E (Pacific Gas & Electric)** dan mengikuti program **SmartAC™**.

Situasi Awal: Penggunaan AC di Hari Panas

- Pada **pukul 14:00 - 18:00 (4 jam puncak beban)**, suhu di Los Angeles mencapai **40°C**, menyebabkan lonjakan konsumsi listrik karena penggunaan AC meningkat.
- **Rumah tangga ini memiliki AC berkapasitas 2 kW**, yang mereka gunakan secara penuh selama periode tersebut.
- Jika **tidak mengikuti program DLC**, mereka tetap menggunakan **2 kW selama 4 jam** dengan tarif

$$2\ \mathrm{kW} \times 4\ \mathrm{jam} \times 0.18\ \mathrm{USD/kWh} = 1.44\ \mathrm{USD}$$

Perhitungan biaya listrik tanpa DLC:

Berpartisipasi dalam Program DLC (50% Pengurangan Daya AC)

Jika pelanggan **mendaftar dalam program DLC**, PG&E akan **secara otomatis mengurangi daya AC mereka sebesar 50%** selama periode beban puncak (4 jam).

Perhitungan biaya listrik dengan DLC

$$(2\ \mathrm{kW} \times 50\%) \times 4\ \mathrm{jam} \times 0.18\ \mathrm{USD/kWh} = 0.72\ \mathrm{USD}$$

Keuntungan bagi pelanggan:

•**Biaya listrik hanya $0.72** selama periode tersebut, menghemat **$0.72 dibandingkan tanpa DLC**.

•**Pelanggan menerima insentif tahunan sebesar $120 dari PG&E**.

•**Total keuntungan pelanggan adalah $120.72 dalam satu tahun**.

Kekurangan:

•Suhu dalam rumah mungkin sedikit meningkat karena **AC berjalan dengan daya lebih rendah**.

Opsi 2: Menggeser Beban ke Waktu dengan Tarif Murah

Daripada benar-benar menghentikan operasional, pabrik memiliki opsi untuk **memindahkan konsumsi listrik ke jam malam (off-peak hours)**, di mana harga listrik turun menjadi **$0.06/kWh**.

Perhitungan biaya listrik jika beban dipindahkan ke jam murah:

$$2.5\ \mathrm{MW} \times 1000\ \mathrm{kW/MW} \times 2\ \mathrm{jam} \times 0.06\ \mathrm{USD/kWh} = 300\ \mathrm{USD}$$

Keuntungan:

- Pabrik tetap beroperasi, tidak ada gangguan produksi.
- **Total biaya listrik hanya $300**, jauh lebih murah dibandingkan $3,750 jika tetap menggunakan listrik di jam puncak.
- **Total penghematan dibandingkan tetap beroperasi di jam puncak adalah $3,450 USD**.

Kekurangan:

- Pabrik harus memiliki fleksibilitas dalam jadwal produksi agar bisa menggeser waktu operasionalnya ke jam murah.

Strategi	Biaya / Pendapatan (USD)	Keuntungan	Kekurangan
✓ Tetap Beroperasi di Jam Puncak	-3,750	Tidak ada gangguan produksi	Membayar listrik sangat mahal
✓ Mengurangi Konsumsi (Dapat Insentif LMP)	3,750	Dapat insentif dari pasar LMP	Harus menghentikan produksi
✓ Menggeser Beban ke Jam Murah	-300	Tetap berproduksi, hemat $3,450	Harus fleksibel dalam operasional

Strategi	Biaya Listrik (USD)	Penghematan per Event (USD)	Total Manfaat (USD, termasuk insentif tahunan)
✓ Tetap Menggunakan AC Penuh	1.44	0	0
✓ Mengikuti Program DLC (50% Pengurangan AC)	0.72	0.72	120.72

MORE ABOUT… Locational Marginal Pricing (LMP) – Kendali oleh Pelanggan atau Agregator

Siapa yang mengontrol beban?
Pelanggan (seperti industri atau bisnis) atau agregator DR yang memutuskan kapan dan bagaimana mengurangi konsumsi listrik mereka berdasarkan sinyal harga dari pasar listrik.

Mekanisme LMP dalam Demand Response:

1. **Penetapan Harga Listrik:**
   Operator pasar listrik, seperti **PJM Interconnection**, menetapkan harga listrik secara real-time di berbagai lokasi menggunakan **LMP**. Harga ini mencerminkan biaya marginal untuk menyediakan listrik di titik tertentu dalam jaringan, mempertimbangkan faktor seperti batasan transmisi dan biaya produksi.
2. **Sinyal Harga kepada Pelanggan:**
   Pelanggan besar atau agregator DR menerima informasi harga LMP secara real-time. Dengan transparansi ini, mereka dapat membuat keputusan yang tepat mengenai konsumsi energi mereka.
3. **Keputusan Pengurangan Konsumsi:**
   Berdasarkan harga LMP saat ini, pelanggan atau agregator memutuskan apakah akan mengurangi konsumsi listrik. Misalnya, jika harga tinggi, mereka mungkin memilih untuk menunda operasi tertentu atau menggunakan sumber daya energi alternatif.
4. **Implementasi Pengurangan Beban:**
   Pelanggan atau agregator menggunakan sistem manajemen energi internal mereka untuk mengurangi beban. Ini bisa melibatkan otomatisasi melalui **Building Management Systems (BMS)** atau keputusan manual oleh manajemen fasilitas.
5. **Kompensasi melalui Pasar:**
   Pengurangan konsumsi listrik dihargai pada tingkat LMP saat itu, karena pengurangan permintaan dianggap setara dengan peningkatan pasokan dalam menjaga keseimbangan jaringan.

- **Contoh:**
  Sebuah pabrik baja mungkin memutuskan untuk menghentikan sementara operasi mesin tertentu saat harga LMP tinggi untuk mengurangi biaya energi dan menerima kompensasi dari pasar listrik

More about … Direct Load Control (DLC) – Kendali oleh Operator Listrik atau Agregator

Siapa yang mengontrol beban?

Operator listrik atau agregator DR yang memiliki otoritas untuk secara langsung mengurangi atau mematikan beban listrik pelanggan selama periode permintaan tinggi.

Mekanisme DLC dalam Demand Response:

1. **Pendaftaran dalam Program DLC:**
   Pelanggan, seperti rumah tangga atau bisnis kecil, mendaftar dalam program DLC yang ditawarkan oleh utilitas atau agregator. Sebagai imbalannya, mereka menerima insentif finansial atau pengurangan tarif listrik.
2. **Pemasangan Perangkat Kontrol:**
   Perangkat kontrol, seperti **smart thermostats** atau **load control switches**, dipasang pada peralatan listrik pelanggan. Perangkat ini memungkinkan operator listrik untuk mengendalikan beban tertentu secara jarak jauh.
3. **Aktivasi Selama Permintaan Puncak:**
   Selama periode permintaan listrik yang tinggi, operator listrik mengirim sinyal untuk mengurangi atau mematikan beban tertentu, seperti AC atau pemanas air, guna menjaga stabilitas jaringan.
4. **Pemulihan Layanan:**
   Setelah periode permintaan puncak berakhir, beban yang dikendalikan dikembalikan ke operasi normal tanpa intervensi pelanggan.

- **Contoh:**
  Sebuah rumah tangga yang berpartisipasi dalam program DLC mungkin mendapati AC mereka secara otomatis dikurangi dayanya oleh operator listrik selama beberapa jam pada hari yang sangat panas untuk mengurangi beban jaringan

1. Kriteria Pemilihan Beban yang Dapat Dikontrol dalam DLC

Untuk menentukan **beban mana yang dapat dikontrol dari pusat**, ada beberapa faktor yang dipertimbangkan:

a. Jenis Beban yang Tidak Sensitif terhadap Gangguan Singkat

- Beban yang bisa dimatikan tanpa mengganggu aktivitas utama pelanggan.

