World Bank Electricity Planning Model (EPM): Mathematical Formulation World Bank Electricity Planning Model

Method · June 2018

1 author:

Deb Chattopadhyay
World Bank

World Bank Electricity Planning Model (EPM): Mathematical Formulation

Debabrata Chattopadhyay
Fernando de Sisternes
Samuel Kwesi Ewuah Oguah

Draft for Review

January, 2018

CONTENTS

FOREWORD: WHY EPM?

This is our first formal attempt from the Power Systems Planning Group, presently a part of the ESMAP, to release EPM as a planning tool for undertaking least-cost planning purposes. Power systems planning – specifically least-cost generation plans – has long been one of the core tasks performed by the World Bank over several decades. It is indeed one of the central tasks performed by all utilities and ministries often funded by one of the donor agencies, but not in all cases. There is no dearth of planning tools ranging from free tools like WASP (Wien Automated System Planning) to the high end commercial tools like PLEXOS – each with its pros and cons.

It naturally raises the question as to "why another tool?" Indeed, this has been part of a long debate and experiments including the procurement of the PSR planning suite, a high-end commercial tool, in 2014. While the tool has served us well for some major studies including Saudi Arabia, Kazakhstan and Sri Lanka, we also realized that the tool is data and time intensive, has some "black box" elements to it, does not meet all our requirements that often go beyond planning, and expensive ($300K upfront costs and $40K per year maintenance fee). We therefore had as much reliance on home-grown models written in General Algebraic Modeling System (GAMS) – a mathematical programming language that allows us to access the same commercial optimization algorithms as PLEXOS and PSR do. The EPM model today is a culmination of many variants of the GAMS models that were written since 2014 into an integrated version with an MS-EXCEL front-end that allows users to input data, run the model, and retrieve outputs (without any knowledge of GAMS *per se*). EPM and its predecessor versions have been used for a wide range of planning and operational analyses for 30 countries (including three regional analyses).

As it stands today, EPM has 80% of the modeling features of a high-end tool like PLEXOS but costs no more than $2.5K per year which is only 5% of the cost of the former. The remaining (20%) features are mostly superfluous to the needs of developing countries and finding data even for the basic modules is onerous. It can be a stepping stone for many utilities around the world to develop an understanding of planning, if not a permanent tool for all generation planning needs. Earlier versions of the model have been provided to our client utilities in Jordan, Uzbekistan, Bulgaria and Bangladesh.

As we see it, EPM is a continued part of our journey to actively support the operational work in all six regions, and build capacity internally and externally. We will use EPM where it makes sense and will complement commercially available tools. We see EPM as potentially a tool that can have wide use beyond the realm of our internal needs to fill in a niche between archaic free tools and the over-built expensive end.

ACKNOWLEDGEMENT

A number of colleagues have contributed to the development and testing of the tool. Thomas Nikolakakis and Miklos Bankuti have been instrumental in developing a version of the model for Bangladesh. Miklos has also developed a seamless extension of the model to undertake hourly dispatch and a link to PSS/E for transmission systems analysis. Tae-Yoon Kim and Jesse Jinyong Yang have developed a financial model backend to the model. Javier Inon has helped us to implement the models for Ukraine, Bulgaria, Tanzania and Ethiopia. Ilka Deluque Curiel has worked tirelessly in testing the model through the implementation of the first integrated version of EPM for the Pan-Arab regional model. Elina Spyrou (Johns Hopkins University) did a superb job of implementing a stochastic programming version of the model and continues to test EPM for a regional version of the model for Central and South Asia. Elina also helped the Bank planning team to produce the first draft of this documentation. Claire Nicolas works as part of the team and implemented the model for Madagascar.

1. INTRODUCTION: LEAST-COST PLANNING FRAMEWORK

Long term planning of a power system needs to consider a range of decisions including the following key ones:

- Addition of new generation assets and retirement of old units;
- Dispatch of existing and new units;
- Allocation of fuel among generation units, especially when there is fuel limitation;
- Flows among nodes/zones/countries;
- Allocation of spinning reserve among generators to cover for a contingency; and
- Load to be shed when supply falls short of demand.

These decisions need to observe a number of constraints that may include *inter alia* meeting*:*

- Demand for all load conditions;
- Capacity reserve needed to ensure a reliable system with adequate capacity;
- Spinning reserve requirement so that the online generators withhold generation to rapidly meet the loss of any outage;
- Limits on transmission flows for safe operation of the transmission system;
- Limits on fuel (e.g., gas/LNG);
- Special characteristics of a hydro system and variable renewable energy;
- Ramp limits on how fast some generators can change their output; and
- Emission limits for carbon and local pollutants.

Even in a moderate system of 10 GW, there may be a hundred or more generating units over a 20-30 year timeframe (i.e., including new generators) and operational decisions that may run into several thousands per year. There are millions of permutations and combinations that one can consider all of which can meet demand and possibly many of the other constraints noted above. The solution that is of most interest to planners often is the so-called "least-cost" one that minimizes total system costs, subject to meeting all of the constraints. System cost in this context refers to not only operational costs but also relevant capital costs needed to build new power plants, opportunity cost of loads that have to be shed due to adequate generation/transmission capacity or fuel not being available, as well as cost of externalities including cost of carbon. More specifically, the least-cost planning implementation in EPM considers the following definition of system costs:

1. Annualized capital costs of new generators over the planning period;
2. Fuel costs for generation;
3. Non-fuel fixed and variable operation and maintenance (O&M) costs;
4. Cost of unserved energy or value of lost load (VoLL);
5. Cost of carbon; and
6. Other penalties associated with violation of any other constraint including capacity/spinning reserve, fuel and transmission flow limits, etc.

The problem is formulated as a linear/mixed integer programming (LP/MIP) problem as discussed in the next section.

2. MATHEMATICAL FORMULATION OF EPM

The model description starts with a declaration of the sets or indices, followed by input parameters and decision variables, before delving into the equations that combine these elements. This is followed by discussions and clarification on the model.

2.1 Notation

Indices/Sets

$d \in D$	where D is the set of types of days or weeks
$f \in F$	where F is the set of fuels
$g \in G$	where G is the set of generators that can be built or the set of technology-specific types of aggregated generators
$q \in Q$	where Q is the set of seasons or quarters
$t \in T$	where T is the set of time periods considered per day (usually 24 hours)
$y \in Y$	where Y is the set of years considered in the planning model
$z, z2 \in Z$	where Z is the set of zones/regions modeled
$sc \in S$	where S is the set of flags and penalties used to include/exclude certain features of the model
Subsets considered	
$EG, NG \in G$	where EG and NG is a partition of set G and the former (EG) contains generators existing at the starting year of the planning horizon and the latter (NG) contains candidate generators1
$MD \in D$	where MD is a subset of days the planner expects the minimum load levels to be binding
$PT, OPT \in T$	where PT and OPT is a partition of set T that distincts hours in peak and off-peak hours
$RE \in F$	where RE is a subset of set F considered as renewable according to regulator's criteria2
$RG \in G$	where MD is a subset of days the planner expects the minimum load levels to be binding
$map_{g,f}$	includes valid combinations of fuels and generators; subset of the set $G \times F$

[1] The generators already planned are included in any of the two sets depending on criteria such as their capacity, status of their construction process etc.

[2] Type of resources considered as renewables might be different from country to country or zones.

