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**Balance**

The artwork on the cover is Alexander Calder’s Mobile, c.1932, which continually redefines the space around it as solid elements respond to slight air movements, always retaining balance and the form of the mobile sculpture.

It is an ideal representation of the myriad nuances of power system planning which need to be perpetually balanced.



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# Foreword

The Vietnam Power System Plan Guidelines is prepared by the Vietnam energy team of the World Bank with the inputs and feedbacks from the consultation workshop on “ Vietnam Power System Planning Methodology and International Experiences” which was organized on Hanoi on November 6, 2018. This guidelines will be further updated if there are additional issues identified and comments received from stakeholders.

The workshop was jointly conducted by the Bank and Ministry of Industry and Trade (MOIT) and fully participated by wide range of stakeholders including Government Agencies, Electricity of Vietnam (EVN), Electricity Regulatory Agency (ERAV), Institute of Energy (IoE), Petroleum of Vietnam (PVN), Energy Association, and representatives of donors including USAID, ADB, EU, AfD, GIZ, ADB, KOICA, UNDP, DANIDA, USA Embassy, Danish Embassy, Norway Embassy, UK Embassy, Belgium Embassy. The World Bank team gratefully acknowledges the contributions from Dr Stuart Thorncraft (Intelligent Energy Systems) and Dr Jennifer Crisp (DigSilent Australia) to the Guidelines. The team also appreciates the excellent presentation by Dr Jaquelin Cochran (National Renewable Energy Laboratory) during the workshop that informed some of the discussion in the Guidelines.

# Context

Vietnam is embarking on its Eighth Power Development Plan (PDP8) at a time marked by several major changes from rapid penetration of variable renewable energy and increasing reliance on imported fuel to the introduction of a wholesale market. These changes call for some modifications to the planning methodology followed in previous plans including PDP7. The key issues were discussed in various fora including a workshop in Hanoi on November 6, 2018.[[1]](#footnote-1) These recommendations emerged:

1. **Include** **a** **Market-oriented Outlook** since future demand-supply including new investments may be shaped to some extent by wholesale market spot prices. Selection of planned generation investments must therefore represent efficient new entrants and spot market price outcomes. Planned transmission investments also need to consider the implications for supporting an efficient electricity market;
2. **Plan for significant levels of** **variable renewable energy** (VRE)in the technology mix. The recently concluded World Bank study provides a good beginning and highlights key ramifications of variability of solar and wind. This issue was also been explored by USAID/NREL in the November workshop. PDP8 needs to embrace these and ensure Vietnam planning remains cutting-edge to include full representation of variability and assessing power system reliability. Issues range from assessing the implications of contingencies that may arise from large swings in wind/solar and levels of ancillary services required to manage variability. There are significant ramifications of such variability including getting the capacity mix right that may require *inter alia* introduction of flexible fast-ramping generators in the market to match higher level of penetration of VRE;
3. **Set a robust flexible transmission network** in view of the market orientation and increased VRE. Given the longitudinal structure of the Vietnam power system, co-optimize the generation and transmission to maintain demand-supply balance, including the ability for peaking support built in one part of the country to respond to cloud cover dropping hundreds of MWs in another part in a matter of seconds. A well-planned system should not expose some customers/retailers to high prices in one part of the network, and others to potentially instability due to variability;
4. **Build mechanisms to deal with uncertainties** – from fuel prices to demand growth and hydrological variation – which has always been a challenge for power system planners. The traditional way to build alternative scenarios and a generation plan for each is no longer good enough. For instance, if there was perfect knowledge that demand growth will be high at 11% pa for the next 30 years, building a lot of capacity is an easy decision. In Vietnam, however, demand growth has been highly variable. Going forward, increasing adoption of energy efficiency and demand response measures would further impact the demand growth. Building too much capacity can lead to stranded assets – even temporary measures can cost hundreds of million dollars over a few years. Building too little leaves the grim prospect of power cuts during summer, high prices, and bankrupt network companies. A practical power system plan should be resilient. It should not have excessive over-build and should be able to get through those super-high growth years using options that are expensive for the year without locking in billions of dollars in assets that are used once in a decade. The same concept of resilience applies to Vietnam’s reliance on imported gas and the ability of the thermal and VRE system to complement hydro; and
5. **Foster** **cross-border power trading** which can be part of the solution to generation requirement as well as flexibility *if* it is embedded in the PDP8 properly and the plan is used to structure the bilateral deals. For instance, storage hydro in Laos can be a useful aid to Vietnam for peaking support as well as a vast source of ancillary services to manage solar/wind in future years. Flexible contracts that can be scaled can be a useful way to deal with high growth years (even if they are more expensive for a limited period) or dry years. On the other hand, baseload/firm hydro deals and/or long term contracts fixed for 25 years, even if cheaper, may not provide the flexibility that the country needs.

