IPM™ MODEL (ICF CONSULTING, INC.)

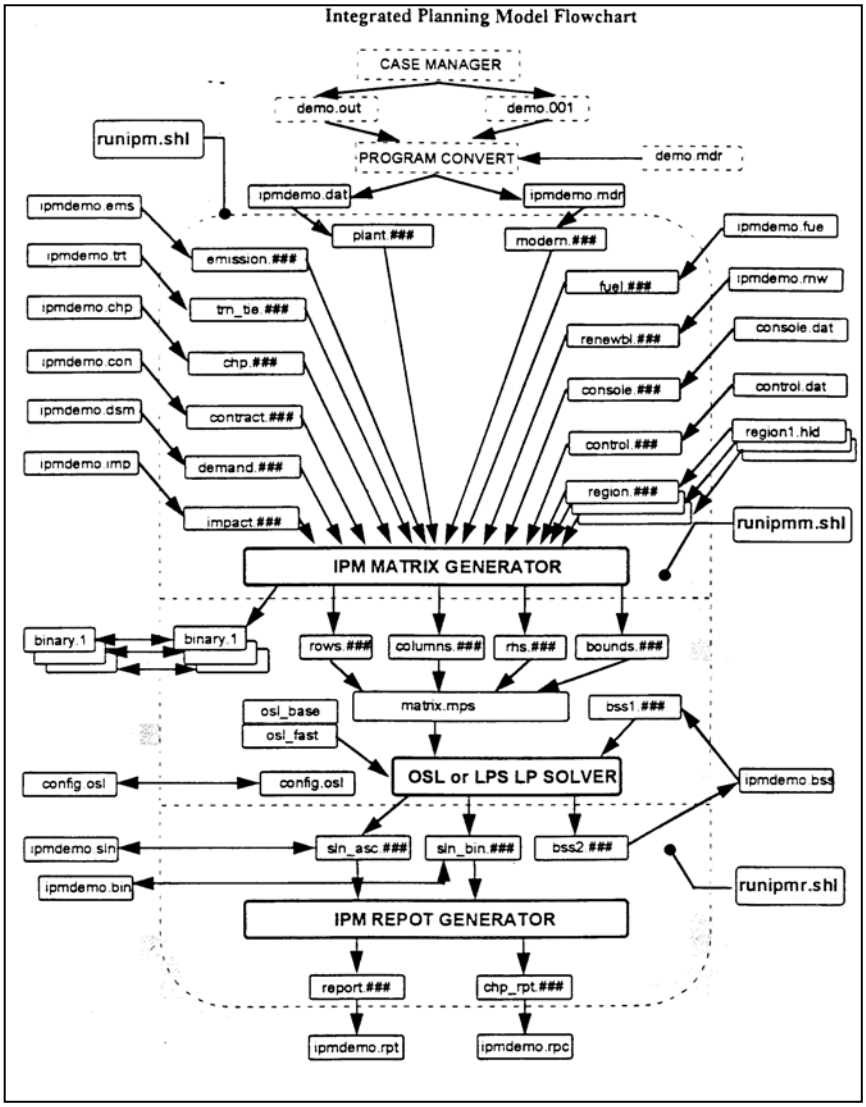
Model overview

The Integrated Planning Model (IPM™) of ICF Consulting, Inc. is a long-term optimization dynamic planning model that uses linear programming formulation to select investment options and to dispatch generation and load management resource to meet overall electricity demand and energy requirements. The dynamic nature of the model implies the capability to use forecast of future conditions, requirements and option characteristics to make decisions for the present.

The model was extensively used throughout the world by private companies and government agencies in the areas of integrated resource planning, detailed modeling of dispatch, strategic planning, options assessment, optimization of utility operations under system-wide constraints, estimation of avoided cost and analysis of uncertainty.

Model structure

IPM™ is a fully integrated software, but as the majority of all the sofware consitst of a number of modules. In IPM™ all its modules are governed by a single main driver of the program, that automatically initiates operation of each of the modules. The IPM™ core module writes the linear programming task in the output file that is processed in the next step in linear-programming solver (XPRESS-MP by Dash Associates, Inc.).