2.2 Variables

Non-negative decision variables	
$build_{g,y}$	Investment in MW
$cap_{g,y}$	Capacity available at year y in MW
$emissions_{z,y}$	Emissions of carbon dioxide in tons
$emissions\_Zo_{z,y}$	Emissions of carbon dioxide in tons per zone z
$fuel_{z,f,y}$	Fuel consumption in MMBTU
$gen_{g,f,q,d,t,y}$	Generator output in MW
$genCSP_{g,z,q,d,t,y}$	Power output of the solar panel in MW
$retire_{g,y}$	Capacity in MW retired
$reserve_{g,q,d,t,y}$	Spinning reserve requirement met in MW
$storage_{z,q,d,t,y}$	Level of energy in MWh stored at zone z
$storage\_inj_{z,q,d,t,y}$	Power level in MW at which the storage unit g is charged during hour (q, d, t)
$storage\_out_{z,q,d,t,y}$	Power level in MW at which the storage unit g is discharged during hour (q, d, t)
$storageCSP_{g,z,q,d,t,y}$	Level of energy in MWh stored in CSP unit at zone z
$storageCSPinj_{g,z,q,d,t,y}$	Power level in MW at which the CSP storage unit is charged during hour (q, d, t)
$storageCSPout_{g,z,q,d,t,y}$	Power level in MW at which the CSP storage unit is discharged during hour (q, d, t)
$trans_{z,z2,q,d,t,y}$	Active power in MW flowing from z to $z2$
$unmetDem_{z,q,d,t,y}$	Unmet demand in MW (or equivalently violation of the load balance constraint)
$unmetRes_{z,y}$	Violation of the planning reserve constraint in MW
$unmetSResZo_{z,q,d,t,y}$	Violation of the zonal/regional spinning reserve constraint in MW
$unmetSResSY_{q,d,t,y}$	Violation of the system-level spinning reserve constraint in MW
Variables for modeling objective function	
$carboncost_{z,y}$	Carbon tax payments by generators
$fixedcost_{z,y}$	Fixed Operation and Maintenance Cost along with capital payments in constant prices
$npvcost$	Net present value of power system cost over the whole planning horizon; objective function that optimization model tries to minimize
$reservecost_{z,y}$	Cost to procure spinning reserves

$totalcost_{z,y}$	Annual system cost in constant prices
$usecost_{z,y}$	Damage/economic loss in constant prices because of unmet demand
$usrcost_{z,y}$	Penalty in constant prices for unmet spinning reserve requirements
$variablecost_{z,y}$	Variable cost including fuel and variable operation and maintenance cost in constant prices

2.3 Input Parameters

$Availability_{g,q}$	Availability of unit g to generate power in quarter q
$Annual\_built\_limit_{y}$	Maximum amount of MW allowed to be built per year
$CapCost_{NG,y}$	Capital cost in USD $ or other monetary unit per MW
$Carbon\_emission_{f}$	Equivalent tons of CO_2 emitted per MMBTU of fuel consumed
$Carbon\_tax_{y}$	Carbon price in USD$ per equivalent tons of CO_2
$Commission\_year_{g}$	Earliest commission year for generators
CRF_{NG}	Capital Recovery factor[3]
$CSP\_storage$	CSP storage capacity in hours
$Demand_{z,q,d,t,y}$	Hourly load level in MW in hour t, day d, quarter q and year y
$DRate_{y}$	Discount rate; real or nominal if cost parameters in real or nominal terms respectively
$Duration_{q,d,t,y}$	Duration of each time slice (block) in hours
$FieldEfficiency_{CSP}$	Efficiency of the CSP solar field
$FixedOM_{g,y}$	Fixed Operation and Maintenance Cost in USD $ or other monetary unit per MW
$FuelPrice_{f,y,z}$	Fuel price in USD $/MMBTU
$GenCost_{g,f,y}$	Generation variable cost (fuel and VOM) in USD $ or other monetary unit per MWh
Gen_zone_{g}	Contains the zone index of the zone the generator belongs to
$HeatRate_{g,f}$	Heat Rate in BTU/MWh
$Life_{NG}$	Operating life for new generators
$LossFactor_{z,z2,y}$	“Linearized” loss factor in % of active power flowing on transmission line
$MaxCapital$	Maximum amount of annualized capital payments in USD$ billion over the horizon

[3] $CRF_{NG} = \frac{WACC}{1-\frac{1}{(1+WACC)^{Life_{NG}}}}$

$MaxFuelOff_{f,y}$	Maximum amount of fuel f (in BTU) that can be consumed in year y
$MaxNewCap_{NG}$	Maximum capacity to be built over the horizon in MW
$MinCapFac_g$	Minimum capacity factor (to reflect minimum load requirements)
$OverLoadFactor_g$	Overload factor of generator g, as %, of capacity
$PlantCap_{EG}$	Existing capacity at initial year in MW
PRM_z	Planning reserve margin per zone z
$RampDn_g$	Ramp-down capability of generator g, as %, of capacity installed4
$RampUp_g$	Ramp-up capability of generator g, as %, of capacity installed
$ResCost_g$	Cost to provide reserves in USD $ or other monetary unit per MWh
$ResOffer_g$	Maximum amount of fuel f (in BTU) that can be consumed in year y
$RESVoLL$	Violation penalty of planning reserve requirement in $/other monetary unit per MW
$Retirement\_year_{EG}$	Latest retirement year for existing generators
$ReturnRate_y$	Discount factor at the starting year of stage ending at year y
$RPprofile_{g,RE,q,d,y,t}$	Renewable generation profile in % of installed (rated) capacity
$SolarMultipleCSP$	CSP output to solar field ratio
$SResSY_y$	System-level spinning reserve constraint in MW
$SResZo_{z,y}$	Zonal/regional spinning reserve constraint in MW
$StageDuration_y$	Duration of a stage represented by year y in years
$StartYear$	First year of the horizon
$Storage\_capacity_{z,y}$	Capacity of storage unit
$Storage\_efficiency_{z,y}$	Efficiency of storage (per charging cycle)
$Storage\_energy_{z,y}$	Energy capability of storage unit
$Sy\_emission\_cap_y$	Cap on CO_2 emissions within the system at year y in equivalent tons
$Topology_{z,z2}$	Network topology: contains 0 for non-existing lines and 1 or -1 to define the direction of positive flow over the line
$TransLimit_{z,z2,q,y}$	Transmission limits by quarter q and year y
$TurbineEfficiency_{CSP}$	Efficiency of the CSP power block
$VarOM_{g,y}$	Variable Operation and Maintenance Cost in USD $ or other monetary unit per MWh
$VOLL$	Penalty/Economic loss consider per MWh of unmet demand

[4] Note that ramping capabilities of generator are usually expressed in MW/min and then based on the minutes the operating reserve requirement is defined, we can estimate the capability in MW and subsequently expressed it in % of installed capacity. In USA, 10 min is typical time for operating reserves and 5 min for regulation reserves.