Contoh di Rumah Tangga:

- **AC (Air Conditioner)** → Bisa dikurangi daya atau dimatikan selama beberapa menit.
- **Pemanas Air Listrik (Water Heater)** → Bisa dijadwalkan ulang untuk menyala saat permintaan listrik rendah.
- **Pompa Kolam Renang atau Pompa Air** → Bisa ditunda selama beberapa jam tanpa dampak langsung.
- **Pengisian Kendaraan Listrik (EV Charging)** → Bisa dikontrol untuk menghindari jam sibuk.

Contoh di Industri:

- **Sistem pendinginan/pemanas industri** → Bisa dikurangi kapasitasnya secara bertahap.
- **Pengolahan air atau sistem pompa besar** → Bisa dijadwalkan ulang.
- **Sistem penyimpanan energi (baterai industri)** → Bisa diatur untuk menyalurkan daya ke jaringan daripada mengambil daya dari jaringan

b. **Beban dengan Kemampuan Remote Control**

- Harus ada teknologi yang memungkinkan operator untuk mengontrol beban dari pusat.
- Beban harus memiliki **perangkat komunikasi pintar (smart controllers)** seperti **smart meters, relay control, atau OpenADR (Open Automated Demand Response).**
- Utilitas atau agregator memerlukan **akses langsung** ke beban melalui **Wi-Fi, ZigBee, PLC (Power Line Communication), atau jaringan 5G**.

c. **Beban yang Berkontribusi Signifikan terhadap Permintaan Puncak**

- DLC lebih efektif jika diterapkan pada beban yang **dominan dalam permintaan listrik total**.
- AC dan pemanas air menyumbang lebih dari **40% konsumsi listrik rumah tangga**, sehingga pengendaliannya bisa berdampak besar dalam menurunkan beban jaringan.
- Di industri, sistem HVAC (Heating, Ventilation, and Air Conditioning) adalah **penyumbang utama konsumsi energi**, sehingga menjadi target utama dalam DLC

2. Cara Operator Menentukan Beban di Setiap Rumah Tangga atau Industri

- Setelah mengetahui jenis beban yang potensial, bagaimana utilitas listrik menentukan **beban mana yang dikontrol di setiap pelanggan?**
- **a. Melalui Pendaftaran Program DLC**
- **Pelanggan secara sukarela mendaftar ke program DLC yang ditawarkan oleh utilitas.**
- Saat mendaftar, pelanggan memilih **peralatan apa saja yang dapat dikontrol** oleh operator.
- **Contoh di AS (PG&E, California):**
- **Pelanggan memilih apakah mereka ingin AC mereka dikontrol otomatis.**
- **Jika setuju, PG&E memasang perangkat kontrol yang dapat mematikan atau mengurangi daya AC mereka selama jam puncak.**

b. Data dari Smart Meters dan IoT Sensors

- Utilitas listrik menggunakan **smart meters dan sensor IoT** untuk mengetahui **pola konsumsi listrik pelanggan**.
- Dengan algoritma AI, operator bisa mengidentifikasi **peralatan mana yang paling mungkin dikendalikan** tanpa terlalu mengganggu kenyamanan pelanggan.
- **Contoh di Kanada (Ontario Hydro One):**
- **Smart meters melacak kapan AC dan pemanas air menyala.**
- **Jika beban mendekati batas jaringan, Hydro One mengirim sinyal untuk mengurangi daya AC pelanggan.**

c. Kategorisasi Beban Berdasarkan Profil Pelanggan

- **Pelanggan rumah tangga** biasanya memiliki pola konsumsi listrik yang lebih standar.
- **Industri memiliki beban yang lebih kompleks**, sehingga DLC lebih spesifik, misalnya:
    - **Pabrik baja** mungkin setuju untuk mengurangi penggunaan oven listrik.
    - **Data center** mungkin setuju untuk mengalihkan daya ke baterai selama jam puncak.

Contoh di Eropa (RWE Jerman):

- **Pelanggan industri besar diberikan skema kustom untuk DLC.**
- **Misalnya, pabrik pengolahan air setuju untuk menunda pemompaan selama 2 jam saat jaringan sedang padat.**

3. Bagaimana DLC Dieksekusi Dari Pusat?

- Setelah beban yang dapat dikontrol diidentifikasi, bagaimana operator listrik mengendalikan beban dari pusat?
- a. Dengan Sinyal Permintaan Jarak Jauh
- **Utilitas mengirimkan sinyal permintaan ke perangkat kontrol pelanggan.**
- Sinyal ini bisa berupa **Wi-Fi, ZigBee, atau Power Line Communication (PLC).**
- Perangkat yang menerima sinyal akan **secara otomatis menyesuaikan konsumsi listrik**.
- **Contoh di AS (Duke Energy, Florida):**
- **Saat jaringan listrik mendekati kapasitas maksimal, Duke Energy mengirim sinyal ke ribuan rumah.**
- **AC pelanggan dikurangi 2 derajat secara otomatis selama 3 jam.**

b. Dengan Perangkat Kontrol Otomatis (Relay atau Smart Thermostat)

- Smart thermostats (misalnya Nest atau Honeywell) dapat dikontrol oleh utilitas.
- Pemanas air dan pompa bisa dimatikan selama beberapa jam.
- Contoh di Australia (AGL Energy):
- AGL Energy menawarkan pelanggan diskon jika mereka mengizinkan pemanas air dikontrol otomatis.
- Saat jaringan mengalami beban tinggi, AGL mengurangi daya pemanas air selama 1-2 jam.

FAZIT

Operator listrik menentukan beban yang dikontrol dalam DLC berdasarkan kriteria teknis, ekonomi, dan kesiapan perangkat pelanggan.Proses ini melibatkan pendaftaran pelanggan, analisis data smart meter, dan komunikasi dengan perangkat pintar.

Eksekusi DLC dilakukan secara otomatis dari pusat menggunakan sinyal jarak jauh atau smart controllers.Jadi, beban yang dikontrol dalam DLC bukan dipilih secara acak, melainkan berdasarkan data konsumsi pelanggan dan kesediaan mereka untuk ikut serta dalam program ini

Kesimpulan: Tahapan Mekanisme Pembayaran dalam DR

Tahapan	Apa yang Terjadi?	Siapa yang Terlibat?	Contoh
1. Pendaftaran	Pelanggan mendaftar dan memilih beban yang dikontrol	Pelanggan, Utilitas, Agregator	Pabrik baja setuju untuk ikut Auto-DR
2. Pemberitahuan DR	Operator listrik mengirim sinyal DR jika diperlukan	ISO, Utilitas, Agregator	CAISO mengaktifkan DR karena heatwave
3. Eksekusi Pengurangan Beban	Beban listrik dikurangi otomatis atau manual	Pelanggan, Operator	Thermostat pelanggan dinaikkan 2 derajat
4. Verifikasi Pengurangan Beban	Smart meters mencatat konsumsi aktual	ISO, Utilitas	Pabrik baja mengurangi 8 MWh
5. Pembayaran	Peserta menerima insentif	Pelanggan,	Pabrik menerima $400

LITERATUR DEMAND RESPONSE

- **Electric Power research Institute (EPRI) – Definition of Demand-Side Management**

https://www.epri.com/search#q=demand%20response&t=research&sort=relevancy

- **Benefits and challenges of electrical demand response: A critical review** (jurnal Elsevier, bisa di download dari kampus free)
- **Demand response and smart grids—A survey** (jurnal Elsevier, bisa di download dari kampus free)

- **Smart grids: infrastructure, technology and solutions** CRC Press, Boca Raton (2013)

Google Scholar (bisa di download free)

KULIAH DYNAMIC PRICING –

SMARTGRID

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The Power of Dynamic Pricing

Using data from a generic California utility, it can be shown that it is feasible to develop dynamic pricing rates for all customer classes. These rates have the potential to reduce system peak demands from 1 to 9 percent.