Model technical requirements

The model runs under the Windows 95/98 operating system and based on Microsoft Access database platform. Preferable hardware configuration for the model includes Pentium III computer with 500 MHz processor, 258 MB of RAM and 12 GB of space on the hard drive. One-IPM optimization run requires approximately 5 minutes for the system of Armenia size dependent on the matrix complexity. Since the model provides the solution in MWs (i.e. integral units solutions are not provided by the model), multiple runs are required to be conducted iteratively to optimize a single scenario (this may take several hours).

Model goal function and constraints

The optimization criterion in IPM™ is minimization of the present value of the total costs of the simulated power system in the entire time horizon, which includes:

- Production cost of electricity and centralized heating generation;
- Capital investments into new power plant and transmission line construction and existing facility rehabilitation during the planning interval years. The capital investments are included in equivalent form as annuities that are calculated as part of total investment at fixed payments on capital;
- The minimized sum also includes costs and revenues associated with electricity purchases and sales outside the energy utility and energy efficiency project costs.

The major groups of constraints include:

- Meeting the demand for electricity in each run-year, season, region and load segment;
- Maintaining necessary level of reliability of the regional sub-systems;
- Constraints on inter-regional transmission;
- Environmental emission constraints;
- Fuel availability.

Minimization of total production and capital costs under the given set of contraints ensures objective commercially-optimum dispatching (utilization) of available generating and transmission resources to meet balance conditions, as well as the commissioning of new resources in view of service-life efficiency.

One important feature of the model for the purposes of the study is its capability to describe existing power plant rehabilitation and upgrading processes. IPM proposes algorithms for the timing and specific rehabilitation methods for optimization of each facility.

Model input data

The IPM™ model computes seasonal load duration curves for all years of study period. Each load duration curve is then divided in a number of segments specified by the user. A

greater number of segments provides a more detailed depiction of customer loads to the model's dispatch algorithm, but also increases the computational time of the model. There are three basic options that the IPM™ model considers to cover electricity and heat demand: generation at domestic power plants, power purchasing from other producers, demand-side management.

The IPM™ model is designed in such a way that individual generating plants are aggregated into "plants" with similar costs and operating characteristics in order to improve the efficiency of model's operation. However, this feature of IPM mostly applies to modeling of large systems and was not used in the current study. Key characteristics, specified in the model's input database include:

Demand:
1. Chronological hourly load curve of the base year;
2. Forecasted annual peak loads;
3. Forecasted annual heat demand;
4. Electricity consumption for the whole study period.

Operational data:
1. Power plant installed capacity;
2. Change of installed capacity of the power plant (capacity additions and retirements);
3. Power plant available capacity in periods of peak load in the system;
4. Power plant forced outage rates;
5. Availability factor of power plant;
6. Capacity factor for hydro power plant;
7. Minimum load of the power plant;
8. Heat rate of power plant and turndown schedules;
9. Available types of fuel, cost of fuel and fuel contraints;
10. Emissions for each plant and emissions limits.

Financial data:
1. Capital investments per MW of capacity;
2. Fixed O&M cost per MW of capacity;
3. Variable O&M costs per MWh of electricity generation (excluding fuel cost);
4. Escalation rates for capital costs, fixed and variable O&M, and fuel cost;
5. Discount rate;
6. Interest rate.

System data:
1. Cost of unserved energy;
2. Interconnections constraints;
3. Transmission and distribution losses;
4. Cost of electricity transmission;
5. Reserve margin.

Export/import:
1. Terms of import/export contracts;
2. Sales/purchase cost under the contract;
3. Available contracted capacity;
4. Schedule of sales/purchases under the contract;
5. Type of contract (firm/non-firm).

DSM data:
1. Additional capital investments in efficient equipment;
2. General and administrative cost;
3. Customer discount for obtaining more efficient equipment;
4. DSM impact on load curve for each hour for typical weekday and weekend;
5. Annual savings due to DSM measures.