$WACC$	Weighted Average Cost of Capital
$WeightYear_y$	Weight on years
$Zo\_emission\_cap_{y,z}$	Cap on CO_2 emissions within zone z and year y in equivalent tons
$zone\_index_z$	Index of zone z, unique number assigned to zone z

2.4 Model formulation: System cost as the objective function

EPM minimizes discounted system cost over the entire planning horizon as described below:

Objective function and its components

$$npvcost = \sum_{z,y} ReturnRate_y * WeightYear_y * totalcost_{z,y} \quad (1)$$

$$totalcost_{z,y} = fixedcost_{z,y} + variablecost_{z,y} + reservecost_{z,y} + usecost_{z,y} + usrcost_{z,y} + carboncost_{z,y} \quad (2)$$

$$fixedcost_{z,y} = \sum_{g \in NG} CRF_{NG} * CapCost_{NG,y} * cap_{g,y} * + \sum_{g} FixedOM_{g,y} * cap_{g,y} \quad (3)$$

$$variablecost_{z,y} = \sum_{g \in Z,f,q,d,t} GenCost_{g,f,y} * Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \quad (4)$$

$$reservecost_{z,y} = \sum_{g \in Z,q,d,t} ResCost_g * Duration_{q,d,t,y} * reserve_{g,q,d,t,y} \quad (5)$$

$$usecost_{z,y} = \sum_{q,d,t} VOLL * Duration_{q,d,t,y} * unmetDem_{z,q,d,t,y} \quad (6)$$

$$usrcost_{z,y} = \sum_{q,d,t} RESVoLL * unmetRes_{z,y} + \sum_{z,q,d,t,y} Duration_{q,d,t,y} * SRESVoLL * unmetSResZo_{z,q,d,t,y} + \sum_{q,d,t} Duration_{q,d,t,y} * SRESVoLL * unmetSResSY_{q,d,t,y} \quad (7)$$

$$carboncost_{z,y} = \sum_{g \in Z,f,q,d,t} Duration_{q,d,t,y} * carbon_{tax_y} * HeatRate_{g,f} * carbon_{emission\,f} * gen_{g,f,q,d,t,y} \quad (8)$$

2.5 Constraints to be observed

Transmission network constraints

$$\sum_{g \in Z,f} gen_{g,f,q,d,t,y} - \sum_{z2} trans_{z,z2,q,d,t,y} + \sum_{z2} \left(1 - LossFactor_{z,z2,y}\right) * trans_{z2,z,q,d,t,y} + storage_{out\,z,q,d,t,y} - storage_{inj\,z,q,d,t,y} + unmetDem_{z,q,d,t,y} = Demand_{z,q,d,t,y} \quad (9)$$

$$trans_{z,z2,q,d,t,y} \leq TransLimit_{z,z2,q,y} \quad (10)$$

System requirements

$$\sum_{g} reserve_{g,q,d,t,y} + unmetSResSY_{q,d,t,y} \geq SResSY_{y} \quad (11)$$

$$\sum_{g \in Z} reserve_{g,q,d,t,y} + unmetSResZo_{z,q,d,t,y} + \sum_{z2} \left(TransLimit_{z2,z,q,y} - trans_{z2,z,q,d,t,y}\right) \geq SResZo_{z,y} \quad \forall\, z,q,d,t,y \quad (12)$$

$$\sum_{g \in Z} cap_{g,y} + unmetRes_{z,y} + \sum_{z2} \sum_{q} TransLimit_{z2,z,q,y} \geq (1 + PRM_{z}) * \max_{q,d,t} Demand_{z,q,d,t,y} \quad \forall\, z,y \quad (13)$$

Generation constraints

$$\sum_{f} gen_{g,f,q,d,t,y} + reserve_{g,q,d,t,y} \leq \left(1 + OverLoadFactor_{g}\right) * cap_{g,y} \quad (14)$$

$$reserve_{g,q,d,t,y} \leq cap_{g,y} * ResOffer_{g} \quad (15)$$

$$\sum_{f} gen_{g,f,q,d,t-1,y} - \sum_{f} gen_{g,f,q,d,t,y} \leq cap_{g,y} * RampDn_{g} \quad \forall\, t > 1 \quad (16)$$

$$\sum_{f} gen_{g,f,q,d,t,y} - \sum_{f} gen_{g,f,q,d,t-1,y} \leq cap_{g,y} * RampUp_{g} \quad \forall\, t > 1 \quad (17)$$

$$\sum_{f} gen_{g,f,q,d,t,y} \geq MinCapFac_{g} * cap_{g,y} \quad \forall d \in M \quad (18)$$

$$\sum_{f,d,t} Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \leq Availability_{g,q} * \sum_{d,t} Duration_{q,d,t,y} * cap_{g,y} \quad (19)$$

Renewable generation

$$gen_{g,f,q,d,t,y} \leq RPprofile_{g,RE,q,d,y,t} * cap_{g,y} \qquad \forall\, RE \notin CSP \tag{20}$$

Concentrated Solar Power (CSP) Generation

$$storageCSP_{g,z,q,d,t,y} \leq cap_{g,y} * CSP\_storage \qquad \forall\, map(g, CSP) \tag{21}$$

$$genCSP_{g,z,q,d,t,y} = RPprofile_{z,RE \in CSP,q,d,t} * cap_{g,y} * \frac{SolarMultipleCSP}{TurbineEfficiency_{CSP} * FieldEfficiency_{CSP}} \tag{22}$$

$$\sum_{f \in CSP} gen_{g,f,q,d,t,y} \leq cap_{g,y} \tag{23}$$

$$\sum_{f \in CSP} genCSP_{g,z,q,d,t.y} * FieldEfficiency_{CSP} - storageCSPinj_{g,z,q,d,t,y} + storageCSPout_{g,z,q,d,t,y} = \frac{gen_{g,f,q,d,t,y}}{TurbineEfficiency_{CSP}} \quad \forall\, g, z, q, d, t, y \tag{24}$$

$$storageCSP_{g,z,q,d,t,y} = storageCSP_{g,z,q,d,t-1,y} + storageCSPinj_{g,z,q,d,t,y} - storageCSPout_{g,z,q,d,t,y} \tag{25}$$

Time consistency of power system additions and retirements

$$cap_{g \in EG,y} = cap_{EG,y-1} + build_{EG,y} - retire_{EG,y} \qquad \forall\, ord(y) > 1 \tag{26}$$

$$cap_{g \in NG,y} = cap_{NG,y-1} + build_{NG,y} \qquad \forall\, ord(y) > 1 \tag{27}$$

$$cap_{g \in NG,y} = PlantCap_{EG} \qquad ord(y) = 1 \tag{28}$$

$$cap_{g,y} = 0 \quad \forall\, (y, g)\colon\ (ord(y) - 1) * StageDuration_{y} + StartYear < Commission\_year_{g} \tag{29}$$

$$cap_{g,y} = 0 \quad \forall\, (y, g \in EG)\colon\ (ord(y) - 1) * StageDuration_{y} + StartYear > Retirement\_year_{EG} \tag{30}$$

Storage constraints

$$storage_{z,q,d=1,t=1,y} = 0 \tag{31}$$

$$storage_{z,q,d,t>1,y} = storage_{z,q,d,t-1,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d,t-1,y} - storage\ out_{z,q,d,t-1,y} \tag{32}$$

$$storage_{z,q,d,t=1,y} = storage_{z,q,d-1,t=241,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d-1,t=24,y} - storage\ out_{z,q,d-1,t=24,y} \tag{33}$$

$$\sum_{t \in PT} storage\ out_{z,q,d,t,y} \leq Storage_{efficiency_{z,y}} * \sum_{t \in OPT} storage\_inj_{z,q,d,t,y} \quad (34)$$

$$storage\ inj_{z,q,d,t,y} \leq Storage\_capacity_{z,y} \quad (35)$$

$$storage\ out_{z,q,d,t,y} \leq Storage\_capacity_{z,y} \quad (36)$$

$$storage_{z,q,d,t,y} \leq Storage\ energy_{z,y} \quad (37)$$

$$storage\ out_{z,q,d,t,y} \leq storage_{z,q,d,t,y} \quad (38)$$

$$storage\ inj_{z,q,d,t,y} \leq Storage\ energy_{z,y} - storage_{z,q,d,t,y} \quad (39)$$

