Renewable energy balancing non-liberalized electricity markets

Juan-José Díaz González

Tim Mennel

Christian Hewicker

1 INTRODUCTION

As part of their commitments under the Paris Climate Agreement of 2015, more and more countries around the globe are undertaking climate change mitigation efforts. Many countries with emerging economies have chosen to set targets for the expansion of renewable energy use, including, among the other sectors, in electricity generation. This leads to new challenges: While hydro power has existed in many countries for decades, new renewable technologies such as onshore wind, solar PV and biomass/-gas are phased-in into the electricity system. The use of variable renewable energy sources has, however, a number of implications for the electricity supply system as a whole. Countries with high shares today have adapted new allocation and system control mechanisms over the past decade to ensure system stability as well as cost efficiency of supply. As for European countries, the power supply systems have undergone substantial changes: changes in market design, and to some extent, changes in network operations[1]: Among other measures, intraday markets have been introduced, and marketing options for demand response have expanded. The requirements on VRE installations have widely increased, and so have the ones on network operators.

While these experiences hold relevant lessons for countries following them in the phase-in of renewable energy sources, they cannot be transferred directly to power systems that are not based on market trading of electricity and ancillary services. System operation as well as remuneration of electricity generation is based on an entirely different set of rules. At the same time, after the initial phase-in of wind and solar power by way of fixed feed-in tariffs, measures to ensure system integration have today become an important task (cf. IRENA 2019). Challenges include, among others, long-term security of supply, an increased need for balancing and network stability.

This paper analyses the current practice of VRE system integration in a selected number of non-liberalized electricity markets and studies further regulatory options in systems not based on markets. As the range of topics is quite large, the focus will be on scheduling and remuneration of electricity generation and the availability of capacity; network integration is not analysed specifically. Our focus is on systems with a single-buyer model, as fully vertically integrated electricity supply industry (ESI) have become very rare today. We suggest new measures to cope with growing share of variable renewable generation in the single-buyer models, building on experiences from market based ESI in Europe and the US. Moreover, our contribution will focus on large-scale renewable energy installations. Large-scale installations today are treated like conventional generation assets in market-based systems in many ways, and the experiences offer valuable lessons for non-market-based systems as well.

[1] See Rubino 2016 and references therein.

Despite the urgency, non-market-based system integration has not attracted much attention so far. More precisely, some authors have studied the subject from a techno-economic system perspective (e.g. Bankuti et al. 2018 for Bangladesh); Jensterle et al. provide a public policy perspective including aspects of RE expansion planning, smart grid deployment and public acceptance. In contrast, we address the question which regulatory measures have to be amended or added to the governance of non-market based ESI, present in many emerging economies.

2 STATUS QUO OF VRE SYSTEM INTEGRATION

In this section we briefly review the status quo of power system integration of variable renewable energy. We begin with the case of liberalized electricity supply systems. We distinguish between centralized and decentralized markets, typical for the US and Europe respectively. Next, we review current practice of non-liberalized electricity supply systems in integrating variable renewable energy by way of example. To cover a range of different systems and geographies, we have selected the cases of Malaysia and Egypt, highlighting both experiences and challenges.

2.1 VRE in liberalized electricity systems

Renewable energy sources such as wind, solar and small hydro power are variable, i.e. their generation cannot be controlled in the same manner as conventional generation based on coal, gas or nuclear energy. To study their role in the electricity supply system, a review of the basic functions in the allocation, scheduling and control of electricity is required. By their system and market integration we refer to the set of measures to enable their secure and cost-efficient participation in serving the customer demand.

In a liberalized system, electricity supply is differentiated in four functionalities, generation, transmission, distribution and (retail) supply to final customers. Traditionally, generation was often connected to the highest voltage level, and thus feeding into the transmission network. While the holds true for large hydro and wind generation assets as well, medium- to small renewable energy generation assets, including wind, solar PV, biomass and hydro, feed into the distribution network (see Figure 1). Some large-scale consumers are connected directly to the transmission network, most consumers are supplied via the distribution network.

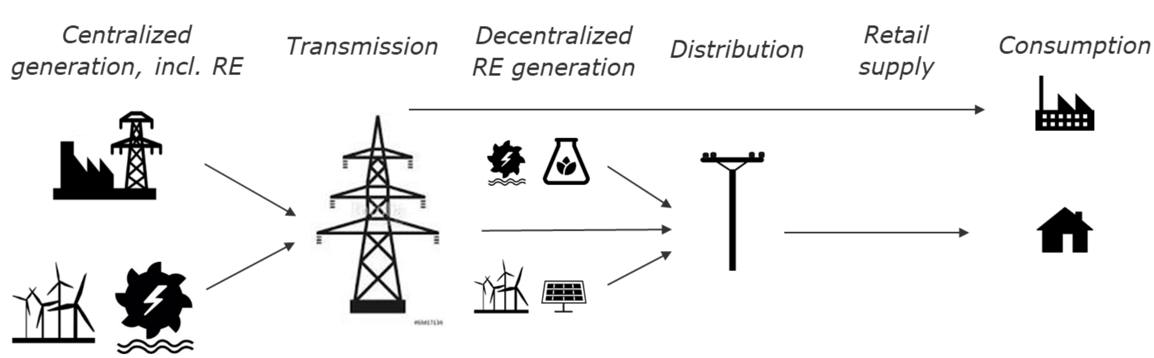

Figure 1: Elements of the electricity supply system

While transmission and distribution are monopolies with regulated revenues, generation is a function with competition in wholesale markets; additionally, electricity trading and retail supply to customers can, but need not, be competitive functions. To enable secure supply, each system is governed by clear rules and dedicated institutions, which can vary in specific aspects but follow some basic patterns (we will explain the basic design choices in U.S. and in European power markets below).

Importantly, a designated system operator[2] has responsibility for the technically safe implementation of dispatch schedules that result from trade in markets where generators commit to deliver and users to consume electricity. To that end, the system operator procures ancillary services[3] from generators and users, normally in competitive markets. In the context of this paper, we focus on the role of the electricity wholesale markets, the role of the system and market operators and the ancillary service markets in integrating variable renewable energy sources.

Support schemes incentivize development and set the role of renewable generation in the market-based system, with direct consequences for the measures aiming at their system integration. For instance, in Europe VRE were first supported by fixed, technology-specific feed-in-tariffs and thus placed outside the market and its price-based remuneration. For large-scale installations[4], the feed-in-tariffs have mostly been replaced over the past decade by feed-in-premia, a remuneration granted additionally to the sales revenue from the wholesale markets[5]. The support schemes and the obligations set on renewable generators have direct consequences on the dispatch and balancing of VRE.

2.1.1 Centralized markets

In centralized markets, all electricity generated is traded at a single market platform, the power pool, which is characterized by the uni-directional exchange of energy from producers to the pool, and from the pool to suppliers. Scheduling is centralized, i.e. the market operator decides both on the (hourly) schedule of each unit and the price to be paid for energy using a central algorithm. In most cases, the pool operates on the basis of one-way bidding, i.e. market clearing is based on centralized demand forecast and suppliers have to accept the price. Alternatively, under two-way bidding suppliers submit bids as well and market clearing is based on a match of demand and supply.

Figure 2 shows the principal structure of trading and clearing in a gross pool, which is e.g. used in some of the U.S. markets, Russia, Australia, New Zealand, Korea, Chile and other countries.

[2] In centralized markets, the role can but need not be combined with the one of the market operator.

[3] These include frequency control as well as not-frequency related services.

[4] In the Guidelines for State Aid in Environmental Protection and Energy 2014-2020, the EU sets a minimal threshold of 500 kW for large-scale installations.

[5] It is a so-called "market based" support mechanism, i.e. a scheme that involves market participation by the installation.

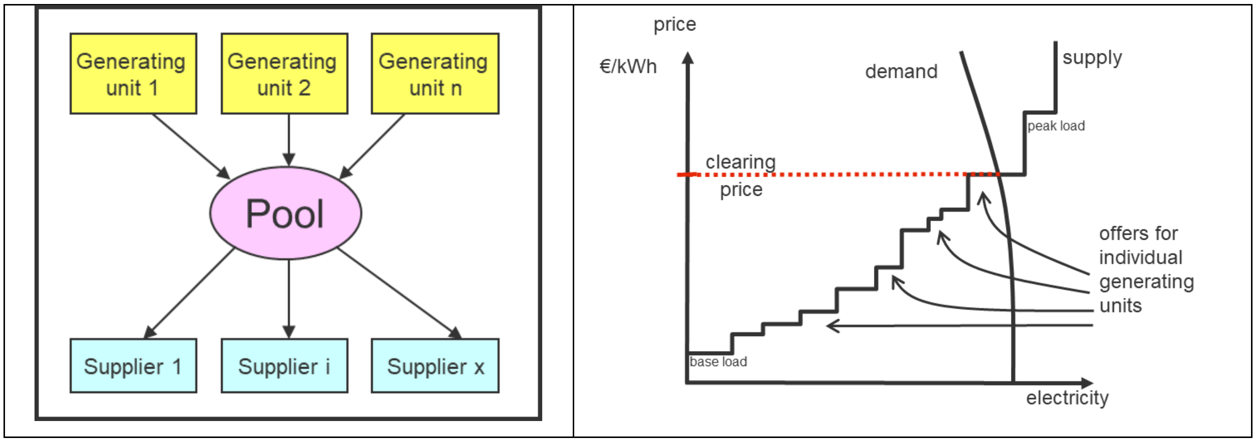

Figure 2: Trading and clearing in a centralised gross pool

A typical example of a pool-based market is the Australian National Electricity Market introduced in 1998 and covering the regions of South Australia, Victoria, ACT, NSW, Tasmania and Queensland. The Australian Electricity Market Operator (AEMO) operates the gross pool and five transmission system operators serve each of the states in the National Electricity Market. Transmission system operators link generators (approximately 200 large electricity generators) to the thirteen major distribution networks that supply electricity to end-users. Energy retailers buy electricity on the wholesale market and then sell it to end users (around 89 retailers).