## What specifically needs to be done?

Embed these features in the design of the PDP 8. In some ways, this will mean a departure from the previous PDPs including PDP 7. For instance, the plan should include:

1. Market simulation and give a broad sense of price forecasts. This will be an effective way to signal to every market participant from local and foreign investors to retailers, industries and smaller customers about future price/revenue trends;
2. A planning model that represents VRE properly and co-optimizes ancillary services. This is now essential to ensure PDP8 is state-of-the-art. There are planning tools that can adequately do this job;
3. A reasonable representation of the transmission network. This may be in the form of multiple zones (e.g., up to20 zones) but this ‘reduced network’ needs to be carefully developed to capture key zones including renewable hubs and major thermal generation and load centers, considering likely future plans for transmission. Create this data using a detailed load flow model in advance of the PDP8 generation planning analysis. Coordinate the transmission plan and load flow models with the generation counterpart to ensure a balanced network. Finally, design the market simulation to check if prices from the generation and transmission plan look reasonable (without excessive price volatility in each region and without uneconomic price separation across the regions);
4. A resilience-based planning approach that improves on deterministic scenarios along the line discussed under Issue 4 in the preceding sub-section. This does not need to be a complex mathematical technique but a considered way to stitch together plans (e.g., for different demand growth) and test the robustness of the final plan;
5. Full consideration of energy efficiency and demand response measures as a resource; and
6. As noted already, include cross-border power trade as a resource in the plan alongside domestic counterparts so that the precise role and selection of import/export can be integrated in the plan.

## Scope and purpose of this note

The key recommendations and next steps can be loosely interpreted in different ways and hence implemented differently. For this reason, this guidance note unites a set of principles and associated key steps that the implementing agency can follow. This Draft Guidance Note lays out the type of data/assumptions to be used as well as the methodology to be followed. The latter would be particularly important to delineate the building blocks of the plan and embed a modern, practical approach.

For example, it is important to recognize the role of uncertainty but the underlying methodology need not be overly complex (e.g., a stochastic programming or robust decision-making model is not necessary). The goal is to keep it workable. Try out a few realistic combinations of demand and fuel prices to come up with a base plan followed by performance testing (and market simulation) of the plan. The objective is to evolve a practical plan that is resilient rather than an experimental ground for complex models that tend to make the process opaque. A pragmatic approach is also needed for modeling of VRE.

Finally, this note also provides a commentary on the selection of planning tools, a set of criteria, and steps to implement the methodology using the planning tools. It is envisaged that the Draft Guidance Note will need to be discussed extensively with stakeholders in Vietnam to agree on the methodological issues to be incorporated in PDP8 including the selection of the planning tools and implementation steps;

# Methodological framework

Figure 1 shows the major building blocks of the methodology and the discussion in this section adds the next layer of details over the contextual discussion.

Figure 1 Major building blocks of the methodology



## (A) Demand forecast

Demand forecasts are the most important inputs to the process as the peak, energy and distribution of demand (‘load shape’) dictate the amount of capacity and generation mix. While uncertainties around demand forecast can never be eliminated, serious risks of overbuilding capacity or falling short of it can be eliminated by using:

1. A good check on the performance of the existing forecasting models and inputs used in the past to see if in retrospect the forecast errors could have been reduced using different/additional set of variables and different set of assumptions.[[2]](#footnote-2) A review of the demand forecast that was undertaken by IES and DigSilent in 2015 noted a number of areas where the PDP7 forecast could be enhanced. These include a better choice and documentation of the methodology and careful management of data that have generally tended to overestimate peak and energy requirements in the past;
2. A combination of “bottom-up” and “top-down” methodology so that the demand forecast builds in different micro/sector-specific and macro/economywide perspectives. In general, it is a good idea to use more than one methodology even within a top-down/bottom-up framework to capture different aspects of the problem;
3. Undertake a screening of energy efficiency and demand response measures that are potential candidates for planning including the MW and GWh potential for each. However, these should **not** be embedded directly in the forecast themselves and should form direct inputs to the least-cost planning model alongside generation candidates.