Ahmad Faruqui, Ryan Hledik and John Tsoukalis

I. Introduction

As the Smart Grid takes shape, it opens new vistas for change. One of those salient opportunities for change that is enabled by the Smart Grid is the pricing of electricity. By and large, existing rate designs hide the temporal variation in the cost of electricity and thereby promote overconsumption of electricity during peak times and underconsumption during off-peak times. In much of North America, the problem is especially pronounced during the top 60 to 100 hours of the year, which may account for as much as 10–18 percent of system peak load. In order to meet this critical-peak load, expensive combustion turbines are purchased and installed, raising rates for all customers.

Dynamic pricing rate designs can remedy this problem and enhance economic efficiency. For that reason, they are receiving increased attention by state commissions throughout the country. California has made a major commitment to it, by approving the deploying of advanced metering infrastructure (AMI) and by establishing critical-peak pricing (CPP) rates as the default tariff for all non-residential customer classes with AMI.[1] Other smart rate designs, such as real-time pricing, may be provided as options.

To show the power of dynamic pricing, we develop a set of illustrative rates using data from a generic California utility and

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compute the benefits that would accrue to the state's economy from widespread deployment of these rates. While the numbers are specific to California, the process and methodology are perfectly general and should be of interest to utilities and regulatory bodies throughout North America.

We develop dynamic pricing rates for four customer classes: Residential, Medium Commercial and Industrial (C&I), Large Commercial, and Large Industrial. In order to show the development of these rates, we begin with a discussion of existing rates. All the dynamic pricing rates are developed to be revenue-neutral to these existing rates.

II. Existing Rates

The Domestic Non-CARE Five Tiered rate was used as the representative rate for residential customers in California. This rate design features an inverted block rate structure, meaning that the customer's rate progressively increases (in steps) as their consumption within a month increases.

The generation component of the rate starts at $0.045/kWh for consumption below the customer's ''baseline'' amount. This baseline amount varies across the various climate zones in California. Once a customer's consumption exceeds their baseline, they are subject to a rate of $0.065/kWh until they reach 130 percent of the baseline. The rate continues to increase as consumption increases. Consumption up to 200 percent of the baseline is charged at $0.151/kWh, up to 300 percent of the baseline is charged $0.186/kWh, and any consumption above 300 percent of the baseline is charged at a rate of $0.221/kWh. For the average residential customer, this averages to a generation rate of $0.092/kWh. When this generation component is added to the average delivery charge of $0.072/kWh and the Basic Charge of $0.020/day, the average all-in summer electricity rate totals to $0.165/kWh.

California has made a major commitment to dynamic pricing by approving the deploying of AMI.

Rate design for commercial and industrial customers is more complicated due to the presence of demand charges. The representative rate for Medium C&I customers contains two such demand charges. For every kilowatt of summer peak load, customers are charged a Facilities Demand Charge of $8.60/kW and a Summer Demand Charge of $18.79/kW. On top of these demand charges, they are charged a flat rate of $0.072/kWh for energy and a $0.015/kWh delivery charge. A customer charge of $85.75/month and a Single Phase Service rebate of −$26.65/month are also applied. Based on the average load profile for a Medium C&I customer (38.4 kW of demand and 66,818 kWh of energy consumption during the summer) the average all-in summer electricity rate totals to $0.153/kWh.

Large commercial customers are represented by a time-of-use (TOU) rate that divides the day into three pricing periods: peak, mid-peak, and off-peak. Customers are charged a different rate for the energy they consume in each of these periods. During the peak period the energy charge is $0.099/kWh, during the mid-peak period it is $0.078/kWh, and in the off-peak period it is $0.050/kWh. The rate also includes demand charges. There is a year round Facilities Charge of $9.71/kW and also a two-tiered summer demand charge. The tier which corresponds to the peak period is $12.33/kW, and the tier that corresponds to the mid-peak period is $4.25/kW. When these are coupled with a delivery charge of $0.014/kWh and a customer charge of $414.98/month, the average all-in summer electricity rate for this class is $0.132/kWh.

Large Industrial customers have a rate schedule which is similar to that used to represent large commercial customers. The three-part energy charge is as follows: $0.077/kWh in the peak

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period, $0.061/kWh in the mid-peak period, and $0.039 in the off-peak period. The year-round Facilities Charge is $2.48/kW, the summer peak charge is $12.33/kW, and the summer mid-peak charge is $4.25/kW. The delivery charge is $0.013/kWh and the customer charge is $2,199/month. Together these charges total an all-in summer electricity rate of $0.092/kWh.

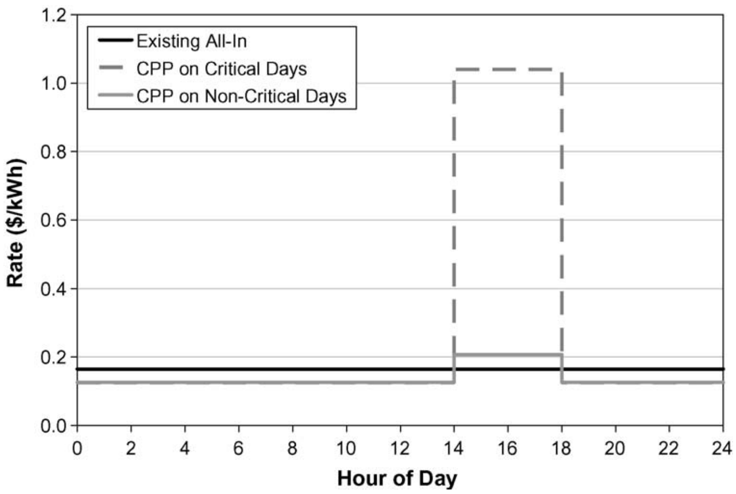

Figure 1: Illustrative CPP/TOU Rate

III. Developing the Critical-Peak Price with Time-of-Use Rate (CPP/TOU)

The CPP/TOU rate layers a CPP rate on top of a TOU. The layered rate means that customers pay a critical rate during peak hours on the few days of the summer when wholesale prices are the highest. During other peak days, the CPP/TOU rate operates like a TOU rate. During peak hours customers will pay a peak rate that is higher then the existing all-in rate. During all other hours, customers have an off-peak rate that is lower than the existing rate. Thus, the CPP/TOU rate is designed to convey the true cost of power generation to electricity customers and to provide them with a price signal that more accurately reflects variation in energy costs over the course of the day. This time-varying rate structure provides customers with an opportunity to reduce electricity bills through reductions in peak period consumption.

Figure 1 illustrates the difference between the CPP/TOU rate structure on a critical day and a peak day. For the Large Commercial and Industrial rate classes, an additional price level, called the mid-peak period, was added to the CPP/TOU rate. This is consistent with the existing structure of Large Commercial and Industrial rates.

The critical-peak rate is dispatched during the 15 ''critical'' days of the summer when market prices are anticipated to be at their highest. For the purposes of this study, the summer period was defined as June through September. The critical rate would be in effect during the hours from 2 pm to 6 pm on these critical days. Customers are notified the day before a critical day will be taking place.