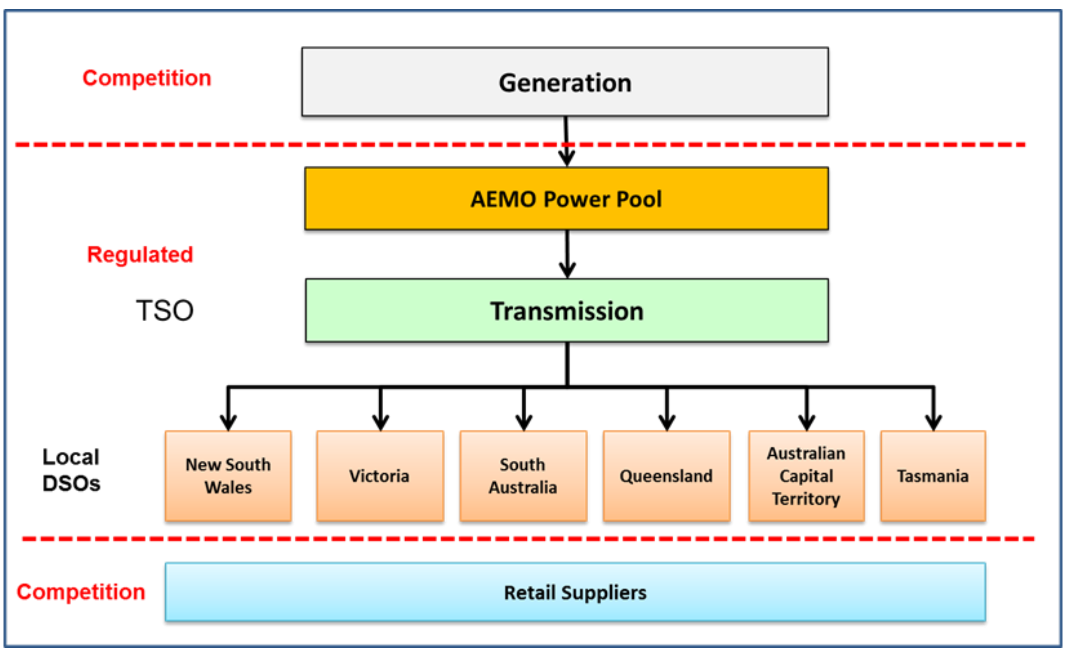

Figure 3: Structure of Australian National Electricity Market (NEM)

A similar case can be found in the United States (US.), where electricity market design is based on power pools run by independent system operators (ISO). Even the market is centralized, it is based on the decentralized decisions of market participants. Central market clearing and dispatch allow the system operator, not only to reliably operate the system, but also to guide market agents towards the optimal dispatch (from the system operator's perspective, taking into account technical and reliability constraints). The two core market elements are the day-ahead market and the real-time market as we will explain later in more detail.

2.1.2 Decentralized markets

Decentralized markets are also called bilateral contract markets, as they allow generators and suppliers to engage into any type of contractual obligations for the delivery of energy, which then provide the basis for the self-scheduling of generators (optimization is done by the generator, not the system operator)[6]. Generators and suppliers act as traders and can either engage in long-term contracts binding both parties for many months or even years, or short-term over-the-counter trading. In contrast to a pool, this market model does not require any central market operator but is essentially based on direct bilateral transactions between different market participants. The market is not cleared based on a centralized market demand forecast but is principally based on a separate supply and demand curve, formed by the individual offers and bids for buying and selling electricity, respectively.

In many countries in Europe this is the prevailing market model but normally bilateral trading is complemented by anonymous trading in a power exchange, i.e. an organized market where a market operator receives bids and offers from market participants and matches them by setting a market-clearing price (unit-price auction). Bidding is usually done on a portfolio basis. The function of market and system operation are fully separate.

The system operator bears responsibility for system planning and operation. Market participants commit to following the schedule resulting from their trading activities, i.e. they commit to a balanced input to and offtake from the system. As deviations are likely to occur, the system operator procures ancillary and balancing services (e.g. frequency control and reserves), ideally via dedicated competitive markets[7]. Such services have traditional been offered by flexible generation units, but are increasingly also provided by demand response and/or storage. The cost of balancing by the system operator are then recovered from market participants through imbalance settlement. Imbalances are typically the result of forecast errors, including load and (weather based) VRE generation forecast, or of unexpected technical problems with generation units.

Germany is a good example of a decentralized market. As in most decentralized markets, the role of the system and the market operator are formally divided: There are four regional TSOs (Amprion, TenneT, 50Hz, TransnetBW) responsible for ensuring the safe and secure operation of the transmission system in their area of operation. As such, they are responsible for ensuring system balance including operational management of operational constraints and of the balancing market. Generators compete both in an anonymous electricity wholesale market and for bilateral contracts, OTC and long-term.

[6] The principle of self-scheduling puts much higher requirements on the ability of producers to themselves schedule their power plants

[7] In some cases where competition cannot be expected due to limited supply, such as blackstart capacity for network restauration, they are subject to administrative procurement, i.e. the system operator uses the service with the remuneration being fixed by regulation.

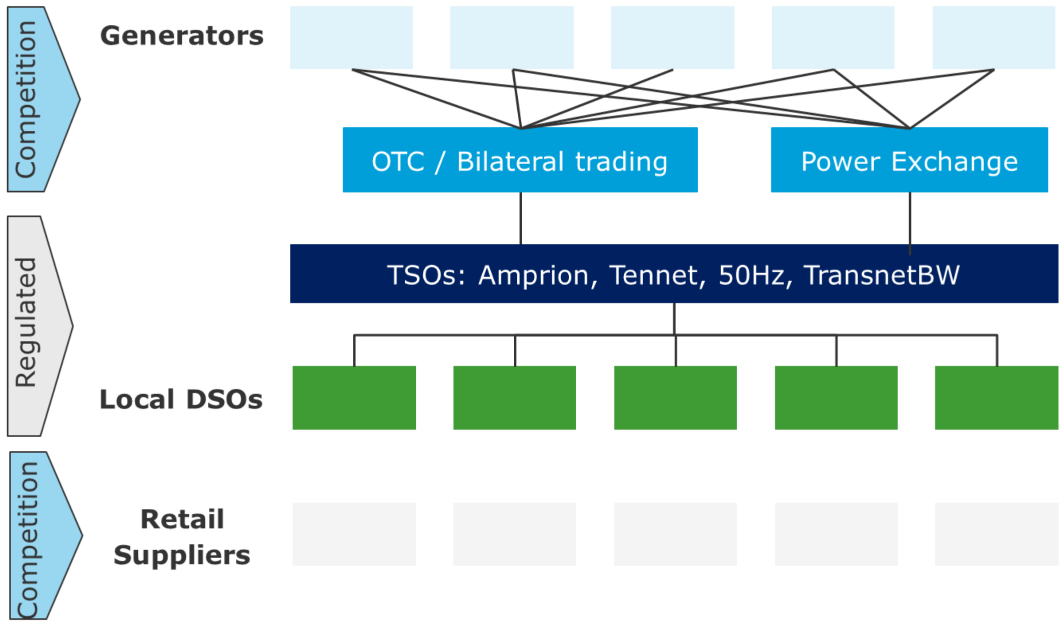

Figure 4: Overview of Electricity Market in Germany Today

2.1.3 Market timeline and VRE integration

In electricity systems ultimately, two targets must be met: First, demand and supply must match precisely, otherwise system stability is endangered. Second, generation should be scheduled and dispatched at least cost, preferably based on a market mechanism. The presence of VRE complicates this fundamental structure, as their generation is variable (depending on the wind and solar radiation at any given moment) and only partially predictable (due to uncertain weather forecasts). As a consequence, specific arrangements have been set up both in centralized and decentralized markets for integrating vRE into the market.