Investment constraints

$$\sum_{y} build_{g \in NG,y} \leq MaxNewCap_{NG} \quad (40)$$

$$build_{g \in NG,y} \leq Annual\ built\ limit_{y} * WeightYear_{y} \quad (41)$$

$$fuel_{z,f,y} \leq MaxFuelOff_{f,y} \quad (42)$$

$$fuel_{z,f,y} = \sum_{g \in Z,q,d,t} Duration_{q,d,t,y} * HeatRate_{g,f} * gen_{g,f,q,d,t,y} \quad (43)$$

$$\sum_{y,g \in NG} ReturnRate_{y} * pweight_{y} * CRF_{NG} * CapCost_{NG,y} * cap_{g,y} \leq MaxCapital \quad (44)$$

Environmental policy

$$emissions\_Zo_{z,y} = \sum_{g \in Z,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_f} * Duration_{q,d,t,y} \quad (45)$$

$$emissions\_Zo_{z,y} \leq Zo\_emission\_cap_{y,z} \quad (46)$$

$$emissions_{z,y} = \sum_{g,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_f} * Duration_{q,d,t,y} \quad (47)$$

$$emissions_{z,y} \leq Sy\_emission\_cap_{y} \quad (48)$$

2.6 Description of the model

Indices and Sets

All sets used in the formulation can be classified in two major categories: temporal resolution of the model and those pertaining to physical elements of a power system. Four sets belong to the former category: Y,Q,D, T which represent different time scales considered in the model: years, quarters, days, and hours.

Hour is the smallest unit of time used in this formulation and we could use the same formulation using just one set for time containing as many hours as the set $D \times Q \times T \times Y$. It is convenient though to keep all the four sets since they reveal some fundamental assumptions of the model: (1) days are used to reflect the chronological sequence of the time slices used for ramping and storage constraints as we will further explain in the constraints section; (2) quarters are used to reflect seasonality in the load patterns, the availability of thermal power units and the thermal limits of transmission lines; (3) years are used to represent annual trends on demand growth and keep track of the lifetime of units; and finally (4) hours are commonly used as the smallest time unit in long term models since the day ahead scheduling models schedule generation units on an hourly basis.

Three sets are power system related. Set G includes all generating units while g are the elements of the set or individual power stations/ generating units. Depending on the size of the system, we might decide to use set g to model individual units of the power system for a small system or aggregated units that represent multiple units of the same technology for a large system. We use the term technology to refer to different technologies or different fuels used: e.g. coal steam turbines, natural gas combined cycle, natural gas combustion turbines, wind farms, solar photovoltaic panels, geothermal, hydropower and diesel generators.

As the model stands now, elements of set G are mapped to sets F and Z, which stand for fuel and zones respectively. Set Z is one of the major sets used in power systems since the power system is a network and physical laws (widely known as Kirchhoff's current law) govern the flow of power over the transmission lines. Given that, a set such as set Z which captures the spatial dimension of the system is necessary. At the finest granularity, set Z might contain buses of the power system but in case we model larger systems, set Z might contain zones of a power system or even countries. Note that the modeler usually decides on the spatial granularity based on the presence of common regulatory rules or pricing schemes in a zone or/and based on the congestion observed on transmission lines connecting adjacent regions. Finally, set F includes different fuels used and we model it to keep track of the consumption of different fuels since for certain fuels domestic upper bounds on consumption might apply or/and issues of energy security might be involved in case of imported fuels. In addition, different type of fuels has different carbon content and lead to different emissions of carbon dioxide, which are important to track in case environmental policies exist.

Objective function

The objective function in this model minimizes the total system cost including violation/penalty terms for constraints that are not met. All generation costs of the system are considered: (1) Fixed costs including annualized capital cost payments for new generators[5] and fixed operation and maintenance costs (2) variable costs including the fuel cost and any variable operation and maintenance costs (3) cost to procure spinning reserves (4) carbon tax payments and (5) penalties for unmet demand and unmet reserve requirements at the system or the zonal level.

[5] Capital costs of existing generators are considered sunk costs and are not included in the objective function.

Load approximation

The model is usually employed to decide or explore optimal generation investment plans at the country or multi-country level. As a result, modeling all the 8,760 hours of a year is not a practical option nor it is essential considering the level of uncertainties associated with forecasting demand for precise hours 20-30 years from now.

If available, we use the forecasts provided along with historical detailed data on the chronological profiles of demand to generate future load time series. Typically, we select three (3) days per quarter in a year. The first day, is the one (24 hours) that contains the maximum peak in the quarter. The second, is the day that contains the minimum peak the quarter. The third, is the a 24-hour day that contains the average per hour in the quarter. In total the load demand in a year is represented by 12 days (3 days x 4 quarters).

It should be noted that the load data structure is completely flexible to collapse the model down to yearly steps, or aggregate the steps within a day. In fact, the model can easily be cast to use annual/seasonal/monthly load duration curves (LDC) by simply treating the hours of the day as blocks.

Value of Lost Load

The Value of Lost Load is an exogenous assumption that reflects the opportunity cost faced by end-use customers for not having electricity. Since the nature of interruption varies a great deal from very infrequent outages in developed nations to routine rolling outages in their developing counterparts, the opportunity costs also vary. These costs of course also vary depending on the costs foregone that would typically be a lot higher in developed countries. A sudden outage in a system that rarely sees any can have a profound impact due to lost production because there may not be any back-up measures. On the other hand, systems in developing countries do have diesel generator sets etc as back-up measures in anticipation of such grid outages that limit the damage. Typical values used in developed economies vary between 4,000 and 40,000$/MWh [1] while in developing countries between from a few hundred dollars [2] and up to 10,000$/MWh [1].

Transmission network constraints

Kirchhoff's laws are physical laws governing the flows over transmission lines in a network. According to first Kirchhoff law, also known as KCL (Kirchhoff's Current Law), the sum of injections in a node should equal zero. In our formulation, KCL corresponds to equation (9). There, we can see that the power provided by generators and storage should be equal to demand (minus the unmet demand) plus/min outflows/inflows from the node to adjacent nodes.

$$\begin{aligned}\sum_{g \in Z,f} gen_{g,f,q,d,t,y} - \sum_{z2} trans_{z,z2,q,d,t,y} + \sum_{z2} \left(1 - LossFactor_{z,z2,y}\right) * trans_{z2,z,q,d,t,y} \\ + storage_{out_{z,q,d,t,y}} - storage_{inj_{z,q,d,t,y}} + unmetDem_{z,q,d,t,y} \\ = Demand_{z,q,d,t,y}\end{aligned} \tag{9}$$

Note that the second Kirchhoff Law (or widely known as KVL- Kirchhoff's Voltage Law) is valid for power systems but for reduced power system, it might not apply depending on the method of network reduction followed. In this particular formulation, KVL is not considered.

Another important feature of our model relates to modeling of transmission losses. We model transmission losses as a percent reduction of the imported electricity at each node. In particular, term $\sum_{z2}\left(1 - LossFactor_{z,z2,y}\right) * trans_{z2,z,q,d,t,y}$ at equation (9) models injections to node z and we can see how the loss factor reduces the amount of energy imported. On the contrary, the outflow is fully considered at the origin node of the network: $\sum_{z2} trans_{z,z2,q,d,t,y}$.