An important input in calculating the CPP/TOU rate is the price of capacity. We have assumed a capacity price of $75/kW-yr, which is based on the cost of a new combustion turbine in California. To calculate the residential critical-peak rate, the capacity price was de-rated by 30 percent to account for the uncertainty associated with two factors: that the critical-peak rate may not be dispatched at the right time and that the rate would be available whenever needed. This de-rate also nets out the revenues that would be realized by the hypothetical combustion turbine in the energy market. In other words, once the de-rate is applied, the new cost estimate represents the fixed payment that the owner of the combustion turbine would need to be made whole financially. The de-rated capacity cost is divided by 60, the number of critical hours in the summer, and then is added to the existing all-in rate to produce the all-in critical rate. For residential customers the critical-peak rate equals $1.04/kWh. The residential off-peak rate was designed to roughly approximate the utility's marginal energy costs during off-peak hours. This was estimated to be $0.0126/kWh. The

  doi:/10.1016/j.tej.2009.02.011

Table 1: CPP/TOU All-In Rates (cents/kWh)

	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Summer)	16.5	15.3	13.2	9.2
Critical-Peak Rate	104.0	98.5	101.2	99.1
Peak Rate	20.7	32.1	19.7	14.6
Mid-Peak	N/A	N/A	11.1	7.8
Off-Peak Rate	12.6	10.0	8.3	5.6

peak rate was then solved to maintain revenue neutrality using the utility's average load profile. Table 1 displays the final CPP/TOU rate structure for all four customer classes.

The methodology for calculating the CPP/TOU for Medium C&I customers varied slightly from the residential CPP/TOU due to the presence of demand charges in the existing rates. The critical rate was set by adding the de-rated capacity price to the energy component of the existing rate. It was assumed that this critical-peak rate replaced the generation-related demand charge in the existing tariff. The off-peak rate was set equal to an approximation of the off-peak marginal energy cost, and the peak rate was solved for revenue neutrality. Ultimately, the new CPP/TOU rate for medium C&I customers no longer had a separate generation demand charge due to the assumption that this cost was recovered through the critical-peak rate.

The CPP/TOU rates for large commercial and industrial customers have four rate levels. Like the existing TOU rate structures, the new dynamic CPP rates have an additional mid-peak level. The mid-peak period runs from 7 am to 2 pm and from 6 pm to 11 pm on every weekday. The critical rate was calculated with the same methodology described for medium C&I customers. Both the off-peak rate and mid-peak rates were set equal to the off-peak and mid-peak energy components of the existing TOU rate. Then, the peak rate was solved for revenue neutrality based on the load profiles for Large Commercial and Industrial customers.

IV. Time-of-Use Rates (TOU)

The TOU rate divides the day into two or more time periods, with a different rate for each period. For example, a peak period might be defined as the period from 12 pm to 6 pm on weekdays, with the remaining hours being considered off-peak. The rate would be higher during the peak period and lower during the off-peak, mirroring the variation in the cost of supplying electricity during those time periods. With the TOU, there would be no uncertainty as to what the rates would be and when they would occur. In other words, the TOU rate is not ''dispatchable,'' and would not technically be considered a ''dynamic'' rate according to many definitions. Figure 2 compares the TOU rate to a flat rate on a weekday.

A TOU rate was designed for the Residential customer class and for the Medium C&I customer class. The TOU was designed to apply only to the summer period from June through September, and the peak period was defined as 2 pm to 6 pm on every weekday.

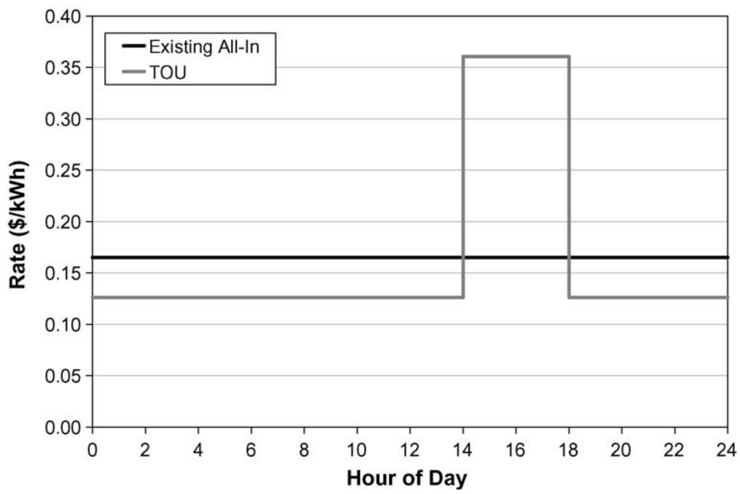

Figure 2: Illustrative TOU Rate

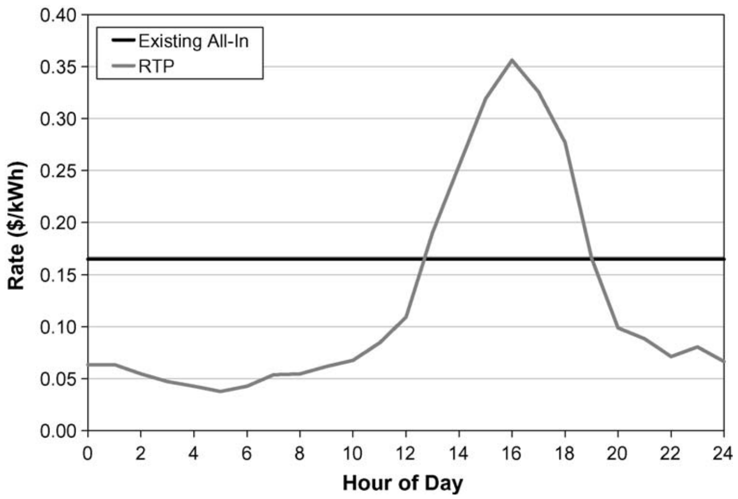

Figure 4: Illustration of RTP Rate

Table 3: Peak Time Rebate All-In Rates and Peak Rebate

	Residential	Medium C&I	Large Industrial	Large Commercial
Existing All-In Rate (Summer)	0.165	N/A	N/A	N/A
New All-In Rate	0.168	N/A	N/A	N/A
Peak Rebate	−0.875	N/A	N/A	N/A
Off-Peak Change	0.000	N/A	N/A	N/A

subtracted from the critical rate. The CPP/TOU critical rate was calculated to be $1.04/kWh and the all-in rate was $0.165/kWh. Therefore the peak rebate is $0.875 for each kilowatt-hour of demand response.

VI. Real-Time Pricing (RTP)

Participants in RTP programs pay for energy at a rate that is linked to the hourly market price for electricity. Participants are made aware of the hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers (generally above 1 MW of load) face hour-ahead prices. These rates include prices that reflect the cost of producing electricity at the most granular level of all rates considered in this article.

RTP programs are generally only offered to Large C&I customers with the exception of Illinois, where two utilities currently offer them to their residential customers. Figure 4 shows how the price for electricity under an RTP program could compare to a flat rate on a peak summer day.

In contrast to the other rates in this article, the RTP rate was designed to be in effect for the entire year, not just the summer. To create this year-round rate with hourly variability, California PX wholesale market prices for SP15 and the year 1999 were utilized. These prices were used as the basis for the price shape, because they represented the best approximation of a time period for which there was robust California electricity market price data with somewhat normal market conditions. The post-1999 market data was heavily influenced by market manipulation and other anti-competitive behavior, and market simulations did not produce the hourly variation in prices normally seen in electricity markets. Today's California ISO real-time electricity market is fairly illiquid and includes price patterns that are not truly representative of marginal energy costs.

The first step in creating the RTP rate was to scale the historical hourly market prices to today's energy costs. This was done in such a way that the scaled price series would equal the generation rate for each customer class. The scaling factors that were used to make this adjustment to the market prices are presented in the second row of **Table 4**.

The next step was to allocate capacity costs. The approach that was taken in this study was to allocate the costs equally across hours. An alternative approach for allocating capacity costs that would send a stronger price signal to customers is described later in this section. The remaining components of the existing tariff are applied under the new rate just as they are under the existing tariff. Table 4 quantifies the hourly variability in the final RTP rates.