In electricity markets, the initial generation schedule is typically determined one day ahead of delivery, either through an organized market with centralized generation scheduling (i.e. in a centralized market) or as part of internal production planning of market participants in a decentralized market. In the latter case, generators must usually nominate at least indicative generation schedules to the TSO. The outcome is a day-ahead schedule of supply to meet demand.

After the end of the day-ahead market until real time, different market design structures exist. Following two well-implemented alternatives:

- For instance in most US. markets, the day-ahead market is complemented by a real-time market. The latter is based on the same offers as the day-ahead market, but account for variations until real time, such as unplanned outages, changing weather and load forecasts etc. Generators must follow real-time dispatch instructions. Similar to the day-ahead market, the real-time market is financially binding. However, settlement is based on the difference between the original generation schedules and/or purchases (i.e. of retailers) in the day-ahead market, on the one side, and dispatched and/or metered volumes, on the other side.

- In the Spanish market, market participants have the additional option to trade their positions in an intraday market. This means that generators and (potentially) suppliers are able to adjust theirs offers based on generation and demand fluctuations. In real-time, the system operator then dispatches electricity according to the schedule resulting from the outcome of the day-ahead bidding and the subsequent adjustments in the intraday trading.

Figure 5 shows a schematic **market timeline for a decentralized model following the Spanish example**. It should be noted that centralized markets allow trading in forward markets[8] and bilateral contracts with 'physical delivery' (which is not shown in the following figure).

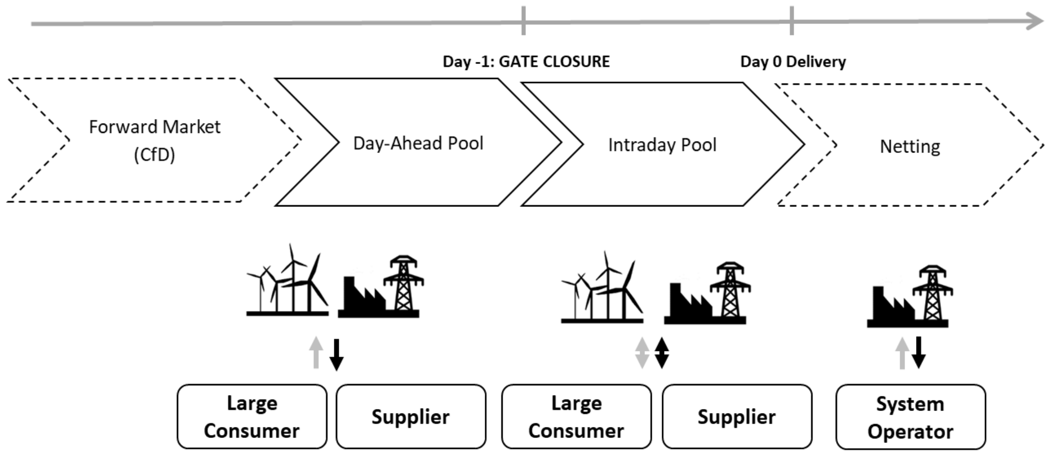

Figure 5: Market timeline in a centralized market (two-sided bidding)

A decentralized system could be described as a combination of a fully decentralized and a central part: The Day-Ahead-Market bears some resemblance to the pool, in that the market operator receives offers by generators and suppliers (and large consumers) and matches demand and supply based on a merit-order approach. Importantly, however, only part of the electricity is traded via the central spot market, with the other part being subject to bilateral trade. Under long-term bilateral contracts, generators commit to delivery to suppliers or large consumers over long periods at fixed prices. In addition, short-term bilateral transactions are undertaken by over-the-counter (OTC) trade. Market participants that want to secure long-term delivery at pre-determined prices have the additional option of trading in forward markets.

During the subsequent hours before delivery, all participants have the option to trade their positions in an intraday market. After intraday trading ends, i.e. at the time of 'gate closure', the final generation and exchange schedules submitted to and confirmed by the system operator (or another central entity) are binding. After gate closure, the system operator controls the balance of the system with the help of a real-time balancing mechanism. For this purpose, the TSO uses balancing services offered by generators, storage, flexible demand etc., which can be activated on short notice and in line with specific technical and contractual specifications.

Figure 6 shows a schematic **market timeline in a decentralized market** following the German example.

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[8] Forward contracts enable market participants to better manage risk

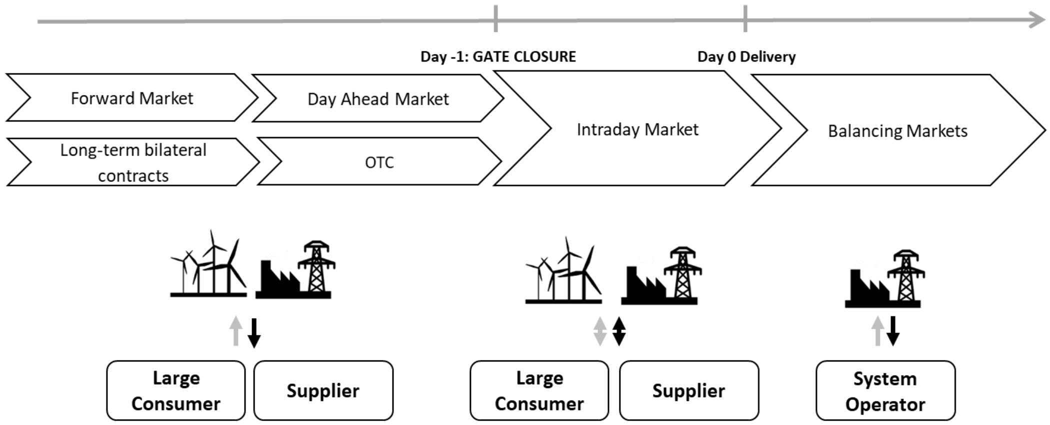

Figure 6: Market timeline in a decentralized market

In the early phase of the energy transition, VRE were usually exempted from any form of centralized scheduling or dispatch by the system operator but were allowed to operate purely based on resource availability. Today in most countries with liberalized markets VRE installations are obliged to participate in the wholesale market and take full balancing responsibility[9], i.e. they have the same status as conventional generators. Consequently, VRE operators are incentivized to improve their scheduling forecast, engage in intraday trading and establish innovative ways to reduce intermittency (e.g. co-location of battery storage). Moreover, they have the option to form virtual power plants by engaging in long-term contractual relationships with demand-response facilities and flexible generators to ensure their faithfulness to scheduling commitments.

In the past two decades, the share of VRE has increased sharply in many market-based electricity supply systems (e.g. Denmark, Ireland and South Australia). Fears that their variable vRE would compromise system stability have not materialized so far, or much less than originally anticipated. While challenges remain and each system has its own specificities as well as energy mix, market arrangements found for VRE have contributed to this positive outcome. It seems plausible to derive some of the lessons learned in liberalized markets can be passed to non-liberalized system with ambitious VRE deployment targets.

2.2 VRE in non-liberalized electricity system

The share of variable renewable energy has grown in some non-liberalized electricity systems and the ambitious renewable-energy targets by 2030 makes it necessary to rethink the design of the electricity system. The measures needed to achieve an efficient integration of a vast amount of renewables will affect different segments of the electricity supply chain. Integration of VRES might become a challenge since no or limited market-based mechanisms are available, and the expansion of variable renewables require a more flexible energy system. Likewise, there is no one-fits-all solutions and the adequate adaptations depend on the existing structure of the power sector, the level of liberalization and renewable

[9] Since 2017, VRE market participation is mandatory in the EU for all installations larger than 500 kW.

integration challenges. In the following, the characteristics of non-liberalized electricity systems will be described and two individual country examples from different regions will be presented.

2.2.1 Characteristics of non-liberalized electricity systems

The traditional power sector model (non-liberalized electricity systems) is based on centralized decision-making by vertically integrated utilities. This vertically integrated utility owns generation and network assets and has a legal obligation to safely supply electricity to end consumers. In this model the government plays a key role, as the vertically integrated utility is either a public or a privately-owned company subject to cost and price regulation and to governmental supervision.[10] In this context, investment decisions w.r.t. transmission and generation expansion are the result of centralized planning under the approval of the government. Is it important to note that the planning process in non-liberalized electricity systems is typically less complex than in liberalised electricity systems[11]. In contrast to electricity generators and suppliers in a liberalized market, cost optimization is not the main aim of vertically integrated utilities. More precisely, the regulated electricity price should be high enough to cover the cost plus the rate-of-return of the utility in addition to the construction, operation and maintenance cost of the power system.

The single buyer model was firstly implemented in the 1990s in some emerging economies as a way to introduce competition between generation plants (promoting cost efficiency) and attract investment to cover the capacity shortages due to increasing demand. Thereby, the generation segment of the power system was opened to new entrants, known as independent power producers (IPPs). Typically, the underlying private investments relied upon a build-own- transfer project approach. In the single buyer system, the IPP sells the output to the purchasing agency for a specific price and duration period in form of a Power purchase agreement (PPA)[12]. The contracts are set in a way that allow the IPP to recover the generation costs (fixed and variable) and include provisions concerning its obligations (e.g. minimum generation level, ancillary services, etc.). In order to reduce the risks for IPP investors, take-or-pay clauses are typically set to grant a minimum dispatch at an established remuneration level. In return for secure revenue streams, IPP are commonly required to be prepared to provide ancillary services to the system operator (sometimes without additional remuneration). Figure 7 illustrates the structural difference between a vertically integrated utility model and a single-buyer model.