## (B) Least-cost generation planning

The **least-cost generation and (zonal) transmission planning model** is the heart of the analysis. When you plan:

1. At the outset, settle issues around discount rate, cost of capital for different technologies by ownership, and a consistent use of real vs nominal for all relevant parameters. Agree on and document the rationale and parameter values;
2. Optimize peak and energy forecasts as well as energy efficiency and demand response measures together with generation resources;
3. Consider portfolio of existing and new generation projects including capacity, operating and capital cost (reflective of any change in capex over the years), efficiency, and planned retirements.
4. Factor in availability of hydro including monthly/seasonal and interannual variability of hydro energy for both run-of-the-river hydro and storage projects (existing and new);
5. Represent renewables as best as possible, accounting for major sources of variability in all time-scales from hourly to seasonal and inter-annual;
6. Include co-optimization of spinning reserve as part of the long-term planning analysis;
7. Design a reduced system representation of transmission that captures the transfer capability across major zones over time considering the transmission plan;
8. Match representation of zonal or regional transmission network to expected locations of RE sources, prospective transmission network upgrades, locations of power exchange points, and locations of expected future generation resources;
9. Co-optimize generation and transmission investments – so that trade-offs between an optimal generation mix and transmission expansion are understood and reflected;
10. Consider fuel price and availability of fuel that may restrict some options more than others;
11. Build limits for each type of technology;
12. Consider cross-border import/export options including transfer capability and price distribution (peak/off-peak prices over the years) that may drive such trade decisions; and
13. Budget for longer term uncertainties around demand growth, fuel prices, hydro availability, major delays in key projects, and other factors that are deemed to be critical.

**CRITICAL PLANNING FACTORS**: Keep these factors to the minimum to stay focused on the material issues. Make a distinction between those that are long term vs short term VRE variability and generator/line outages (that are dealt with in other components of the modeling). There are different ways to deal with uncertainties including complex and/or computationally intensive stochastic programming (SP) and robust decision making (RDM) models. There are practical limitations on the ability to implement the latter models. For example, there is no reliable commercially available power system planning tool that can be adopted for large scale SP/RDM. However, it is possible to adopt the underlying principles and implement them in a simpler and transparent framework. It is therefore suggested to: (i) restrict the analysis to a small number of scenarios that combine uncertain parameters in a consistent way; (ii) develop a base plan around a most likely scenario; (iii) test the base plan against all credible scenarios including credible contingency scenarios; and (iv) adjust the plan to the extent it exposes the system to a risk of significant over or underinvestment.

**PLANNING FOR DEVIATIONS**

When undertaking generation planning, beyond basic physical considerations, consider potential important deviations from a pure least-cost norm taking into account:

1. Wholesale Electricity Market considerations including the Wholesale Electricity Market (WEM) Rules and generator behavior that may have a bearing on the investment and dispatch including deviations from a pure least-cost norm;
2. A realistic limit on total investment that is available for generation including public and privately financed projects;
3. Commercial constraints for existing and prospective IPPs on generation take-or-pay volume; and
4. Major policy considerations around renewable energy, energy efficiency, GHG emission reduction targets (e.g., Nationally Determined Contributions, relevant national plans), and energy security (e.g., maximum share of import), cross-border export promotion, and fuel diversity.

## (C) Operational dispatch simulation

The **operational dispatch simulation** part plays an important supporting role in testing the operational feasibility of the plan. Largely, this part is conducted in two different ways: i) a long-term simulation and ii) detailed operational simulation. The long-term simulation model needs to make simplifying assumptions around the time resolution, representation of chronological constraints on ramping, and allocation of spinning reserve. The operational simulation model checks the performance of the plan using additional constraints that are relevant in short-term system operation including ramping, minimum up/down time of generating units. It is also a useful exercise to pre-empt the need for the system/market operator to run the system efficiently as envisaged in the least-cost plan and the operational dispatch model can be a useful aid to system operation. These issues help frame the operational analysis:

1. Derive the demand representation across the long-term and operational simulation models from the same load database. The operational simulation specifically should emphasize the need to simulate extreme weather events (e.g., 10% probability of exceedance load level during extreme summer events, etc.) Test demand response (DR) and other peak shaving measures fully through the operational simulation based on the optimal/least-cost plan that determines *inter alia* the quantum of DR selected in the plan. The operational simulation should form the basis for contracting for DR in the short term (e.g., next peak season);
2. Cover detailed operational dispatch simulation only for major scenarios and spot years (e.g., 2020, 2025, 2030, etc and/or any landmark year for policy implementation) keeping in view the significant computational load. There should be a clear focus on feasibility and robustness assessment and fine tuning the base plan. For instance, in a dry year, extreme weather events, high LNG prices, and extended periods of low solar/wind availability;
3. Ensure that the robustness of the plan and augmenting it through the operational simulation is an integral part of the analysis. Specifically, as the share of VRE is expected to increase, these checks assume special significance. For instance, it is possible that the base plan may be vulnerable to ramping limits in some cases under extreme solar/wind variability and would require additional flexibility through demand response and/or storage that is not fully captured in the long-term analysis;
4. Pay special attention to the operation of the hydro system as the VRE share increases. It is likely that the existing rules for operating the hydro system require significant changes to make the most of the economic solar/wind capacity. The dispatch simulation study should clearly articulate the hydro system operation policies including analysis of the provincial water management plans that are linked to many hydro power plants in Vietnam as part of the PDP8;
5. In the operational simulation, give adequate consideration to co-optimization of ancillary services and allocation of spinning reserves. At the minimum, consider two classes of reserve to distinguish between fast and slow reserve that are provided by different groups of generators. The analysis should be preceded by an assessment of spinning reserve capacity of the existing generation system and a clear spinning reserve standard that needs to be met for each category in line with the provision in the Vietnam Wholesale Electricity Market(WEM) Rules;
6. A dispatch simulation study would also yield performance metrics around system reliability including expected unserved energy, loss of load expectation (LOLE), etc. These metrics must comply with the system reliability standard.[[3]](#footnote-3) A corollary of this requirement is that the tool needs to be able to perform Monte Carlo simulation or one of the methods of moments to calculate these indices.