Table 2: Time-of-Use All-In Rates

	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Summer)	16.5	15.3	N/A	N/A
Peak Rate	36.1	31.0	N/A	N/A
Off-Peak Rate	12.6	10.0	N/A	N/A

The first step in designing the Residential rate was to set the off-peak energy rate to $0.126/kWh, the same estimate of off-peak marginal energy costs that was assumed in calculating the CPP/TOU rate. The peak rate was then solved to be revenue-neutral to the existing rate using the average Residential customer's load profile. The Medium C&I TOU was created in a similar manner. The off-peak rate was set equal to the assumed marginal energy cost for that period, with a slight discount to ultimately produce a significant peak-to-off-peak differential. Then, the peak rate was solved for revenue neutrality. It was assumed that the generation demand charge would be recovered through the peak rate in the revenue neutrality calculation. As a result, the Medium C&I TOU rate does not additionally include a generation demand charge. Table 2 outlines the TOU rate structures created for Residential and Medium C&I customers.

V. Peak-Time Rebate (PTR)

Because of the presence of Assembly Bill 1X, which prevents CPP rates from being offered to residential customers, the utilities in California have proposed deployment of peak-time rebate (PTR) as the dynamic rate for the residential customer class. Rather than charging a higher rate during critical events, the PTR gives customers the opportunity to buy through at the existing rate. However, customers have an incentive for reducing critical-peak usage in the form of a rebate that for each kilowatt-hour of load reduction that is provided during the critical period. Figure 3 illustrates the PTR rate on a critical day. It is important to note that this rate structure requires the establishment of a baseline load for each individual customer, from which the reductions can be computed.

While all forms of dynamic pricing are designed to provide customers with the opportunity to save on their electric bill, the PTR provides a level of bill protection that is not embedded in these other rates. Because it provides a rebate during critical events but does not increase the rate during other hours, in the short run a customer's bill can only decrease under the PTR. However, payment of the rebates will result in an increase in the utility's revenue requirement and, as a result, an increase in the electricity rate in the future. It is estimated that this increase would be equal to 1.5 percent of the existing all-in rate. This has been illustrated in Figure 4 and is shown in Table 3 as an increase in the existing rate from $0.165/kWh to $0.168/kWh.

For this analysis, a PTR rate was developed for Residential customers as this is the only rate class that is likely to be offered a PTR in California. The rebate given for demand response during critical hours is determined using the critical-peak rate in the residential CPP/TOU. The rebate is simply the existing all-in rate

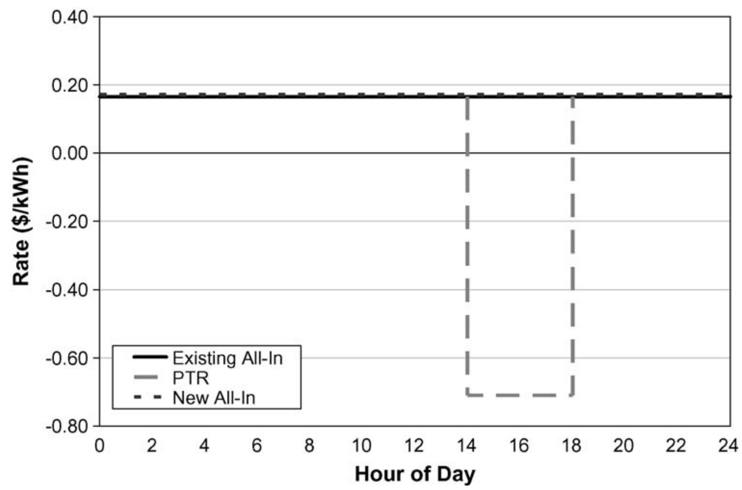

Figure 3: Illustrative PTR Rate

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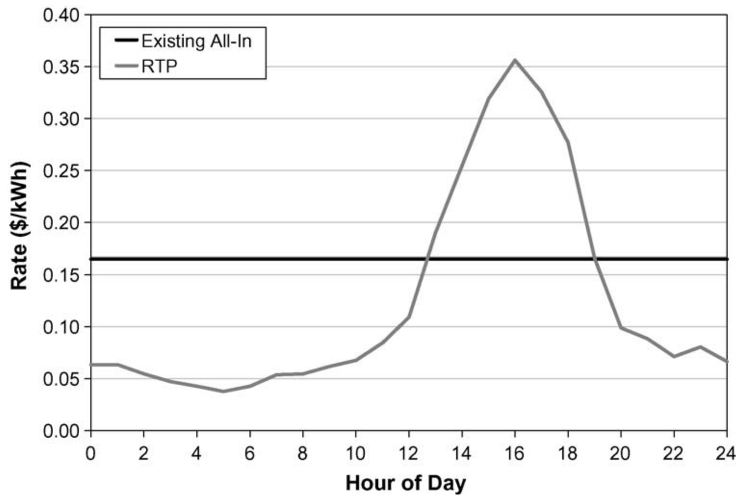

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Peak Rebate	−0.875	N/A	N/A	N/A
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subtracted from the critical rate. The CPP/TOU critical rate was calculated to be $1.04/kWh and the all-in rate was $0.165/kWh. Therefore the peak rebate is $0.875 for each kilowatt-hour of demand response.

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The next step was to allocate capacity costs. The approach that was taken in this study was to allocate the costs equally across hours. An alternative approach for allocating capacity costs that would send a stronger price signal to customers is described later in this section. The remaining components of the existing tariff are applied under the new rate just as they are under the existing tariff. Table 4 quantifies the hourly variability in the final RTP rates.

Table 4: Range of Prices under RTP

	Residential	Medium C&I	Large Commercial	Large Industrial
Existing All-In Rate (Year-round)	16.3	12.1	11.5	7.6
Scaling Factor	3.1	2.4	2.4	1.9
Max Hourly Price (cents/kWh)	69.4	54.0	55.4	43.3
Simple Average Price (cents/kWh)	8.2	6.4	6.5	5.1
75th Percentile Price (cents/kWh)	9.8	7.6	7.8	6.1
25th Percentile Price (cents/kWh)	5.8	4.5	4.6	3.6

A. An alternative approach to RTP rate design

The RTP rate that was described previously allocates the cost of capacity across all hours. An alternative approach could be to allocate this cost only to the critical-peak hours, using a methodology similar to that used to develop the CPP/TOU rate. This would send a stronger price signal to customers and, as a result, encourage greater demand response at times when it is needed most. The extent to which hourly electricity prices do not reflect this capacity cost may also be a more equitable means of allocating the costs.

This alternative RTP design is referred to in this study as the Peak RTP. An illustration of how this rate would differ from the other RTP rate design (referred to hereafter as the ''Smooth RTP'') is shown in Figure 5.

The Peak RTP rate is significantly higher than the Smooth RTP during critical hours, but presents an off-peak discount during all other hours of the year. This would provide customers with opportunities for larger bill savings and, thus, a greater incentive to shift load away from the critical-peak periods.

VII. The Potential Impact of Dynamic Pricing

The illustrative rates described in the previous section have the potential to meet the four ratemaking objectives identified in a recent whitepaper: economic efficiency, equity, choice, and simplicity.[2] However, it is difficult to know exactly how well these rates will perform under these criteria since they have not been offered to California's customers. Regardless, the impacts of the rates can be simulated using the best available data to develop a deeper understanding of the relative magnitude of the benefits that each rate may provide. In this section the results of such simulations are summarized. Specifically, the simulations produced estimates of impacts on-peak demand and monthly bills at the individual customer level. These impacts were developed for a distribution of customers and multiplied into system-level data to arrive at projections of the impacts on the California economy in terms of overall peak demand reduction and the change in the total resource cost.