Model output data

Many detailed and summary reports can be generated by the IPM™. Among the standard reports are:

1. Capacity, load and energy generated in the system;

2. Capacity factor, energy generated, average heat rate and emissions by each power plant;
3. Total cost, total fixed cost and total variable cost by each power plant for each year of study period;
4. Optimized schedules of capacity additions;
5. Selected DSM program statistics: start date, impact on the load, cost and benefits of the program.
6. Fuel cost for each power plant;
7. Annual cost for each regions differentiated by O&M cost, fuel cost and capital cost;
8. Amount of exported/imported electricity;
9. Average and marginal costs of generated electricity;
10. Emissions amounts;
11. Available capacity by each segment of the load curve;
12. Thermal energy generation by CHPs and boilers.

Reliability modeling

IPM™ conducts the reliability modeling using so-called "derating method". According to this method, each simulated generating unit and transmission line is assigning its own forced outage and planned outage rate. The dispatchable capacity is then derated for the probability of outage. In other words, when the model dispatches units to the specific segments of the Load Duration Curve it allocates the expected value of the available capacity of each of the units, rather then the total installed capacity of the unit.

The above mechanism is used to account for the probabilistic nature of outages in energy demand constraints of the model. In addition, IPM™ is equipped with a set of constraints that assure the desired level of reliability of the system, determined by the sizes and forced outage rates of the units in the system. The first type of such constraints provides for maintaining a pre-determined level of Loss of Load Probability (LOLP) in the system. These constraints represent LOLP in each run year and season as a function of the amount of capacity installed in different generating technologies, each of them characterized with a specific size of generating unit and a specific forced outage rate. Due to those constraints the model is capable to account for higher reliabilities of configurations consisting of smaller, although less economical units, versus configurations consisting of larger units, which although more efficient in terms of capital and operational cost, are less desirable from the reliability point of view.

The more advanced approach assumes that there is no pre-defined level of reliability that has to be maintained in the system. Instead, the level of reliability should be determined on the market. In other words, only as much of reliability will be maintained in the system as much the customers will be willing to pay for it. In that approach the LOLP constraints are replaced with Expected Unserved Load (EUL) constraints, where each kWh of unserved load is associated with a price, representing the customers willingness to pay to avoid random blackouts. The Expected Unserved Load is represented as a function of the configuration of the system in a similar manner as the Loss of Load Probability. In that approach the Expected Unserved Load can be introduced to the

objective function, since it has the specific price assigned to it. This allows for treating reliability as a market-determined parameter of the system, in other words an optimized variable of the model. Again, in that approach the key input information determining functional representation of the Expected Unserved Load are the sizes and forced outage rates of the units that are included in the system.

Functional representations of LOLP and EUL are developed based on capacity margin probability distributions, which are constructed as convolutions of the available capacity distributions and the electric load distributions. Given the multitude of units simulated in IPM™ the capacity probability distributions cannot by developed based on precise analysis of the decision trees representing different possible events in the system. Instead, the IPM™ uses an approximate method which utilizes Gram-Charlier expansion for approximation of the actual distribution, which is further linearized based on the Taylor's Theorem.

Hydro power plants simulation

IPM™ algorithm is based on the concept of filling up the seasonal Load Duration Curves with generation from various available generating units (existing, or newly constructed) while minimizing the total cost of the system, which includes both operational costs and the capital costs of the system. If only the operational costs had been accounted for while determining the optimal dispatch stacks, hydro units would have always been dispatched at the bottom of the stack, since their operational costs are very low. However, IPM™ recognizes that while the reservoir type hydro plants are constrained in the amount of energy that they produce, they can be operated in a very flexible manner, with many start-ups and shut-downs. Given that, IPM™ attempts to always dispatch the reservoir hydro units as high in the stack as possible, because that way they not only benefit the system with their low generation costs, but also meet the system requirements for capacity, which otherwise would have been satisfied by the other purposely built peaking sources such as gas turbines or other peaking units. This phenomenon can be visualized as peak shaving, as the hydro-power plants are virtually flattening the load curve that needs to be further satisfied by the other types of power plants in the system.