**BEYOND LEAST COST ANALYSIS**

Operational simulations also need to go beyond the realm of purely least-cost analysis to consider market and commercial issues including:

**Evolution of market prices:** that can be derived from the shadow price of the hourly demand constraints. The outputs of operational dispatch can be useful in revealing any significant price volatility that the system may be exposed to under extreme events. These may be useful in not only fine-tuning the investment plan, but also tightening WEM Rules in some cases;

**Commercial issues:** Dispatch simulations include detailed constraints around start-up/shut-down time, ramp rates, and limits on ability of generators to provide reserve response. Check if some of these constraints start to bind seriously as the share of solar and wind go up significantly over the years. These simulations can also be useful in testing the impact of commercial take-or-pay contractual limits. If there are significant take-or-pay for coal and gas offtakes in the system, these constraints may lead to significant inflexibility in the dispatch. Thermal generation may need to be given priority in the dispatch if this amounts to rejecting part of the wind/solar generation. If the dispatch outcomes dictate a significant share of wind/solar rejection arising from the way the power purchase agreements (PPA) have been designed, this is a major concern that needs to be addressed in the PDP8.

## (D) Transmission planning

In the past, the role of a transmission plan has been to evacuate power from large power stations. However, it is now more complex as the system gets bigger, demand growth more uncertain, and the siting and mix of new generation *highly* uncertain. The previous development of a small number of large power plants is likely to evolve into many smaller plants being developed at many locations. The transmission planner has to take on the role of mitigating part of this uncertainty so that there is a robust backbone system that can cater to a widely varying set of generation development from large coal/gas fired power stations to VRE and power import from Lao/China, etc. The proliferation of VRE also entails a potentially large share of non-synchronous generation and inverter-based equipment that can render parts of the system weak, where penetration levels are very high. In addition to ensuring sufficient spinning reserve is available and allocated to the relevant providers in appropriate locations, the transmission planner must ensure that high fault current, low inertia, and voltage control issues are adequately addressed. While a flexible and secure transmission system is of essence, the economics of transmission remain paramount and overinvestment in transmission must be avoided. To achieve these ends as a transmission planner:

1. Consider the transmission plan and the location of generation as well as major constraints in the system for reduced system representation for generation planning. It is likely that the current 3-zone system needs to be improved to consider VRE-heavy provinces as additional zones and also identify other potential transmission bottlenecks emerging in the system;
2. Embed cross-border power import in the transmission plan to ensure major imports through LVI and other prospective interconnectors can be safely accommodated in the system;
3. Create a stronger linkage to generation planning and associated operational simulations. Employ the scenarios studied as part of generation planning for transmission planning to assess the flexibility of the transmission plan and evaluate augmentation options for the plan to accommodate a range of generation development possibilities.[[4]](#footnote-4) The conventional approach to test the adequacy and security of the system for peak/off-peak demand is no longer sufficient. In the analysis, consider specific dispatch conditions from the operational simulations that indicate potentially problematic conditions (low Short Circuit Ratio or SCR) with large influx of VRE in some parts of the network and analyze these conditions. The process of transmission plan development must seamlessly work from generation plan to operational simulation and transmission system security analysis for it to be internally consistent. If there is a major system insecurity issue found that requires additional transmission investment either in form of Static VAr Compensator (SVC), static synchronous compensator (STATCOM), battery storage, or through generation re-dispatch of synchronous generation to render greater inertia – these must be settled in the planning stage. It requires a level of scrutiny on the transmission plan that has not been received in PDP7, but is critical at this stage;
4. Incorporate additional contingencies around VRE in addition to the standard (n-1) contingency. Include those that may arise from a major weather event such as a cyclone, causing a sudden drop in wind coupled with outage of a critical line. It will be useful to consider time simulation studies with high resolution VRE data to assess the robustness of the transmission system. Again, this level of scrutiny is unprecedented – probably not just in Vietnam but in many other countries – but is deemed to be important enough for PDP8 to invest in such detailed analysis;
5. Establish a reasonable generator dynamic database to perform a critical dynamic analysis of the system. This substantial effort should precede the PDP8 development through limited tests conducted on key generators to derive the representative parameters so that this can pave the way for a more complete dynamic database going forward;
6. Consider the stability induced transfer capability limits as part of generation planning since both angular and voltage stability studies are essential for the Vietnam power system;
7. System security *and* economics can both be enhanced through appropriate deployment of smart grid technologies. As the *World Bank Smart Grid Implementation Support* study conducted by CESI (Italy) in 2015 revealed, there is significant room for deployment of smart grid technologies in the Vietnam system including advanced HVDC, SVC, Dynamic Line Rating (DLR) and power quality monitoring system.[[5]](#footnote-5) In addition, VRE is particularly suited to use of special protection schemes (SPS) that allow greater utilization of the transmission system but still preserve the security for contingencies. PDP8 presents an opportunity to bring these options into the fold to deal with some of the system security issues in an era of high VRE and distributed energy resources; and
8. Perform a cost-benefit analysis of all major investments be it a cross-border link, or a new HVDC link, or some other smart grid solution. While the generation and dispatch simulation ensures a rigorous check on economics of generation, the same is needed for transmission assets and should be enshrined in the PDP8 for it to be the basis of sound economic regulation of transmission.