A common constraint for transmission networks refers to the capacity limits of transmission lines. In particular, as equation (10) implies, the flow over a specific line cannot exceed a certain limit, which is defined either by thermal limit of the line or upper bounds imposed by reliability considerations. Note that we model flows over a particular transmission line with two positive variables, one for each direction. Please observe that the transmission limit parameter might change per year to reflect planned upgrades or additions to the transmission network. Moreover, the transmission limit differs per season since ambient temperature affects the capacity available for power transfers.

$$trans_{z,z2,q,d,t,y} \leq TransLimit_{z,z2,q,y} \tag{10}$$

System requirements

In our formulation, we model two products that the system operator might require generators to provide during operation: (1) energy and (2) spinning reserves. Per NERC's definition, spinning reserves refers to "unloaded generation that is synchronized and ready to serve additional demand" [3]. Note that more products exist, especially in organized U.S. wholesale markets such as non-spinning reserves or flex ramp. Operating reserves (spinning and non-spinning reserves) provide the capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection [3]. Moreover, under the spinning reserves different products might exist with respect to the response times required etc.

The amount of spinning reserve required depends on several factors that the planner/operator considers such as the load level and the associated forecasting error, the forecasting error attached to the renewable generation and the size of the largest unit committed on the system to be able to accommodate N-1 outages. Equation (12) indicates that spinning reserve can be provided by interconnections On top of system-wide reserve requirements, zonal requirements apply to accommodate for outages on transmission lines connecting adjacent regions/zones/nodes.

$$\sum_{g} reserve_{g,q,d,t,y} + unmetSResSY_{q,d,t,y} \geq SResSY_y \tag{11}$$

$$\sum_{g \in Z} reserve_{g,q,d,t,y} + unmetSResZo_{z,q,d,t,y} + \sum_{z2}\left(TransLimit_{z2,z,q,y} - trans_{z2,z,q,d,t,y}\right) \geq SResZo_{z,y} \quad \forall\, z,q,d,t,y \tag{12}$$

Planners usually consider a planning reserve margin (PRM) to account for forecasting error in demand projections. Typical values for the PRM vary between 10%-20% depending on the system characteristics and stringency of the capacity adequacy criterion in place. Equation (13) indicates that interconnections can be accounted for as reserve margin. Note that intermittent units do not contribute towards the planning reserve constraint at their full capacity but at a fraction specified by the planner, e.g. in the U.S. markets this fraction is calculated based on available historical data as the capacity factor during a set of peak hours [4].

$$\sum_{g \in Z} cap_{g,y} + unmetRes_{z,y} + \sum_{z2} \sum_{q} TransLimit_{z2,z,q,y} \geq (1 + PRM_z) * \max_{q,d,t} Demand_{z,q,d,t,y} \quad \forall z, y \tag{13}$$

Generation constraints

We decide to include spinning reserves since they will "consume" capacity that could be used for power generation.

$$\sum_{f} gen_{g,f,q,d,t,y} + reserve_{g,q,d,t,y} \leq \left(1 + OverLoadFactor_g\right) * cap_{g,y} \tag{14}$$

Equation (14) assures that the power generated by the unit along with the spinning reserves provided by the same unit do not exceed the unit's capacity.[6] Note that the capacity is augmented by an overload factor. This factor is typically 10% for those generators that can handle overload conditions for a short period of time, and zero for those generators that cannot handle such conditions.

Given that spinning reserve products are usually defined with respect to response time of generator to a certain dispatch signal, only a certain percentage of the generator's unit qualify as a reserve offer. We capture this characteristic in the model through equation (15).

$$reserve_{g,q,d,t,y} \leq cap_{g,y} * ResOffer_g \tag{15}$$

Ramping constraints acknowledge that the generation units have inertia in changing their outputs and differences in generation outputs between consecutive hours should be constrained by the ramping up and down capabilities of the unit.

[6] Depending on the scope of the project, the dispatch constraint (14) might be slightly different. For example, ReEDS model implemented by NREL [16] treats quick start capacity service provided by a generator in the same way as spinning reserves under constraint (14) and on top of that, it accounts for planned and forced outages by considering average outage rates.

$$\sum_{f} gen_{g,f,q,d,t-1,y} - \sum_{f} gen_{g,f,q,d,t,y} \leq cap_{g,y} * RampDn_g \quad \forall\, t > 1 \tag{16}$$

$$\sum_{f} gen_{g,f,q,d,t,y} - \sum_{f} gen_{g,f,q,d,t-1,y} \leq cap_{g,y} * RampUp_g \quad \forall\, t > 1 \tag{17}$$

Another important feature of generators is the minimum load. The minimum load can either be determined based on technical specifications provided by the manufacturer or be calculated as an "economic" minimum beyond which the unit can provide energy economically. The minimum load constraint is really important for unit commitment and requires the use of binaries variables that make sure the constraint is enforced when the unit is on. However, in the planning models operations are approximated through a simple dispatch model for representative hours of the year. In the same manner, an approximation of the minimum load constraint is applied for some thermal units the min load constraint is judged to be important. Constraint (18) is forcing all units to generate power equal to at least their minimum loading levels for specific days in the year.

$$\sum_{f} gen_{g,f,q,d,t,y} \geq MinCapFac_g * cap_{g,y} \qquad \forall d \in M \tag{18}$$

Generating units require maintenance every year. Given that, we should consider the units as unavailable for certain periods during the year.

$$\sum_{f,d,t} Duration_{q,d,t,y} * gen_{g,f,q,d,t,y} \leq Availability_{g,q} * \sum_{d,t} Duration_{q,d,t,y} * cap_{g,y} \tag{19}$$

Solar PV and wind generation modeling

Variable renewable generation (solar PV and wind without storage) sources differ from conventional units in that its output is, to a certain extent, uncontrollable and intermittent. The power generated by renewables such as wind or solar depends on wind velocity or solar irradiation. Collecting historical data that register weather information (such as wind speed, temperature, wind direction, etc.) or the power generation output by installed renewables at specific locations, analysts usually employ statistical methods such as k-means to reduce the amount of hours required to approximate the intermittent nature of renewables [5].

$$gen_{g,f,q,d,t,y} \leq RPprofile_{g,RE,q,d,y,t} * cap_{g,y} \tag{20}$$

Note that the renewable profile is highly dependent on the region/location the resource is located. This formulation implicitly models that aspect since g might have different elements for the same generation technology at different locations.

Concentrated Solar Power (CSP) modeling

CSP technology modeling differs from other renewable technologies due to the complexity derived by its storage capabilities. The CSP configuration considered in this model consists of two integrated subsystems; these include the thermal storage system, and power cycle. Thermal storage is modeled using a simple energy balance approach that includes charging and discharging energy. The power cycle model provides a simple mechanism for modeling the conversion from thermal energy output from the solar field, and thermal storage into electrical energy.

$$storageCSP_{g,z,q,d,t,y} \leq cap_{g,y} * CSP\_storage \qquad \forall\, map(g, CSP) \tag{21}$$

Equation (21) indicate that at any time the CSP storage level cannot exceed its storage capability.

$$genCSP_{g,z,q,d,t,y} = RPprofile_{z,RE \in CSP,q,d,t} * cap_{g,y} * \frac{SolarMultipleCSP}{TurbineEfficiency_{CSP} * FieldEfficiency_{CSP}} \tag{22}$$

The power output of the solar panel is calculated by multiplying the nameplate capacity of the CSP power plant, the capacity factor of the system, and the solar multiple, then, dividing this by the turbine and solar field efficiencies (Equation (22)).

$$\sum_{f \in CSP} gen_{g,f,q,d,t,y} \leq cap_{g,y} \tag{23}$$

Equation (23) indicate that all the power output produced by CSP generators at any given zone, cannot exceed the nameplate capacity. Finally, Equations (24) and (25) detail the power balance formulations for the power cycle and thermal storage subsystems.

$$\sum_{f \in CSP} genCSP_{g,z,q,d,t.y} * FieldEfficiency_{CSP} - storageCSPinj_{g,z,q,d,t,y} + storageCSPout_{g,z,q,d,t,y} = \frac{gen_{g,f,q,d,t,y}}{TurbineEfficiency_{CSP}} \qquad \forall\, g,z,q,d,t,y \tag{24}$$

$$storageCSP_{g,z,q,d,t,y} = storageCSP_{g,z,q,d,t-1,y} + storageCSPinj_{g,z,q,d,t,y} - storageCSPout_{g,z,q,d,t,y} \tag{25}$$

Time consistency of power system additions and retirements

We use constraint (26) to track the capacity in consecutive years. In particular, capacity at year y equals capacity at previous year plus any investment minus any retirement at year y.

$$cap_{g \in EG,y} = cap_{EG,y-1} + build_{EG,y} - retire_{EG,y} \qquad \forall\ ord(y) > 1 \tag{26}$$

Four more constraints are formulated to fix the capacity at pre-specified levels in certain years.