The approach employed to assess load response is driven by a modeling system called The PRISM (Pricing Impact Simulation Model) Suite. PRISM was developed during the

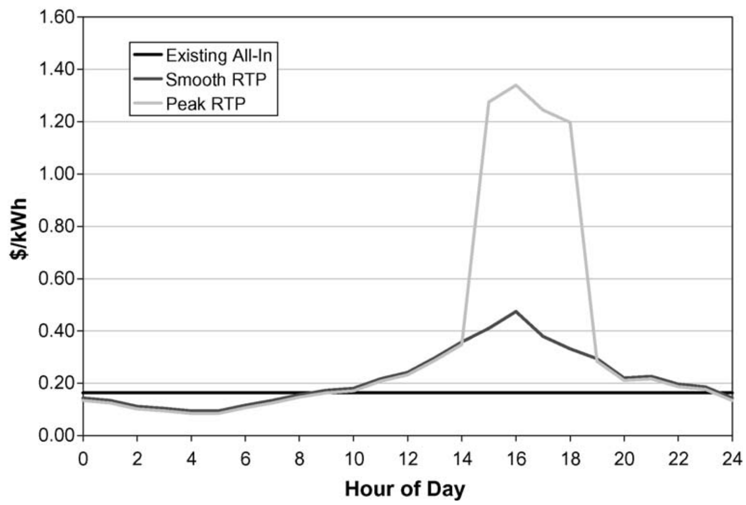

Figure 5: Comparison of Peak RTP to Smooth RTP on Critical Day

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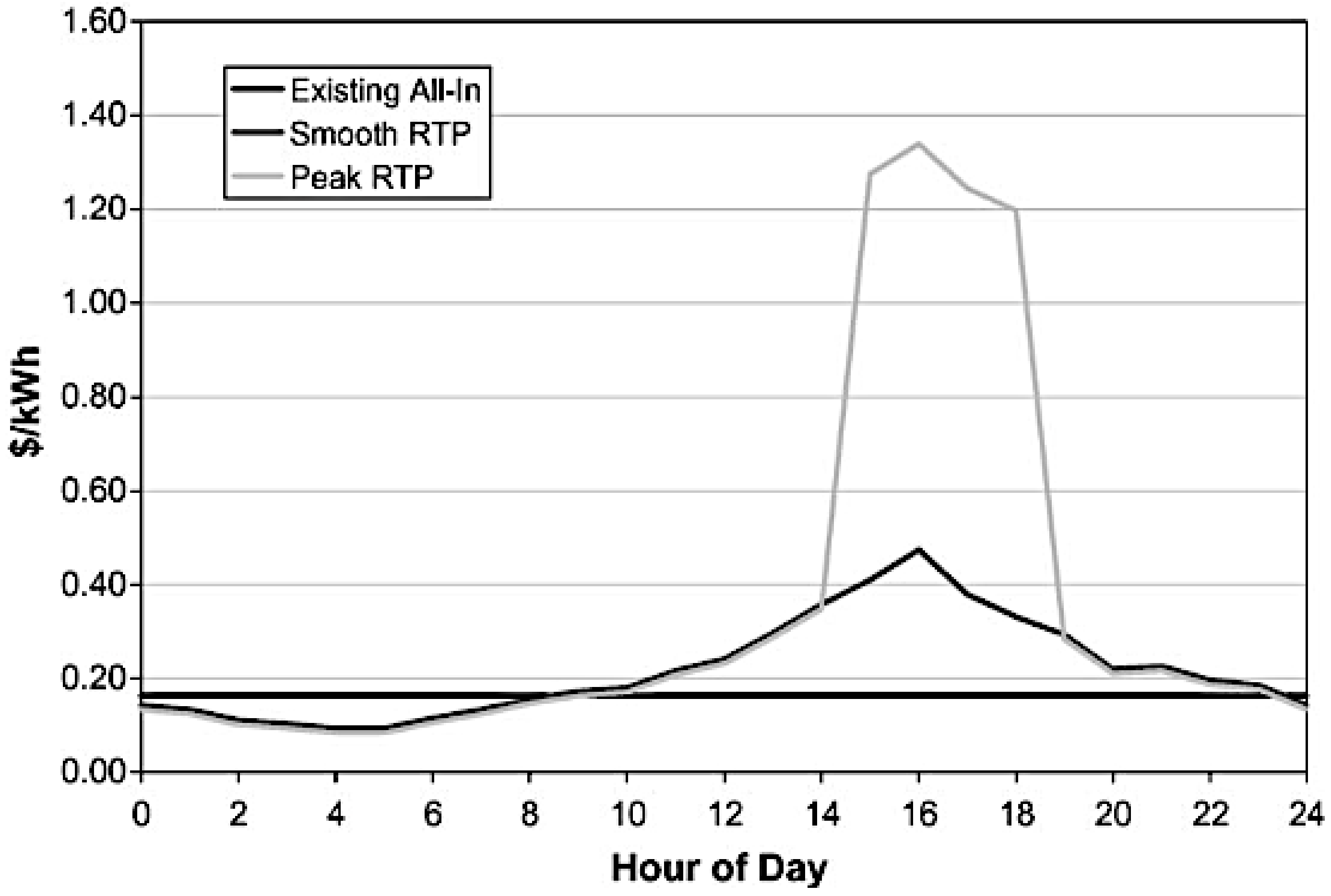


Figure 5: Comparison of Peak RTP to Smooth RTP on Critical Day

Step 1: Menentukan Tarif dan Biaya Tetap

Kategori Waktu	Tarif (¢/kWh)

Customer Charge (Single-Phase) = $13.00 per bulan

Minimum Charge (Single-Phase) = $26.50 per bulan (jika total biaya di bawah ini, pelanggan tetap membayar minimal $26.50)

1. Customer Charge ($13.00 per bulan)

Apa itu?
Customer Charge adalah **biaya tetap yang harus dibayar oleh setiap pelanggan**, terlepas dari jumlah listrik yang mereka gunakan.

Mengapa ada Customer Charge?
Biaya ini digunakan oleh penyedia listrik untuk menutupi **biaya administrasi, pemeliharaan meter, dan layanan pelanggan**, meskipun pelanggan tidak menggunakan listrik sama sekali.

Contoh:

Jika seseorang tidak menggunakan listrik sama sekali dalam satu bulan (0 kWh), mereka tetap harus membayar **$13.00** sebagai biaya tetap.

- **Apa itu?**
  Minimum Charge adalah jumlah **biaya listrik minimum** yang harus dibayar pelanggan **setiap bulan**, termasuk pemakaian listrik dan customer charge.
- **Bagaimana cara kerjanya?**
  - Jika total biaya listrik (dari penggunaan kWh + Customer Charge) **lebih besar dari $26.50**, maka pelanggan membayar sesuai jumlah yang dihitung.
  - Jika total biaya listrik **lebih kecil dari $26.50**, pelanggan tetap harus membayar **minimal $26.50**.
- **Tujuan Minimum Charge:**
  Ini digunakan untuk memastikan bahwa pelanggan yang memiliki **pemakaian listrik sangat rendah** tetap berkontribusi pada biaya operasional sistem listrik, seperti pemeliharaan jaringan dan infrastruktur

3. Contoh Perhitungan

Misalkan seorang pelanggan hanya menggunakan **50 kWh** dalam sebulan. Kita hitung total biaya:

1. **Hitung Biaya Pemakaian Listrik:**
   - Misalkan menggunakan tarif **Flat Rate** yang kita hitung sebelumnya (**11.8479 ¢/kWh**).
   - Biaya listrik:

$$(50 \times 11.8479) \div 100 = 5.924 \text{ USD}$$

2. **Tambahkan Customer Charge ($13.00):**
   - Total biaya sebelum Minimum Charge:

$$5.924 + 13.00 = 18.924 \text{ USD}$$

3. **Bandingkan dengan Minimum Charge:**
   - Karena **$18.92 lebih kecil dari $26.50**, pelanggan tetap harus membayar **$26.50**.