## (E) Wholesale market analysis: generator bid

To assess the market implications of the plan foreshadowed in the previous subsections, it is necessary to simulate how generators in the new WEM would translate their costs into generation offers and bids. A pure least-cost generation plan and dispatch intrinsically *assume* generators reveal their true costs and in a deterministic setting there are no risks. Both these assumptions obviously do not hold in a real-life (imperfect and uncertain) marketplace. Since the market has not yet started, it presents a challenge because there is no past price/dispatch history that can be used to calibrate how generators go about the price discovery process and manage their risk and/or game the market prices if they possess market power. Nevertheless, there are theoretical options and these two simulations could be considered as part of the generator bid analysis:

1. A simple approximation of the long run marginal cost (LRMC) of each generator that the incumbent generator may aim to recover by bidding part of its capacity at short run marginal cost (SRMC) and the rest at a higher cost to earn a return on investment. The second component, especially for peaking generators, may mean high offers/bids during peak hours. The relevant segments of capacity that is bid at SRMC vs. rent-seeking mode can be calibrated against the least-cost generation plan outcomes. That is, if the generator is part of the optimal plan, the total net revenue that the generator is expected to earn can be derived from the least-cost dispatch. The offer parameters can be tuned to target this return. There are alternative ways to decide on the share of capacity for which the generator is willing to reveal its true SRMC. If there is a physical constraint on minimum loading, the generator would typically be offering at minimum this part of the capacity at cost (if not below cost to avoid being shut down and incur a start-up cost). A presence of a contract (including any vesting contract as a transition mechanism) or a known take-or-pay fuel obligation may also render part of its capacity to be offered at marginal cost. In general, a baseload generator would have a high share of its capacity offered at marginal cost compared to peaking generators. In summary, the bidding parameters need to reflect a range of factors from physical constraints, contractual obligations, market concentration, transition mechanism (e.g., vesting contract), and a revenue target. It is essentially a simple but crude/ad-hoc way to turn a least-cost planning outcome into market prices, but one that can be constructed with relative ease; and
2. A more complex game-theoretic model, in particular, the Cournot gaming model has been used extensively in wholesale electricity market simulations and is a possibility that can be explored. There are different variants of the Cournot gaming model including the transmission-constrained Cournot gaming model that may best fit the proposed long-term planning and short-term simulations that are proposed for PDP8.[[6]](#footnote-6)

The offers/bids produced by the LRMC/Cournot model would form inputs to the capacity expansion model and operational dispatch. These offers/bids effectively “replace” the cost information used in these models in their least-cost mode. The output of the simulations using offer/bid would be market spot prices that may under certain circumstances be higher than the marginal cost estimates derived using pure least-cost assumption. As discussed earlier, the spot prices underlying the PDP8 generation and transmission investment plan can be useful information for prospective investors and consumers.

## (F) Renewable data analysis

A second important ancillary component of the planning analysis would be good quality renewable resource data spanning 20 if not 30 years to feed into generation planning, dispatch simulation, as well as transmission planning analysis. This data needs to provide a measure of:

1. Solar/wind quality across different **locations** including the diversity and complementarity of these (as well as hydro) resources to provide balanced output over wide geography. Use the resource data for selection of sites for wind and solar over the long term;
2. **Variability** within a day if not at sub-hourly scale, over the days, weeks, months, seasons, and years. The seasonal and inter-annual variability are as significant as short-term variability. Both long-term analysis and short-term dispatch need to ensure that the rest of the generators can vary their output to make the most of the available VRE resource; and
3. Size of the **VRE contingency** event since VRE remains highly uncertain in all time scales. VRE contingency can be a short-term consideration and the economic cost of managing the contingency can be measured by additional spinning reserve requirement that short term variation of solar/wind entail. There is however potentially a more serious longer term dimension of the VRE contingency that also must be considered. The economic cost of the longer term VRE contingency can be measured in term of the additional fuel and capacity that needs to be preserved for a low wind/solar season/year. Analysis of past VRE data is needed to put reasonable bounds on the contingency parameters that would be used in the planning and dispatch models.