- The first constraint states that the total capacity of a new generator equals the capacity of that new generator built the previous year plus the capacity to be built the current year:

$$cap_{g \in NG,y} = cap_{NG,y-1} + build_{NG,y} \qquad \forall\ ord(y) > 1 \tag{27}$$

- The second constraint forces the capacity at the first year of the horizon to be equal to the known level:

$$cap_{g \in NG,y} = PlantCap_{EG} \quad ord(y) = 1 \tag{28}$$

- Third constraint forces the capacity of planned and candidate units at zero for years preceding the commission year of the unit. In other words, this constraint takes into account construction times and makes sure that enough time is allowed for a unit to become operational.

$$cap_{g,y} = 0 \quad \forall\ (y,g):\ (ord(y) - 1) * StageDuration_y + StartYear < Commission\_year_g \tag{29}$$

- The fourth constraint forces the capacity of existing units at zero in case they exceeded their lifetime. Note that a similar constraint would apply for new units in case more than 20 years were modeled.

$$cap_{g,y} = 0 \quad \forall\ (y, g\ \in EG):\ (ord(y) - 1) * StageDuration_y + StartYear > Retirement\_year_{EG} \tag{30}$$

Storage modeling

Economically efficient storage in power systems has mainly been pumped hydro storage for a considerable amount of years. Nowadays, more storage technologies are being added on the power system. However, for time being no investments in new storage technologies are considered. The existing pumped hydro storage units are aggregated at the zonal levels and represented as one unit with characteristics reflecting the ones provided by all units in the zone.

Storage is modeled differently compared to conventional units since it requires two more variables: (1) one to keep track of the storage level and (2) one to model the charging of the unit. The generator output of conventional units corresponds to the output of the storage unit when it is discharged. Moreover, the chronological sequence of the time slices is important in order to make sure that the simulated operation is feasible e.g., we cannot discharge a storage unit if charging of the unit has not preceded. Finally, storage of energy requires the conversion of electricity to another form of energy e.g. mechanical for flywheels or chemical for fuel cells and common batteries. The conversion of one form of energy to another involves losses that we should take into account in our models.

Three constraints are used to make sure that the operation of storage would be feasible taking into account the time sequence of load blocks. The time sequence in this particular application is relevant at the week level. As a result, we initialize the storage levels at the first hour of each week modeled and assume that zero storage level would be available at the beginning of one week because of storage operations at previous week. Constraint (31) enforces this initialization:

$$storage_{z,q,d=1,t=1,y} = 0 \tag{31}$$

Then constraints (32) keeps track of the energy stored in the unit between consecutive hours of the same day: the energy stored in the unit at time slice *t* equals the energy stored in the unit at time slice *t-1* plus any injection discounted by the efficiency minus any discharge at time *t*. Third, constraint (33) makes sure that the last time slice of the previous day plus any injection discounted by the efficiency minus any discharge at time *t* is equal to the energy stored in the unit at time slice *t*.

$$\begin{aligned} storage_{z,q,d,t>1,y} \\ &= storage_{z,q,d,t-1,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d,t-1,y} \\ &- storage\ out_{z,q,d,t-1,y} \end{aligned} \tag{32}$$

$$\begin{aligned} storage_{z,q,d,t=1,y} \\ &= storage_{z,q,d-1,t=241,y} + Storage\_efficiency_{z,y} * storage\ inj_{z,q,d-1,t=24,y} \\ &- storage\ out_{z,q,d-1,t=24,y} \end{aligned} \tag{33}$$

Constraint (34) forces the storage unit to discharge all its energy during the day. Essentially, it assumes daily cycles for the storage units, where the unit is charged during off peak hours and discharged during peak hours.

$$\sum_{t\,\in PT} storage\ out_{z,q,d,t,y} \leq Storage_{efficiency_{z,y}} * \sum_{t\,\in\,OPT} storage\_inj_{z,q,d,t,y} \tag{34}$$

Note that storage units can be charged or discharged at a rate, which cannot exceed a specific value. To model this behavior, we include constraints (35) and (36) respectively.

$$storage\ inj_{z,q,d,t,y} \leq Storage\_capacity_{z,y} \tag{35}$$

$$storage\ out_{z,q,d,t,y} \leq Storage\_capacity_{z,y} \tag{36}$$

Similarly, the energy stored in a storage unit cannot exceed its designed capability.

$$storage_{z,q,d,t,y} \leq Storage\ energy_{z,y} \tag{37}$$

Moreover, we include some constraints that represent the storage operations:

First, the power provided by the storage unit at any time slice *t* should not exceed the energy stored at the unit at the beginning of the time slice *t*:

$$storage\ out_{z,q,d,t,y} \leq storage_{z,q,d,t,y} \tag{38}$$

Second, the energy stored in the unit cannot exceed a certain limit as indicated by constraint (37). In that case, the maximum amount of injection of power to the storage unit cannot exceed the energy differential between the storage level at the beginning of the period and the maximum amount of energy that can be stored in the unit:

$$storage\ inj_{z,q,d,t,y} \leq Storage\ energy_{z,y} - storage_{z,q,d,t,y} \tag{39}$$

Investment constraints

Planners consider several constraints when they decide on a generation investment plan. Common constraints refer to budget, land use, scheduling of new construction and consumption of specific fuels for energy security considerations.

Constraint (40) usually reflects land use considerations, regulation that imposes an upper bound on capacity of specific technologies or simply resource potential (e.g., for wind there is a finite amount of locations where wind farms can provide the capacity factor modeled).

$$\sum_{y} build_{g\ \in NG\ ,y} \leq MaxNewCap_{NG} \tag{40}$$

Constraint (41) is usually employed to reflect practical limitations on construction and spread the construction of new units more uniformly over time.

$$build_{g\ \in NG\ ,y} \leq Annual\ built\ limit_{y} * WeightYear_{y} \tag{41}$$

Constraint (42) imposes an upper bound on fuel consumption. This upper bound might correspond to the fuel reserves a country might have at its disposal or the capacities of refinement units or importing units such as size of LNG terminals. Constraint (43) simply estimates the fuel consumption. Note that in case we want to reduce the number of variables in our model, we can get rid of the fuel variable since it is defined in terms of the generation variable.

$$fuel_{z,f,y} \leq MaxFuelOff_{f,y} \tag{42}$$

$$fuel_{z,f,y} = \sum_{g\ \in Z\ ,q,d,t} Duration_{q,d,t,y} * HeatRate_{g,f} * gen_{g,f,q,d,t,y} \tag{43}$$