4. Contoh Perhitungan Lain: Konsumsi Lebih Besar

Misalkan pelanggan menggunakan **300 kWh** dalam sebulan, maka:

1. **Hitung Biaya Pemakaian Listrik:**

$$(300 \times 11.8479) \div 100 = 35.5437 \text{ USD}$$

2. **Tambahkan Customer Charge ($13.00):**

$$35.5437 + 13.00 = 48.5437 \text{ USD}$$

3. **Bandingkan dengan Minimum Charge:**
   - Karena **$48.54 lebih besar dari $26.50**, pelanggan membayar **$48.54**, bukan minimum charge.

1. **Customer Charge** adalah biaya tetap yang harus dibayar setiap bulan, **terlepas dari pemakaian listrik**.
2. **Minimum Charge** adalah batas minimal yang harus dibayar pelanggan setiap bulan, jika total tagihan mereka **lebih kecil dari $26.50**. **Jika total tagihan lebih besar dari Minimum Charge, pelanggan membayar sesuai pemakaian listrik mereka**.
3. **Minimum Charge penting untuk menjaga keberlanjutan infrastruktur listrik, meskipun pelanggan memiliki pemakaian sangat rendah**.

Step 2: Menentukan Pola Konsumsi Listrik

A. Pelanggan yang Mengikuti TOU (Mengoptimalkan Konsumsi ke Off-Peak)

Kategori Waktu	Konsumsi (kWh)
Priority Peak (Mahal)	200 kWh
Mid-Peak (Sedang)	500 kWh
Off-Peak (Murah)	500 kWh

B. Pelanggan yang Tidak Mengikuti TOU (Menggunakan Listrik Merata)

Kategori Waktu	Konsumsi (kWh)
Priority Peak (Mahal)	400 kWh
Mid-Peak (Sedang)	500 kWh
Off-Peak (Murah)	300 kWh

Ada dua skenario **dengan total konsumsi yang sama (1.200 kWh)**

Konversi tarif dari **¢/kWh ke USD** dilakukan dengan rumus:

$$\text{Biaya per kategori} = (\text{Konsumsi (kWh)} \times \text{Tarif (¢/kWh)}) \div 100$$

A. Perhitungan untuk Pelanggan yang Mengikuti TOU

1. **Priority Peak:**

$$(200 \times 15.6812) \div 100 = 31.3624 \text{ USD}$$

2. **Mid-Peak:**

$$(500 \times 12.6812) \div 100 = 63.4060 \text{ USD}$$

3. **Off-Peak:**

$$(500 \times 7.1812) \div 100 = 35.9060 \text{ USD}$$

4. **Total sebelum biaya tetap:**

$$31.3624 + 63.4060 + 35.9060 = 130.6744 \text{ USD}$$

5. **Total setelah biaya tetap:**

$$130.6744 + 13.00 = 143.6744 \text{ USD}$$

Karena **totalnya lebih besar dari minimum charge ($26.50), pelanggan membayar $143.67**.

Step 3: Menghitung Biaya Listrik dalam USD

B. Perhitungan untuk Pelanggan yang Tidak Mengikuti TOU

1. **Priority Peak:**

$$(400 \times 15.6812) \div 100 = 62.7248 \text{ USD}$$

2. **Mid-Peak:**

$$(500 \times 12.6812) \div 100 = 63.4060 \text{ USD}$$

3. **Off-Peak:**

$$(300 \times 7.1812) \div 100 = 21.5436 \text{ USD}$$

4. **Total sebelum biaya tetap:**

$$62.7248 + 63.4060 + 21.5436 = 147.6744 \text{ USD}$$

5. **Total setelah biaya tetap:**

$$147.6744 + 13.00 = 160.6744 \text{ USD}$$

Karena **totalnya lebih besar dari minimum charge ($26.50), pelanggan membayar $160.67**.

Step 4: Menghitung Penghematan dari Mengikuti TOU

$$\text{Penghematan} = \text{Biaya Non-TOU} - \text{Biaya TOU}$$

$$160.6744 - 143.6744 = 17 \text{ USD}$$

Persentase penghematan:

$$\left(\frac{17}{160.6744}\right) \times 100 = 10.58\% \text{ penghematan}$$

Kesimpulan

1. **Pelanggan yang mengikuti TOU membayar $143.67**, sedangkan pelanggan yang tidak mengikuti TOU membayar **$160.67**.
2. **Penghematan mencapai 10.58%** dengan memindahkan konsumsi listrik ke jam **off-peak**.
3. **Pelanggan yang tidak mengikuti TOU membayar lebih mahal karena terlalu banyak menggunakan listrik di priority peak yang memiliki tarif tertinggi.**
4. **TOU menjadi strategi yang efektif untuk pelanggan yang memiliki fleksibilitas dalam mengatur konsumsi listriknya**

VS FLAT TARIF

Perbandingan Tarif TOU, Non-TOU, dan Flat Rate

- Sekarang kita membandingkan skenario **TOU**, **Non-TOU**, dan **Flat Rate** untuk pelanggan yang memiliki total konsumsi listrik yang sama (**1.200 kWh per bulan**).

Step 1: Menentukan Tarif Flat

Sebagai pendekatan, kita menetapkan **tarif flat sebagai rata-rata dari tarif TOU**:

$$\text{Tarif Flat} = \frac{\text{Tarif Priority Peak} + \text{Tarif Mid-Peak} + \text{Tarif Off-Peak}}{3}$$

$$= \frac{15.6812 + 12.6812 + 7.1812}{3} = 11.8479\ ¢/\text{kWh}$$

Step 2: Menghitung Biaya Listrik dengan Tarif Flat

$$\boxed{\text{Biaya Flat} = (\text{Total Konsumsi (kWh)} \times \text{Tarif Flat (¢/kWh)}) \div 100 + \text{Customer Charge}}$$

$$= (1.200 \times 11.8479) \div 100 + 13.00$$

$$= 142.1748 + 13.00 = 155.1748 \text{ USD}$$

Dibandingkan dengan minimum charge ($26.50), pelanggan tetap membayar $155.17 karena lebih besar dari minimum charge.

Step 3: Perbandingan Biaya di Setiap Skenario

Skenario Tarif	Total Biaya Bulanan (USD)
Mengikuti TOU	$143.67
Tidak Mengikuti TOU	$160.67
Flat Rate (Rata-rata)	$155.17

1. Pelanggan dengan TOU membayar lebih murah daripada skenario lainnya ($143.67).
2. Pelanggan dengan tarif flat membayar lebih murah dibanding pelanggan yang tidak mengikuti TOU, tetapi masih lebih mahal daripada pelanggan yang mengikuti TOU.
3. Tarif flat menjadi alternatif yang stabil bagi pelanggan yang tidak bisa mengatur pola konsumsi listrik mereka ke jam-jam tertentu.

Menentukan Nilai Tarif CPP

1. **Critical Peak Pricing (CPP)** adalah tarif yang lebih tinggi yang dikenakan saat beban sistem listrik mencapai puncak kritis. Biasanya, ini terjadi selama **hari-hari tertentu ketika permintaan listrik sangat tinggi**, seperti saat musim panas dengan suhu ekstrem.
2. Untuk menetapkan **tarif CPP**, kita bisa menggunakan pendekatan berikut:
   - **CPP harus lebih mahal dibandingkan Priority Peak,** karena ini hanya berlaku dalam kondisi kritis.
   - **Biasanya 1.5 hingga 3 kali lipat dari Priority Peak**, tergantung dari regulasi dan insentif pengelolaan beban listrik.
   - Dari tarif sebelumnya:
   - **Priority Peak = 15.6812 ¢/kWh**
   - Kita tetapkan $\text{CPP} = 2 \times 15.6812 = 31.3624 \text{ ¢/kWh}$ nario awal.