Fortunately, good quality renewable data in an hourly time-scale for 30 years is available including the World Bank funded service providers like [SolarGIS](https://solargis.com/) (for solar) and [Vortex](https://www.vortexfdc.com/) (for wind). This is more than adequate for the purpose of planning studies (but not necessarily so for specific RE projects).

# Choice of Planning Tools

There is a wide range of planning tools that with different features that can cater to various sub-components of the modeling tasks discussed earlier. IRENA’s *Planning for the Renewable Feature* report published in 2017 discusses as many as 85 planning tools for long term planning for generation and transmission.[[7]](#footnote-7) These tools range from free tools such as WASP-IV that has been used for capacity planning since 1972 to modern age commercial planning tools in the electricity market era like PLEXOS, PROPHET, and PSR. All these tools are in use for different applications in various parts of the world and have their pros and cons. This discussion is not about recommending a specific tool for PDP8 but to provide a list of criteria that may be used by MOIT and the Institute of Energy to make a choice. These criteria may include:

* **Functionality** to determine if the tool is “Fit-for-purpose” for the job at hand covering major issues that need attention.
* **Cost** of licenses considering that potentially multiple licenses, training, and maintenance of databases will need to be continued over many years.
* **Transparency** of the model. Is the modeling methodology sufficiently documented? Can it be used to explain the capacity and dispatch outcomes of the model?
* **Reliability** of the model and support from the vendor. Can the model be used to replicate known outcomes, does it run properly without any non-convergence issues, do the results remain the same across different versions?
* **User-friendliness** – can data be entered in the model easily, including bulk changes and the results available in a format that can be directly used in reports/presentations? Does it have a robust standard set of plots and tables to quickly review the results, reports that can be easily customized for each application, and a graphical interface to plot the results and map the flows?

In order to make a proper selection of the planning tool for PDP8, it is useful for the PDP8 team in Vietnam to give due consideration to the following issues:

1. There are four main analytical components – (i) multi-year capacity planning optimization, (ii) dispatch, (iii) market bids, and (iv) transmission systems analysis. In theory, there is a need for four separate modules, but the more advanced models such as PLEXOS can combine multiple functions (e.g., the first three modules). While this is not essential, there is an efficiency gain from having a common database and the seamless transition from one model to another. There is a trade-off between such efficiency gain and cost. At minimum, there is likely to be two models, namely an optimization tool for the first three modules and a power flow /stability simulation model;
2. Weight the ‘functionality’ criterion as the most important attribute. If a model is not capable of representing renewable energy and spinning reserve in sufficient detail, it is unlikely to be of much value given Vietnam’s aspirations to integrate large volume of renewables during the PDP8 planning period;
3. Accord value to a tried and tested model with the data and experienced user(s) as long as it is compliant with the functionality. This may be the case for the transmission analysis software and possibly one or more of the other modules. The advantage of an existing model should be weighed against a move to a more modern and/or integrated model.[[8]](#footnote-8) There are also multiple generation/dispatch models of the Vietnam power system available including [PLEXOS](https://energyexemplar.com/products/plexos-simulation-software/), [PSR/SDDP](https://www.psr-inc.com/softwares-en/), [PROPHET](http://products.iesys.com/Prophet/Index), [BALMOREL](http://www.balmorel.com/), LIPS-OR (Lahmeyer International, Germany), etc.[[9]](#footnote-9) There is also a PSS/E load flow model that is used by the NLDC and the Institute of Energy;
4. Coordinate the study with other modules. The market bidding module is not as readily available as some of the other modules. PLEXOS and PROPHET are two products that include a market bidding module integrated in the optimization. However, it is a module that can be kept as a stand-alone module to develop bids/offers that can be fed into a standard planning or dispatch model to replace the cost assumptions as long these planning/dispatch tools are able to handle multiple tranches of cost parameters for each generator.[[10]](#footnote-10) The availability of a market module perhaps should not in itself drive the decision to select a planning tool. It is also possible to keep the wholesale market simulation analysis as a stand-alone task that could be undertaken as a special study. Indeed, it is important to coordinate such a study with the other modules for it to be consistent in terms of data/assumptions and scenarios;
5. Consider the cost of the planning toolkit, combining the license cost, training, data and human resource when forming a decision. It is especially important to consider the long-term cost covering at least two planning cycles, possibly a decade. Make an informed decision ahead of time and avoid the decisions to drop the chosen planning tool in a year or two. As the previous points allude, the process of selection of tools ought to consider those that are not at the highest end in terms of functionalities but does the job at the expense of some loss in efficiency. This could either be due to the need to manually transfer data across more than one model or having a less user-friendly interface;
6. Ensure the transparency of the model. Many advanced models unfortunately do not offer complete documentation of the underlying models. This can make interpretation of the results extremely difficult. This is particularly true in a system like Vietnam that has all the ingredients for a potentially complex outcome. It is important to have a solid foundation on modeling principles through a rigorous training program including a demonstration of how the modeling tools employ these principles;
7. Determine the reliability of the model and support from the vendor when selecting the tool. Optimization tools are still evolving as newer technologies and policies and electricity market features keep getting added. An artefact of these continuous changes is that even the best modeling package is prone to errors. It is paramount that the model is tested, supported by a community of users and supported by the vendor to rectify bugs, answer questions and even be prepared to step in to do some analysis if quick turnaround is critically important. Vendors with a consulting arm and a larger team are often better placed to ensure reliability of the model;
8. Verify the usability of the model to get data in/out efficiently, set up scenarios and process multiple runs in one go, perform intuitive data error checks and measures to avoid errors, and the interface of generation planning output to PSS/E format. These features can save significant time and avoid frustrating data entry and processing tasks, freeing up valuable time to focus on the core analysis. Nevertheless, it is **not** the most important criterion and certainly not the only one to decide on the selection of the tool. It is worth remembering that if the model scores well on the other more important criteria, it is not that difficult to get used to an interface with lower usability scores. The bulk of data preparation and analysis of results takes place in MS-Excel and as long as the model facilitates an easy transfer to/from MS-Excel, this is usually adequate;
9. Consider the experience of the user group/planning team. A user-friendly package is often of interest to a group of planning engineers who lack the experience and confidence to use a model that is seemingly difficult to handle. On the other hand, utilities, consulting groups, ministries, regulators with experienced hands are less obsessed with a flashy interface. In fact, many of these organizations to date continue to use their home-grown planning tools which is also an option to keep in mind. However, given the purpose of this Guidance Note to select an existing planning tool, this note does not elaborate on the pros and cons of buying vs developing options. It is critical to reiterate the need to develop a clear understanding of the principles underlying the tool and not rely on it as a ‘black box’.

In summary, the choice of planning tool requires some structured thinking and the preceding discussion provides some pointers. It is certainly not advisable to have a preconceived notion of a particular brand and acquire it at any cost because there is every chance that the functionality is not adequate, or the cost begins to seriously hurt two years down the line when a huge investment has been made to collect data and train people to use the software. The core modeling group should set a clear set of functions, that are needed, available budget, and keep an open mind to match it with the available tools. It is beneficial to think ahead and cover at least the next two planning cycles to make sure the investment is worthwhile and sustainable.

# Implementation of Planning Analysis

Getting the methodology and planning tool right are critical as the previous two sections discuss. However, it is also important to get the implementation of these right by managing the process including appropriate prioritization of the tasks. Planning analysis can an inordinately expensive and time consuming absent proper management. This concluding section there sets out a few concrete steps to implement PDP8:

1. Form an internal Steering Group of MOIT and relevant stakeholders in Vietnam to discuss the needed functionalities, existing stock of data and tools, and budget that can realistically be spent on the incumbent PDP8 and also for the next planning cycle. It is important to involve not only the current core planning body but also the system operator and the relevant personnel from the regulatory agency as all these groups have been involved in the analytical studies and have had access to different tools and data. It is also important to join forces, share experience with different models, and integrate the existing database. The Steering Group may consult experts outside the group as may be needed. The outcome of the discussions should be: (a) shortlist of planning tools that should be examined to complement existing ones, number of licenses needed (if any); and (b) data gaps that need to be addressed;
2. Start working on the majority of data requirements without waiting for the planning tool. Hourly/sub-hourly VRE profiles, load, dispatch data and daily/weekly inflows for hydro stations for the past years are critical along with missing parameters for the existing generation system. These could include ramp rates, spinning reserve capability, minimum loading, heat rate, fuel limit, and dynamic data for stability analysis. Categorize the new data into items that can be procured/collected for sure without much effort/delay; those that would require some effort and those unlikely to happen in the timeframe. A clear set of decisions on these would be very useful while making a decision on the planning tools. For example, if past sub-hourly load data is not available, there is little point delving deep into sub-hourly VRE data/analysis; if past hydrology details are not available, that severely limits the value of any sophisticated hydro analysis tool; and, if a realistic dynamic database (as opposed to ‘generic’ dynamic data) is not available, it reduces the importance of any meaningful stability analysis. A good handle on availability of data would also prepare the planning team to probe the software vendors on their ability to customize the tool to fit the available data;
3. Prepare the best available dataset for modeling and share it with prospective software vendors as part of the tendering process so vendors may use it to set their models up for demonstration purposes;
4. Organize a demonstration of prospective planning tools, perform the selection, and procure required licenses;
5. Organize training for at least two weeks, spending at least half of it on the working principles and the rest on use of the tool;
6. Develop a Data and Assumptions Workbook and get it signed off by the Steering Group. This should include scenario definitions and relevant parameters. The workbook should cover both generation and transmission planning, including specific scenarios/years for which the load flow and stability analyses should be conducted. Agree on a format for key outputs including a summary table of key metrics such as NPV of system cost, investments, capacity and generation mix, any unserved energy, emissions, and compliance of load flow/stability against contingencies;
7. Present the first-cut least-cost planning results (i.e., before conducting any operational simulation or iteration between generation and transmission plan or robustness of the base plan, etc.) to the Steering Group to assess if the plan and its variations across the scenarios look broadly sensible, or if it requires going back to data/assumptions, or further probes into the results;
8. Once the checks on the results are completed, fine tune the base capacity plan, including robustness of the plan, dispatch simulation to assess the feasibility of system operation, and transmission analysis for compatibility of the plan against the generation counterpart. All these parameters may require adjustments to the base plan enhancing the performance of the plan;
9. Perform a simulation of wholesale market analysis as an ancillary task once the base plan is finalized. It should be generated off the dispatch simulation tool using the final plan as an input. A select set of scenarios that demonstrate a range of wholesale prices can be a useful aid to market participants, current and prospective investors and regulator among others; and
10. Develop the comprehensive documentation and dissemination of the plan in multiple layers from a high level strategic vision component down to the technical details. Make these public, including the MOIT website, and include the modeling database and spreadsheets containing results.
1. World Bank and MOIT Workshop on Power Development Plan, Hanoi, November 6, 2018. [↑](#footnote-ref-1)
2. S.Thorncraft and T.George, *Appraisal of Draft Revised Master Plan on Power Development for Period 2011-2020 with Vision to 2030: Task 1 – Demand Forecasting*, Report prepared for the World Bank, Intelligent Energy Systems and DigSilent, August 2015. [↑](#footnote-ref-2)
3. We should mention that the reliability standard in Vietnam has some ambiguity as has been raised in past review of PDP7 by the Bank. One of the important pre-requisite for the PDP8 would be to establish a reliability criterion and include it in the Grid Code and Wholesale Electricity Market (WEM) Rule. [↑](#footnote-ref-3)
4. The concept of ‘option value’ is used to assess the flexibility that a specific transmission project adds to the system to cope with uncertainties in the system. In Australia, the regulatory framework allows the transmission investment proponent to claim market benefits associated with option value. <https://www.aer.gov.au/system/files/D18-98444%20AER%20-%20Draft%20RIT-T%20application%20guidelines%20-%2027%20July%202018.pdf> [↑](#footnote-ref-4)
5. World Bank, *Smart Grid Implementation Support*, National Power Transmission Coordination of Vietnam, Final Report, 2015. [↑](#footnote-ref-5)
6. There is a good discussion on some of the early models that were developed in the nineties in: J.Bushnell et al, *An International Comparison of Models for Measuring Market Power in Electricity Markets*, Energy Modeling Forum, Stanford University, 1999. [↑](#footnote-ref-6)
7. IRENA, Planning for the renewable future: Long-term modelling and tools to expand variable renewable power in emerging economies, 2017. Appendix 4 lists the models reviewed in this report focusing mainly on renewable integration issues. The report is available online: <http://www.irena.org/publications/2017/Jan/Planning-for-the-renewable-future-Long-term-modelling-and-tools-to-expand-variable-renewable-power> [↑](#footnote-ref-7)
8. It is for example possible that the current model is dated as is often the case with both generation and transmission model. Some utilities have moved on from WASP because it has limited capability to represent VRE characteristics. Transmission planning software have also been in the need for a facelift in many cases to account for better (e.g., plant specific) dynamic models, integrated analysis of contingencies and better graphical interface. There is a trade-off in the fixed cost involved in moving from an existing platform vs efficiency gains from a more modern tool with more functions, higher accuracy and better computational performance. [↑](#footnote-ref-8)
9. LIPS-OR and PROPHET have been used in World Bank studies for pumped-storage analysis and VRE integration, respectively. [↑](#footnote-ref-9)
10. There are probably simple workarounds to use the heat rates as a proxy for bid parameters to represent rising costs. [↑](#footnote-ref-10)