Constraint (44) represents a budget constraint. It limits the capital expenses withdrawal to be lower than a pre-specified amount. In this formulation, we assume that the $MaxCapital$ parameter is similar to the maximum debt payments that a power system planner can do over the horizon.

$$\sum_{y,g\,\in NG} ReturnRate_y * pweight_y * CRF_{NG} * CapCost_{NG,y} * cap_{g,y} \leq MaxCapital \tag{44}$$

An alternative constraint that addresses the same concern but relies on different information is expressed by constraint (49). In that case, the planner does not know the maximum amount of debt payments that the power plant owners might do but he has a good understanding of the maximum capital available to the system for investment. In that case, the sum of the overnight capital expenditure is not allowed to exceed this known budget.

$$\sum_{g\,\in NG,y} CapCost_{g,y} \leq MaxBudget \tag{49}$$

Environmental policy

Environmental concerns often lead policymakers to adoption of caps on the amount of emissions of certain pollutants. Several countries have announced targets to reduce their carbon dioxide emissions below particular amounts. Given that the power system is a big contributor to carbon dioxide emissions, power system CO_2 caps are usually enforced at the country or at multi-country level. Constraints (45) and (46) impose the caps decided by regulators. Note that constraints (47) and (48) are modeled as "hard" constraints with no violation allowed. We would like to note that environmental policy might impose caps on more pollutants beyond carbon dioxide. For example, in the USA certain caps apply on NO_x and SO_x emissions. The dual variables of constraint (46) and (48) provide valuable information to the planner since they estimate the additional cost the planner would have to bear to decrease the amount of the pollutant by an infinitely small amount. In other words, the dual prices of (46) and (48) provide an approximation of the prices that the planner would pay per unit of pollutant if slightly stricter regulation would be applied.

$$emissions\_Zo_{z,y} = \sum_{g\,\in Z,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_f} * Duration_{q,d,t,y} \tag{45}$$

$$emissions\_Zo_{z,y} \leq Zo\_emission\_cap_{y,z} \tag{46}$$

$$emissions_{z,y} = \sum_{g\,,q,d,t} gen_{g,f,q,d,t,y} * HeatRate_{g,f} * carbon_{emission_f} * Duration_{q,d,t,y} \tag{47}$$

$$emissions_{z,y} \leq Sy\_emission\_cap_y \tag{48}$$

Another policy mechanism related to carbon emissions is a carbon tax (less popular than the cap and trade system at present). We model the carbon tax as part of the objective function. Note that the carbon tax does not correspond to an actual cost for the society since it is a transfer payment for emitters to the government. It reflects an actual cost, though, only if it attempts to monetize the public health cost and the damage to the environment. However, it reflects an actual cost for power system since generators would probably have to pay the tax to the government and that's why it is part of the objective function (8).

$$carboncost_{z,y} = \sum_{g \in Z,f,q,d,t} Duration_{q,d,t,y} * carbon_{tax_y} * HeatRate_{g,f} * carbon_{emission\,f} * gen_{g,f,q,d,t,y} \tag{8}$$

Monte Carlo Simulation

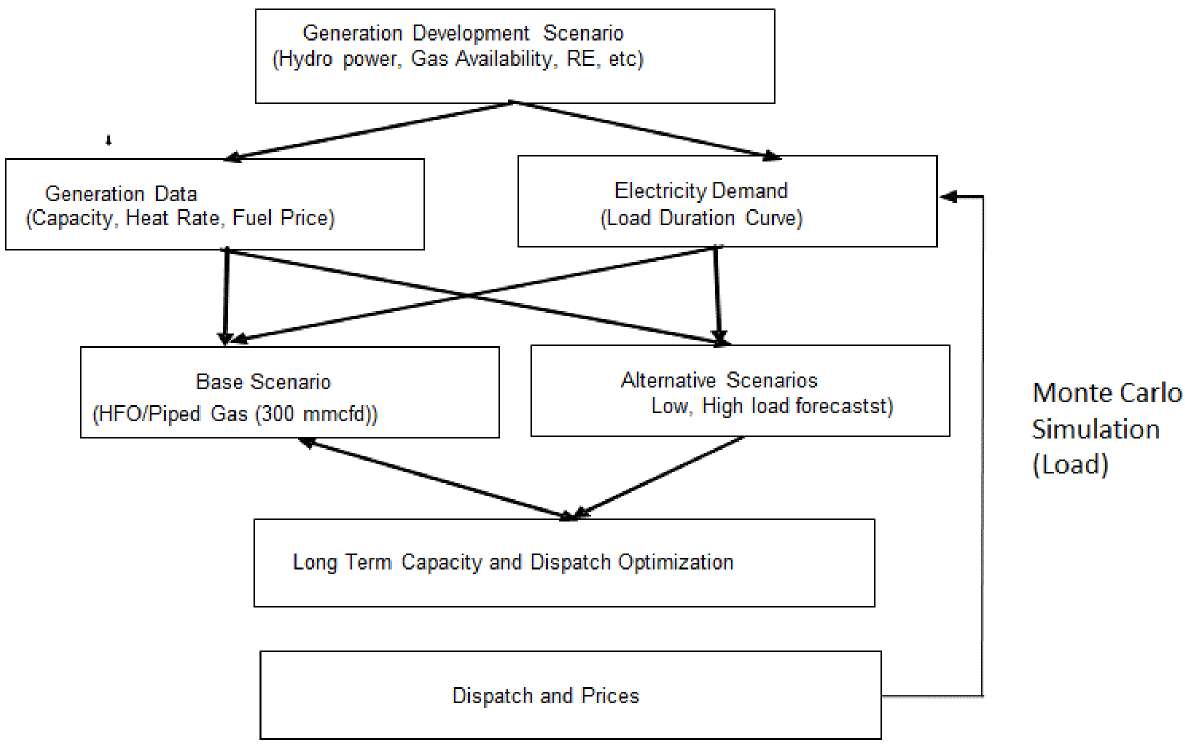
EPM has a Monte Carlo module that allows simulation of variability in key parameters such as demand and random outages of generators. The current implementation allows the user to select a reasonable number of samples (e.g., 100-500) for load and available generators and run it for each of them. The resultant system cost, unserved energy, etc can be then used to form a probability distribution of these key performance indices. This is useful to form a view of the impact of uncertainties on:

- Investment decisions – if the user allows the investment decisions to be re-optimized for each demand condition for instance. A robust investment plan can then be formed by looking at the investment profile across all samples and a pre-determined criterion, i.e., select those generators that appear in at least 90% of the samples; and/or
- Performance of a specific investment plan – the user may also allow EPM to be solved after freezing the investment decisions and subject it to uncertainties to see whether the investment plan leads to significant over or under-capacity and lead to either significant stranded capacity or unserved energy in a number of samples.

Monte Carlo simulation can be very useful in assessing the value of specific projects such as an interconnector or an incumbent project that the Bank/utility is specifically interested in. It is possible for instance to run EPM in Monte Carlo mode without and with the project. The difference in system cost for each sample provides the "benefit" of the project. A distribution of these projects can be very useful in assessing the value at risk of the project.

Figure *1* below shows a typical implementation of the model including Monte Carlo simulation that we used for Tanzania.