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[10] In some countries, privately and publicly owned companies coexist and are both subject to the same traditional cost-of-service regulation.

[11] Since market forces influenced by policies and regulations determine the generation expansion.

[12] A PPA is a contract between the owner of a generation asset (the electricity seller) and an off-taker (the electricity buyer) usually signed for a long-term period between 10-20 years. The PPA may take a number of forms, but are typically designed to ensure that the generator covers its operating costs and earns a return on its investment.

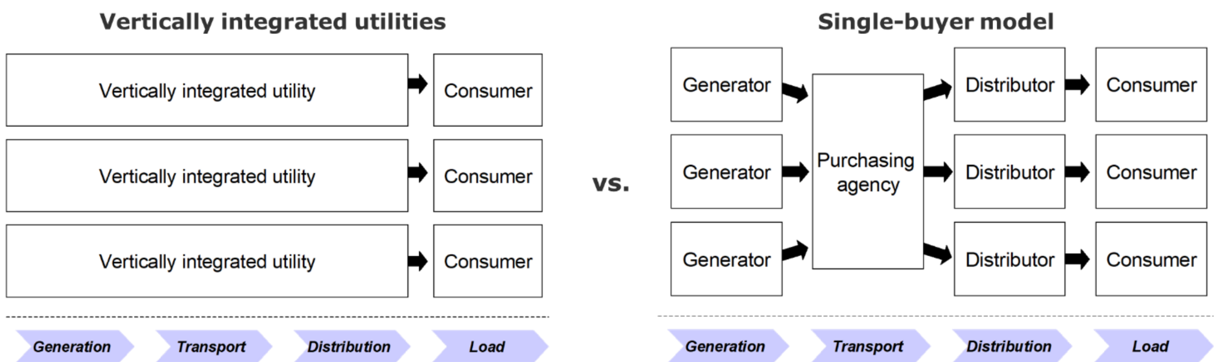

Figure 7: Traditional vertical integrated model vs. single-buyer model

As signatories of the Paris Agreement and committed to respond to the challenge of climate change, countries with a single-buyer model (such as Malaysia or Egypt) have set RE targets to guide the transition of their power mix towards a more renewable based system. VRES (in particular solar PV and wind energy) are emerging as cost-effective alternatives to conventional power plants. Clearly, this is an argument in favour of increasing the share of VRES in the generation mix. The planned expansion of variable renewables will require more flexible energy systems to ensure reliable and cost-effective system integration. This means that planning and operation of the required flexibility level might be achieved through rapid dispatchable generation (as hydro or gas plant), if available. However, even this option has its limitations and entail high capital investment. Thus, other mechanisms should be investigated in order to respond to an increasingly intermittent generation mix.

In the following, two case studies of single buyer power systems in different regions of the world and with VRE experience are presented. All two cases have their own specificities w.r.t their generation mix, system structure, IPP penetration and future RES targets. The analysis of these cases will shed light on the functioning of a single buyer system and the current measures for the integration of utility-scale VRES generations.

2.2.2 Peninsular Malaysia

East Asia and the Pacific is one of the world's fastest-growing economic regions in the world. Located at the tip of the Asian landmass, Malaysia economically relevant in the region and has ambitious RE targets. Malaysia has two separate electricity supply systems: one for Peninsular Malaysia, which is based on a specific version of the single buyer paradigm, and one for East Malaysia, which is vertically integrated. For the purpose of this paper, we will focus on Peninsular Malaysia system, which provides electricity to 26 million people (electrification up to 99.6%) with a planned demand growth of 0.9% p.a. over the next decade[13] and is interconnected with Thailand in the North and Singapore in the South. In terms of electricity generation, Tenaga Nasional Berhad (TNB), the electric utility in Peninsula Malaysia, is the largest public listed power producer in Southeast Asia.

Single Buyer

[13] Peninsular Malaysia Electricity Supply Industry Outlook 2019

The single buyer is in the center of the Malaysian Peninsula system. More precisely, the SB is a dedicated, ring-fenced[14] department within TNB, with the responsibility to manage electricity procurement services. Power generation continues to remain largely in the hands of TNB (holding SLAs[15]) and Independent Power Producers (IPPs) (with PPAs), with a large and medium scale RE generators (mainly solar)[16] entering the system via competitive bidding for long term PPAs or as merchant generators. The New Enhanced Dispatch Agreement (NEDA) was implemented in 2015 and is designed to enhance competition and cost efficiency of the SB market. It allows generators holding a SLA/PPA (TNG generators and IPPs) to compete against merchant generators. In this context, the SB procures electricity from PPA/SLA holders and merchant generators to meet demand at least cost. Besides generation, TNB also keeps its core activities from the past as vertically integrated utility: system operation, transmission, distribution and retail. However, the company acts as a holding of subsidiaries that are tasked with the different functions:

- The system is operated by the ring-fenced Grid System Operator (GSO)
- TNB transmission operates electricity transmission in the transmission level
- TNB distribution is responsible for the distribution of electricity
- Retail activities are undertaken by TNB retail

The following figure presents the structure of the system with a non-regulated and regulated part.

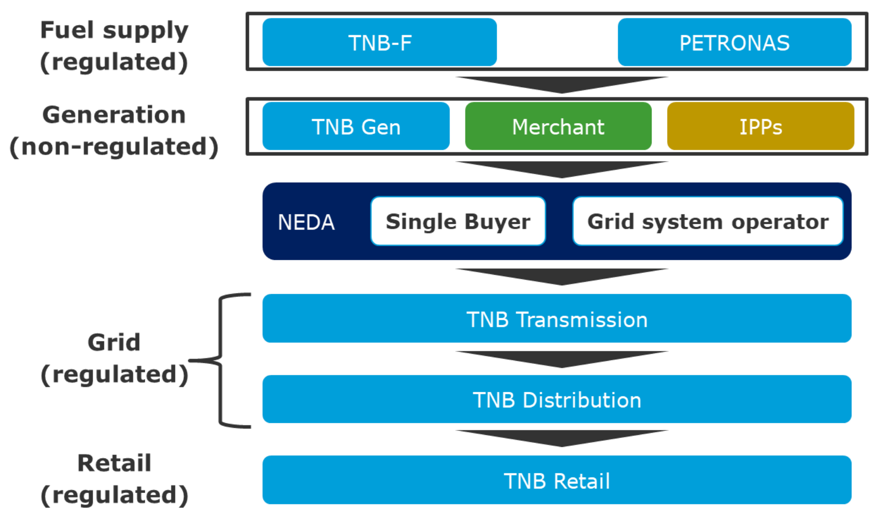

Figure 8: Malaysia electricity system structure

In addition to managing the electricity procurement, the SB takes the responsibility of performing electricity planning, preparing demand forecast reports and long-term capacity plant-up plans to support the development of the Malaysia Electricity Supply Industry (MESI).

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[14] Ring-fencing requirements ensure that the Single Buyer performs its functions and duties in a fair and non-discriminatory manner in managing the contracts or agreements for the purchase of electricity on behalf of the off-taker.

[15] SLA – Service line agreement, a long-term bilateral contract that stipulates the conditions of power sales, similar to a PPA.

[16] In 2018, there were 44 power plants operational in the country (22 gas plants, 7 coal plants, 11 hydroelectricity plants and 4 large scale solar plants).

Participants and scheduling

In the current system, generators can have a PPA/SLA with the SB or be merchant generators. The scheduling process is performed by the SB, which uses the PPA/SLA prices and merchant bids[17] to set the Day-Ahead schedule in the form of a merit-order. The Day-Ahead market relies on system marginal pricing (SMP) where the price is set by the most expensive marginal generator scheduled to meet the load forecast for every 30-min interval (48-SMP per day). Thus, the current model could be described as a cost-based bidding system complemented by an optional price-based bidding resulting in a Least Cost Dispatch Scheduling. The Least Cost Dispatch Scheduling is passed to the GSO, which reruns the schedule when required (e.g. due to transmission constraints) and issues real-time dispatch instructions (except for price takers). Typically, the SLA/PPA includes energy and frequency/balancing response obligations, whose activation falls under the responsibility of the GSO. Each SLA/PPA specifies which capacity shall be used for preserving and frequency response and any failure to meet dispatch instruction has a penalty. The 2,900MW minimum Operating Reserve is available to the GSO within a short interval of time to meet demand, in case a generator goes into forced outage or there is a disruption in supply.[18]

The following figure (Figure 9) presents the interaction of generators with the SB to set the Day-Ahead schedule.