Struktur Tarif Setelah Penambahan CPP

Kategori Waktu	Tarif (¢/kWh)
Critical Peak Pricing (CPP) (Waktu Puncak Kritis)	**31.3624 ¢/kWh**
Priority Peak (5-9 PM, Senin - Jumat)	15.6812 ¢/kWh
Mid-Peak (7 AM - 5 PM, Senin - Jumat & 5-9 PM, Sabtu - Minggu)	12.6812 ¢/kWh
Off-Peak (9 PM - 7 AM, setiap hari & 7 AM - 5 PM, Sabtu - Minggu)	7.1812 ¢/kWh
Flat Rate (Rata-rata TOU sebelumnya)	11.8479 ¢/kWh

Step 2: Menentukan Pola Konsumsi Listrik

Kita buat **3 skenario** dengan **event CPP** yang terjadi selama **50 kWh**:

A. Pelanggan TOU + CPP (pelanggan taat TOU tetapi kena CPP)

- **CPP Event:** 50 kWh (mengambil dari Priority Peak)
- **Priority Peak (Normal):** 150 kWh (200 kWh - 50 kWh)
- **Mid-Peak:** 500 kWh
- **Off-Peak:** 500 kWh

B. Pelanggan Non-TOU + CPP (Tidak peduli TOU)

- **CPP Event:** 50 kWh (mengambil dari Priority Peak)
- **Priority Peak (Normal):** 350 kWh (400 kWh - 50 kWh)
- **Mid-Peak:** 500 kWh
- **Off-Peak:** 300 kWh

C. Pelanggan Flat Rate

- **Total konsumsi tetap 1.200 kWh** tanpa pembagian waktu.

Step 3: Menghitung Biaya Listrik dalam USD

A. Pelanggan TOU dengan CPP

$$\text{Biaya CPP} = (50 \times 31.3624)/100 = 15.6812 \text{ USD}$$

$$\text{Biaya Priority Peak} = (150 \times 15.6812)/100 = 23.5218 \text{ USD}$$

$$\text{Biaya Mid-Peak} = (500 \times 12.6812)/100 = 63.4060 \text{ USD}$$

$$\text{Biaya Off-Peak} = (500 \times 7.1812)/100 = 35.9060 \text{ USD}$$

$$\text{Total Sebelum Customer Charge} = 15.6812 + 23.5218 + 63.4060 + 35.9060 = 138.515 \text{ USD}$$

$$\text{Total Setelah Customer Charge} = 138.515 + 13.00 = 151.515 \text{ USD}$$

B. Pelanggan Non-TOU dengan CPP

$$\text{Biaya CPP} = (50 \times 31.3624)/100 = 15.6812 \text{ USD}$$

$$\text{Biaya Priority Peak} = (350 \times 15.6812)/100 = 54.8842 \text{ USD}$$

$$\text{Biaya Mid-Peak} = (500 \times 12.6812)/100 = 63.4060 \text{ USD}$$

$$\text{Biaya Off-Peak} = (300 \times 7.1812)/100 = 21.5436 \text{ USD}$$

$$\text{Total Sebelum Customer Charge} = 15.6812 + 54.8842 + 63.4060 + 21.5436 = 155.515 \text{ USD}$$

$$\text{Total Setelah Customer Charge} = 155.515 + 13.00 = 168.515 \text{ USD}$$

C. Pelanggan Flat Rate

$$\text{Biaya Flat} = (1.200 \times 11.8479)/100 + 13.00 = 155.1748 \text{ USD}$$

Step 4: Perbandingan Biaya di Setiap Skenario

Skenario Tarif	Total Biaya Bulanan (USD)
TOU + CPP	$151.52
Non-TOU + CPP	$168.52
Flat Rate	$155.17

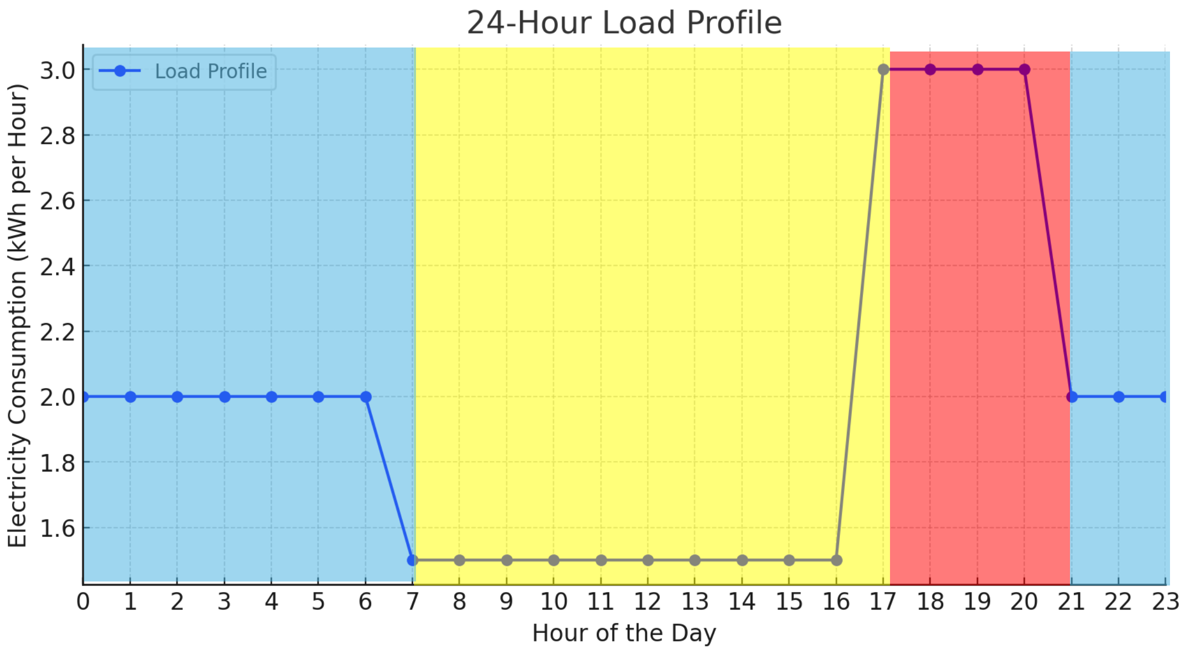
Step 5: Analisis dan Kesimpulan

1. Pelanggan TOU masih lebih hemat dibandingkan Non-TOU, meskipun ada event CPP.
2. Non-TOU lebih mahal ($168.52) karena masih banyak konsumsi di Priority Peak.
3. Flat Rate lebih stabil ($155.17), tetapi tetap lebih mahal dari TOU.
4. Strategi terbaik untuk pelanggan adalah menghindari CPP dengan cara mengurangi konsumsi listrik pada jam-jam kritis.
5. Pelanggan yang bisa memanfaatkan TOU dan menghindari CPP tetap membayar paling sedikit.

ILUSTRASI BEBAN HARIAN dalam tarif dinamis

Tarif Listrik

- **Priority Peak = 40 sen/kWh = $0.40/kWh**
- **Mid-Peak = 20 sen/kWh = $0.20/kWh**
- **Off-Peak = 10 sen/kWh = $0.10/kWh**
- **Tarif Flat = 15 sen/kWh = $0.15/kWh**
- **Customer Charge = $1.00 per hari** (biaya tetap per hari)
- **Red (Priority Peak, 17:00 - 21:00)** → Tarif tertinggi.
- **Yellow (Mid-Peak, 07:00 - 17:00)** → Tarif sedang.
- **Light Blue (Off-Peak, 21:00 - 07:00)** → Tarif paling murah.



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