Figure 1: Typical implementation of EPM (including Monte Carlo simulation)



2.7 Limitations of the model and Planned Developments

There are known limitations of the model, albeit we have addressed some of them in some of the customized versions of the model:

a. There is no integrated hourly dispatch model linked to EPM to carry out detailed production costing analysis for extended periods, unlike the commercial tools like PLEXOS/PSR. That said, the implementation for Bangladesh does have such a facility that we plan to link to EPM;
b. Trading of capacity reserve which can be an important source of benefits in an interconnected system is not modeled. This is planned to be included in a future update of EPM;
c. There is no consideration of Kirchoff's voltage law, albeit there is a DC-OPF model implemented for the West African system that considers this feature which will need to built into EPM;
d. EPM currently can use Monte Carlo, but lacks the ability to undertake a stochastic programming based analysis. This is addressed in a special implementation for Bangladesh. Given the substantial complexity of solving a large stochastic programming model, we are not contemplating yet making it a regular feature of the model. However, we do have the bespoke model that can adapted for other systems, if needed; and
e. Hydro representation in the model is fairly basic at the moment limited to seasonal energy limits. This will require further enhancements that we plan to do around a future case study for a hydro dominated system.

2.8 Customized configuration of the model

Depending on the scope of each study for which it is used for, analysts can decide on the subset of constraints they would like to use for the intended analysis. Activation and deactivation of different sets of constraints can be easily accomplished using a set of flags as we have demonstrated for a case study for the Pan-Arab region (**Table *1***). One flag can be associated with one or multiple constraint and depending on the value of the flag, the respective constraint might be included or excluded from the model formulation. Usually, when the flag has a positive value the constraint is included in the formulation but when the flag has a zero value, the constraint is not part of the formulation. In table below, we list all the flags available to the analyst and explain the rationale for its flag use. Finally, the third column of the table we report if the flag was active or not for the results provided as part of the study.

Table 1 Sample configuration of the model for the Pan-Arab region

Flag	Constraints associated	Rationale	Status for the analysis
Mingen_constraints	(18)	Many planning models omit minimum load constraints since it is hard to approximate its binary nature with a linear constraint	Inactive
Spinning_Reserve_constraints	(11), (12), (15)	High level planning models might not consider spinning reserves because the relative comparison of generation units in terms of reserve costs is similar to the one based on energy costs and the approximate accuracy of the power forecast makes the consideration of reserves redundant. However, reserve consideration might be important if certain units cannot qualify as reserve providers or/and they have variable energy profiles.	Active
Planning_reserve_constraints	(13)	Margin reserves	Active
Ramp_constraints	(16), (17)	Ramp constraints are meaningful only when the time sequence of the time blocks is respected. Moreover, in case individual generation units are aggregated to form one aggregated unit, enforcement of the constraint might not be relevant because ramping capability will actually vary with the number of units that are online, generating power.	Inactive
Fuel_constraints	(42)	Fuel constraints might not be relevant when access to high quantities of internationally traded fuels such as LNG, Oil is easy and facilities for fuel handling are bigger than the size the fuel needs of the power system. Another reason that might render the fuel constraints redundant could be the enforcement of environmental policies. In that case, certain policies might implicitly	Active

Flag	Constraints associated	Rationale	Status for the analysis
		require much lower fuel consumption than the consumption that would be possible based on capacity of fuel handling facilities or available fuel reserves. Third, another set of constraints that might implicitly take into account fuel constraints is constraint (40). By limiting the capacity of new generators, an upper bound on consumption of certain fuels is implied.	
Capital_constraints	(44)	In economies where access to capital for power system investment financing is easy, constraint (44) might not be needed.	Inactive
CO2path_constraints	(46)	Constraint (46) imposes CO_2 caps on zones of the system. Constraint (46) might be relevant in case different environmental targets/policy apply for the different zones e.g., when each zone is a different country or state. However, in case zones represent different buses of the power system of a region with single environmental targets, constraint (46) might not have a practical meaning.	Inactive
CO2total_constraints	(48)	Constraint (48) represents a single environmental policy on carbon emissions, applicable for the whole system. Constraint (48) might not be relevant when the system consists of zones that correspond to countries with different environmental goals.	Inactive

On top of the flags associated with constraints, we also include a flag that allows us to either load as input data test cases to test if the model behaves properly or use realistic data for the cases study to perform the analysis of the power system.

Please keep in mind that depending on the purpose of each study and the available data, different constraints might be identified as redundant. For example, in cases of limited knowledge of the transmission capabilities we might not be able to formulate constraint (10). Another example could be constraint (40) in cases no limit on investment in certain technologies or regions apply.

3. REFERENCES

[1] A. Van Der Welle and B. Van Der Zwaan, "An overview of selected studies on the value of lost load (VOLL)," *Energy Research Centre of the Netherlands (ECN), Amsterdam,* 2007.

[2] Electricity Commission. *Investigation into the Cost of Unserved Energy*, Prepared by Concept Economics, 2008.

[3] NERC, "Glossary of Terms Used in NERC Reliability Standards," [Online]. Available: http://www.nerc.com/pa/stand/glossary of terms/glossary_of_terms.pdf. [Accessed 12 December 2016].

[4] B. Hobbs and C. Bothwell, "System Adequacy with Intermittent Resources : Capacity Value and Economic Distortions," ISO New England, 2016. [Online]. Available: https://www.iso-ne.com/static-assets/documents/2016/09/PSPC09222016_A4_Cindy-Bothwell-Johns-Hopkins-University-System-Adequacy-with-Intermittent-Resources-Capacity-Value-and-Economic-Distortions.pdf. [Accessed 2 October 2016].

[5] L. Baringo and A. J. Conejo, "Correlated wind-power production and electric load scenarios for investment decisions," *Applied Energy,* vol. 101, pp. 475-482, 2013.

[6] CESI, "Pan-Arab Regional Energy Trade Platform (PA-RETP). Power Market Study: Gas Comsumption Assessment for the Power Sector accross MENA Region," CESI, 2016.

[7] CESI-Ramboll, "Feasibility Study of the Electrical Interconnection and Energy Trade between Arab Countries," Arab Fund for Economic and Social Development, 2014.

[8] A. Salimi-Beni, D. Farrokhzad, M. Fotuhi-Firuzabad and S. Alemohammad, "A new approach to determine base, intermediate and peak-demand in an electric power system," in *International Conference on Power System Technology, 2006. PowerCon 2006.*, 2006.

[9] P. Khajavi, H. Monsef and H. Abniki, "Load profile reformation through demand response programs using smart grid," in *Proceedings of the International Symposium Modern Electric Power Systems (MEPS), 2010*, 2010.

[10] A. Khazaee, M. Ghasempour, H. Hoseinzadeh and H. Hooshmandi, "DEMAND MANAGEMENT PROGRAM FOR LARGE INDUSTRIAL CONSUMERS BY USING THE AMI SYSTEM," in *23rd International Conference on Electricity Distribution*, 2015.

[11] The World Bank, "Energy Efficiency Study in Lebanon," The World Bank, Washington, DC, 2009.

[12] Presidency of the Council of Ministries Central Administration of Statistics, "Energy".

[13] Palestinian Electricity Regulatory Council, "Annual Report 2011,," Palestinian Electricity Regulatory Council, 2011.

[14] A. Hainoun, "Construction of the hourly load curves and detecting the annual peak load of future Syrian electric power demand using bottom-up approach," *International Journal of Electrical Power & Energy Systems,* vol. 31, no. 1, pp. 1-12, 2009.

[15] DSIRE, "N.C. Clean Energy Technology Center," DSIRE, [Online]. Available: http://programs.dsireusa.org/system/program/tables. [Accessed 12 December 2016].

[16] W. Short, P. Sullivan, T. Mai, M. Mowers, C. Uriarte, N. Blair, D. Heimiller and A. Martinez, "Regional Energy Deployment System (ReEDS)," NREL, 2011.