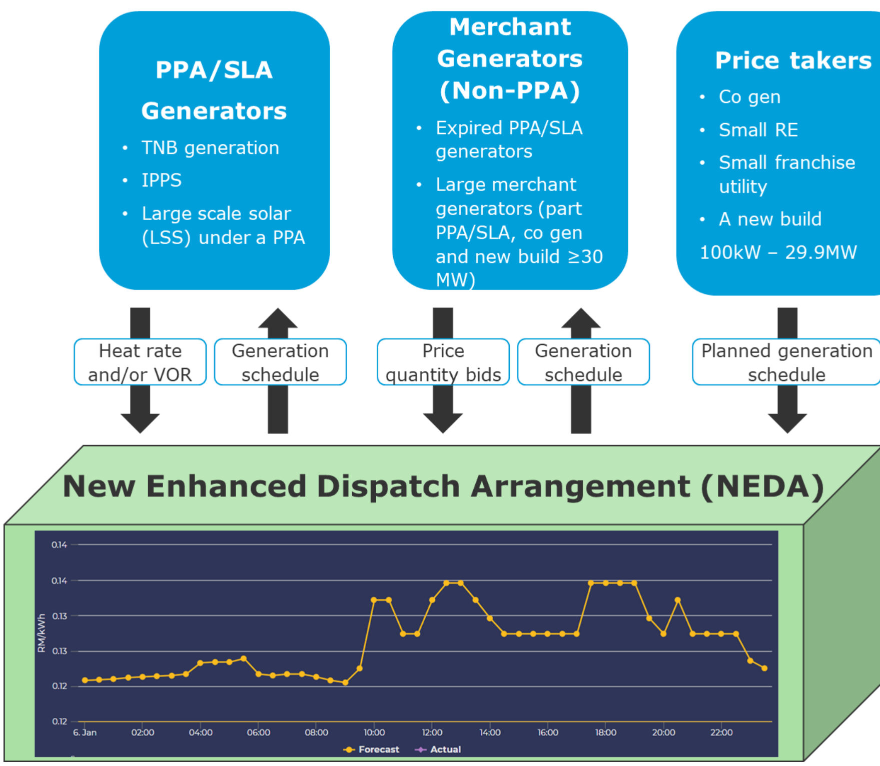

Figure 9: New Enhanced Dispatch Arrangement (NEDA) / Source: DNV based on Briefing Session to NEDA Participants, Single Buyer 2016

17 Another category called price taker exists, which encompasses the small plants. Price takers are not entitled to submit bids and submit just planned generation schedule on D-1.

18 Peninsular Malaysia Electricity Supply Industry Outlook 2019

Generation mix and RES target

The electricity generation mix is dominated by fossil fuels (mainly coal and natural gas) accounting for nearly 90% of generation in 2020[19]. Power generation continues to be heavily reliant on fossil fuels because of its vast availability and technical capacity to generate base load. However, in response to the Paris Agreement, Malaysia has set an ambitious target of reducing carbon emissions by integrating renewable energy into its energy mix, 29% RE capacity share by 2025 in Peninsular Malaysia. Due to its large technical potential and generation profile (converge with demand profile), Malaysia is betting on vast solar energy deployment. According to the 2021-2039 generation development plan, 1,178 MW of new RE capacities is foreseen in Peninsular Malaysia from 2021 onwards (1,098MW of solar and 80MW of non-solar)[20]. As a result, the RE capacity (including large hydro) is projected to increase from 17% in 2021 to 29% in 2030. The foreseen capacity mix development for Peninsula of Malaysia over the next decades is represented in Figure 10, illustrating the remaining fossil fuel dependence and significant RE penetration. The planned increased in variable RE generation creates the need to implement effective renewable integration measures besides grid reinforcements. As a measure to control intermittent generation from solar PV, the Ministry has set a penetration limit for grid connected solar PV at 24% of the estimated peak demand. Besides, new thermal capacity (Combined Cycle Gas Turbine and highly efficient coal plants) is planned to provide system flexibility.

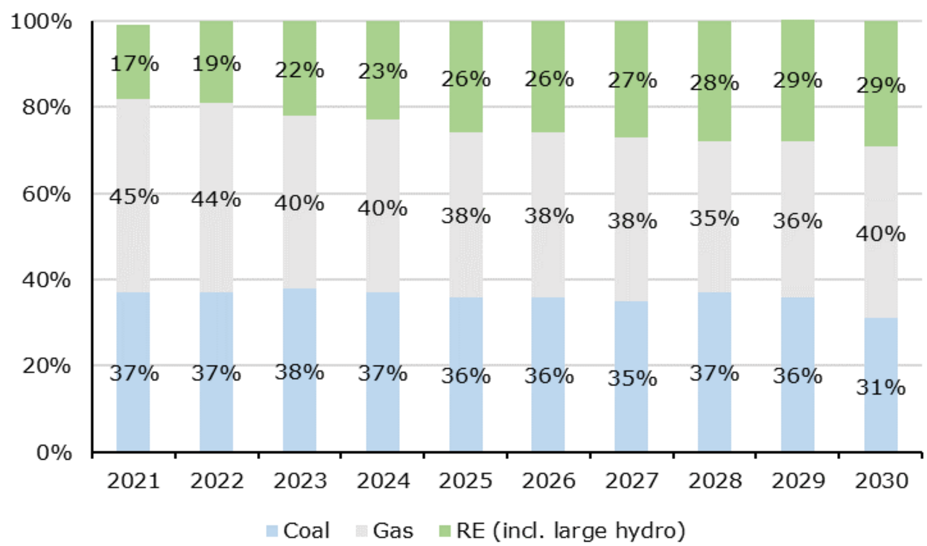

Figure 10: Development of Peninsula Malaysian electricity capacity mix (2021-2030) / Source: DNV based on Peninsular Malaysia generation development plan, March 2021

System integration of variable renewables

Malaysia is increasingly interested in integrating renewable energy into its energy mix with a focus on solar energy. From a resource perspective, it has the largest renewable energy potential in Malaysia. This

[19] Total electricity capacity was around 27 GW and generation 170,000 GWh in 2018.

[20] REPORT ON PENINSULAR MALAYSIA GENERATION DEVELOPMENT PLAN 2020 (2021 – 2039), March 2021

moved the government to introduce the Feed-in Tariff (FiT) mechanism in 2011 allowing electricity generated to be sold to utility companies at a fixed tariff during a specific duration (21-24 years).

In the last years the Large Scale Solar (LSS) program (implemented in 2016) has allocate PPAs (public tendering) with a duration of 21 years to Large Solar Scale projects (>30 MW). As mentioned previously, these large solar plants are treated as a must run unit and have defined in the PPA a maximums annual allowable quantity and an energy rate. In addition, large solar project can also be merchant and exposed to system marginal pricing or be price takers in case of smaller sized projects (<30 MW). In both cases, PPA linked or merchant project, the solar PV generators submits their generation forecast on D-1 to assist the SB and GSO in the planning, scheduling and the grid operation.

2.2.3 Egypt

Egypt is the most populous country in the region (with more than 100 million inhabitants) and has one of the fastest-growing populations globally. It is an energy producing economy (oil and gas) with a power system relying on conventional generation (mainly gas) and limited interconnection to its neighboring countries, Jordan and Libya. Due to a growing population and economic development, electricity demand in Egypt has increased rapidly over the last years.

Single Buyer

Historically, generation, transmission and distribution were integrated in the state utility Egyptian Electricity Holding Company (EEHC) forming a regulated state monopoly. Currently, Egypt relies on a Single Buyer (SB) model with EEHC controlling generation (almost entirely, the rest is covered by IPPs), transmission, and distribution through different subsidiaries[21]. In the following, the different elements of the electricity power system are described in more detail:

- Generation: The power generation phase is divided in three generation groups:
    - EEHC generation is subdivided in six companies (one hydropower plant and five thermal electricity generation companies), which account for approximately 90% of Egypt's generation capacity.
    - Private generation currently provided by three IPPs accounts for only 10% of total generating assets (approximately 2 GW non-renewable capacity). These IPPs have signed PPAs with the SB for generation project under Build-Own-Operate-Transfer (BOOT) contracts for 20 years. After the contract expires, the assets are transferred to EEHC.
    - The public New and Renewable Energy Agency (NREA) provide renewable generation to the SB under PPAs for a project lifetime of 25 years. These projects are allocated through the FiT or tender scheme.
- Transmission and SB: The Egyptian Electricity Transmission Company (EETC) holds a monopoly on transmission (TSO) and also acts as the SB:

[21] The system is regulated by the Egyptian Electric Utility and Consumer Protection Regulatory Agency (EgyptERA).

- The TSO has the responsibility to ensure long-term ability of the transmission system to meet the demand on electricity. This includes the purchase of the balancing power and ancillary services required for a safe and stable grid operation.
- The single buyer manages the electricity demand by purchasing electricity from power plants. This energy is sold to distribution companies or large consumers connected to the transmission grid (ultra-high and high voltage level)[22].

- Distribution and retail: Nine distribution entities in different regions are responsible for the medium and low voltage grid and also act as retailers by purchasing electricity from the SB and selling it to end consumers.

The following figure presents the structure of the Egyptian power system.

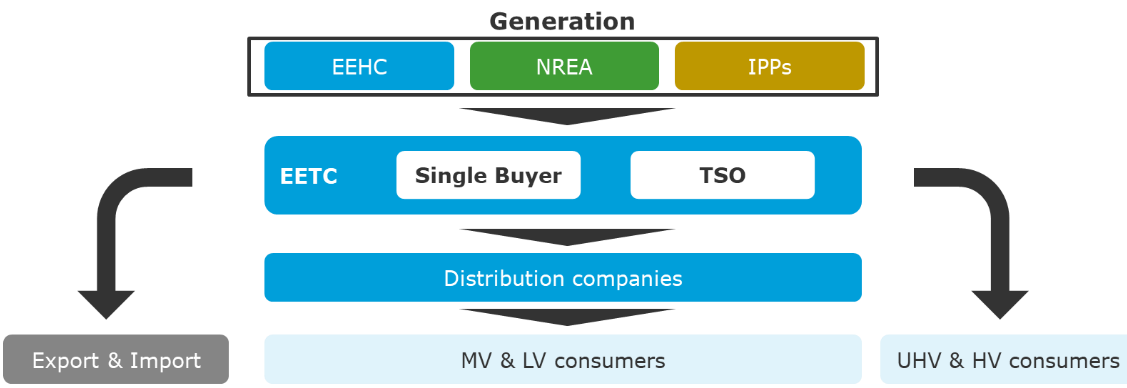

Figure 11: Egypt electricity system structure / Source: DNV

Participants and scheduling

In the current system, the SB plays a pivotal role buying some energy from independent generators through PPAs and selling it to distribution companies. The regulated tariff paid by end consumers includes generation, transmission, distribution and commercial costs.

For scheduling generation costs are calculated per power plant and the schedule is determined centrally according to actual availability of the cheapest and most efficient generation plant as well as considering special PPA clauses (e.g. minimum run time). Meaning that thermal power plants' efficiency rates are the differentiating factor between generation plants with the same fuel source. All generators are centrally scheduled and dispatched and are remunerated for metered production. Consequently, there are no 'imbalances' for either generation or demand. Meaning that the costs incurred for balancing the grid in real time are passed to the end consumer through the regulated electricity tariff.

Generation mix and RES target

Egypt has vast potential for renewable energy deployment (specially hydropower, wind and solar) and is committed to diversify the energy mix (currently dominated by gas-fired power plants). This is reflected in its energy diversification strategy to 2035 and its commitment under the Paris Agreement. The strategy

[22] Approximately 100 consumers with 15% of total annual consumption.

is to progressive deploy renewable energy in order to reach 42% of electricity generation from renewables by 2035 (20% of the electricity mix by 2022). It is important to note that Egypt plans to increase the role of private actors (IPPs) in developing renewable generation projects and diversifying the energy mix in a more competitive environment. Similar as in Peninsula Malaysia, this ambitious increased in variable RE generation share creates the need to implement effective renewable integration measures besides grid reinforcements.

In 2018/2019, Egypt renewables installed capacity amounted approximately 5 GW (2.8 GW of hydropower, 1.1 GW of solar and 1.1 GW of wind power) and total installed non-renewable electricity generation capacity amounted 53 GW (mainly gas fired plants). As can be observed in Figure 12, gas powered generation capacity has increased substantially since 2017 resulting in a capacity share of 90% in the energy mix.[23] The additional gas power generation capacity was justified due on concerns about energy security in a growing economy. However, a slowdown in economic growth in the last years has resulted in a situation where considerable excess capacity exists. A positive aspect is that the newly installed combined cycle plant has increased the flexibility of the system and will allow to integrate more solar and wind generation in the future.

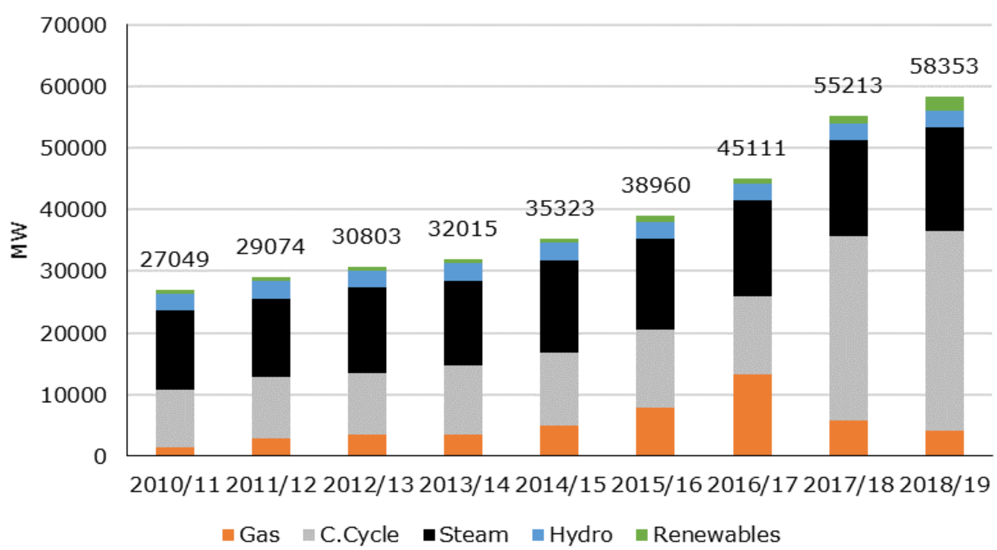

Figure 12: Development of Egypt electricity capacity mix (2010-2019) / Source: DNV based on EEHC Annual Report 2018/2019

System integration of variable renewables

In the last decade, Egypt has introduced supporting regulations to promote private and public renewable generation projects (wind energy and solar PV mainly). Besides, the creation of the New and Renewable Energy Authority (NREA) as the state agency responsible for developing renewable energy projects has

[23] EEHC Annual Report 2018/2019

been key for integrating renewable in the system. Different support schemes have been implemented (under the Renewable Energy Law) to promote renewable energy projects[24].

- **FIT scheme (since 2014):** Under the FiT scheme private renewable energy projects are promoted under the build, own and operate modality. The generators sell the generated electricity to the SB (or a distribution company) via a PPA for a fixed FiT over a defined period (25 years for solar PV and 20 years of wind). The FiT level depends on the technology and size of the project[25].
- **Tender scheme (since 2017):** Egypt implemented the tender mechanism to allocate large-scale solar and wind projects to private actors under state-owned EPC contracts with NREA or under a BOOT contract as an IPP. In both cases (NREA or the IPP) a PPA is signed with EETC[26]. The tender scheme allows to identify most efficient projects through competitive bidding.

In the subsequent chapter we will describe different options for possbile improvement of VRE system integration in non-liberalized electricity systems based on the experience gained in liberalized systems and own developed ideas.

3 OPTIONS FOR IMPROVEMENT OF VRE SYSTEM INTEGRATION IN NON-LIBERALIZED ELECTRICITY SYSTEM

The first section described the market integration of VRE in liberalized electricity supply industries, the second VRE system integration in non-liberalized ESI as of today. The intermittency of VRE presents several challenges to both systems including power system planning, dispatch and balancing; and safe network operation. The focus of this paper is on the second challenge: dispatch and balancing. In this section, we outline options for improvement of current practice in non-liberalized ESI to cope with higher shares of VRE and thus higher levels of intermittency. Our approach is both sketchy and stylized: In real-world cases recommendations on improvements have to be tailored to the situation, since the market resp. system rules vary from country to country. Nonetheless, we shed some light on solutions for a problem gaining in urgency as more and more emerging economies engage in VRE expansion as part of their climate policy efforts.

Our suggestion are built on the following assumptions based on:

- From an economic perspective, the Single Buyer model should allow optimal dispatch of VRE (holistic approach)
- The single-buyer model is often used as transitional arrangement before introduction of competitive wholesale market

[24] IRENA 2018, Renewable Energy Outlook Egypt

[25] Three categories can be differentiated, small solar PV roof top systems (less than 500 KW), medium/large wind plants (< 50MW) and medium/large wind solar plants (< 50MW). For small solar PV projects, the FiT scheme is an alternative to the net metering scheme that incentivizes self-consumption.

[26] For instance, the BOOT (Build, Own, Operate, Transfer) 200-megawatt photovoltaic solar power plant at Kom Ombo is linked to a 25-year power purchase agreement (PPA) and network connection contract and usufruct agreement.

- However, due to political motives and defined PPA preferences intervention of day-ahead schedule might lead to suboptimal resource allocation.
- Besides, the SB has not a strong profit motive and therefore no incentive for innovation in flexibility options.
- It is to see delays toward liberalized electricity markets due to investment, knowledge and political reasons.

In addition, the options proposed to enhance flexibility in a SB system rely on following key conditions:

- A balancing mechanism could incentivise additional flexibility from market players besides obligations set in the PPAs.
- A price signal could encourage better forecasting of new VRES capacity (e.g. in form of a balancing penalty).
- Market players are interested in signing contractual arrangements (e.g. between VRE generators and flexible generators/consumers) to improve economic performance.

The analysis is presented in a series of figures. Figure 13 shows the typical status quo situation: Given information on the load provided by suppliers and large customers, the Single Buyer dispatches the available generation capacity, taking direct control of its operation. He does so on the basis of PPAs that specify remuneration and minimum usage hours per year. In other words: there is no balancing, and it is the Single Buyer's responsibility to account for the intermittency of VRE generation (which is also remunerated on the basis of PPAs and feed-in/dispatch priority).

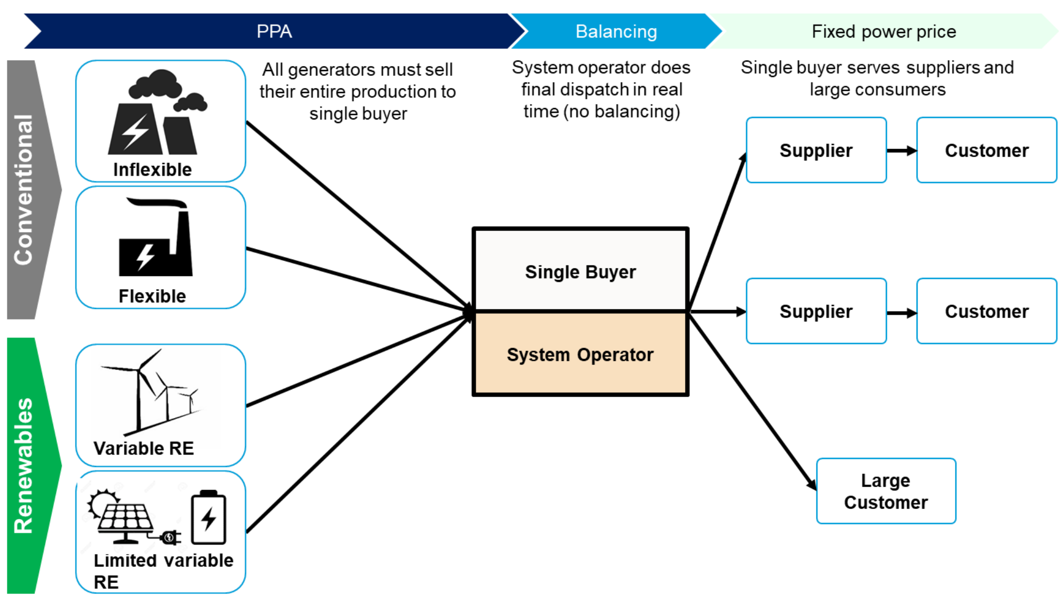

Figure 13: Status quo of dispatch in stylized Single Buyer ESI

We argue that the status quo approach, while functional in a conventional ESI, reaches its limits in a system with increasing shares of VRE. Thus, responsibility for availability and day-ahead planning by conventional generation units as well as dedicated balancing services operated by the system operator should be introduced. This should be undertaken to guarantee system stability and to enhance efficient operations of generation assets:

- In the status quo approach, the Single Buyer takes responsibility for the dispatch and has to rely on availability statements of generation operators that he cannot verify. In contrast, an extra established balancing mechanism, could unfold extra flexibility from generators not contemplated in the PPAs.
- In addition, flexible large customers able to provide demand response (DSM) could also participate in the balancing mechanisms to support the system when needed.
- Extra balancing services should be remunerated, either on the basis of an administratively set price, or by a price determined by competitive procurement.
- The increasing share of VRE in the system leads to increased uncertainty with regard to their feed-in, with repercussions for the dispatch and system stability. VRE could also be allowed to provide flexibility services following the example of some liberalized markets.

This line of reasoning leads to the approach for the concept of balancing shown in Figure 14, the first model: commercial balancing.

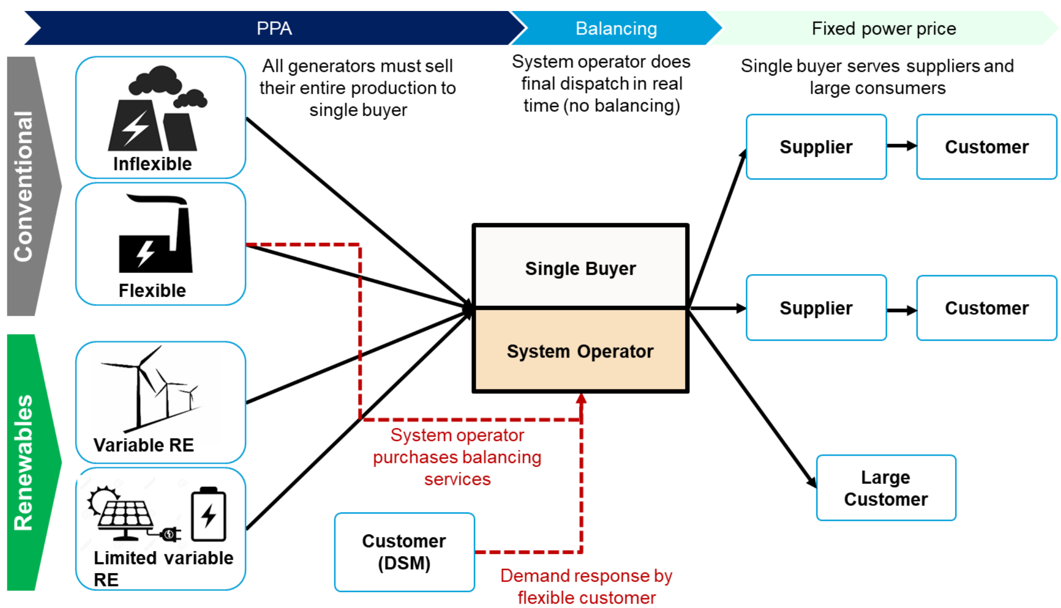

Figure 14: Balancing model 1 – commercial balancing

In the setup the system operator procures balancing services from flexible plants – or from flexible (large) consumers in the form of demand response. The form of the procurement should be tailored to the specific system, characterized by its energy mix in general and its VRE share in particular, as well as the load patterns. In addition, the system operator must establish penalties for those generation units that do not meet their day-ahead dispatch requirements, as established by the single buyer on the basis of availability statements and subsequently communicated to the system operator. The penalties should provide an incentive to reduce imbalances, especially for VRE generation. As for the level of penalty, it is common that the cost for the procurement of balancing services is wheeled onto those generation units that have not complied with the pre-established dispatch schedule. However, the price should not be detrimental for VRE projects investment but serve as an incentive for innovation in flexibility options.

In the system described in Figure 14, VRE generation units are exempted from the duty of scheduling their generation and have priority dispatch. This is typical for renewable generation supported by feed-in-tariffs, reflecting a situation common in Europe about one decade ago. As a consequence, the task of estimating the day-ahead feed-in falls to the single buyer that must include the result into the dispatch schedule communicated to the system operator. With an ever larger number of installations, the estimate process becomes more challenging, moreover, the technical options for balancing available to VRE generation units are not used, because these have no incentive to do so. In the EU, so called balancing responsibility has been mandatory for all large-scale renewable installations since 2016[27], i.e. wind installations with a capacity larger than 3 MW (the threshold is 500 kW for other VRE installations) must submit a day-ahead schedule that they have to respect and adjust if necessary. This has triggered a reduction of forecasting errors and VRE imbalances.

Given the weather dependency, this is a challenge for VRE installations, a challenge that can be met by several options available to the installation operator. Clearly, he will establish a high-quality day-ahead weather forecast to minimize the uncertainty of generation. However, it is likely that some uncertainty will persist, in particular w.r.t. the high precision that the planning of the dispatch schedule requires.

This changes in the second model: While the system operator retains the ultimate obligation to ensure system stability, and thus procures balancing energy as in the first model, in the second model the new (additional) VRE installation is mandated to be balancing responsible. Clearly, this poses a challenge, given the inherent intermittency problem. In the following, we describe three fundamental options for the VRE installation operator to offset imbalances and thus ensure the faithfulness to the planned schedule. These are not only available in liberalized electricity supply industries, but can, at least in principle, also be established in electricity supply industries based on the single buyer paradigm. They are variants of the second model:

- Option 2a: VRE operator closes a contract with a conventional flexible power producer.
- Option 2b: VRE operator closes a contract with an energy intensive, flexible consumer.
- Option 2c: VRE operator, conventional operator and energy intensive, flexible consumer create of a virtual power plant and offer balancing services.

The three options are highlighted in Figure 15, Figure 16 and Figure 17 respectively. For the balancing to work, the VRE installation and its partner/partners have to form one balancing unit; in a decentralized bilateral market they would be included into one balancing group. This means that they join their capacity into one bid and report their schedule jointly to the system operator. Faithfulness to the schedule can only be guaranteed jointly, as the flexible partner will adjust its generation resp. consumption to unforeseen changes in VRE generation to offset the balance in real time. Clearly, this requires the establishment of communication technologies between the units as well as joint planning. Also, it comes at a cost for the VRE installation, since the flexible units will require a remuneration for the service

[27] Cf. EU Guidelines on State aid for environmental protection and energy 2014-2020, Art. 3.3.2.1

delivered. A market based RE support mechanism, such as market premium or a portfolio standard, will have to account for these costs.

While complicating the operation of a VRE installation, the second model has several advantages, in particular once the share of VRE in total generation has become large. Decentralizing the task of balancing means that the use of the balancing potential in the system will be optimized, relieving the system operator of a growing burden. It also sets incentives for the improvement of VRE generation forecast, which are slim as long as the problems arising from intermittency are delegated to a centralized institution.

Whether the advantages of the second model outweigh the complications created for VRE operators is a matter to be studied individually, country by country. Typically, in the early phase of VRE development, producers move along a learning curve, so that a feed-in-tariff remuneration without balancing responsibility will be preferred. At a later stage, policy makers may decide to introduce it for new VRE as well as an additional remuneration for being balancing responsible and even provide balancing in services (e.g. virtual power plant or co-location of batteries). It might be even possible that future VRE auctions include energy storage requirement as can be observed in liberalized markets (e.g. Portugal).

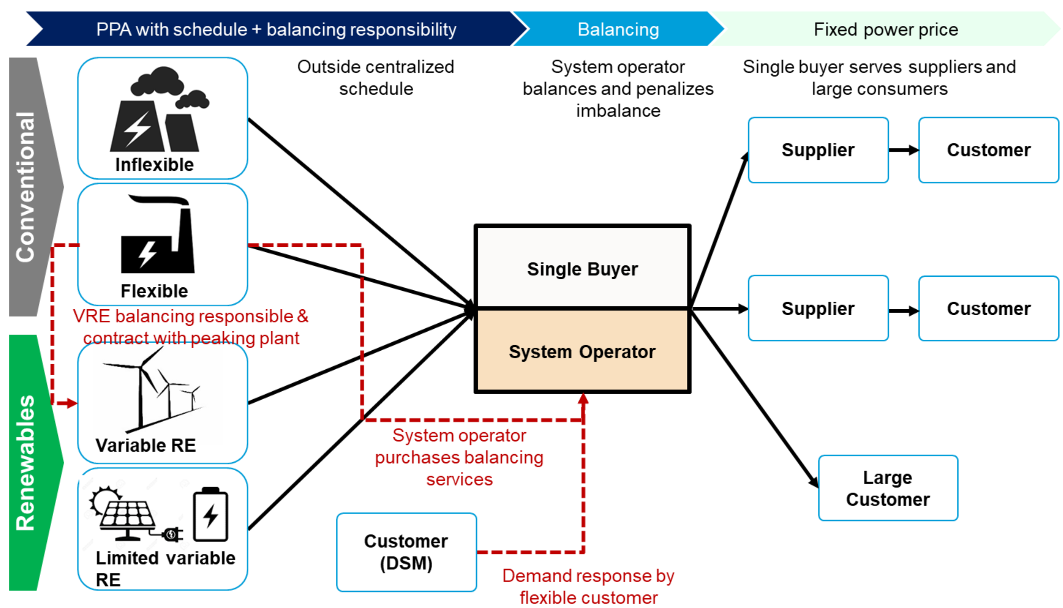

Figure 15: Balancing model 2a – VRE balancing responsible / contract with flexible generator

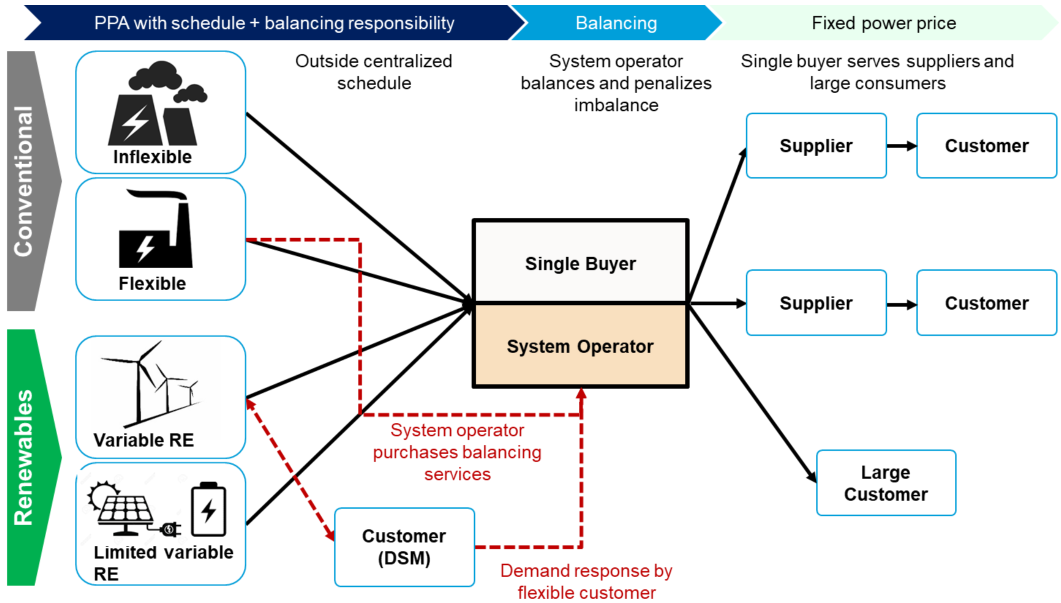

Figure 16: Balancing model 2b – VRE balancing responsible / contract with flexible consumer

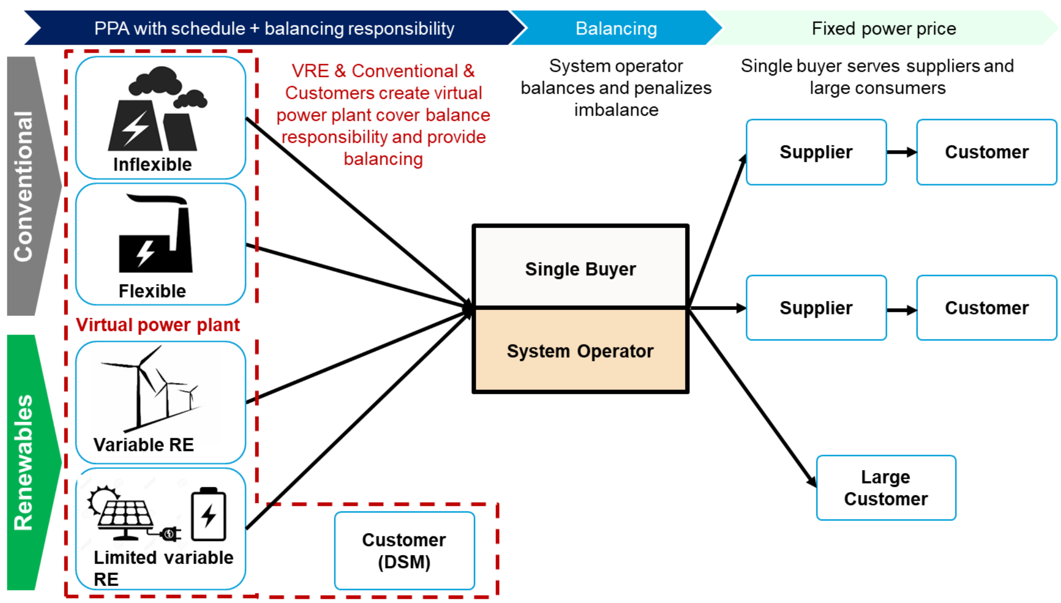

Figure 17: Balancing model 2b – VRE balancing responsible / virtual power plant

4 CONCLUSIONS

This paper has analyzed current practice of VRE system integration in liberalized electricity markets to derive some lessons that can be useful for non-liberalized system with ambitious VRE deployment targets. In order to shed light on the functioning of non-liberalized electricity markets, two relevant single-buyer cases have been presented, namely Peninsula of Malaysia and Egypt. The focus has been set on the specificities of dispatch and balancing with regards to imbalances generated by VRE. Based on this, options to improve dispatch and balancing of large-scale VRE in SB electricity systems have been identified. The aim of these suggested measures is to allow non-liberalized markets to cope with a higher share of VRE and thus higher levels of intermittency in the coming years, planned as part of their climate policy efforts. We argue that the status quo approach where the Single Buyer takes full responsibility for the balancing has its limitations in a system with increasing shares of VRE. We suggest the introduction of dedicated balancing services contracts with flexible generators and large consumers (DSM) to allow the SB to utilize least-cost balancing units more efficiently. In addition, we propose the allocation of balancing responsibility among VRE producers to incentivize them to pursue options minimizing imbalances such as closure of a balancing contract with a flexible generator/consumer or the creation of a virtual power plant.

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